David T. Doot
Secretary

January 3, 2014

VIA ELECTRONIC MAIL

TO: MEMBERS AND ALTERNATES OF THE NEPOOL PARTICIPANTS COMMITTEE

RE: Supplemental Notice of January 10, 2014 NEPOOL Participants Committee Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that a meeting of the NEPOOL Participants Committee **will be held on Friday, January 10, 2014, at 10:00 a.m.** at The Seaport Hotel, 200 Seaport Boulevard, Boston, MA. The Participants Committee meeting will be held in the Seaport Ballroom in the Seaport Hotel (not in the WTC Building) for the purposes set forth on the attached agenda and posted with the meeting materials at http://www.nepool.com/NPC_2014.php. For your information, this meeting is recorded, as are all the NEPOOL Participants Committee meetings.

2014 NEPOOL Annual Fees FOR PARTICIPANTS WHO DO NOT TYPICALLY RECEIVE INVOICES FROM ISO-NE, PLEASE NOTE: The NEPOOL annual fees will be in the February invoices for all Participants in the Pool as of January 1, 2014. To avoid a Payment Default, the payment for the annual fee must be received by the ISO not later than the second business day following issuance of the invoice, or Wednesday, February 12, 2014. Invariably, numerous Participants fail to pay these invoices on time and end up in a Payment Default with additional penalties assessed. As a courtesy, the ISO has sent a reminder and additional payment information directly to Participants who do not typically receive weekly invoices. However, we urge all Participants to anticipate this February invoice and plan accordingly.

Directions to the Seaport Hotel are included with this notice. Please note, as previously indicated, that the discounted block of rooms for the January 10 meeting is full and the hotel is sold out. You may be able to be put on a waiting list at the Seaport if there are any cancellations by calling the hotel directly (1-877-732-7678) and reference the "NEPOOL Participants Committee" block of rooms. We have negotiated an additional discounted block of rooms at the Westin Waterfront Hotel www.westin.com/bostonwaterfront, 425 Summer Street, Boston, within walking distance to the Seaport Hotel. Rooms are available at the discounted rate of $209.00 on a first-come, first-served basis through Monday, January 6, 2014. Reservations can be made by calling the Westin Waterfront directly (1-888-627-7115) and referencing the "New England Power Pool" block of rooms or by using the following link: https://www.starwoodmeeting.com/Book/NewEnglandPowerPool.

Respectfully yours,

/s/
David T. Doot, Secretary

FINAL AGENDA

1. To approve the draft minutes of the Participants Committee meeting held on December 6, 2013. Draft minutes of the December 6 meeting are included for the first time with this supplemental notice and posted on the NEPOOL website. To the extent you have any comments on the minutes, please provide those no later than noon on Wednesday, January 8. We will circulate revised minutes as appropriate on January 8, with the Committee voting to approve only if members are prepared to do so on January 10.

2. To adopt and approve all actions recommended by the Technical Committees set forth on the Consent Agenda included with this supplemental notice.

3. To receive an ISO Chief Executive Officer Report.

4. To receive an ISO Chief Operating Officer Report.

5. To discuss 2014 Business Priorities.

6. To consider and take action, as appropriate, on revisions to the Information Policy proposed in response to FERC Order No. 787 (on Gas/Electric Information Sharing; RM13-17). Background material and a draft resolution are posted with this supplemental notice.

7. To consider and take action, as appropriate, on revisions to Market Rule 1 Appendix A proposed in response to the FERC's October 3, 2013 order directing Tariff clarifications with respect to the application of proposed Energy Market Offer Flexibility Changes (Docket No. ER13-1877). Background material and a draft resolution are posted with this supplemental notice.

8. To consider and take action, as appropriate, on the following revisions regarding Capacity Zone Modeling:

   a. Proposed revisions to Market Rule 1, Section 12 and any related amendments. (RC)

   b. Proposed revisions to Market Rule 1, Section 13 as proposed by NRG and recommended by the Markets Committee. (MC)

   c. Proposed revisions to Open Access Transmission Tariff, Attachment K and any related amendments. (TC)

   Background materials and draft resolution(s) are posted with this supplemental notice. The RC (sub-item a) and TC (sub-item c) recommendations will be voted prior to the MC recommendation (sub-item b).

9. To receive a report on current matters relating to regional wholesale power and transmission arrangements that are pending before the regulators and the courts. The litigation report will be posted in advance of the meeting.

10. To receive reports from committees and subcommittees.

11. To transact such other business as may properly come before the meeting.

PRELIMINARY

A meeting of the NEPOOL Participants Committee was held beginning at 10:00 a.m. on Friday, December 6, 2013 at The Colonnade Hotel, Boston, MA pursuant to notice duly given. A quorum determined in accordance with the Second Restated NEPOOL Agreement was present and acting throughout the meeting. Attachment 1 identifies the members, alternates, and temporary alternates attending the meeting.

Mr. Calvin Bowie, Chair, presided and Mr. David Doot, Secretary, recorded. Mr. Bowie welcomed the members, alternates and guests who were present, including FERC Commissioner John Norris, his Legal Advisor, Andrew Weinstein, and State Regulators who joined the annual meeting.

APPROVAL OF NOVEMBER 8, 2013 MEETING MINUTES

Mr. Doot referred the Committee to the preliminary minutes for the November 8, 2013 meeting as circulated in advance of the meeting. Following motion duly made and seconded, those preliminary minutes, with a correction to the attendance, were unanimously approved.

CONSENT AGENDA

Mr. Doot referred the Committee to the Consent Agenda that was circulated in advance of the meeting. Following motion duly made and seconded, the Consent Agenda was approved with abstentions by: BP, Brookfield, Energy America, Hess, and Integrys. Each of the representatives attributed their positions to Consent Agenda Item #1, which related to Net Commitment Period Compensation (NCPC-) Local Second Contingency Protection Resource (LSCPR) Cost Allocation.

OP 12 REVISIONS (VOLTAGE SCHEDULING-RELATED REVISIONS)

Mr. Donald Gates, Chair, Reliability Committee, referred the Committee to the materials posted in advance of the meeting concerning revisions to Operating Procedure No. 12 (OP 12) and related appendices, which provided details regarding voltage and reactive control service. He summarized the changes briefly and then explained that the Reliability Committee had unanimously recommended Participants Committee support~~ed~~ for the revisions at its November 19, 2013 meeting. He said that this matter would have been on the Consent Agenda but for the timing of the vote and notice of actions.

The following motion was duly made, seconded, and unanimously approved:

> RESOLVED, that the Participants Committee supports the proposed revisions to Operating Procedure No. 12, as recommended by the Reliability Committee at its November 19, 2013 meeting, together with such further non-substantive changes as may be approved by the Chair and Vice-Chair of the Reliability Committee.

COMMENTS OF FERC COMMISSIONER JOHN R. NORRIS

Mr. Bowie welcomed FERC Commissioner John Norris to Boston and to the meeting and introduced him to the Committee. Commissioner Norris expressed appreciation to Mr. Bowie for his leadership role as Chairman of the Participants Committee over the past two years. He recalled his participation in the 2010 Summer Meeting in Connecticut, noting it was good exposure to New England and the issues facing the region, notably different from those facing the Midwest region where he was from.

Commissioner Norris said that he participated in a Congressional oversight hearing the prior day entitled "*FERC's Role in the Changing Energy Landscape*," which was remarkably similar to the ~~headline~~theme of the 2013 NEPOOL Annual Report, "*Today's Changing*

Landscape." He commented that the electric industry's landscape was changing at an unprecedented- pace, largely attributable to new technology. He stated those changes included:

- the abundant supply of natural gas and low natural gas prices;
- expanded use of demand response and other demand side management measures;
- the use of new technology to measure and control the transmission grid; and
- the use of smart meters and innovative control systems for residential, commercial and industrial customers all designed to permit wiser and more efficient use of energy.

He noted that there was big shift towards natural gas-fired generation across the country, but that other regions of the country did not face the same pipeline restrictions as did New England. The need to build gas pipelines in New England was inevitable. He identified three steps that he recommended be taken before building gas pipelines:

1. Assure full utilization of the current infrastructure. The FERC had held numerous gas-electric technical conferences over the previous several years, and recently issued revised Final Rules relating to communications between transmission and pipeline operators of confidential market information in order to maximize the utilization of current resources (Order No. 787).
2. Review scheduling patterns for the day-to-day operations of the electric and natural gas sectors. Natural gas operations were set on a national level and would be more difficult to change to accommodate the needs of the New England electric operations because of the broader ramifications in other areas of the country. The FERC encouraged and would welcome solutions tailored for New England's particular needs (e.g., dual fuel capability).
3. Present to the FERC New England's plans to address the challenges to New England of limited gas transportation into the region so that the FERC could help enable New England to achieve its plans.

Commissioner Norris referred to the recently issued New England Governors' Statement on the topic, stating that the collaboration among the states in New England reflected in that Statement was the right approach for New England to make broad decisions about its future and to address the limitations in available gas transportation capacity into the region. He also

referred to the ISO pay-for-performance proposal, which he acknowledged was the topic of ongoing discussions, noting his understanding that the ISO was extremely concerned about capacity resources being available to produce energy and operating reserves when needed.

Focusing on the stakeholder process, Commissioner Norris emphasized that he thought it was extremely important for stakeholders to participate actively in the stakeholder process to consider changes to current regional arrangements. He noted that changes in New England's market could have a broader impact on regional costs and reliability. In determining whether a filing to change those markets would be just and reasonable, the Commissioners looked very closely at whether consensus was achieved in the stakeholder process and, if not, why not. He expressed his view that the region would be well-served arriving at broadly supported outcomes rather than relying on litigated outcomes that could be unpredictable and undesirable to the parties.

Transitioning to discussion of ~~the~~ capacity market issues, Commissioner Norris noted that the FERC had held a technical conference in September to discuss the overall concern with whether the various capacity markets across the country are achieving their goals and, if not, what changes need to be made to those markets. He reported the FERC had extended the comment period into January 2014, noting the comments already received had been very helpful and informative, and he encouraged all interested parties to submit comments. He noted his concern that long-term capacity and other resources were being developed under the current construct and there was some urgency in his opinion in deciding whether to make adjustments to the current market designs or to fundamentally alter those designs. He stated the FERC needed to know how severe the problem was with the current markets and whether the right market signals were being sent for the long-term investment in capacity that was needed in New

England. He questioned whether New England's capacity surplus in recent years had masked market design issues and whether the capacity market was sending the necessary price signals for long-term supply. He stated he did not anticipate the FERC would make a generic determination on these issues in the near future, but would continue to work on short-term issues on capacity, gas pipeline capacity, pay-for-performance proposals, and other short-term measures to address the immediate concerns.

With regard to transmission, he acknowledged that the FERC needed to address the ongoing return on equity (ROE) cases and send a clear signal regarding regulatory policy going forward. He shared his belief that a significant amount of transmission still needed to be built in New England and across the country, and that New England had the opportunity with new transmission to increase its utilization of renewables and hydro. He indicated his view that the FERC's job was to implement policies that were well-conceived to attract the level of capital needed to support the appropriate expansion and modernization of the distribution and transmission networks in order to maintain and improve reliability and efficiency. He concluded his comments on transmission by reviewing that the FERC last year updated its Return on Investment Policy for transmission investment to focus incentives in the following three areas: (1) deploying advanced technologies to make the electric grid more efficient; (2) reducing congestion to lower costs for consumers; and (3) reaching location-constrained resources with the transmission system. He stated the FERC was now ready to review applications before it that would apply those incentives to projects that meet those goals. He indicated his belief that the FERC would articulate its ROE policy soon in order to guide future decisions.

Committee members then asked Commissioner Norris questions. Commissioner Norris agreed with a member that it would help if New England's market structure were simpler and

more navigable and that the FERC would support movement in that direction. Regarding Order 1000 and a request for a sense of the timing on the FERC's ruling on New England's compliance filings, Commissioner Norris stated his view that the FERC would be turning its attention to the Order 1000 compliance filings early in 2014 and that New England should be among those addressed earliest since the regional arrangements had already largely complied with Order 1000 requirements. He explained that the FERC wanted to complete its review of the initial Order 1000 filings so that it could turn its attention to Order 1000's interregional requirements. In response to a request as to whether there was anything that could be done at FERC to improve regional collaboration, Commissioner Norris indicated that the FERC strongly encouraged collaboration. The Commission was far more likely to accept a broadly supported proposal than one that arises out of a broken-down stakeholder process.

OTHER BUSINESS – GOVERNORS STATEMENT

Ms. Heather Hunt, Executive Director, New England States Committee on Electricity, (NESCOE), referred the Committee to the Governor's Statement circulated and posted in advance of the meeting. She said that the Statement reflected the six New England Governors' (Governors) continued commitment to moving forward with regional energy infrastructure development. The Governors had observed the increasing interdependence between the electric and natural gas systems and the operational and associated cost issues. The Governors had also had the opportunity to assess various studies related to those topics. Ms. Hunt summarized that the Statement reflected the Governors' assessment that there was a need for increased investment in energy efficiency, renewable power, natural gas pipeline, and transmission. The commitments the Governors proposed to achieve a regional energy infrastructure included:

- Moving forward collaboratively and working jointly with the ISO and NESCOE on advancing a regional energy infrastructure initiative.
- Ensuring the costs of investment are shared appropriately across the states.
- Moving forward on a consensus basis, respecting individual states policies, statutes, and preferences and ensuring that the policies of potential host states would be respected.
- Ensuring involvement of NEPOOL in the mechanics and processes going forward in order to share the Governors' preliminary thoughts and to seek additional ideas on objectives from NEPOOL.

Mr. Doot indicated that NESCOE had agreed to come back to the Committee at an appropriate point in the near future for discussion on process and substance, and Ms. Hunt committed to work with the NEPOOL Officers to ensure that happened.

REPORT OF THE ISO CHIEF EXECUTIVE OFFICER

Mr. van Welie referred the Committee to the summaries of the ISO Board and Board Committee meetings that had occurred since the November 8 meeting, circulated in advance of the meeting. Mr. Doot asked whether there was feedback received from the ISO Board on the Sector meetings held at the November 8 meeting and if there were recommendations to change the format at future meetings. Mr. van Welie reported that the Board enjoyed the interaction, liked the format of meeting with the individual Sectors as it proved to be informative to hear their individual views, and seemed to nurture increased dialogue, which was a good thing. He indicated that the ISO appreciated the Sectors providing the ISO with their questions in advance of the meetings as it permitted the Board to better prepare, allowing for more interactive and constructive dialogue.

REPORT OF THE ISO CHIEF OPERATING OFFICER

Dr. Vamsi Chadalavada, ISO Chief Operating Officer, reviewed highlights from the December COO report, which was circulated in advance of the meeting and posted on the

NEPOOL and ISO websites. Focusing specifically on report highlights, he stated that in November: (i) natural gas prices were 51% higher and oil prices were 1.0% lower than October 2013 average values; (ii) Real-Time Hub locational marginal prices (LMPs) were up 25% from October 2013 averages; (iii) ~~Net Commitment Period Compensation (~~NCPC~~)~~, totaling $5.3 million, was $2.9 million higher than October 2013 NCPC; (iv) first contingency payments, totaling $3.8 million, were $2.1 million higher than October's first contingency payments; (v) second contingency payments totaled $253,000, which was lower than the $461,000 in October; and (vi) voltage support payments totaled $1.2 million, up $1.1 million from October.

He reported that, based on the 50/50 and 90/10 load forecasts, the lowest Winter Operable Capacity Margin was projected for the week beginning January 18, 2014. He reviewed that, starting on December 9, the ISO would publish by 8:00 a.m. each day hourly forecasted demand for the current day and the next two days by reliability region/load zone.

Dr. Chadalavada provided an update on the Winter Reliability Program, stating that 56 Generators were participating in the Winter Fuel Procurement Program and all had submitted Monthly Fuel Inventory Surveys, with 43 having met or exceeded their required fuel inventory for December 1, and with 13 still working through the verification process.

He then highlighted several operational observations, including:

- The amount of load clearing in the Day-Ahead Market had increased in marked contrast to earlier in the year and past years.
- The Replacement Reserve trigger continued to work effectively for its intended purpose of pricing operator reliability actions.
- When resources ~~are~~ generally needed for system reliability do not clear the Day-Ahead Market, they may be committed in the RAA process, contributing to uplift.
- Some resources in NEMA had changed offer parameters (following consultation with the ISO Internal Market Monitor) that may increase uplift for second contingency protection.

- The 2013 Regional System Plan was approved by the ISO Board on November 8.
- A draft interim photovoltaic (pv) forecast and pv interconnection issues would be discussed with the Distributed Generation Forecast Working Group on December 16.
- ICF International would report on Phase II of the Natural Gas Study at the December 18 Planning Advisory Committee (PAC) meeting.
- Results of the reliability determination analysis for a number of non-price retirement requests would be presented at the December 19 Reliability Committee meeting.

Regarding the Forward Capacity Market, Dr. Chadalavada reported on the ISO's November 25 Exigent Circumstances filing to address the insufficient competition gap in the Market Rules as well as to modify the administrative price for existing capacity resources. He reported also that non-price retirement requests for Vermont Yankee had been approved and other requests were under study, and the study results would be presented at the December 19 Reliability Committee meeting. He stated that FCA8 would commence on February 3, 2014. He reported that stakeholder meetings on the capacity zone issue were ongoing, with the Reliability, Markets and Transmission Committees slated to vote on changes to Market Rule 1 Section 12 and OATT Attachment K at a joint December 17 meeting.

Committee members commented and asked clarifying questions on the COO presentation. In response to a member's request for more detailed information concerning Day-Ahead and Real-Time demands, Dr. Chadalavada committed to provide in future reports information as to what cleared over the peak-hour, as that information would be more informative of the commitments. In his report, Dr. Chadalavada had identified some uplift that was the result of a change in offer parameters by one of the resources in the dispatch. Numerous members asked questioned seeking more specific details, to which Dr. Chadalavada demurred given the Information Policy restrictions on providing this information publicly. He did explain

that the implications were for NEMA alone, and not system-wide, but changes in offer parameters by other resources in New England could impact other areas of New England. A question was asked about the reason for the spike in Real-Time prices. Dr. Chadalavada responded that the spike was the function of high loads during colder weather, which caused the region to be deficient on Thirty-Minute Operating Reserves for a short period.

2013 NEPOOL ANNUAL REPORT

Mr. Doot referred the Committee to the 2013 NEPOOL Annual Report that was circulated at the meeting and posted on the NEPOOL website in advance of the meeting. He highlighted the emphasis in that Report on collaboration, and expressed the hope as the region works to address its many challenges that it would work to collaborate fully. He commented on the remarkable level of litigation activity in New England, with over 180 proceedings in which NEPOOL was either active or was monitoring, including six active appeals before the Federal Courts. He requested feedback on ways NEPOOL might be more successful in collaborating, reaching consensus, or at least compromising on issues that were preferable to address within the region rather than through order of the FERC or the courts following litigation. He expressed his personal appreciation to the NEPOOL ~~t~~Team for its efforts drafting and finalizing the NEPOOL Annual Report and encouraged stakeholder feedback on the Report.

ELECTION OF 2014 PARTICIPANTS COMMITTEE OFFICERS

Mr. Bowie referred the Committee to the slate of 2014 NEPOOL Participants Committee Officers circulated and posted in advance of the meeting. He expressed his gratitude for the Committee's support over the past two years as he served as its Chairman, to NEPOOL Counsel and the NEPOOL ~~t~~Team for its support and service to NEPOOL, to the NEPOOL Officers for

their wisdom and collegial advice, and to the ISO and the ISO Board for working through the issues and in serving jointly on the Joint Nominating Committee. He noted how fitting it was that both he and his good friend, Commissioner Michael Harrington, appointed as a Commissioner of the New Hampshire Public Utilities Commission (NHPUC) at the same time as he began his tenure as Participants Committee Chairman, were concluding their terms at the same time.

The follow motion was then duly made, seconded and unanimously approved:

> RESOLVED, that the Participants Committee hereby adopts and ratifies the results of the election held in accordance with Section 4.6 of the Bylaws and elects the following individuals for 2014 to the offices set forth opposite their names to serve until their successors are elected and qualified:

Chair	Joel S. Gordon
Vice-Chair	Timothy J. Brennan
Vice-Chair	Brian E. Forshaw
Vice-Chair	August G. "Gus" Fromuth
Vice-Chair	Doug Hurley
Vice-Chair	Thomas W. Kaslow
Secretary	David T. Doot
Assistant Secretary	Paul N. Belval

APPROVAL OF 2014 BUDGET FOR ESTIMATED PARTICIPANT EXPENSES

Mr. Joel Gordon, Chair, Budget & Finance Subcommittee (Subcommittee), referred the Committee to the materials posted in advance of the meeting concerning the estimated budget for 2014 Participant Expenses (a copy of which is included as Attachment 3 to these minutes). He reported that consistent with past practice, the ~~Budget & Finance~~ Subcommittee worked with NEPOOL Counsel, the ISO and NEPOOL's Independent Financial Advisor to develop the 2014 Budget. He said that, at its November 18 teleconference, the Subcommittee discussed the proposed 2014 Budget and recommended its adoption without objection. During the Subcommittee's discussion, one member inquired about the need to continue credit insurance for

those Market Participants not providing collateral under the ~~ISO-NE~~ Financial Assurance Policy. He explained that the ISO committed to look into that issue in 2014.

The following motion was then duly made, seconded, and unanimously approved without discussion or comment:

> RESOLVED, that the Participants Committee adopts the estimated budget for Participant Expenses for 2014 as presented at this meeting.

ISO NEW ENGLAND'S FCM PERFORMANCE INCENTIVES PROPOSAL

Ms. Allison DiGrande, Chair Markets Committee, referred the Committee to the materials posted in advance of the meeting concerning ISO proposed revisions to the Forward Capacity Market (FCM) rules to implement its FCM Performance Incentives Proposal (PI Proposal) and related mitigation design. The ISO's PI Proposal would be implemented beginning with the Capacity Commitment Period associated with the ninth Forward Capacity Auction (FCA9) (beginning June 1, 2018). The PI Proposal would replace the existing FCM Shortage Event mechanism with a new 'performance incentive' mechanism, resulting in capacity payments to Resources that would be a combination of two components: (1) a base capacity payment and (2) a performance payment or charge.

Ms. DiGrande reported that during stakeholder discussions, the ISO agreed to two changes to an earlier version of the PI Proposal: (1) a so-called "stop loss" provision to cap aggregate performance charges at annual limits; and (2) a phase in over time of the Performance Payment Rate (PPR) for performance better than the associated benchmark rather than being set from the start at the full proposed rate of $5,455 per MWh. She said that, over the preceding year, the Markets Committee, along with state regulators, reviewed the ISO's PI Proposal, with 13 amendments proposed to amend the ISO's PI Proposal at the November 13-14, 2013 Markets

Committee meeting. One of the amendments received broad support at the Markets Committee (See Brookfield Amendment #3 below). The remaining amendments were not supported by the Markets Committee, and the once-amended main motion failed to receive a Markets Committee recommendation. At the request of the ISO, the Markets Committee also voted, but failed to recommend Participants Committee support for, the ISO's unamended PI Proposal.

Mr. Bowie reviewed the process for Participants Committee consideration of the ISO FCM PI Proposal and referred the Committee to the list of 16 amendments reflected in the materials from NEPOOL Counsel circulated and posted in advance of the meeting. He explained that the Committee would review each of the amendments in the order reflected in those materials.

The following main motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports revisions to Market Rule 1, Appendix A to Market Rule 1 and Section 1.2.2 (Definitions) to implement the FCM Performance Incentives Proposal (FCM PI) and mitigation design, as proposed by ISO and as circulated to this Committee in advance of this meeting, together with any changes agreed to by the Participants Committee at this meeting and such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

Members then commented and asked clarifying questions on the PI Proposal. Publicly Owned Entity representatives stated objections to the Proposal because they viewed them as redundant to changes already made and/or efforts currently underway to provide enhancements to the Energy and Reserve Markets, and could impose significantly greater costs to the region. One such Publicly Owned Entity representative expressed a desire to see how other initiatives played out first before committing to broader, fundamental changes to the Forward Capacity Market. Transmission Sector representatives objected to the Proposal noting the fundament changes to unit configuration that would occur, expressing the view that units should not be

penalized if they acted in accordance with ISO dispatch instructions. Further, Transmission representatives added that the PI Proposal should include an exemption for Resources unable to perform because of transmission limitations which would be entirely outside of their control.

Generator representatives provided a variety of views. Members acknowledged that past operational events and deteriorating Resource performance factors supported the effort to enhance Resource performance incentives. One member expressed concern that, without some change, performance problems could increase, creating greater future problems. He urged support for the Proposal, but with a preference to provide a transmission outage exemption and to eliminate the Peak Energy Rent (PER) deduction. Several Generator representatives objected to the PI Proposal because it penalized Resources for following ISO dispatch direction, it did not have a transmission outage exemption (which they viewed as illogical given the ISO's involvement in scheduling all transmission outages), and it would not support new generation investment in the region.

In support, a Governance Only member stated the Proposal was an appropriate response to the significant inflection point in energy infrastructure, reliability, and market design, and would facilitate the kinds of technologies that were creating this inflection point and would make for a more efficient, lower cost, and more reliable system.

End Users expressed opposition to the Proposal. One member expressed appreciation to the ISO for its October 2012 White Paper, stating there was a lot to like about the design of PI, but objected to the Proposal because it did not provide an adequate basis upon which Demand Response could participate in the markets. Consumer Advocate End Users objected to the Proposal because it would apply risk to all resources 24/7, was untested, and would create an uncertain but much greater level of risk. They expressed a strong preference for a more

modulated, less comprehensive approach. Other End User representatives objected to the Proposal because it was too risky for the market and, without adequate exemptions for Resources like energy efficiency and variable resources, could result in the region overpaying for capacity.

A NESCOE representative stated that NESCOE did not have a collective position on the ISO's PI Proposal or on any amended PI proposal.

The ISO representative expressed appreciation to the Committee for their engagement over the past year, noting that, based on stakeholder feedback, the ISO had incorporated the phase-in of the PPR and the annual "stop loss", and if the PI Proposal were to be implemented, the ISO would request continued feedback on improving it.

The Committee then proceeded to consider each of the proposed amendments.

—***Brookfield Amendment #1***:- The Brookfield Energy Marketing (Brookfield) representative made a motion, which was duly seconded, to amend the main motion to provide an exemption for Intermittent Power Resources from the penalties associated with the PI Proposal (Brookfield Amendment #1).

The Committee commented on Brookfield Amendment #1. Some expressed support for the amendment because intermittent units were already subject to a major de-rating of their capacity value, and imposing a penalty would have no effect on intermittent unit performance, which ~~is~~was driven by factors (i.e., the weather) outside of owner/operator control. Opposition was expressed to the fact that such Resources were seeking an exemption from PI penalties but also wanted to maintain eligibility for bonus payments for performing better than their capacity rating. Others opposed Brookfield Amendment #1 in order to not upset the fact that, under the PI Proposal, the capacity market for the first time would define the same product- for all sellers.

Dr. Robert Ethier stated the ISO did not support any exemptions and has done its best in developing the PI Proposal to create a level playing field so that all Market Participants would be treated the same and evaluated by the same criteria. He explained the ISO's reasoning, including: ensuring that, when offering into an auction, Resources offer based on the same set of performance expectations/requirements and reflecting their true characteristics, without adjustment for the benefits of any special treatment or special exemptions; preventing incentives from undermining incentives; and preventing a shift in risk of the consequences of a failure to perform from a Resource that receives an exemption to everyone else.

Following final comments by Brookfield, the Committee considered and failed to approve Brookfield Amendment #1 by a show of hands.

MMWEC Amendment #1: The MMWEC representative offered a motion, which was duly seconded, to amend the main motion to make Intermittent Resources exempt from the PI penalty and ineligible to receive a performance payment (MMWEC Amendment #1).

The Committee commented on the MMWEC Amendment #1. Much of the same support for, and opposition to, Brookfield Amendment #1 was also expressed in response to MMWEC Amendment #1, except for the fact that the Resources would neither receive penalties for failure to perform nor share in distributions of penalty revenues if they were to perform.

Following final comments by MMWEC, the Committee considered and failed to approve MMWEC Amendment #1 with a 53.33% Vote in favor (Generation – 2.14%; Transmission – 17.17%; Supplier – 1.56%; Alternative Resources – 4.56%; Publicly Owned Entity – 17.17%; and End User – 10.73%). (See Vote 1 on Attachment 2).

Brookfield Amendment #2: The Brookfield representative offered a motion, which was duly seconded, to amend the main motion so as to exempt from PI non-performance penalties

any External Transactions supporting Import Capacity Resources that were not dispatched by the ISO due to inaccurate LMP forecast/latency in scheduling protocols (Brookfield Amendment #2). The ISO stated they could not support the amendment for the reasons stated previously.

The Committee considered and failed to approve Brookfield Amendment #2 by a show of hands.

NU Amendment #1: The NU representative offered a motion, which was duly seconded, to amend the main motion in the manner identified by NU in the materials posted in advance of the meeting so as to exempt a Resource from FCM PI if that Resource's inability to deliver energy or reserves during a scarcity condition was due to an outage or de-rate of a transmission facility in the New England Control Area (NU Amendment #1).

The Committee commented and asked clarifying questions. The Brookfield representative highlighted the limitations of NU Amendment #1 and explained, by way of examples, why Brookfield would oppose the Amendment as too limiting. A Generator representative stated that the proposed transmission outage exemption was appropriate because it treated all the capacity sellers similarly. The NESCOE representative stated that, while the States did not have a collective position on the PI Proposal, they viewed these types of exemptions as appropriate in the sense that they were very structured and provided consumer savings by not imposing otherwise uncontrollable risk on generators. The ISO stated that it could not support NU Amendment #1.

Following final comments by NU, the Committee considered and approved NU Amendment #1 by a show of hands, with an opposition noted by NextEra.

Brookfield Amendment #3: The Brookfield representative then offered a motion, which was seconded, to amend the once-amended main motion such that, if a Resource were subject to

an ISO-imposed limit, the ~~r~~Resource would not be penalized for non-delivery of energy or reserves above that ISO-imposed restriction (Brookfield Amendment #3).

The Committee commented and asked clarifying questions on this amendment. In response to a question, the Brookfield representative explained that Brookfield Amendment #3 was more expansive than its prior amendment because Resources following dispatch instructions for any reason, including to avoid overloading a transmission line, would not be penalized. The ISO stated it could not support Brookfield Amendment #3 for reasons previously stated.

Following final comments by Brookfield, the Committee considered and failed to approve Brookfield Amendment #3 with a 56.84% Vote in favor (Generation – 7.36%; Transmission – 3.43%; Supplier – 14.71%; Alternative Resources – 14.17%; Publicly Owned Entity – 0%; and End User – 17.17%). (See Vote 2 on Attachment 2).

MMWEC Amendment #2: The MMWEC representative offered a motion, which was duly seconded, to amend the once-amended main motion so as (i) to exempt from the PI Proposal (a) Import Capacity associated with contracts with the New York Power Authority (NYPA) and (b) Resources unable to perform or out-of-service due to a planned outage or loss of transmission; and (ii) to revise ISO-proposed Section III.13.7.2.5 to read as follows: "The ISO shall review the Performance Payment Rate in the stakeholder process ~~as needed~~ annually and shall file with the Commission a new Capacity Performance Rate if and as appropriate." (MMWEC Amendment #2).

The Committee commented and asked clarifying questions on the amendment. A NESCOE representative reported that the States would collectively oppose the amendment as they believed planned maintenance outages were a risk better borne by the generator. The ISO stated it also opposed MMWEC Amendment #2.

The Committee considered and failed to approve MMWEC Amendment #2 by a show of hands.

NextEra Amendment: The NextEra representative offered a motion, which was duly seconded, to amend the once-amended main motion so as (i) to set the PPR at $5,455 per MWh beginning with FCA9 (i.e., no phase-in)~~,~~; (ii) to provide a limited exemption for transmission-related outages; and (iii) to make a change to the monthly "stop loss" provisions (NextEra Amendment).~~-~~ To avoid confusion, the NextEra representative explained that the limited exemption for transmission-related outages included in the NextEra Amendment would replace in its entirety NU Amendment #1 already voted and approved.

The NESCOE representative noted the States' concern, previously expressed, that a PRR set at $5,455 per MWh would result in consumers having to pay more costs than the resulting benefits would justify as well as with NextEra's removal of the NU Amendment #1 language for transmission-related outages. He stated that, while the States did not have a collective position on the NextEra Amendment, were the NextEra Amendment to pass and be included in the PI Proposal, the States would oppose the PI Proposal.

The ISO stated that, while it supported the $5,455 MWh penalty amount, it had concluded that it was more appropriate to phase that value in to see how that design worked, and therefore would not support the NextEra Amendment.

Following final comments, the Committee considered and failed to approve the NextEra Amendment by a show of hands.

EquiPower Amendment:~~-~~ The EquiPower Resources Management (EquiPower) representative offered a motion, which was duly seconded, to amend the once-amended main motion so as to permit an existing Resource to submit a Static De-List Bid for up to the

megawatt amount that the Market Participant expected may not be physically available due to reductions in ratings as measured by EFORd multiplied by summer Qualified Capacity at 90 degrees (EquiPower Amendment).

The NESCOE representative stated the States strongly opposed the amendment for the reasons identified at the Markets Committee meeting.

The ISO stated that it could not support the EquiPower Amendment because it believed it appropriate for Resources to submit price and megawatt pairs for each megawatt for which they were qualified.

The Committee considered and failed to approve the EquiPower Amendment by a show of hands.

NU Amendment #2: The NU member offered a motion, which was duly seconded, to amend the once-amended main motion so as to maintain the current FCM performance rules for passive demand resources (NU Amendment #2).

An End User representative stated support for the amendment and expressed appreciation to NU for introducing it. The ISO stated it could not support the amendment.

The Committee considered and failed to approve NU Amendment #2 by a show of hands.

NU Amendment #3: The NU member then offered a motion, which was duly seconded, to amend the once-amended main motion by inserting the current Market Rule provisions in the ISO-proposed Section III.13.7.1.1.3 so as to use the resulting hourly MW values for calculating an Existing Generating Resource's Capacity Performance Payment under FCM PI (NU Amendment #3).

The ISO stated it could not support the amendment because it would fundamentally undermine the PI design.

The Committee considered and failed to approve NU Amendment #3 by a show of hands.

PSEG Amendment: The PSEG Energy Resources & Trade (PSEG) representative offered a motion, which was duly seconded, to amend the once-amended main motion so as to set the FCA9 Starting Price at $22/kW-month.

Generator representatives expressed support for the amendment, insisting that there would be no downside to increasing the FCA Starting Price and the increase would be helpful to the market. The NESCOE representative indicated that the States had not had an opportunity to discuss the PSEG Amendment, nor had there been any prior discussion in the stakeholder process, and suggested that it was important for those discussions to take place before consideration of the PSEG Amendment.

The ISO stated that it did not support the PSEG Amendment at that time, but recognized the need to periodically evaluate the auction starting price and urged that there be process around that issue. The ISO noted its plans and expectation for presentation and discussion of a sloped demand curve at the following month's Markets Committee meeting, and suggested that, based on feedback to be received, it would make a determination as to how to proceed for FCA9.

Following final comments by the PSEG representative, the Committee considered and failed to approve the PSEG Amendment by a show of hands.

Dominion Alternative: The Dominion Energy Marketing (Dominion) representative offered a motion, which was duly seconded, to amend the once-amended main motion so as to replace the ISO's PI Proposal with an EFORd pay-for-performance approach and maintain the enhanced Shortage Event penalty mechanism recently accepted by the FERC (effective as of November 3, 2013) (together, the Dominion Alternative). The ISO stated it did not view as an improvement, and as a result could not support, the Dominion Alternative.

The Committee then considered and failed to approve the Dominion Alternative by a show of hands.

NRG Alternative: The NRG Power Marketing (NRG) representative offered a motion, which was duly seconded, to amend the once-amended main motion so as to replace the ISO's proposed FCM PI Tariff revisions, as proposed to be amended by the previously approved motion to amend, with Market Rule revisions that (1) would increase the Reserve Constraint Penalty Factors (RCPF) for System TMOR from $500 to $1,000 and for System TMNSR from $850 to $1,500, and (2) would replace the then effective 'Shortage Event' mechanism with a mechanism to measure performance using an EFORp 'availability' metric that would impose charges or provide credits to resources based on their availability in pre-defined peak hours during the Capacity Commitment Period. (the NRG Alternative).

The Committee commented and asked clarifying questions on the NRG Alternative. Members in support expressed their view that the NRG Alternative was a major improvement over the PI Proposal because it was more likely to incent new investment, more appropriately reflected the abilities of existing Resources, and placed stronger incentives in the energy market. One member opposing the NRG Alternative explained that while his company was supportive of improving energy pricing, it could not support the NRG Alternative because it would replace the PI Proposal with something that would not address all the performance issues.

In response to questions, the NRG representative clarified that the cap on the availability penalties related to a Force Majeure event would only be calculated from the time of the event going forward and could not be used to mitigate penalties incurred prior to the event. The NRG representative also explained that, as with the then-current FCM rules, there would not be an explicit obligation to cover for the loss of a Resource caused by a catastrophic event. Rather,

each owner would- be expected to weigh its alternatives and limit its losses as appropriate by measuring the cost of its alternatives against the availability penalties, capped at 20%, to be assessed.

The NESCOE representative stated that collectively the States did not have an opinion on the NRG Alternative. ~~The Vermont~~A representative of the Connecticut Department of ~~Public Service representative~~Energy and Environmental Protection expressed support for the Alternative because it would improve price formation, would result in market rather than administrative response by units, and ultimately was an appropriate and preferable alternative to what they believed to be a deeply flawed ISO PI Proposal.

The NextEra member highlighted that the NextEra Amendment, which had not been supported by the Committee, was intended similarly to bring the right incentives into the market, and believed that, absent full Commission approval of that amendment, the ISO PI Proposal should be rejected in its entirety and Equivalent Forced Outage Rate mechanisms considered. She stated that NextEra would ~~will~~ abstain on the NRG Alternative largely due to concerns with the Alternative's details, but stressed the importance of sending a signal to the FERC that an alternative was the right choice for the region at that time, with the understanding that details going forward would be worked out.

Those members who expressed support for the NRG Alternative explained that it was a rational approach, taking measured steps to address evolving regional challenges in the proper market context, and identifying and implementing further- incremental changes with the benefit of experience rather than waiting until June 1, 2018 (the start of the Capacity Commitment Period associated with FCA9) as proposed by the ISO. They further expressed support for the NRG Alternative because the region could minimize the large anticipated increase in capacity

prices under the PI Proposal, while the benefits of other initiatives could be a~~ddr~~ssessed. Others attributed their support to an increased confidence that the changes proposed by the NRG Alternative~~s~~ could be hedged in the market place.

Some members, while acknowledging that many elements of the NRG Alternative had been discussed during the stakeholder process, expressed concern with the swiftness with which the NRG Alternative had eventually evolved. They indicated that, while they found the Alternative preferable to the ISO Proposal, they needed additional time to consider whether they could support the Alternative and would therefore abstain when asked. Others expressed the view that, had the ISO Proposal programmatically dealt with prior concerns raised, they would have preferred the incentives provided by the ISO Proposal. Absent those changes, however, these members ~~would~~ preferred the ~~ISO Proposal in its entirety and an order to work~~NRG Alternative and looked forward to working through ~~those~~its details.

The ISO identified its concerns with the NRG Alternative, noting: (1) the Alternative, relative to what was then in place in the Tariff, would take a step backwards with respect to incenting Resource performance; (2) the Alternative would not resolve the "zombie resource" or "money for nothing" problems so characterized; and (3) the ISO had not had an opportunity to fully consider~~ed~~ the latest changes proposed by the NRG Alternative which had just been presented to the Committee.

Following final comments by NRG, the Committee considered and approved the NRG Alternative with a 80.28% Vote in favor (Generation – 14.71%; Transmission – 13.73%; Supplier – 15.45%; Alternative Resources – 3.37%; Publicly Owned Entity – 17.17%; and End User – 15.85%). (See Vote 3 on Attachment 2).

NRG Amendment #2: The NRG member offered a motion, which was duly seconded, to amend further the NRG Alternative, as reflected in the twice-amended main motion, so as to eliminate the FCM PER deduction (NRG Amendment #2).

The Committee commented and asked clarifying questions on the amendment. An End User representative expressed support noting that he did not believe the PER deduction as then structured was a hedge for load because it was poorly designed to do that, was arbitrary, had unwanted effects on Demand Response (DR) and other Resources not dispatched within those hours, and did not provide a hedge against scarcity pricing. An AR representative echoed those sentiments, indicated his view that the energy market was already sufficiently mitigated, and indicated that he would support the elimination of the PER deduction. A Transmission member expressed opposition to eliminating PER, indicating that it was a hedge for load, as well as a protection against the exercise of market power. The NESCOE representative, supporting the view that the PER deduction could result in consumer savings but also supporting a reconsideration of the mechanism, indicated that the States would, however, collectively oppose the elimination of the PER deduction at that time.

The ISO indicated that, in the context of its PI Proposal, it would support discussion about PER and how it worked in conjunction with PI, but with PI stripped out of the Proposal before the Committee, the ISO could not support NRG Amendment #2.

Following final comments by NRG, the Committee considered and failed to approve NRG Amendment #2 with a 44.01% Vote in favor (Generation – 17.17%; Transmission – 0%; Supplier – 17.17%; Alternative Resources – 6.55%; Publicly Owned Entity – 0%; and End User – 3.12%). (See Vote 4 on Attachment 2).

GDF SUEZ Amendment: The GDF SUEZ Energy Marketing North America (GDF SUEZ) representative offered a motion, which was duly seconded, to amend the twice-amended main motion so as to modify the PER deduction to avoid potential outcomes where Resources would effectively operate a loss when called on by the ISO to provide generation, operating reserves or regulation services in Real-Time (GDF SUEZ Amendment).

Mr. Doot clarified for the Committee that were this amendment to pass, NEPOOL would make the confirming changes to the Market Rules under the twice-amended main motion. The ISO said that it did not support the GDF SUEZ Amendment.

Following final comments by GDF SUEZ, the Committee considered and failed to approve the GDF SUEZ Amendment by a show of hands, with the vote being approximately the same as the roll call vote taken on NRG Amendment #2.

NRG Amendment #3: The NRG representative offered a motion, which was seconded, to amend further the NRG Alternative, as reflected in the twice-amended main motion, so as to revise the current Market Rules; (i) to permit offer prices for existing Resources (de-list bids) based on 'long-run average costs' rather than 'net risk-adjusted going-forward costs'~~,~~; (ii) to establish the Dynamic De-List Bid threshold at 80% of the Offer Review Trigger Price of a combustion turbine~~,~~; and (iii) to enable Existing Resources with IMM-approved offers above the Dynamic-List Bid threshold to participate in the auction at prices below the IMM-approved price (NRG Amendment #3).

The NESCOE representative stated that, while the States did not at that time have a collective position, he would recommend opposition to this Amendment. A Publicly Owned Entity representative stated that, while members of his Sector liked certain elements of NRG Amendment #3, there were certain parts they could not support and therefore would oppose the

Amendment as a package. A Supplier representative expressed support noting that in the current market design all new Resources were required to bid at their long run average cost, but all existing Resources were prohibited to bid at their long run average cost, creating a gap causing a lot of dislocation in the current capacity market. He stated that gap would not get fixed until all Resources were allowed to offer based on their commercial business interests, and not subject to administratively set caps on their potential profitability. An End User representative expressed opposition to the amendment, acknowledging the disconnect between the way business people view risk and rules resulting in bidding at an administratively set number, and the need to address that disconnect, but questioning the suitability of NRG Amendment #3 to correctly address that issue. The ISO stated that it could not support this amendment.

The Committee then considered and failed to approve NRG Amendment #3 by a show of hands, with ~~the~~ support coming generally from generators and some suppliers, and opposition or abstentions by others.

Twice-Amended Main Motion (i.e., the NRG Alternative): The Committee then considered and approved the twice-amended main motion (i.e., the NRG Alternative) with a 80.28% Vote in favor (Generation – 14.71%; Transmission – 13.73%; Supplier – 15.45%; Alternative Resources – 3.37%; Publicly Owned Entity – 17.17%; and End User – 15.85%). (See Vote 3 on Attachment 2).

Unamended ISO Proposal: The ISO requested consideration and a vote on its unamended ISO Proposal, as offered and seconded at the beginning of the discussion. A Transmission representative expressed support for the unamended ISO Proposal stating that, when New England decided to establish a capacity market, the region decided that it was a better way to go rather than~~-~~ a pure energy market with higher Real-Time energy prices, and once that

decision was made, the goal was to try to mimic the results achieved from a pure, uncapped energy market, which was what the ISO had done and reflected in its Proposal. He encouraged members to re-read the ISO's October 2012 White Paper and note that the ISO was appropriately recognizing the different value of flexible versus inflexible resources in trying to get to the point where more flexible resources would get paid more, and less flexible resources, less.

The Committee considered and failed to approve the ISO's unamended FCM PI Proposal with a 10.28% Vote in favor (Generation – 2.86%; Transmission – 2.86%; Supplier – 1.29%; Alternative Resources – 2.66%; Publicly Owned Entity – 0%; and End User – 0.61%). (See Vote 5 on Attachment 2).

With regard to the timing of the filing of the ISO's Proposal and the NRG Alternative under the jump ball provisions of the Participants Agreement, Mr. Hepper stated that the filing would not be submitted before December 31, and that ISO and NEPOOL Counsel would work together to identify a date for the FERC filing as early in January as feasible.

FCM PI-RELATED FINANCIAL ASSURANCE POLICY REVISIONS

Mr. Doot referred the Committee to the materials posted in advance of the meeting regarding revisions to the ISO Financial Assurance Policy to establish financial assurance requirements under the FCM PI Proposal. He explained that ~~these~~the revisions would be made if the PI Proposal ~~is~~was implemented without change in relevant respect, and with the understanding that the FA Changes and any proposed revisions thereto would be re-presented to NEPOOL for subsequent consideration in the Participant~~s~~ Processes if the Commission require~~s~~d changes to the underlying FCM PI Proposal that impact the financial assurance requirements. Mr. Gordon reported that the ~~Budget & Finance~~ Subcommittee recommended that, if the FCM PI Proposal ~~is in place then this is the FA program that would~~were to be implemented, the FA

Changes be implemented to appropriately collateralize the Pool to protect against potential defaults from ~~the~~ potential PI penalties ~~as a~~ resulting ~~of~~from the ~~new~~revised market design.

The following motion was duly made~~,~~ and seconded ~~and approved unanimously~~:

> RESOLVED, that the NEPOOL Participants Committee supports the changes to the ISO-NE Financial Assurance Policy to establish financial assurance requirements under the FCM Performance Incentives (PI) Proposal (FA Changes), as proposed by the ISO and as circulated to this Committee in advance of this meeting, together with such further non-substantive changes as the Chief Financial Officer of ISO New England and the Chairman of the Budget and Finance Subcommittee may approve; it being understood that a vote in favor of this resolution reflects solely support for the FA Changes, as appropriate, if and only if the FCM PI Proposal is approved and implemented as proposed by the ISO, and is without prejudice to any position taken by a Participant(s) on the underlying FCM PI Proposal, and with the further understanding that the FA Changes and any proposed revisions thereto shall be re-presented to NEPOOL for subsequent consideration in the Participants Process if the Commission requires changes to the underlying FCM PI Proposal that impact the financial assurance requirements.

A representative of members that provide energy efficiency in the region reported that he raised questions with the ISO Credit Department regarding how this would work for his clients. Due to the extreme uncertainty on the PI Proposal, he explained that they would not seek an amendment at this time, but depending on how the FERC responds to the jump ball filing, may seek changes to the FAP.

The Committee considered and approved the motion with oppositions noted by: CSG, NHOCA, Small DG Group (AR), Small LR Group (AR), UCS, Utility Services, and VEIC; and abstentions by: Brookfield, CSC, CTOCC, Environment Northeast, First Wind, Kimberly-Clark, LIPA, Linde, NextEra, Praxair, NGrid, Provisional LR Group (AR), Small RG Group (AR), UI, and Vitol.

IMM-PROPOSED ORTP FOR FCA9

Ms. DiGrande referred the Committee to the materials posted in advance of the meeting regarding IMM-proposed revisions to Market Rule 1, Appendix A regarding Offer Review Trigger Prices (ORTP) for FCA9, the revised methodology for Demand Response ORTP, and an annual indexation approach for years between full recalculation (ORTP Changes). She reported that, at its November 13-14, 2013 meeting, the Markets Committee considered and failed to recommend Participants Committee support for the IMM-proposed ORTP Changes with a 16.57% Vote in favor. Prior to the Markets Committee's vote on the IMM's ORTP Changes, four motions to amend the main motion were considered (two failed and two were supported). The twice-amended main motion (as amended by EnerNOC and EMI) was considered by the Markets Committee but failed with a 56.24% Vote in favor.

The following main motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports revisions to Market Rule 1, Appendix A regarding Offer Review Trigger Prices (ORTP) for the ninth Forward Capacity Auction (FCA9), the revised methodology for Demand Response ORTP, and an annual indexation approach for years between full recalculation, as proposed by the ISO's Internal Market Monitor (IMM) and circulated to this Committee in advance of this meeting, together with any changes agreed to by the Participants Committee at this meeting and such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

The Committee members then commented and asked clarifying questions on the motion. NHPUC Commissioner Harrington expressed continued support for the NESCOE filing at the FERC, which sought an exemption for renewables from the ORTP and that consideration of ORTPs should be tied to state renewable portfolio standard (RPS) laws so there was an evolving cap that would grow with RSP requirements but there would not be ~~a~~an unlimited amount of renewables that would be exempt from the review process. He argued that all wind resources

needed a properly established ORTP, not a zero price. The NEPGA representative agreed with Commissioner Harrington's comments. The NESCOE representative explained that, while the States would collectively support the EnerNOC Amendment, the majority of the States would oppose the NextEra Amendment, and the States would collectively oppose the Exelon Amendment.

The NextEra representative stated NextEra would offer an amendment regarding the IMM's proposed ORTP for on-shore wind, explaining that it sought a sound, well-analyzed, reasoned economic analysis for ORTPs, rather than policy arguments. Another generator representative disagreed, arguing that policy element was extremely important as it was primarily wind projects that were signing rate-based, state-supported contracts and the purpose of the Minimum Offer Price construct was to have the IMM review the costs and revenues projected and make sure any out of market revenues were not included. Another generator representative commented that the ISO spent a lot of time conducting the Wind Integration Study and the numbers were properly inputted and well supported from government sources and the results were what they were. An AR representative stated the ORTPs were based on appropriate analysis, and not on policy, and he would support the ISO's IMM-proposed changes.

EnerNOC Amendment: The EnerNOC representative offered a motion, which was duly seconded, to amend the main motion (EnerNOC Amendment), so as to add a new Section III.13.1.4.2.4 to Market Rule 1, as follows:

> ***Consistency of the New Demand Resource Qualification Package and the Registration of Demand Resource Customers***. A Project Sponsor is prohibited from enrolling a customer with a different measure type than was selected in the New Demand Resource Qualification Package if the customer or Project Sponsor has received any out-of-market revenues associated with the installation or delivery of that different measure type.

The ISO stated that it could not support the motion to amend for the reasons outlined in its memorandum presented to the Markets Committee and posted with the meeting materials in advance of this meeting.

The Committee considered and approved the EnerNOC Amendment with a 75.97% Vote in favor (Generation – 10.2%; Transmission – 17.17%; Supplier – 17.17%; Alternative Resources – 14.17%; Publicly Owned Entity – 0%; and End User – 17.17%). (See Vote 6 on Attachment 2).

***NextEra On-Shore Wind Amendment*:** The NextEra representative offered a motion, which was duly seconded, to amend the once-amended main motion (as amended by the EnerNOC Amendment) so as to set the ORTP for on-shore wind at $8.53/kW-month (NextEra Amendment).

Members opposing the NextEra Amendment commented that the IMM's analysis was correct and the data chosen in NextEra's analysis had a number of problems as that data did not take into account the curtailments in many areas of the region because of transmission constraints, particularly in Maine because of the Maine Power Reliability Program, which would lower the capacity factors being experienced there. An AR representative disagreed with the argument that the ORTP level needed to be set at a very high number. He explained that the FERC required the IMM to set a level that was appropriate for each technology and that was exactly what the IMM, with input from wind developers, have attempted to do here.

In support of the NextEra Amendment, a NHPUC representative stated NH believed that setting an ORTP at zero was inconsistent with the goal to protect the market against buyer-side market power and, without this protection, NH was concerned that the efficiency of the market would be harmed to the long run detriment of the consumers. A member commented that the

IMM's proposed ORTP for on-shore wind would potentially disrupt the market, and the unwillingness of the IMM to further evaluate and reconsider its proposal did not make sense. He encouraged support for the NextEra Amendment.

The ISO stated that it could not support the NextEra amendment for the reasons already indicated.

Following final comments by NextEra, the Committee considered and failed to approve the NextEra Amendment by a show of hands.

***EMI Off-Shore Wind Amendment*:** The Energy Management Inc. (EMI) representative offered a motion, which was duly seconded, to amend the once-amended main motion so as to set the ORTP for off-shore wind at $0.00 kW-month (EMI Off-Shore Wind Amendment).

The MA DPU representative stated the MA DPU was in favor of the EMI Amendment and EMI had shown sufficient documentation to prove that the ORTP for off-shore wind projects should be set at zero and should be in place for FCA8. A member of the Transmission Sector spoke in support of the amendment and urged that an ORTP for off-shore wind be calculated and filed with the FERC, rather than simply set at the starting price.

The ISO indicated that it continued to oppose the amendment for the reasons indicated at the Markets Committee.

The Committee considered and approved the EMI Off-Shore Wind Amendment by a show of hands.

***Exelon Amendment*:** The Exelon representative explained that Exelon had circulated an amendment that it offered at the Markets Committee, but given the outcome at the Markets Committee and in the interest of time, with the understanding that it had satisfied the stakeholder

process, would rely on the Markets Committee vote and not seek a vote at the Participants Committee.

***Twice-Amended Main Motion*:** The Committee then considered the twice-amended main motion (as amended by the EnerNOC and EMI Off-Shore Wind Amendments). The twice-amended main motion was voted and failed with a 54.94% Vote in favor (Generation – 2.14%; Transmission – 17.17%; Supplier – 4.29%; Alternative Resources – 14.17%; Publicly Owned Entity – 0%; and End User – 17.17%). (See Vote 7 on Attachment 2).

***Unamended ISO ORTP Proposal*:** At the request of the ISO, the Committee considered and failed to approve the ISO's unamended ORTP Proposal by a show of hands.

ISO NOVEMBER 25, 2013 EXIGENT CIRCUMSTANCES FILING

Mr. Doot reported that, as there was no time to review the ISO's November 25 Exigent Circumstances filing proposing FCM Administrative Pricing Rule Changes, a special teleconference meeting would be scheduled for December 10 to review with members that filing and NEPOOL's response.

LITIGATION REPORT

Mr. Doot referred the Committee to the December 4 Litigation Report that had been posted in advance of the meeting. He encouraged anyone with comments or questions on the Report to please contact him or any of NEPOOL's Counsel.

OTHER BUSINESS

Mr. Doot referred the Committee to the NEPOOL calendar for December. He reported that the next regularly-scheduled meeting of the Participants Committee would be January 10, 2014 at the Seaport Hotel in the Seaport Ballroom in Boston.

—There being no further business, the meeting adjourned at 4:35 p.m.

Respectfully submitted,

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David T. Doot, Secretary

MEMBERS AND ALTERNATES PARTICIPATING IN
DECEMBER 6, 2013 PARTICIPANTS COMMITTEE MEETING

PARTICIPANT NAME	SECTOR	MEMBER NAME	ALTERNATE NAME	PROXY
Ashburnham Municipal Light Plant	Publicly Owned		Gary Will	
Bangor Hydro-Electric Company	Transmission		Stacy Dimou	Joe Staszowski (A9)
Boylston Municipal Light Department	Publicly Owned		Gary Will	
BP Energy Company	Supplier			Nancy Chafetz
Braintree Electric Light Department	Publicly Owned		Dave Cavanaugh	
Brookfield Energy Marketing / Cross-Sound Cable	Supplier	Aleksandar Mitreski	Jose Rotger	
Calpine Energy Services, LP	Supplier	John Flumerfelt		
Central Maine Power Company (CMP)	Transmission	Eric Stinneford (tel)		
Chicopee Municipal Lighting Plant	Publicly Owned		Gary Will	
Cianbro Companies	End User			Don Sipe (A9, A10)
Citigroup Energy Inc.	Supplier	Barry Trayers (tel)		
Competitive Energy Services, LLC	Supplier			Glenn Poole; Dennis Duffy (A9)
Concord Municipal Light Plant	Publicly Owned		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned	Brian Forshaw		
Connecticut Office of Consumer Counsel (CT OCC)	End User	Elin Katz	Joe Rosenthal	Paul Peterson
Corinth Wood Pellets LLC	End User			Don Sipe (A9, A10)
Conservation Law Foundation (CLF)	End User		Naim Jonathan Peress	
Conservation Services Group (CSG)	AR	Doug Hurley		
Consolidated Edison Energy, Inc.	Supplier	Jeff Dannels		
Dominion Energy Marketing, Inc.	Generation	Ronald Hart (tel)		
Dragon Products Company LLC	End User			Don Sipe (A9, A10)
DR Power	Supplier	Jerry Tudan		
Dynegy Marketing and Trade, LLC	Supplier			William Fowler
Elektrisola, Inc.	End User			Don Sipe (A9, A10)
Energy America, LLC	Supplier			Nancy Chafetz
EnerNOC, Inc.	AR	Herb Healy	Greg Geller	
Entergy Nuclear Power Marketing Inc.	Generation		Chad Cooper	
Environment Northeast	End User	Mike Henry (tel)		
EquiPower Resources Management, LLC	Generation	Jim Ginnetti	William Fowler	
Essential Power, LLC	Generation	M.Q. Riding		
Exelon Generation Company	Supplier	Steve Kirk	William Fowler	
First Wind Energy Marketing, Inc.	AR	John Keene		Bob Stein
Food City, Inc.	End User			Don Sipe (A9, A10)
Galt Power, Inc.	Supplier	Nancy Chafetz		
Generation Group Member	Generation	Dennis Duffy	Abby Krich	
Granite Ridge Energy, LLC	Supplier		William Fowler	
Groton Electric Light Department	Publicly Owned		Gary Will	
H.Q. Energy Services (U.S.) Inc.	Supplier		Robert Stein	
Hardwood Products Company	End User			Don Sipe (A9, A10)
Harvard Dedicated Energy Limited	End User	Mary Smith		
Hess Corporation	Supplier			Nancy Chafetz
High Liner Foods (USA) Incorporated	End User		William P. Short III (tel)	Donald Sipe
Hingham Municipal Lighting Plant	Publicly Owned		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned		Gary Will	
Holyoke Gas & Electric Department	Publicly Owned		Brian Beauregard	
Hudson Light and Power Department	Publicly Owned		Gary Will	
Hull Municipal Lighting Plant	Publicly Owned		Gary Will	
Industrial Energy Consumer Group	End User	Donald Sipe		
IPR-GDF SUEZ Energy Marketing North America	Generation	Thomas Kaslow		John Flumerfelt

MEMBERS AND ALTERNATES PARTICIPATING IN
DECEMBER 6, 2013 PARTICIPANTS COMMITTEE MEETING

PARTICIPANT NAME	SECTOR	MEMBER NAME	ALTERNATE NAME	PROXY
Ipswich Municipal Light Department	Publicly Owned		Gary Will	
Integrys Energy Services Inc.	Supplier			Nancy Chafetz
Kimberly-Clark Corporation	Supplier			Vicki Karandrikas (tel)
LaBree's Inc.	End User			Don Sipe (A9, A10)
Linde Energy Services	Supplier			Vicki Karandrikas (tel)
Littleton (MA) Electric Light & Water Department	Publicly Owned		Dave Cavanaugh	
Littleton (NH) Water & Light Department	Publicly Owned		Craig Kieny (tel)	
Long Island Lighting Company (LIPA)	Supplier	William Killgoar		
Maine Public Advocate Office (ME OPA)	End User		Tim Schneider	Paul Peterson
Maine Skiing, Inc.	End User	Donald Sipe		
Mansfield Municipal Electric Department	Publicly Owned		Gary Will	
Marblehead Municipal Light Department	Publicly Owned		Gary Will	
Marden's Inc.	End User			Don Sipe (A9, A10)
Mass. Attorney General's Office	End User	Fred Plett	Christina Belew	Jesse Reyes
Mass. Municipal Wholesale Electric Company (MMWEC)	Publicly Owned	Gary Will		
Middleborough Gas and Electric Department	Publicly Owned		Gary Will	
Middleton Municipal Electric Department	Publicly Owned		Gary Will	
Millennium Power Partners	Generation		Ken Dell Orto	
MoArk, LLC	End User			Don Sipe (A9, A10)
New England Power Company (National Grid)	Transmission	Timothy Brennan		Tim Martin
New Hampshire Electric Cooperative (NHEC)	Publicly Owned		Steve Kaminski	Brian Forshaw
New Hampshire Office of Consumer Advocate (NH OCA)	End User	Paul Peterson		
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
NU / NSTAR	Transmission	James Daly	Calvin Bowie	Joe Staszowski
NRG Power Marketing, Inc.	Generation	Peter Fuller		
PalletOne of Maine	End User			Don Sipe (A9, A10)
Pascoag Utility District	Publicly Owned			
Paxton Municipal Light Department	Publicly Owned		Gary Will	
Peabody Municipal Light Plant	Publicly Owned		Gary Will	
PowerOptions, Inc.	End User	Cynthia Arcate		Paul Peterson
PPL EnergyPlus, LC	Supplier		Sharon Weber (tel)	
Praxair, Inc.	End User			Vicki Karandrikas (tel)
Princeton Municipal Light Department	Publicly Owned		Gary Will	
Provisional Group Member - Load Response Sub-Sector	AR	Brad Swalwell (tel)		
Provisional Group Member	Transmission	Steve Conant		
PSEG Energy Resources & Trade LLC	Supplier	Joel Gordon		
Rowley Municipal Lighting Plant	Publicly Owned		Gary Will	
Rumford Paper Company	End User	Donald Sipe		
Russell Municipal Light Dept	Publicly Owned		Gary Will	
Shipyard Brewing LLC	End User			Don Sipe (A9, A10)
Shrewsbury Electric & Cable Operations	Publicly Owned		Gary Will	
Small Distributed Generation Group Member	AR	Doug Hurley		
Small Load Response Group Member	AR	Doug Hurley		
Small Renewable Generation Group Member	AR	Erik Abend (tel)		
South Hadley Electric Light Department	Publicly Owned		Gary Will	
St. Anselm College	End User			Don Sipe (A9, A10)
Sterling Municipal Electric Light Department	Publicly Owned		Gary Will	
Taunton Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned		Gary Will	
The Energy Consortium (TEC)	End User		Mary Smith	

MEMBERS AND ALTERNATES PARTICIPATING IN
DECEMBER 6, 2013 PARTICIPANTS COMMITTEE MEETING

PARTICIPANT NAME	SECTOR	MEMBER NAME	ALTERNATE NAME	PROXY
TransCanada Power Marketing Ltd.	Generation		Mike Hachey	P. Fuller (NRG Amend 1)
Union of Concerned Scientists (UCS)	End User	Paul Peterson		
United Illuminating Company (UI)	Transmission		Alan Trotta	
Utility Services Inc.	End User			Paul Peterson
Vermont Electric Cooperative	Publicly Owned	Craig Kieny (tel)		
Vermont Electric Power Company, Inc. (VELCO)	Transmission	Frank Ettori		Mark Sciarrotta
Vermont Energy Investment Corporation	AR		Doug Hurley	
Vermont Public Power Supply Authority (VPPSA)	Publicly Owned	David Mullett		Brian Forshaw
Verso Maine Energy LLC	Generation	Glenn Poole	David Norman	
Vitol, Inc.	Supplier	Joe Wadsworth		Jose Rotger
Wakefield Municipal Gas and Light Department	Publicly Owned		Gary Will	
Wallingford DPU Electric Division	Publicly Owned	Dave Cavanaugh		
Wellesley Municipal Light Plant	Publicly Owned	Dave Cavanaugh		
West Boylston Municipal Lighting Plant	Publicly Owned		Gary Will	
Westerly Hospital, The	End User			Don Sipe (A9, A10)
Westfield Gas & Electric Light Department	Publicly Owned		Gary Will	
Z-TECH LLC	End User			Don Sipe (A9, A10)

VOTES TAKEN AT
DECEMBER 6, 2013 PARTICIPANTS COMMITTEE MEETING

TOTAL

SECTOR	VOTE 1	VOTE 2	VOTE 3	VOTE 4	VOTE 5	VOTE 6	VOTE 7
GENERATION	2.15	7.36	14.71	17.17	2.86	10.30	2.15
TRANSMISSION	17.17	3.43	13.73	0.000	2.86	17.17	17.17
SUPPLIER	1.56	14.71	15.45	17.17	1.29	17.17	4.29
AR	4.56	14.17	3.37	6.55	2.66	14.17	14.17
PUBLICLY OWNED ENTITY	17.17	0.00	17.17	0.000	0.000	0.000	0.000
END USER	10.73	17.17	15.85	3.12	0.61	17.17	17.17
% IN FAVOR	53.33	56.84	80.28	44.00	10.28	75.97	54.94

GENERATION

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4	Vote 5	Vote 6	Vote 7
Dominion Energy Marketing, Inc.	A	F	F	F	O	A	
Entergy Nuclear Power Marketing LLC	A	A	A	F	O	A	O
EquiPower Resources Management, LLC	O	O	A	F	O	O	O
Essential Power, LLC	A	O	F	F	O	A	O
GDF SUEZ Energy Marketing North America	O	O	O	F	F	O	O
Generation Group Member	F	F	F	F	0.5	F	F
Millennium Power Partners	O	A	A	F	A	A	O
NextEra Energy Resources, LLC	O	O	A	F	O	A	O
NRG Power Marketing, LLC	O	A	F	F	O	F	O
TransCanada Power Marketing Ltd.	O	A	F				
Verso Maine Energy LLC	O	F	F	F	O	F	A
IN FAVOR (F)	1	3	6	10	1.5	3	1
OPPOSED (O)	7	4	1	0	7.5	2	7
TOTAL VOTES	8	7	7	10	9	5	8
ABSTENTIONS (A)	3	4	4	0	1	5	1

TRANSMISSION

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4	Vote 5	Vote 6	Vote 7
Bangor Hydro-Electric Co.	F	A	F	A	O	F	A
Central Maine Power Co.	F	O	A	O	O	A	F
New England Power Co.	F	O	O	O	F	F	F
The United Illuminating Co.	F	F	F	O	O	F	F
NU /NSTAR	F	O	F	O	O	F	A
Vermont Electric Power Co.	A	O	F	O	O	F	F
IN FAVOR (F)	5	1	4	0	1	5	4
OPPOSED (O)	0	4	1	5	5	0	0
TOTAL VOTES	5	5	5	5	6	5	4
ABSTENTIONS (A)	1	1	1	1	0	1	2

ALTERNATIVE RESOURCES

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4	Vote 5	Vote 6	Vote 7
Renewable Generation							
First Wind Energy Marketing	O	F	O	F	F	F	F
Small RG Group Member	A	F	F	F	O	A	A
Distributed Generation							
Conservation Services Group	A	F	A	O	O	F	F
Small DG Group Member	A	F	A	O	O	F	F
Load Response							
EnerNOC, Inc.	O	A	O	F	O	F	A
Vermont Energy Investment Corp.	A	F	A	O	O	F	F
Small LR Group Member	F	F	A	O	A	F	F
LR Provisional Group Member	F	F	F	F	O	F	A
IN FAVOR (F)	1	6	1	3	1	6	5
OPPOSED (O)	2	0	2	4	5	0	0
TOTAL VOTES	3	6	3	7	6	6	5
ABSTENTIONS (A)	4	1	4	0	1	1	2

VOTES TAKEN AT
DECEMBER 6, 2013 PARTICIPANTS COMMITTEE MEETING

SUPPLIER

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4	Vote 5	Vote 6	Vote 7
BP Energy Co.	A	A	A	F	A	A	A
Brookfield Energy Marketing /CSC	S	S	S	S	S	S	S
Brookfield Energy Marketing	F	F	F	F	A	A	A
Cross-Sound Cable	A	F	F	F	O	A	A
Calpine Energy Services	O	O	F	F	O	--	O
Competitive Energy Services, LLC	A	F	F	F	O	F	F
Consolidated Edison Energy, Inc.	A	A	F	F	O	A	O
Dynegy Marketing and Trade, LLC	O	A	F	F	O	A	O
Energy America, LLC	A	A	A	A	A	A	A
Exelon Generation Company	O	F	A	F	O	F	O
Galt Power, Inc.	A	A	A	A	A	A	A
Granite Ridge/Merrill Lynch Commodities	O	A	F	F	O	A	O
H.Q. Energy Services (U.S.) Inc.	O	F	O	F	F	F	F
Hess	A	A	A	A	A	A	A
Integrys Energy Services, Inc.	A	A	A	A	A	A	A
Kimberly-Clark Corporation	A	A	A	A	O	A	A
Linde Energy Services, Inc.	A	A	A	A	O	A	A
LIPA	A	F	F	A	O	A	A
PPL EnergyPlus, LLC	O	A	A	F	O	A	A
PSEG Energy Resources & Trade LLC	O	F	F	F	O	F	O
Vitol Inc.	A	A	F	F	O	A	A
IN FAVOR (F)	0.7	6	9	12	1	4	2
OPPOSED (O)	7	1	1	0	12.3	0	6
TOTAL VOTES	7.7	7	10	12	13.3	4	8
ABSTENTIONS (A)	11.3	12	9	7	5.7	14	11

PUBLICLY OWNED ENTITY

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4	Vote 5	Vote 6	Vote 7
Ashburnham Municipal Light Plant	F	O	A	O	O	O	O
Boylston Municipal Light Dept.	F	O	A	O	O	O	O
Braintree Electric Light Department	F	O	F	O	O	A	O
Chicopee Municipal Lighting Plant	F	O	A	O	O	O	O
Concord Municipal Light Plant	F	O	F	O	O	A	O
CT Municipal Electric Energy Coop.	F	O	F	O	O	O	O
Groton Electric Light Dept.,	F	O	A	O	O	O	O
Hingham Municipal Lighting Plant	F	O	F	O	O	A	O
Holden Municipal Light Dept.	F	O	A	O	O	O	O
Holyoke Gas & Electric Dept.	F	O	A	O	O	O	O
Hudson Light and Power Dept.	F	O	A	O	O	O	O
Hull Municipal Lighting Plant	F	O	A	O	O	O	O
Ipswich Municipal Light Dept.	F	O	A	O	O	O	O
Littleton (MA) Electric Light Dept.	F	O	F	O	O	A	O
Littleton (NH) Water & Light Dept.	F	A	F	O	O	--	--
Mansfield Municipal Electric Dept.	F	O	A	O	O	O	O
Marblehead Municipal Light Dept.	F	O	A	O	O	O	O
Mass. Municipal Wholesale Electric Co.	F	O	A	O	O	O	O
Middleborough Gas and Electric	F	O	A	O	O	O	O
Middleton Municipal Electric Dept.	F	O	A	O	O	O	O
New Hampshire Electric Coop.	F	O	F	O	O	A	O
Paxton Municipal Light Dept.	F	O	A	O	O	O	O
Peabody Municipal Light Plant	F	O	A	O	O	O	O
Princeton Municipal Light Dept.	F	O	A	O	O	O	O
Rowley Municipal Lighting Plant	F	O	A	O	O	O	O
Russell Municipal Light Department	F	O	A	O	O	O	O
Shrewsbury's Electric & Cable Operations	F	O	A	O	O	O	O
South Hadley Electric Light Dept.	F	O	A	O	O	O	O
Sterling Municipal Electric Light	F	O	A	O	O	O	O
Taunton Municipal Lighting Plant	F	O	F	O	O	A	O
Templeton Municipal Lighting Plant	F	O	A	O	O	O	O
Vermont Electric Cooperative	F	O	F	A	O	A	A
VT Public. Power Supply Authority	F	O	F	A	O	A	A
Wakefield Municipal Gas and Light	F	O	A	O	O	O	O
Wallingford, Town of	F	O	F	O	O	A	O
Wellesley Municipal Light Plant	F	O	F	O	O	A	O
W. Boylston Municipal Lighting Plant	F	O	A	O	O	O	O
Westfield Gas & Electric Light Dept.	F	O	A	O	O	O	O
OIN FAVOR (F)	38	0	12	0	0	0	0
OPPOSED (O)	0	36	0	37	38	26	35
TOTAL VOTES	38	36	12	37	38	26	35
ABSTENTIONS (A)	0	2	26	1	0	10	1

VOTES TAKEN AT
DECEMBER 6, 2013 PARTICIPANTS COMMITTEE MEETING

END USER

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4	Vote 5	Vote 6	Vote 7
Cianbro Companies	A	F	F	A	O	F	A
Connecticut Office of Consumer Counsel	F	A	F	O	O	F	F
Conservation Law Foundation	O	F	O	O	F	F	F
Corinth Wood Pellets, LLC	A	F	F	A	O	F	A
Dragon Products Company	A	F	F	A	O	F	A
Elektrisola, Inc.	A	F	F	A	O	F	A
Environment Northeast	F	F	A	A	O	A	--
Fairchild Semiconductor Corporation	A	F	F	A	O	F	A
Food City, Inc.	A	F	F	A	O	F	A
Hardwood Products Company	A	F	F	A	O	F	A
Harvard Dedicated Energy Limited	A	F	F	O	O	A	A
High Liner Foods (USA) Inc.	F	F	F	A	O	F	A
Industrial Energy Consumer Group	F	F	F	F	O	F	A
LaBree's Inc.	A	F	F	A	O	F	A
Maine Public Advocate Office	A	F	F	A	O	F	F
Maine Skiing, Inc.	F	F	F	F	O	F	A
Marden's Inc.	A	F	F	A	O	F	A
Mass. Attorney General's Office	O	F	F	O	O	F	F
MoArk, LLC	A	F	F	A	O	F	A
NH Office of Consumer Advocate	A	F	A	O	O	F	F
PalletOne of Maine	A	F	F	A	O	F	A
PowerOptions, Inc.	A	F	F	O	O	F	F
Praxair, Inc.	A	A	A	A	O	A	A
St. Anselm College	A	F	F	A	O	F	A
Shipyard Brewing Co., LLC	A	F	F	A	O	F	A
The Energy Consortium	A	F	F	O	O	A	A
Union of Concerned Scientists	O	F	O	O	A	F	F
Utility Services Inc.	A	A	A	O	A	A	A
Westerly Hospital, The	A	F	F	A	O	F	A
Z-TECH, LLC	A	F	F	A	O	F	A
IN FAVOR (F)	5	27	24	2	1	25	7
OPPOSED (O)	3	--	2	9	27	0	0
TOTAL VOTES	8	27	26	11	28	25	7
ABSTENTIONS (A)	22	3	4	19	2	5	22

ESTIMATED 2014 NEPOOL BUDGET COMPARED TO
2013 NEPOOL BUDGET AND 2013 PROJECTED ACTUAL EXPENSES

Line Items	2014 Proposed Budget	2013 Approved Budget	2013 Current Forecast
NEPOOL Counsel Fees (1)	$3,600,000	$3,600,000	$3,600,000
NEPOOL Counsel Disbursements (1)	$ 55,000	$ 55,000	$ 55,000
Independent Financial Advisor Fees and Disbursements (2)	$ 50,000	$ 60,000	$ 50,000
Committee Meeting Expenses	$ 650,000	$ 650,000	$ 647,000
Review Board Compensation (4)	$ 108,000	$ 112,000	$ 112,000
Review Board Administrative and Support Expense	$ 30,000	$ 30,000	$ 30,000
CFTC Counsel (5)	$ 0	$ 10,000	$ 40,000 (6)
Generation Information System (3)	$1,065,000	$1,065,000	$1,046,000
Credit Insurance Premium (3)	$ 450,000	$ 425,000	$ 425,000
NEPOOL Audit Management Subcommittee ("NAMS") Consultant (7)	$ -	$ -	$ -
SUBTOTAL EXPENSES	$6,008,000	$6,007,000	$6,005,000
Revenue			
NEPOOL Membership Fees (3) (8)	($1,800,000)	($1,750,000)	($1,855,000)
Generation Information System (3) (9)	($1,065,000)	($1,065,000)	($1,046,000)
Credit Insurance Premium (3) (10)	($ 450,000)	($ 425,000)	($ 425,000)
TOTAL REVENUE	($3,315,000)	($3,240,000)	($3,326,000)
TOTAL NEPOOL EXPENSES	**$2,693,000**	**$2,767,000**	**$2,679,000**

Notes

(1) 2014 NEPOOL Counsel fees and disbursements are estimated to remain consistent with 2013 budgeted and actual levels.

(2) 2014 proposed estimate provided by Michael M. Mackles, NEPOOL's Independent Financial Advisor.

(3) 2014 proposed estimate provided by ISO New England Inc. ("ISO").

(4) 2014 proposed estimate (a $4,000 reduction from 2013) reflects the following: (i) no change to current Review Board arrangements; (ii) three or fewer appeals in 2014; (iii) no change in the annual retainer paid to two of the three members of the Review Board, which is $36,000; and (iv) agreement to remove the prior $4,000 additional compensation paid to the Board's Chairman, such that the Chairman, also, will receive payments based on annual retainer of $36,000.

(5) Reflects a $10,000 reduction from 2013 estimates given the fact that the final CFTC exemption order was issued in March 2013, and as a result no additional budget for CFTC Counsel is proposed for 2014.

(6) Includes amounts paid to CFTC Counsel in 2013 for work performed and budgeted in 2012.

(7) An operational audit of the ISO could be performed in 2014, and if NEPOOL were to decide to retain a professional to assist in such an audit, some amount would be required for this item. Historically, the NEPOOL Participants Committee has voted separately on funds for any such professional.

(8) The 2014 proposed estimate is based on the 2013 actual receipts through October 2013, plus a forecast (a) for new members, of 5 members at $5,000 each, 4 members at $1,000 each, 3 members at $500 each, and (b) for terminated members, of 16 at $5,000 each, 3 at $1,250 each, and 6 at $500 each.

(9) Generation Information System costs are paid by "GIS Participants" under Allocation of Costs Related to Generation Information System, which was approved by the NEPOOL Participants Committee on June 21, 2002.

(10) Credit insurance premium is paid by Qualifying Market Participants according to methodology described in Section IX of the ISO Financial Assurance Policy

CONSENT AGENDA

From the notice of actions of the December 10-11, 2013 ***Markets Committee***[1] meeting, dated December 11, 2013, which has been previously circulated:

1. **TO BE ADDRESSED AS DISCUSSION AGENDA ITEM #7**
   Revisions to Market Rule 1 Appendix A (Energy Market Offer Flexibility)

   Support revisions to Market Rule 1 Appendix A in response to the FERC compliance requirements contained in the October 16, 2013 Order (Docket No. ER13-1877-000), as recommended by the Markets Committee at its December 10-11, 2013 meeting, with such further non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

   The motion to recommend Participants Committee support was approved with a 65.33% Vote in favor (Generation - 0%; Transmission - 19.6%; Supplier - 6.53%; AR - 0% (12.17% reallocated to the other 5 Sectors), Publicly Owned Entity - 19.6%), and End User - 19.6%).

From the notice of actions of the December 19, 2013 ***Reliability Committee***[2] meeting, dated December 23, 2013, which has been previously circulated:

2. **Retirement of OP6 (System Restoration)**

   Support the retirement of OP6 (System Restoration) and move of responsibilities to MLCC 18 and Appendix A to OP1 (*see* #3 below), as recommended by the Reliability Committee at its December 19, 2013 meeting, with such further non-substantive changes as the Chair and Vice-Chair of the Reliability Committee may approve.

   The motion to recommend Participants Committee support was unanimously approved.

3. **Revisions to OP 1 (Added Responsibilities due to Retirement of OP6)**

   Support revisions to Appendix A (Assignment of Responsibilities) to OP1 (Central Dispatch Operating Responsibilities and Authority) that add system restoration responsibilities for ISO-NE, Market Participants, and Transmission Operators as a result of the retirement of OP6, as recommended by the Reliability Committee at its December 19, 2013 meeting, with such further non-substantive changes as the Chair and Vice-Chair of the Reliability Committee may approve.

   The motion to recommend Participants Committee support was unanimously approved.

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[1] Markets Committee Notices of Actions are posted on the ISO website at: http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/actions/index.html

[2] Reliability Committee Notices of Actions are posted on the ISO website at: http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/relblty/actions/index.html.

Summary of ISO New England Board and Committee Meetings
January 10, 2014 Participants Committee Meeting

Since the last update, the Markets Committee, the System Planning and Reliability Committee, and the Board of Directors met on December 19 in Holyoke.

The System Planning and Reliability Committee was provided with an overview of activities and events that were a major focus during the third and fourth quarters of 2013, including approval of the 2013 Regional System Plan, interregional and intraregional compliance filings on FERC Order 1000, progress of the stakeholder process on the zonal modeling planned to be in place for Forward Capacity Auction #9, and the completion of siting hearings for the interstate project. The Committee also discussed the impacts of retirements on fuel diversity and the increased need for gas, resource qualification issues for Forward Capacity Auction #8, and wind integration issues and the operation of wind facilities and curtailments based upon resource locations. The Committee received an update regarding ongoing work on including distributed generation in the planning process. The Committee noted a report on winter outlook and discussed the fuel procurement for operations this winter. Finally, the Committee held an executive session to discuss corporate goals for 2014.

The Board of Directors met to review the NEPOOL process and votes on both the Forward Capacity Market Pay for Performance proposal and the NEPOOL-supported proposal from NRG. The Board discussed the substantive aspects of both proposals, the stakeholder considerations for supporting the alternative proposal, and management's views on the two alternatives. The Board discussed further background on the issues and the importance for the revenue from the Forward Capacity Market to be tied to performance. After considering all issues, the Board consensus was to file the two alternatives under the jump ball provisions and continued full support for the Pay for Performance proposal.

The Markets Committee received reports from the internal and external market monitors, and the COO's report on reliability costs. The Committee reviewed the External Market Monitor's quarterly report on market performance and discussed changes made in reserve pricing which is expected to procure more reserves in the market and reduce out-of-market commitments. Next, the Committee discussed the high prices seen over the past few weeks and the gas price differential between New York and New England. The Committee received a report on recent filings made in response to administrative pricing and the ISO's exigent circumstances filing. Finally, the Committee held an executive session to discuss corporate goals for 2014.

NEPOOL Participants Committee Report

January 2014

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - December natural gas prices over the period were 115% higher, while oil prices were 0.7% higher than November 2013 average values
  - Average RT Hub Locational Marginal Prices (LMPs) over the period were 115% higher than November 2013 averages
  - Average December 2013 natural gas prices and RT Hub LMPs were up 139% and 126%, respectively, from December 2012 averages
- Average daily (peak hour) DA cleared physical energy as percent of forecasted load was 95.3% in December and 95.9% in November

Underlying natural gas data furnished by:

ICE Global markets in clear view

Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - December payments totaled $20.4M, up $12.6M from November*
  - First Contingency payments totaled $17.7M, up $12.3M from November
    - $16.1M paid to internal resources, up $11.1M from November
      - $7.7M charged to DALO, $8.4M to RT Deviations
    - $1.5M paid to resources at external locations, up $1.2M from November
      - $1.5M charged to DALO at external locations, $6K to RT Deviations
  - Second Contingency payments totaled $2.1M, up $1.9M from the November total of $255K
  - Voltage payments totaled $564K, down $1.6M from November
  - Distribution payments totaled $13K, up $13K from November
  - NCPC payments over the period as percent of Energy Market value were 1.8%

*First Contingency payments made to postured Dispatchable Asset-Related Demands (DARDs), not reflected in the totals above, were $90K.

Highlights, cont.
Winter 2013-14 Reliability Program

- Dual-Fuel Unit Fuel-Switch Testing
  - As of January 3, 2014, 13 out of 14 units have successfully tested their switching capability*
- Program Oil Inventories
  - As of December 1, 11 out of 56 units had failed to meet initial inventory requirements, representing 1.8% of total program inventory
  - As of January 1, all but one unit had cured their initial inventory shortfalls
  - Replenishment status reporting pending verification of inventory purchase
- Status of Demand Resource Dispatch
  - As of January 3, 1 out of 10 possible dispatch calls have been made

*As of January 2, 2014, 12 of the 14 units in the Winter Reliability Program received testing uplift totaling $1.4M

Highlights, cont.
Winter 2013-14 Reliability Program, cont.

- NE Fleet Fuel Oil Survey Inventory
  - As of Dec 1: 3,440,998 Barrels
  - As of Jan 2: 3,352,217 Barrels

- Winter Program Inventory
  - Awarded (Initial Inventory): 3,057,554 Barrels
  - Awarded (Replenishment): 484,477 Barrels
  - Initial Inventory Shortfall as of Dec 1: 53,742 Barrels
  - Initial Inventory Shortfall as of Jan 2: 127 Barrels
  - **Program Oil burned through Jan 5: 732,439 Barrels**
    - **Equivalent Oil MWh burned* 439,434 MWh**

*** Based on an average heat content of 6,000,000 Btu/Barrel and proxy heat rate of 10,000 MWh/MMBtu**

Highlights, cont.
Capacity Deficiency December 14, 2013

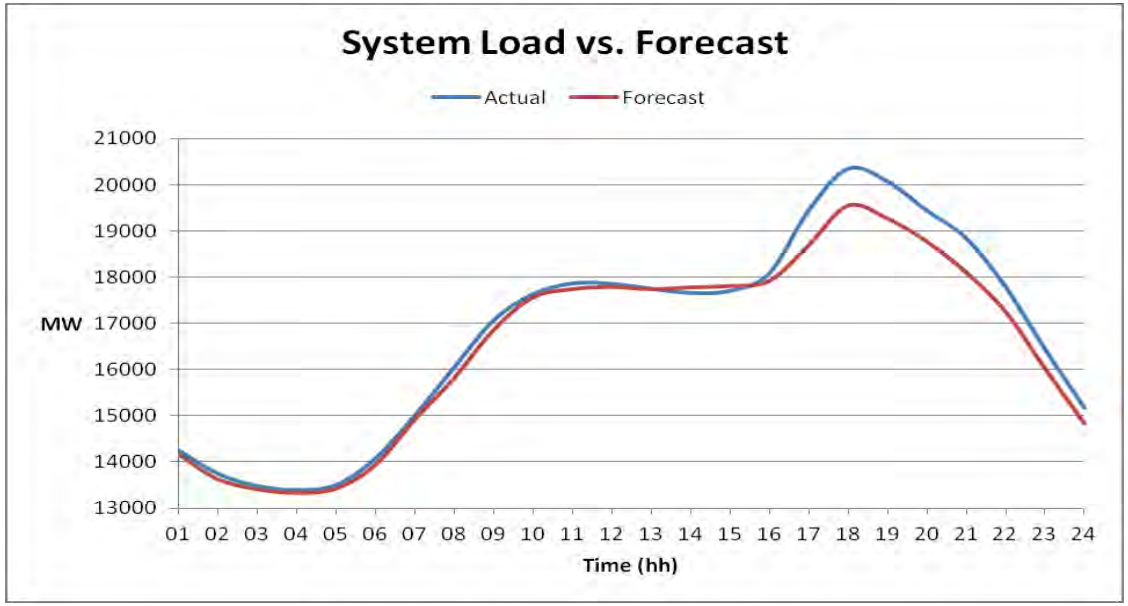
- On Saturday Evening December 14, 2013 the New England Balancing Area implemented M/LCC #2 Abnormal Conditions Alert and OP #4 Action During A Capacity Deficiency to manage a reserve deficiency on the system
- The Primary Contributing Factors causing the deficiency included:
  - Interchange Curtailments from Neighboring systems
  - Loads running over the Forecast
  - Generator Outages and Reductions approximately 400 MW
- We experienced shortages in Ten and Thirty Minute Reserves and a Shortage Event as defined under FCM Market Rules

Highlights, cont.
Interchange Curtailments

- The expected net deliveries for the peak hour were 3,277MW and the actual net deliveries were 2,591 MW due to curtailments
- The majority of curtailments were experienced on the Hydro Quebec Interfaces due to loads in HQ running well over forecast
- Control Area to Control Area Emergency Import purchased from 17:42 – 18:30 (240 MW from New York)
- No Capacity Transactions were curtailed across any interface during the event

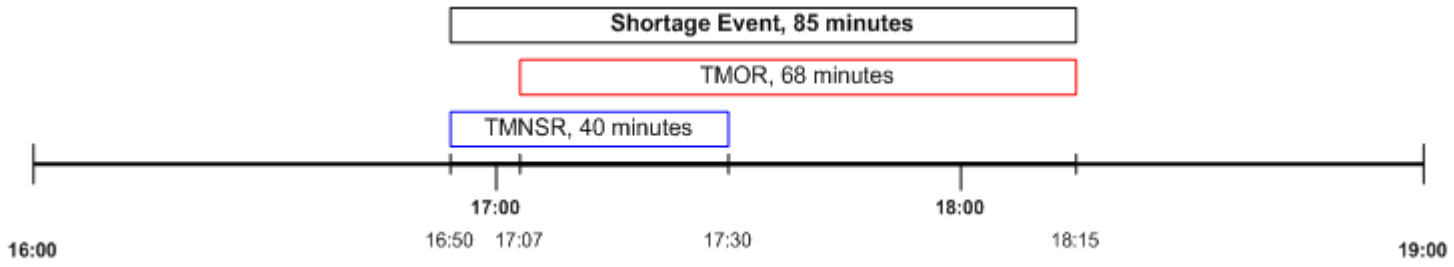
Highlights, cont.
Loads Over Forecast

- For the first 16 hours on Saturday, the actual load vs. forecast load were very close as can be seen on the load graph below
- During h/e 17:00, the actual load started to diverge above the forecast value significantly and ultimately by 632 MW



Highlights, cont.
Shortage Event

- The timeline for the shortage event is as follows:



Highlights, cont.

- December 14, 2013 FCM shortage event
  - Total event duration 16:50 – 18:15 p.m. (85 minutes)
    - Based on contiguous overlap of:
      - System TMNSR violation 16:50 – 17:30 (40 minutes)
      - System TMOR violation 16:35 – 18:15 combined with OP4 – Action 2 at 17:07 – 18:15
  - Event penalties (estimated) total $6.7M *
    - 132 Generators: $6.692M
      - 21 resources and $629K in Maine Capacity Zone
      - 111 resources and $6.063M in Rest-of-Pool Capacity Zone
    - 3 Imports: $45K

* Subject to verification

Highlights, cont.
MLCC #2 and OP #4 Implementation Timeline

Action(s)	Implemented	Canceled
MLCC 2	17:00	10:00 on 12/15
OP#4 Action 1	17:00	21:30
OP#4 Action 2	17:07	20:45
OP#4 Action 5	17:40	18:30

Highlights, cont.
Winter Reliability Program DR Assets Dispatched Performance Across Entire Dispatch

Duration of the December 14th, 2013 Real Time Event (Local Time)		MW Dispatched	Initial Performance (net of performance allocated to coincident OP4 Dispatch)	Percent Performance vs. Dispatch
Start Time (after 30 minute ramp)	End Time			
5:35 PM	9:50 PM	21	30.975	147.5%

Highlights, cont.

RTDR Performance under Action #2 of OP #4 on December 14th, 2013 (includes Winter Reliability Assets)

Including all Intervals of Dispatch (17:40 to 20:50)

Load Zones	Dispatched MW (Net CSO)	Initial Performance (MW)	Percentage of Initial Performance to Dispatched MW
CT	52.1	19.3	37.0%
ME	126.9	133.5	105.2%
NEMA	3.5	1.6	44.0%
NH	3.2	1.4	45.1%
RI	10.2	6.1	59.6%
SEMA	7.0	0.3	3.9%
VT	25.9	23.2	89.5%
WCMA	19.0	6.0	31.8%
Total	**247.8**	**191.3**	**77.2%**

Highlights, cont.

- The lowest 50/50 and 90/10 Winter Operable Capacity Margin is projected week beginning January 18th.
- The lowest 90/10 Winter Operable Capacity Margins are projected week beginning January 11th and 18th.

Highlights, cont.

- The 2014 Regional System Plan overview and scope of work is scheduled for Planning Advisory Committee discussions on January 22
- Stakeholder comments on the draft interim photovoltaic forecast and interconnection issues are due by January 7 and follow-up discussions are planned for the Distributed Generation Forecast Working Group meeting on January 27
- Final preparations for administration of the eighth Forward Capacity Auction (FCA #8) will continue through January
  - FCA #8 is scheduled to begin on Monday, February 3
  - FERC has not yet issued an order on the FCA #8 informational filing made in November 2013

Highlights, cont.
Forward Capacity Market Update

- CCP #8 (2017-2018)
  - Final preparations are underway for execution of FCA #8
  - ISO has made its final determination that Brayton Point Station is required to address system reliability concerns and the Non-Price Retirement (NPR) request was not approved
  - NPR requests from Norwalk Harbor Station and 603 MW of demand resources have been approved
  - FERC approved the Installed Capacity Requirement and associated requirements on December 30

- CCP #9 (2018-2019)
  - On December 17 at the joint meeting of the RC, MC, and TC, the new Capacity Zone Tariff Language, specifically Section 12 and Attachment K, failed to gain support of the committee members. NRG sought a vote on changes to Section 13 regarding bilateral transactions that did gain support. The PC will be voting on these changes in January.
  - Preparations are beginning for the opening of the Show of Interest window on February 18

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature – Below Average (-2.2) Max 57, Min 9 Precipitation 4.55” (Liquid) Above Average Normal 3.73”	Hartford	Temperature – Below Average (-1.3) Max 65, Min 5 Precipitation 2.72” (Liquid) – Below Average Normal = 4.03”

Peak Load:	21,514 MW	December 17, 2013	18:00

MLCC2:			
12/12/13	08:30 – 21:00	All of New England	Capacity Deficiency
12/14/13 – 12/15/13	17:00 – 10:00	All of New England	Capacity Deficiency
12/17/13	10:30 – 21:30	All of New England	Capacity Deficiency
OP-4 :			
12/14/13	16:48 – 20:45	All of New England	Capacity Deficiency Steps 1,2, and 5

NPCC Simultaneous Activation of Reserve Events:		
12/02/2013	NYISO	501MW
12/12/2013	ISO-NE	790MW
12/15/2013	ISO-NE	518MW
12/23/2013	NYISO	520MW

System Operations

Minimum Generation Warnings & Events:

Minimum Generation Warning	**12/01/13 – 12/02/13**	**Start-23:00, Expired-06:00 Interchange Cuts Only**
Minimum Generation Warning	**12/03/13**	**Start-00:01 Expired-06:00 No Actions Taken**
Minimum Generation Warning	**12/06/13**	**Start-00:01, Expired-06:00 Interchange Cuts Only**
Minimum Generation Warning	**12/08/13**	**Start- 06:00, Expired-09:00 SS Denied Only**
Minimum Generation Warning	**12/21/13**	**Start – 13:00, Expired – 17:00 Interchange Cuts Only**
Minimum Generation Warning	**12/21/13 – 12/22/13**	**Start – 22:00, Expired – 10:00 Interchange Cuts Only**
Minimum Generation Event	**12/21/13 – 12/22/13**	**Start-23:00, Expired-05:00 Interchange Cuts Only**
Minimum Generation Warning	**12/22/13 – 12/23/13**	**Star-22:00 , Expired-09:00 Interchange Cuts & SS Denied**
Minimum Generation Warning	**12/23/13**	**Start-21:00, Expired–23:59 No Actions Taken**
Minimum Generation Warning	**12/24/13**	**Start-00:01, Expired-08:00 Interchange Cuts & SS Denied**
Minimum Generation Event	**12/24/13**	**Start-01:30, Expired-05:00 Interchange Cuts Only**

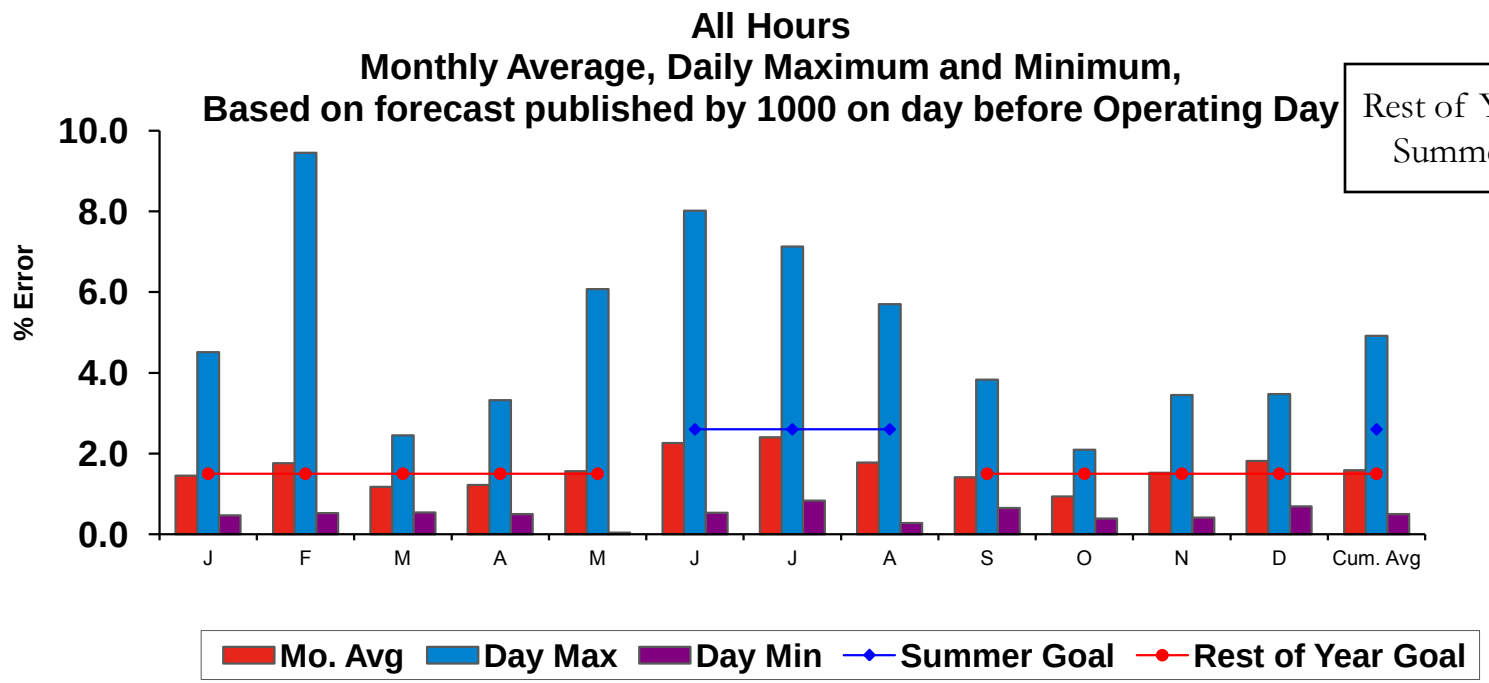
System Operations

Minimum Generation Warnings & Events:

Minimum Generation Warning	**12/26/13**	**Start-03:00, Expired-06:00 No Actions Taken**
Minimum Generation Warning	**12/30/13**	**Start- 01:00, Expired-08:00 Interchange Cuts Only**
Minimum Generation Event	**12/30/13**	**Start – 02:00, Expired – 06:00 Interchange Cuts Only**

2013 System Operations – Load Forecast Accuracy

Dashboard Indicator



Rest of Year Goal < 1.5%
Summer Goal < 2.6%

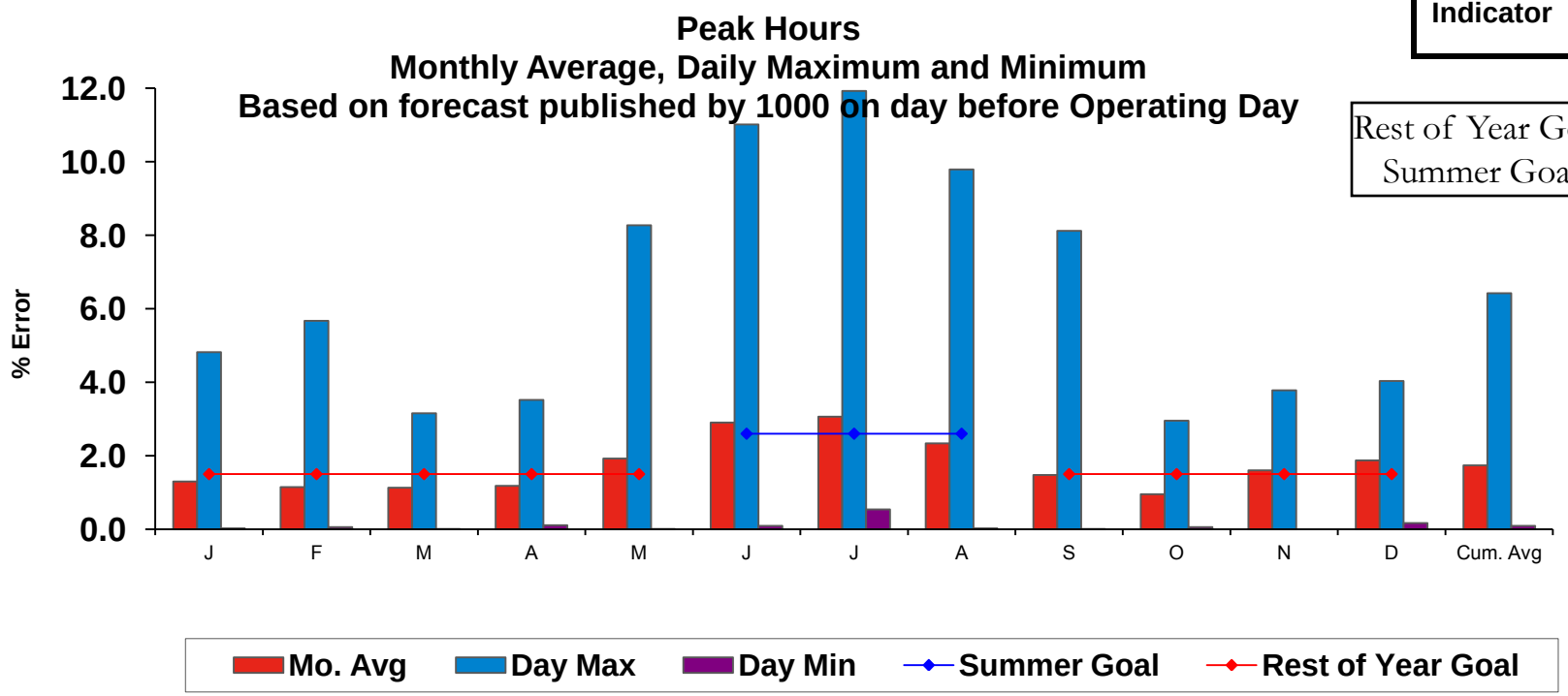
	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Mo Avg	1.45	1.64	1.17	1.22	1.56	2.26	2.40	1.78	1.41	0.94	1.52	1.82	1.59
Day Max	4.51	9.45	2.45	3.32	6.07	8.02	7.13	5.70	3.83	2.09	3.45	3.47	4.92
Day Min	0.46	0.52	0.54	0.50	0.40	0.53	0.83	0.28	0.42	0.39	0.41	0.69	0.50
Summer Goal						2.6	2.6	2.6					
Rest of Year Goal	1.50	1.50	1.50	1.50	1.50				1.50	1.50	1.50	1.50	
Rest of year Actual	1.45	1.64	1.17	1.22	1.56				1.41	0.94	1.52	1.82	1.41
Summer Actual						2.26	2.40	1.78					2.15

Summer Goal - 2.6%, Rest of Year Goal - 1.5%

Summer consists of June, July & August

2013 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



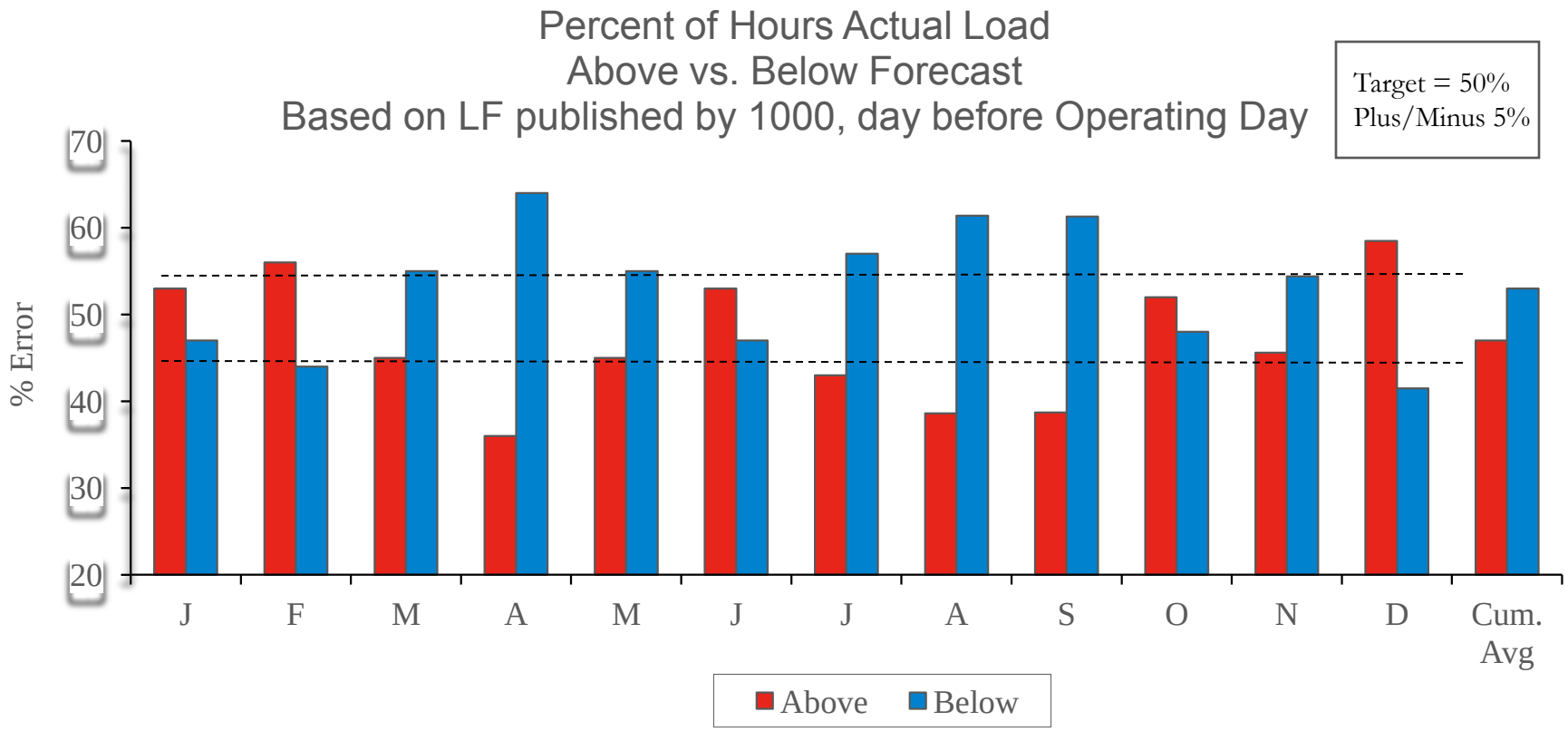
Rest of Year Goal < 1.5%
Summer Goal < 2.6%

	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Mo Avg	1.30	1.15	1.13	1.18	1.92	2.90	3.06	2.34	1.48	0.95	1.60	1.87	1.74
Day Max	4.82	5.67	3.16	3.52	8.27	11.02	11.93	9.79	8.12	2.95	3.78	4.03	6.42
Day Min	0.02	0.06	0.01	0.11	0.01	0.09	0.54	0.02	0.01	0.06	0.00	0.17	0.09
Summer Goal						2.6	2.6	2.6					
Rest of Year Goal	1.50	1.50	1.50	1.50	1.50				1.50	1.50	1.50	1.50	
Rest of year Actual	1.30	1.15	1.13	1.18	1.92				1.48	0.95	1.60	1.87	1.34
Summer Actual						2.9	3.06	2.34					2.77

Summer Goal - 2.6%, Rest of Year Goal - 1.5%

Summer consists of June, July & August

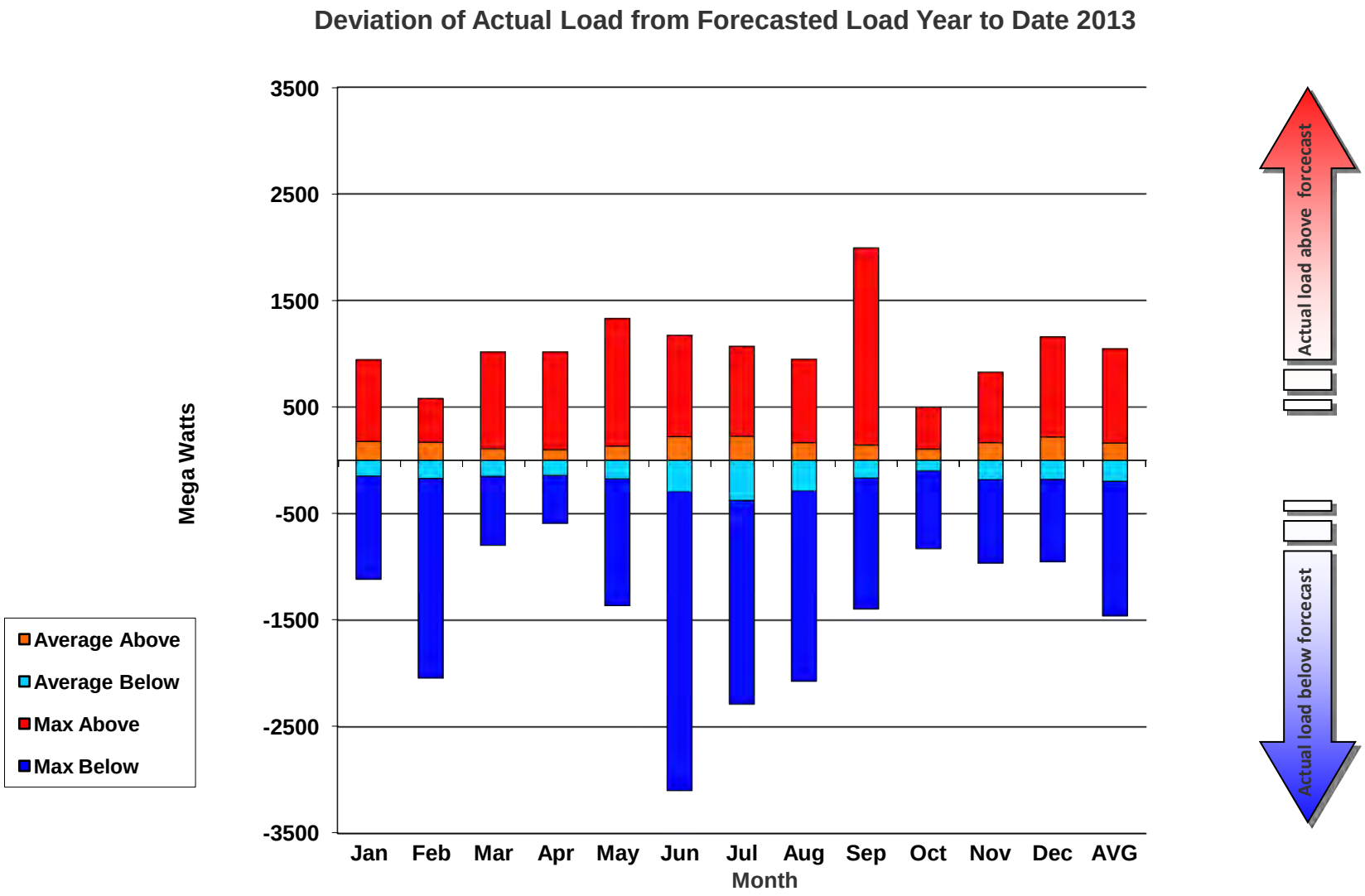
2013 System Operations - Load Forecast Accuracy



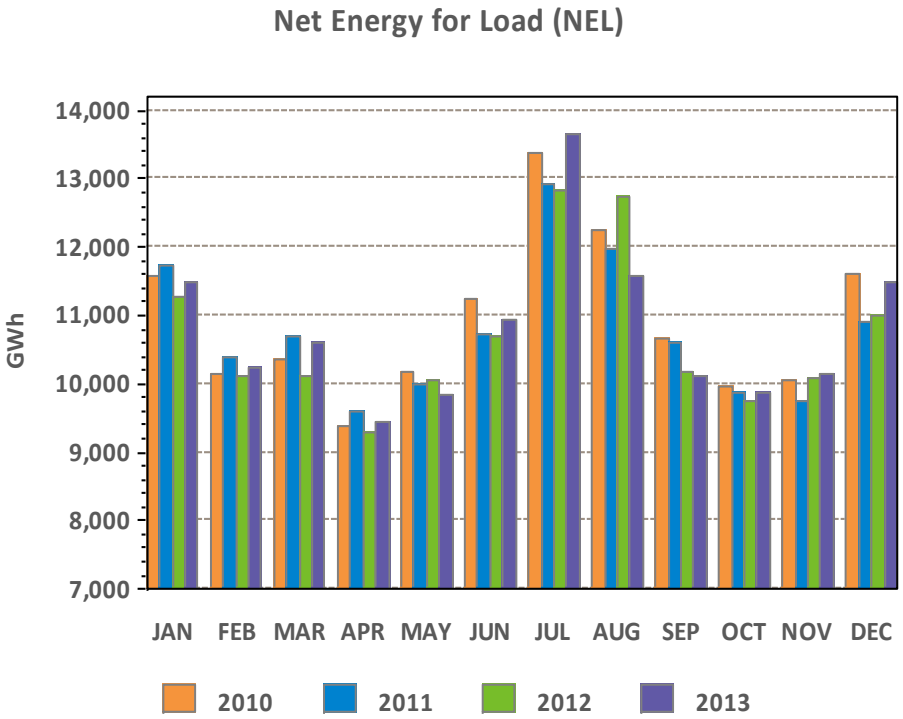
	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	53.2	56.0	44.9	35.7	45.0	52.6	42.7	38.6	38.7	52.0	45.6	58.5	47.0
Below %	46.8	44.0	55.1	64.3	55.0	47.4	57.3	61.4	61.3	48.0	54.4	41.5	53.0
Avg Above	176.0	169.0	107.0	100.0	134.0	222	226	166.0	141.0	107.0	166.0	218.0	161.0
Avg Below	-147.0	-171.0	-150.0	-132.0	-174.0	-296	-375	-288.0	-165.0	-99.0	-181.0	-178.0	-197.6
Avg All	21.0	-6.0	-30.0	-51.0	-39.0	-59.0	-138.0	-112.0	-17.0	8.0	-20.0	58.0	-32.1

Percent of hours that the actual load was above versus below the forecast

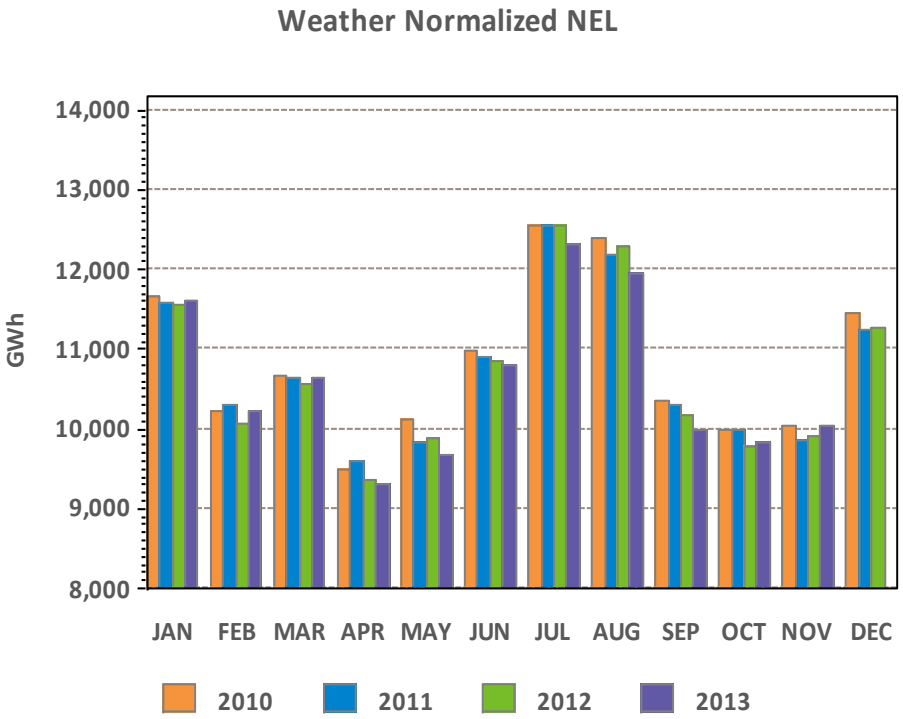
2013 System Operations - Load Forecast Accuracy



Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL



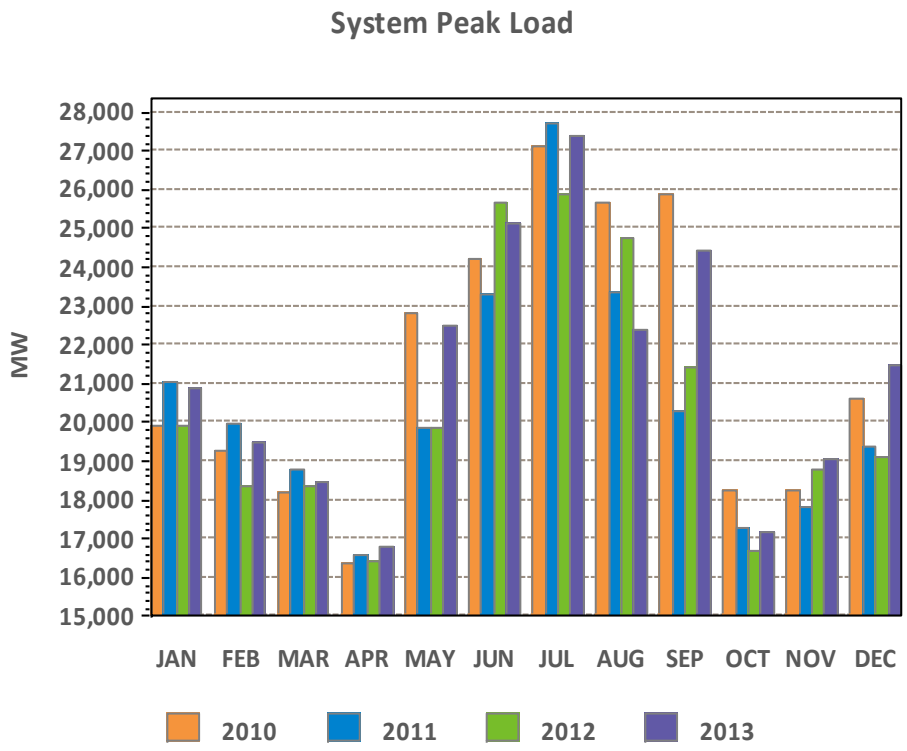
Ann Tot (TWh): 130.8 129.2 128.1 129.3

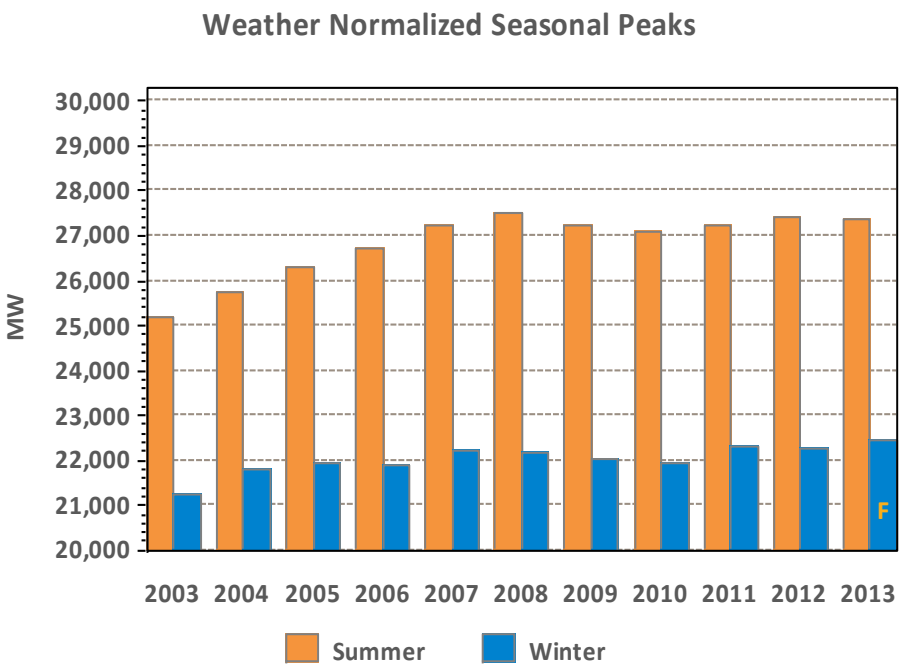


Ann Tot (TWh): 129.9 129.0 128.2 116.4

NEPOOL NEL is the total net energy required to serve load for the month, in GWh. NEL is calculated as: Generation – pumping load + net interchange. Current month's data may be preliminary. Weather normalized NEL may be reported on a one-month lag.

Monthly Peak Loads and Weather Normalized Seasonal Peak History



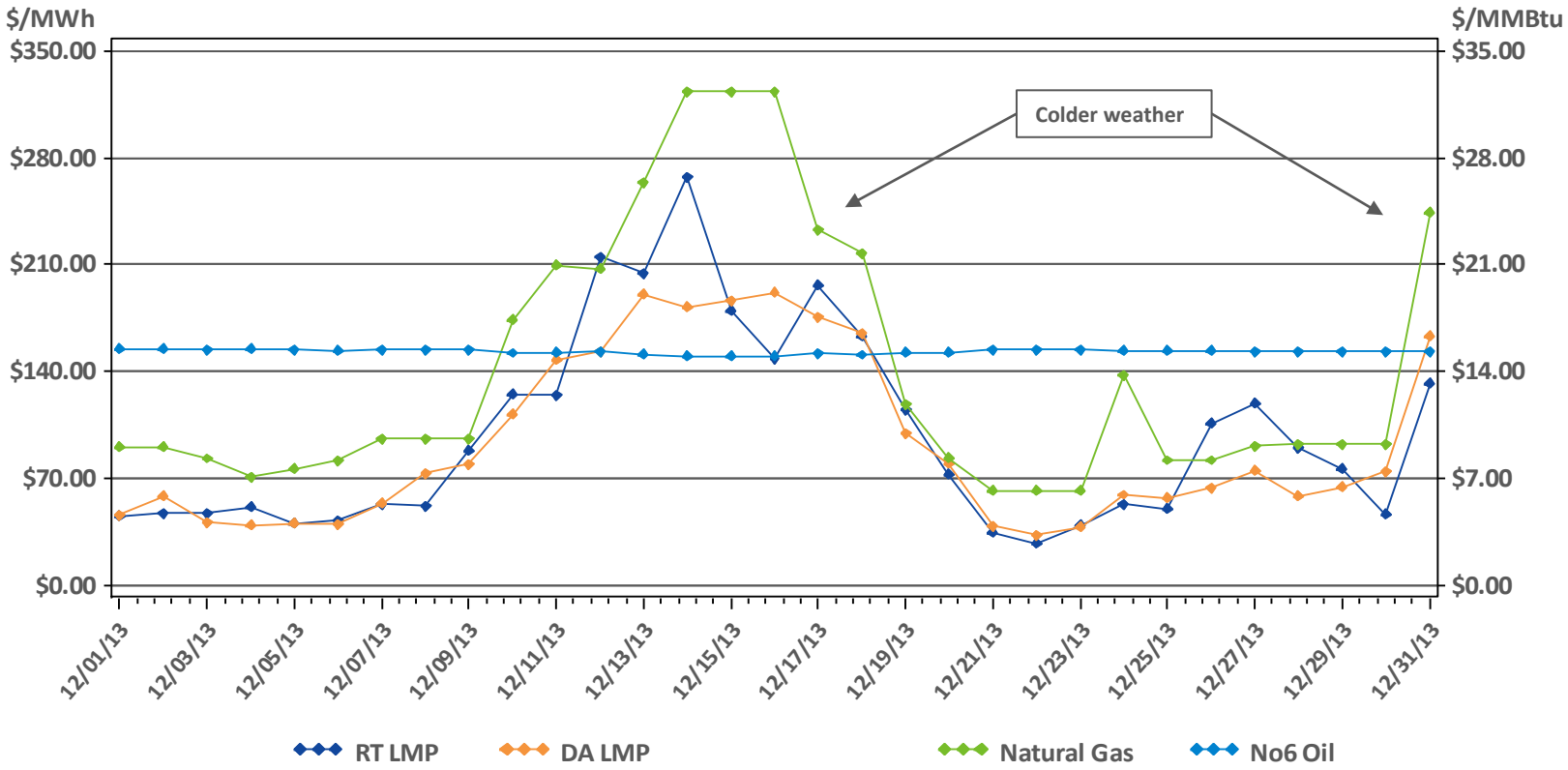


Winter beginning in year displayed

*** F – designates forecasted values, which are updated in April/May of the following year.**

MARKET OPERATIONS

DA and RT ISO-NE Hub Prices and Input Fuel Prices: December 1-31, 2013

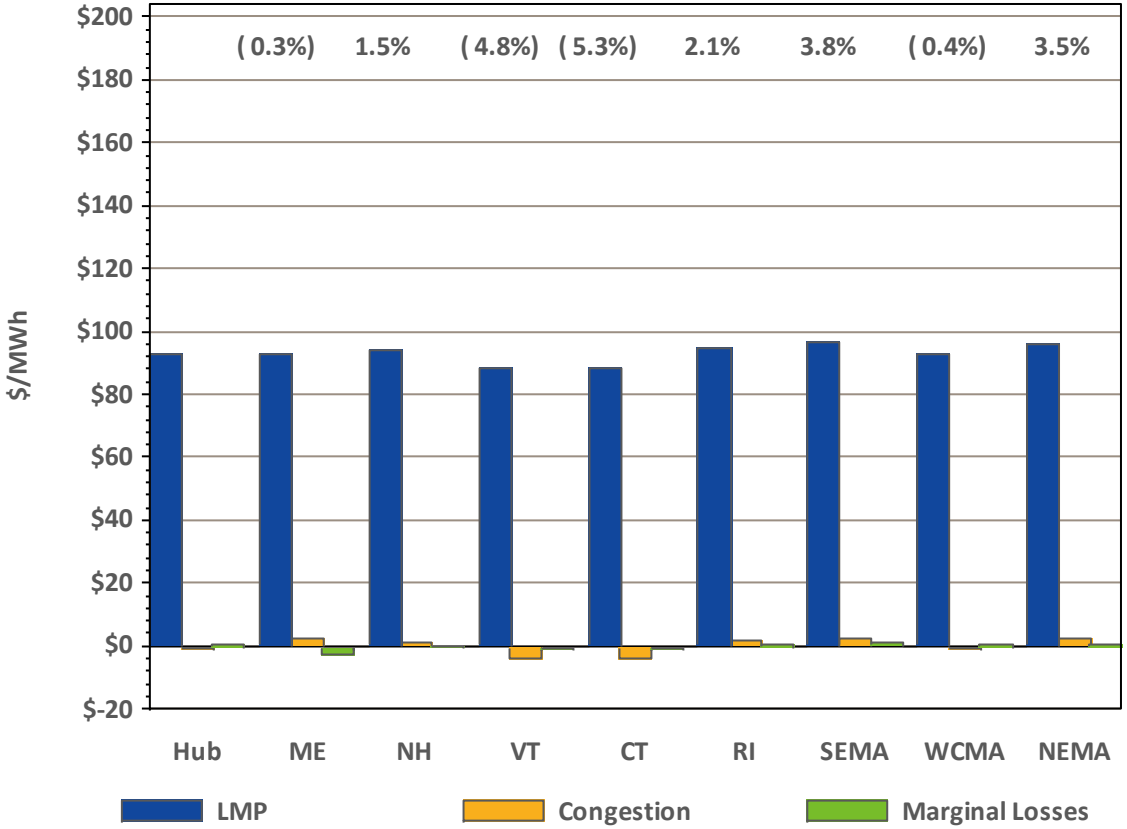


Underlying natural gas data furnished by:

ICE Global markets in clear view

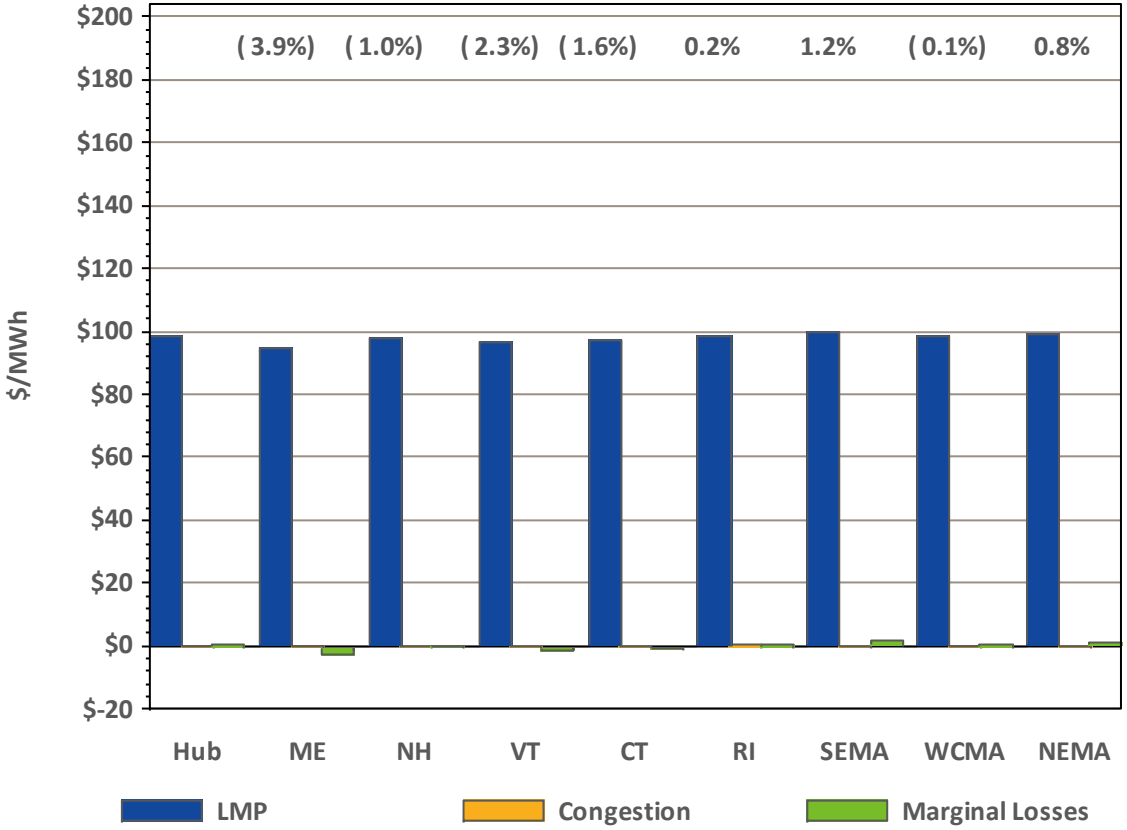
Average price difference over this period (DA-RT): $-5.57
Average price difference over this period ABS(DA-RT): $18.38
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 19%
Gas price is average of Massachusetts delivery points; No6 Oil is New York Spot Price from DOEs Energy Information Administration

DA LMPs Average by Zone & Hub, December 2013

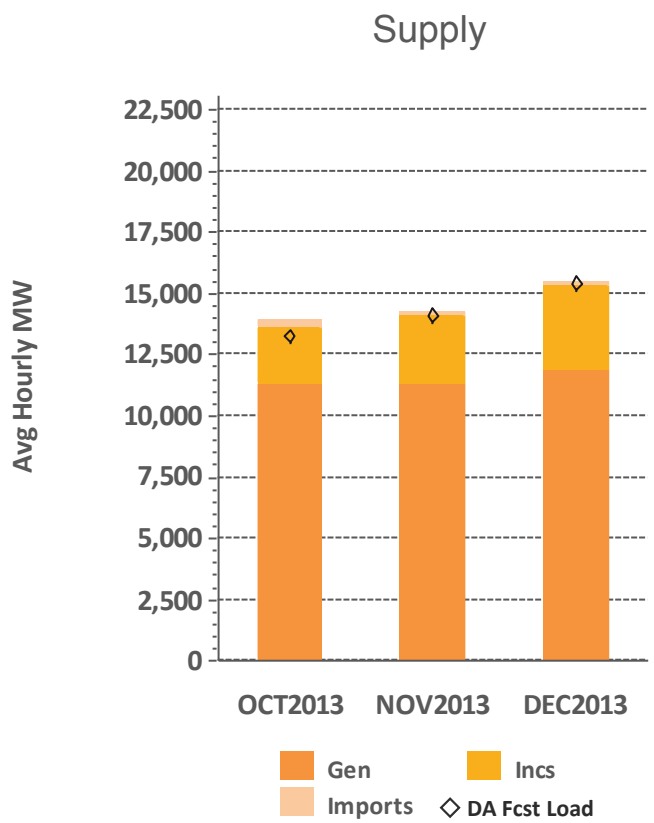


ME - Maine
NH – New Hampshire
VT – Vermont
CT – Connecticut
RI – Rhode Island
SEMA – Southeastern Massachusetts
WCMA – Western/Central Massachusetts
NEMA – Northeastern Massachusetts

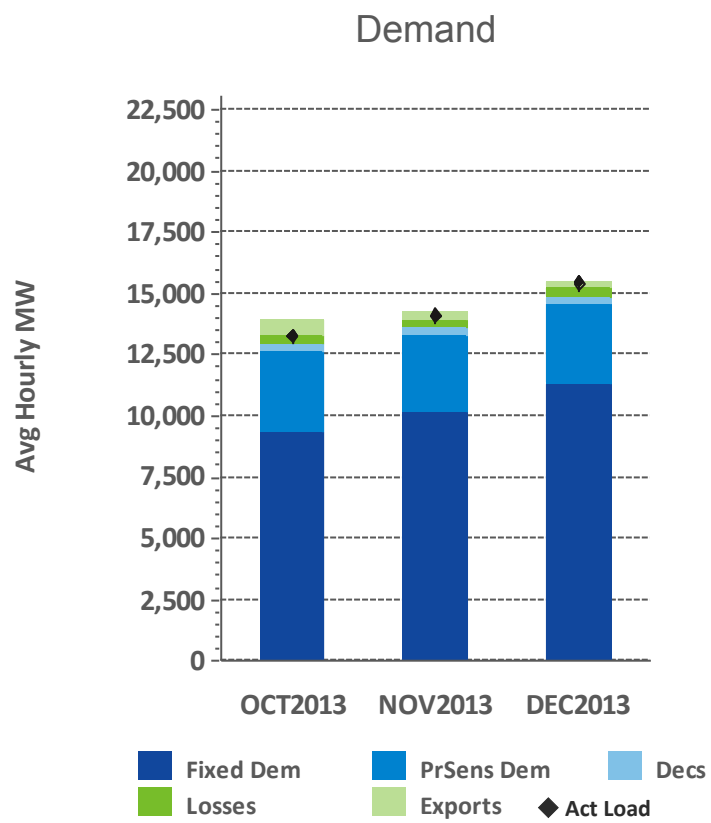
RT LMPs Average by Zone & Hub, December 2013



Components of Cleared DA Supply and Demand – Last Three Months

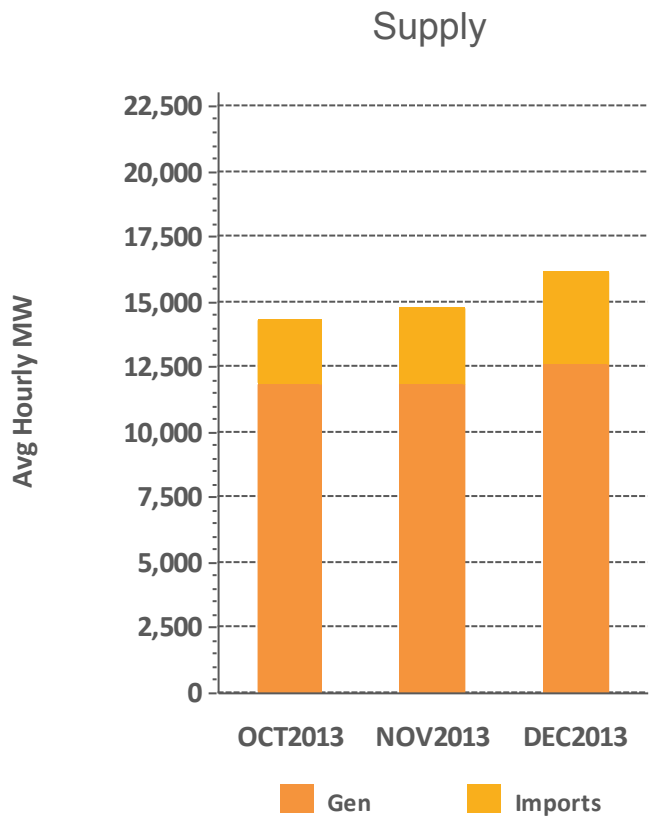


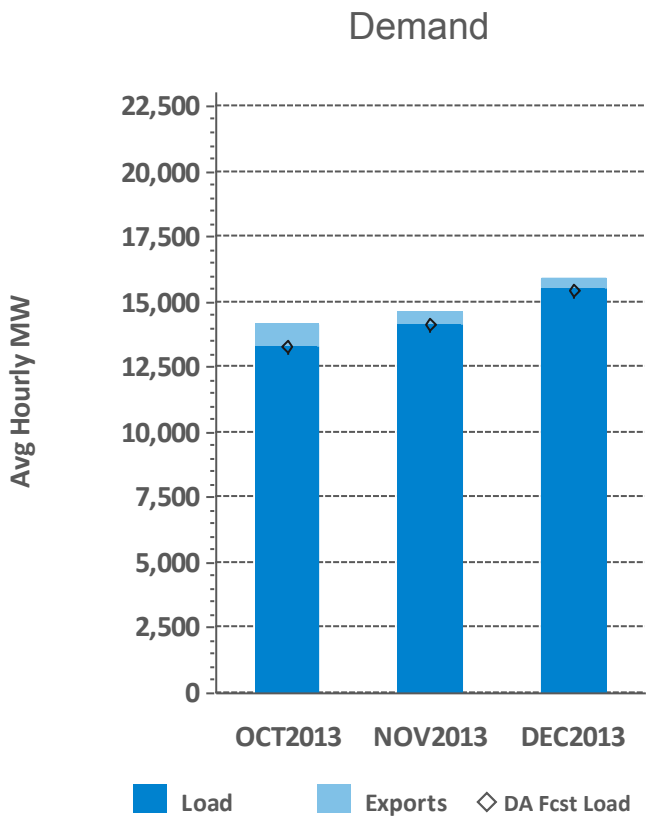
Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load



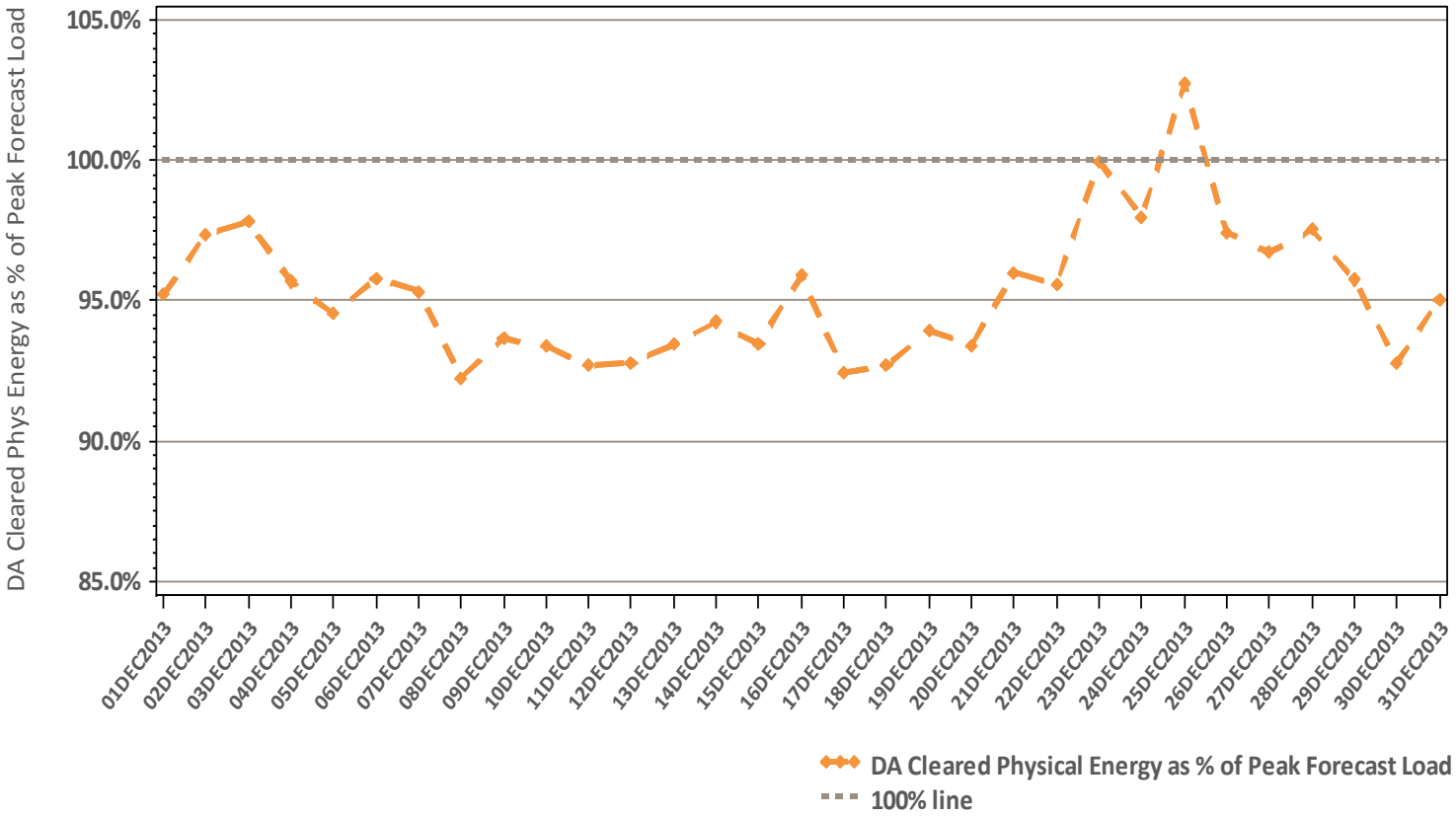
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

Components of RT Supply and Demand – Last Three Months



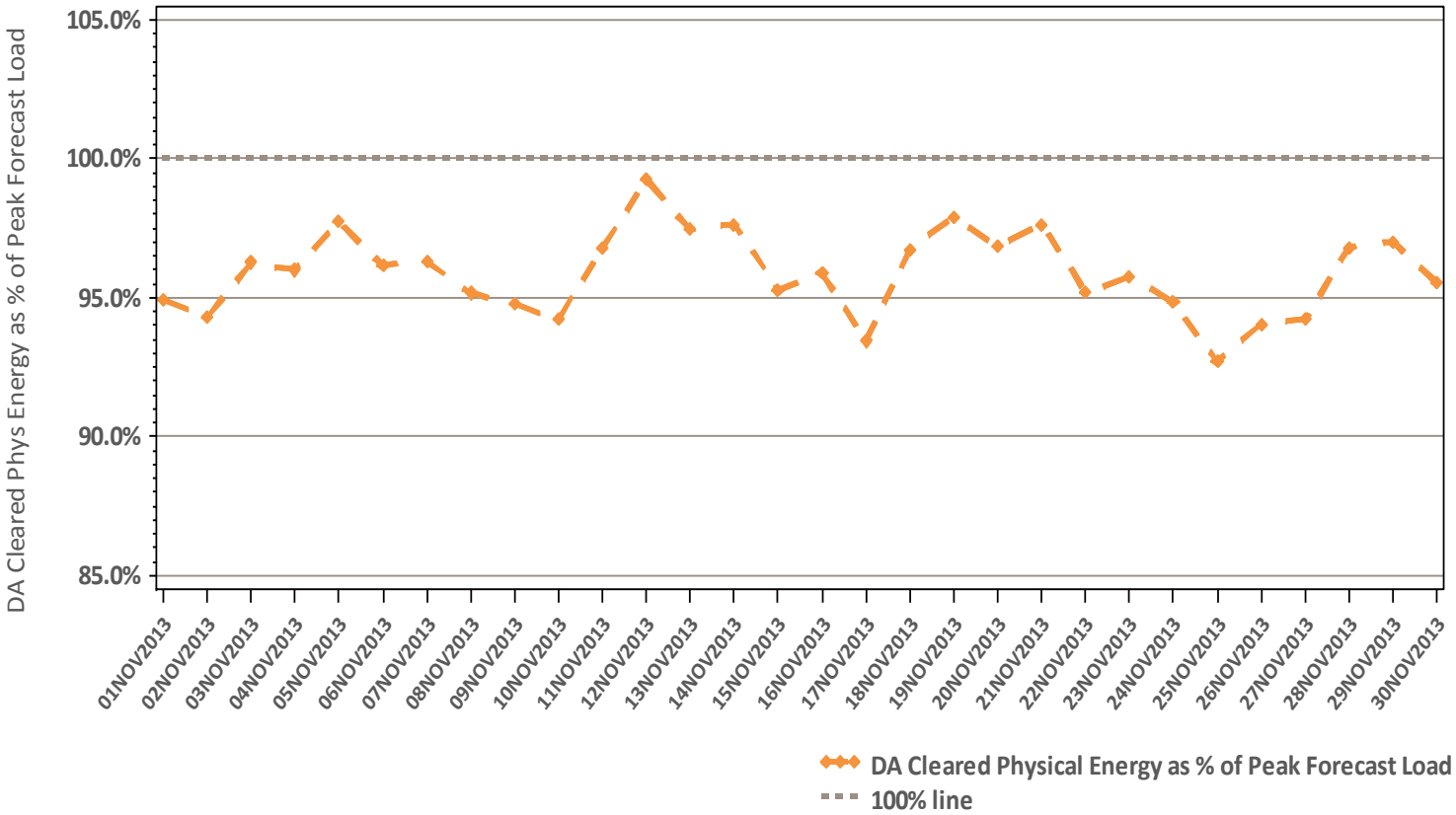


DA Cleared Physical Energy as Percent of Forecast (peak hour): December 2013



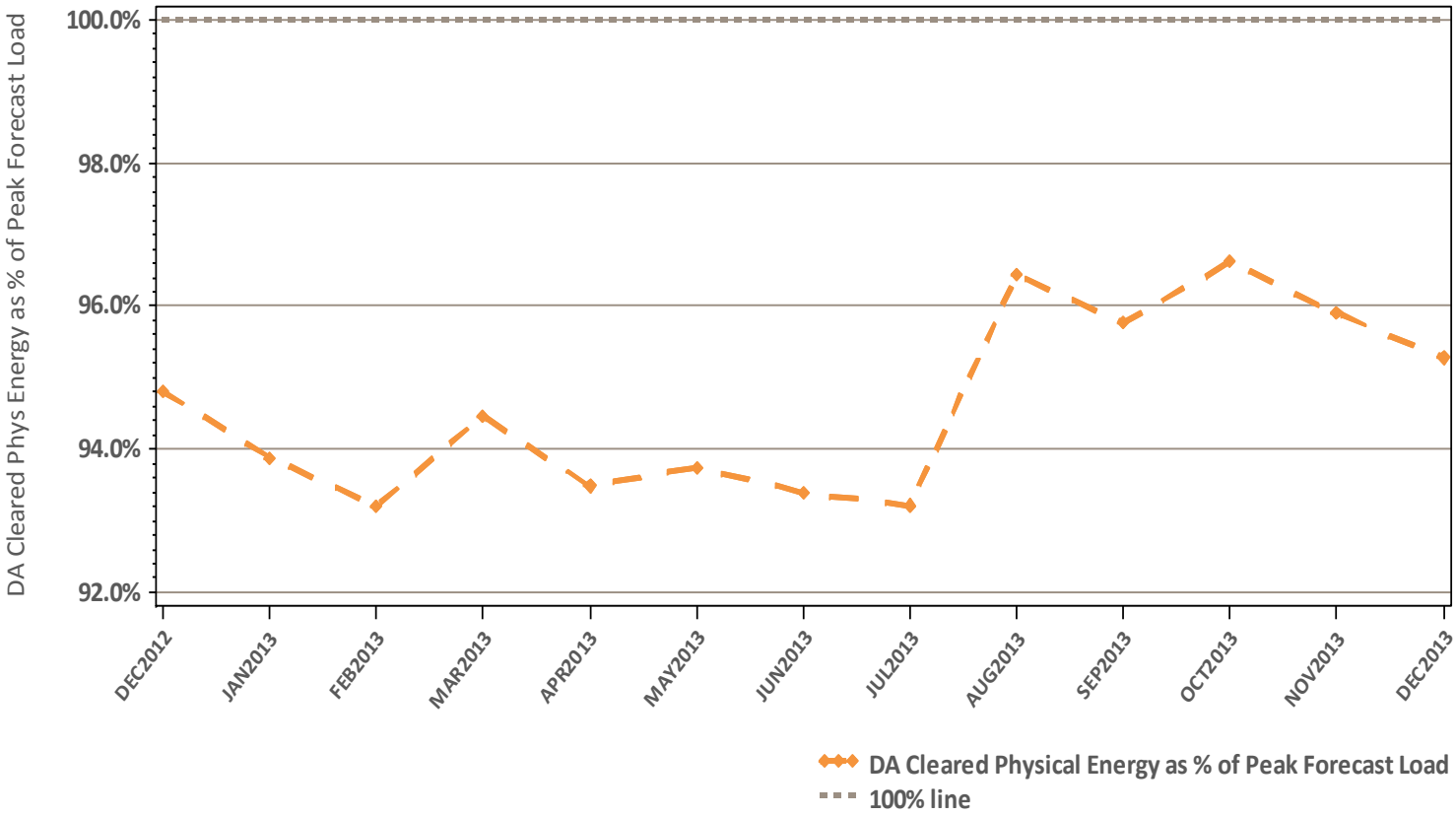
DA Cleared Physical Energy = DA Cleared {Fixed Demand (FAD) + Price Senstive Demand (PSD) + DECs - INCs}
--Analysis reflects the peak forecasted hour--

DA Cleared Physical Energy as Percent of Forecast (peak hour): November 2013



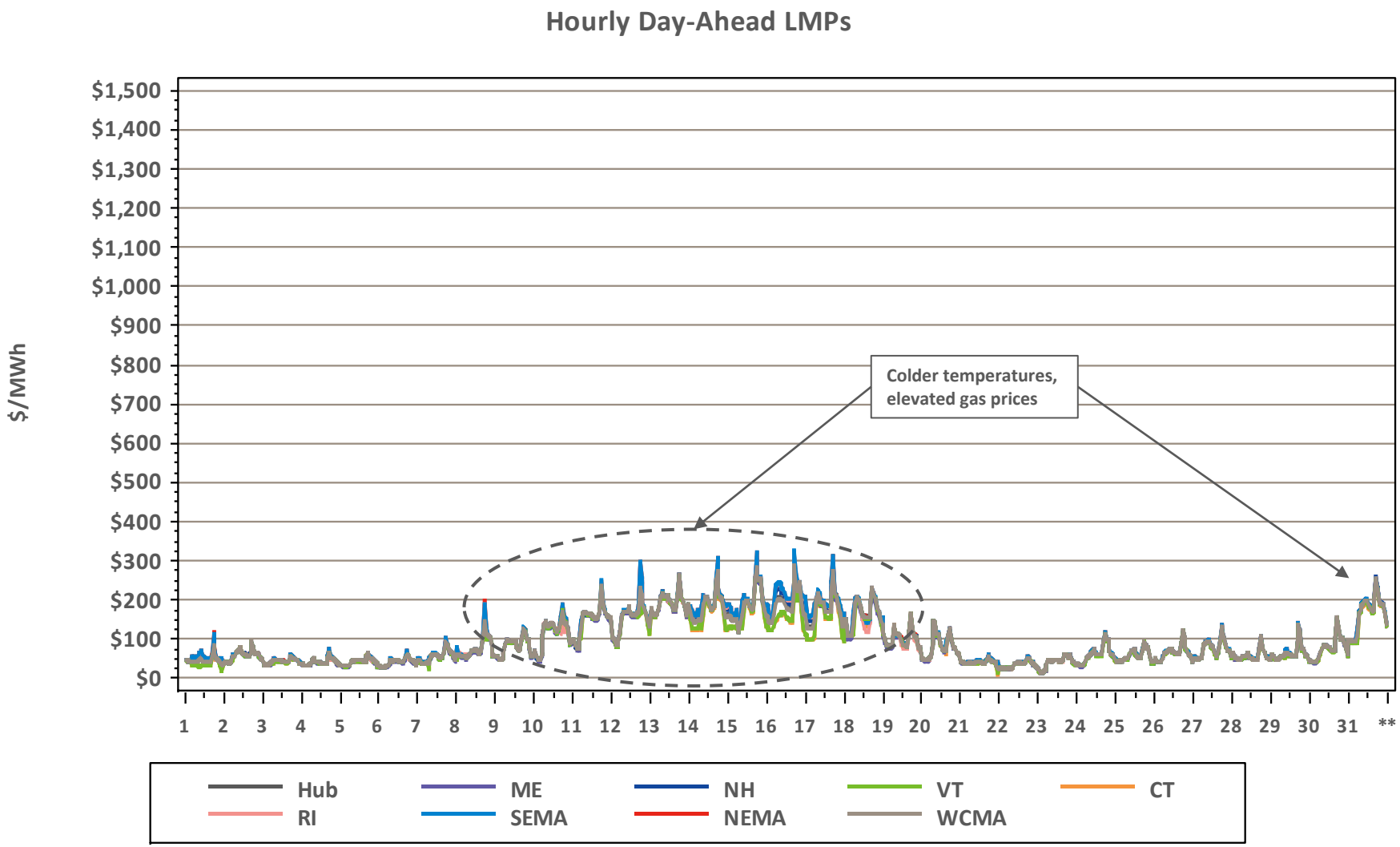
DA Cleared Physical Energy = DA Cleared {Fixed Demand (FAD) + Price Senstive Demand (PSD) + DECs - INCs}
--Analysis reflects the peak forecasted hour--

DA Cleared Physical Energy as Percent of Forecast (peak hour): Last 13 Months

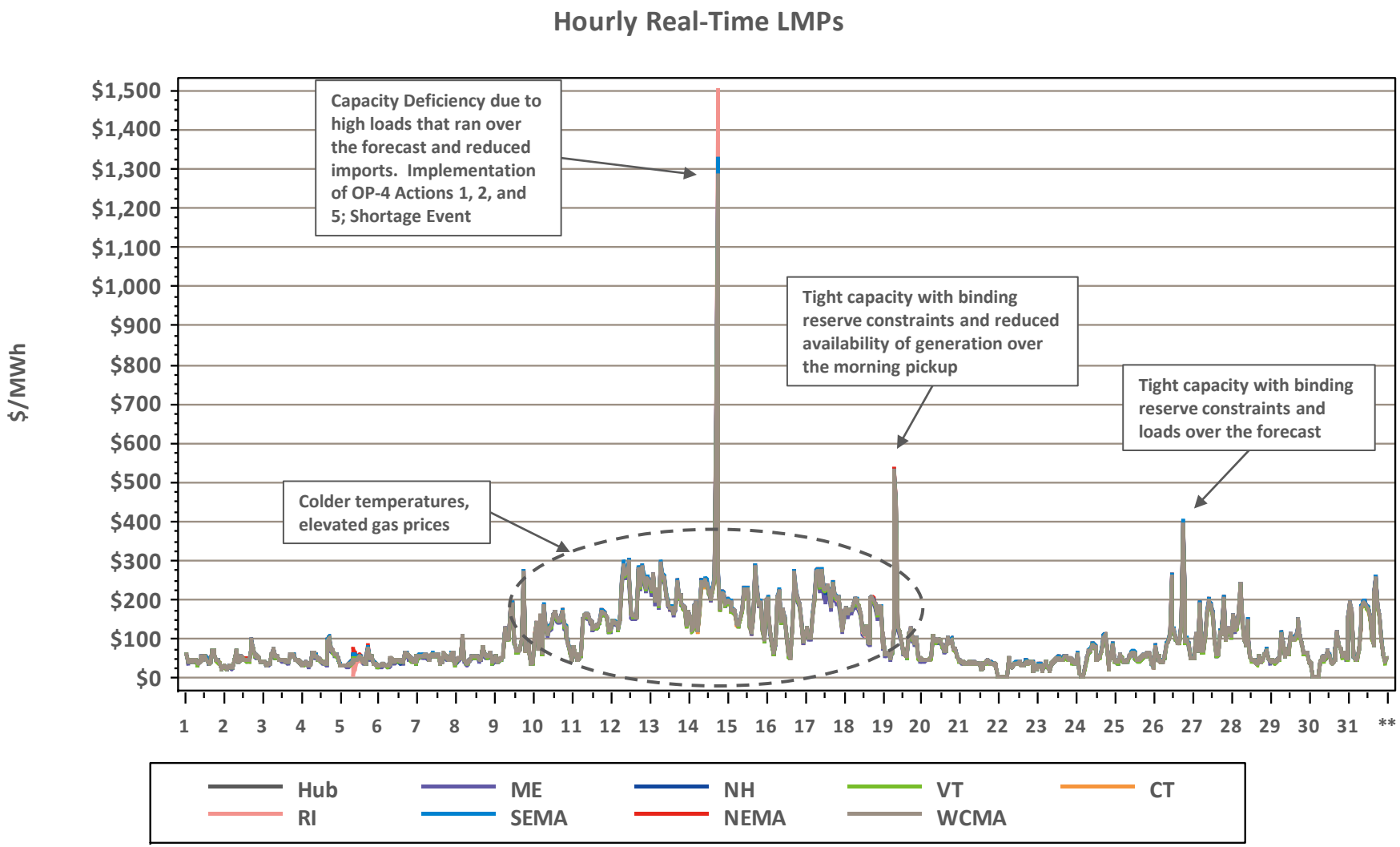


DA Cleared Physical Energy = DA Cleared {Fixed Demand (FAD) + Price Senstive Demand (PSD) + DECs - INCs}
--Analysis reflects the peak forecasted hour--

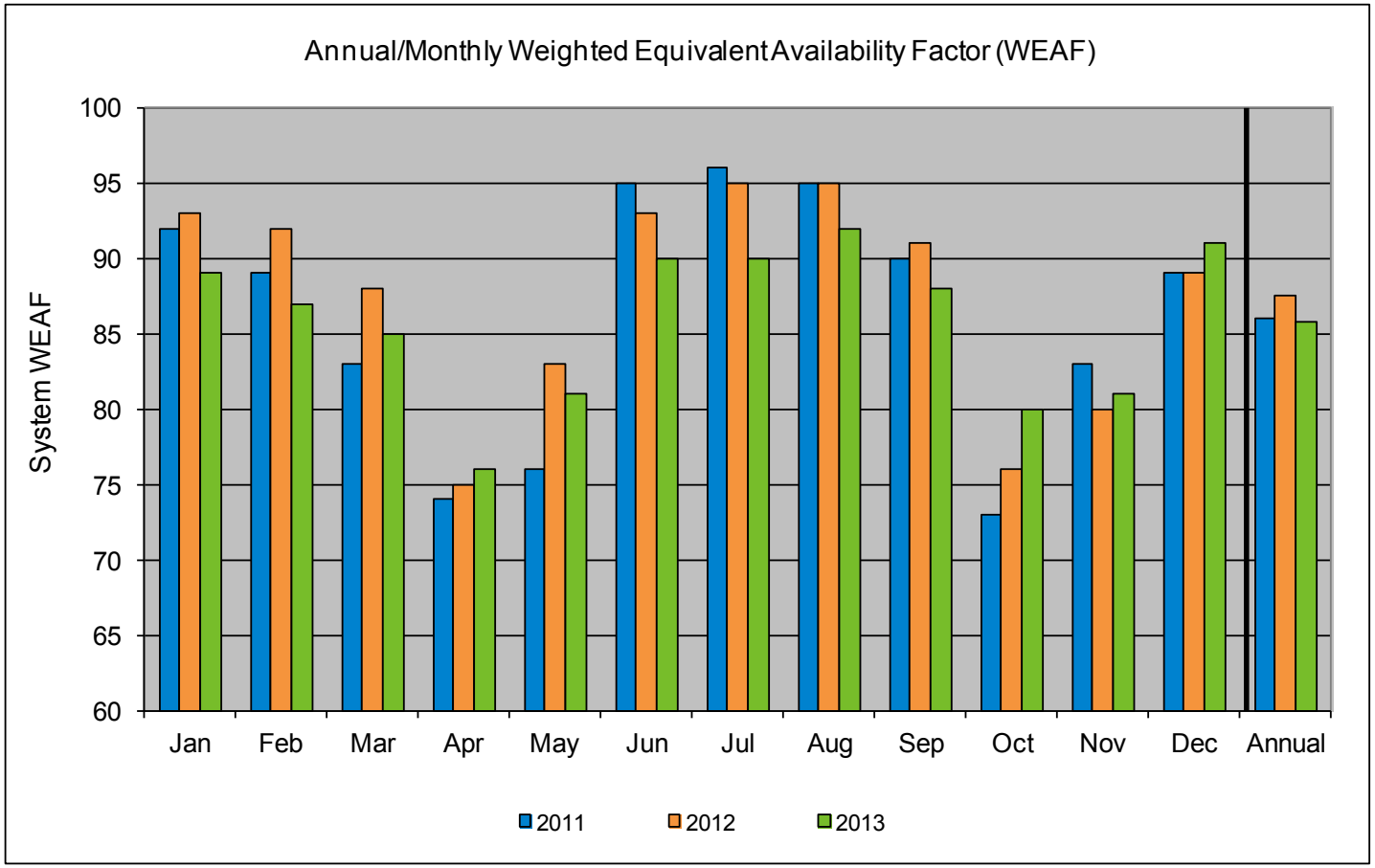
Hourly DA LMPs, December 1-31, 2013



Hourly RT LMPs, December 1-31, 2013



System Unit Availability



Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2013	89	87	85	76	81	90	90	92	88	80	81	91	86
2012	93	92	88	75	83	93	95	95	91	76	80	89	88
2011	92	89	83	74	76	95	96	95	90	73	83	89	86
2010	91	93	90	83	74	93	93	93	86	77	81	91	87

Data as of 1/3/14

BACK-UP DETAIL

LOAD RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for January 2014

Load Zone	RTDR*	RTEG**	On Peak	Seasonal Peak	Total
ME	137.20	6.24	83.73	0.00	227.17
NH	3.72	11.45	64.72	0.00	79.89
VT	27.83	2.01	88.86	0.00	118.69
CT	66.50	66.19	80.89	299.33	512.91
RI	10.31	6.62	75.38	0.00	92.31
SEMA	7.68	10.65	110.63	0.00	128.96
WCMA	21.88	19.87	101.02	28.69	171.46
NEMA	7.26	20.24	200.67	0.00	228.17
Total	**282.39**	**143.26**	**805.89**	**328.02**	**1,559.56**

* Real Time Demand Response
** Real Time Emergency Generation
NOTE: CSO values include T&D loss factor (8%) and, as applicable, a reserve margin gross-up of either 14.3% or 16.1%, respectively, for portions of resources that selected a multi-year obligation in the FCA 1 or FCA 2. Otherwise, reserve margin gross-ups were discontinued with FCA 3.

NEW GENERATION

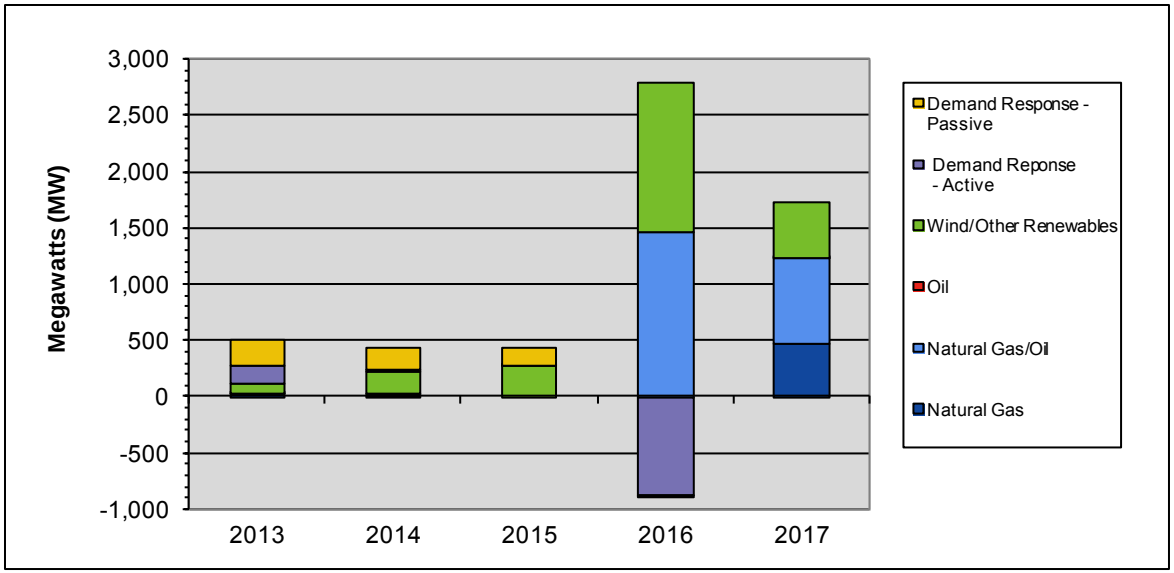
New Generation Update

Based on 1/1/14 Queue Update

- One new project, a wind project with a 2017 expected in-service date, has applied for interconnection study since the last update
- Three projects went commercial, resulting in a net decrease in new generation projects of 56 MW
- In total, 47 generation projects are currently being tracked by the ISO, totaling 5,000 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



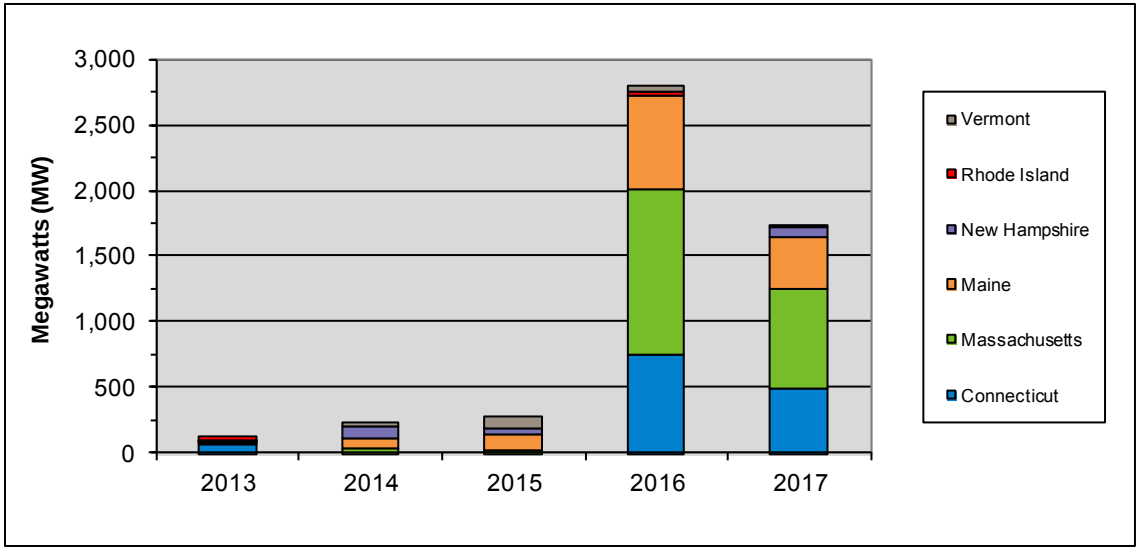
	2013	2014	2015	2016	2017	Total MW	% of Total*
Demand Response - Passive	225	188	157	-12	0	558	11.1
Demand Response - Active	169	19	3	-868	0	-677	-13.5
Wind & Other Renewables	74	201	273	1,327	497	2,372	47.2
Oil	0	0	0	0	14	14	0.3
Natural Gas/Oil	11	8	0	1,461	748	2,228	44.3
Natural Gas	30	21	0	0	482	533	10.6
Totals	**509**	**437**	**433**	**1,908**	**1,741**	**5,028**	**100.0**

*** Sum may not equal 100% due to rounding**

- 2013 values include the 115 MW of generation that went commercial in 2013
- Active DR value reflects the 600 MW limit on Real-Time Emergency Generation resources
- DR reflects changes from the initial FCM Capacity Supply Obligations in 2010-11

Actual and Projected Annual Generator Capacity Additions

By State



	2013	2014	2015	2016	2017	Total MW	% of Total*
Vermont	0	30	97	33	20	180	3.5
Rhode Island	28	0	0	29	0	57	1.1
New Hampshire	8	98	51	0	74	231	4.5
Maine	10	78	107	716	403	1,314	25.5
Massachusetts	16	24	18	1,265	762	2,085	40.5
Connecticut	53	0	0	745	482	1,280	24.9
Totals	**115**	**230**	**273**	**2,788**	**1,741**	**5,147**	**100.0**

*** Sum may not equal 100% due to rounding**

- 2013 values consist of the 115 MW of generation that went commercial in 2013

New Generation Projection

By Fuel Type

Fuel Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	4	175	1	68	3	107
Hydro	5	64	0	0	5	64
Landfill Gas	0	0	0	0	0	0
Natural Gas	2	503	0	0	2	503
Natural Gas/Oil	6	2,217	0	0	6	2,217
Oil	1	14	0	0	1	14
Solar	3	16	2	10	1	6
Wind	26	2,043	3	38	23	2,005
Total	47	5,032	6	116	41	4,916

- Green denotes projects with a high probability of going into service
- Yellow denotes projects with a lower probability of going into service or new applications

New Generation Projection

By Operating Type

Operating Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	4	175	1	68	3	107
Intermediate	10	2,318	0	0	10	2,318
Peaker	7	496	2	10	5	486
Wind Turbine	26	2,043	3	38	23	2,005
Total	47	5,032	6	116	41	4,916

- Green denotes projects with a high probability of going into service
- Yellow denotes projects with a lower probability of going into service or new applications

New Generation Projection

By Operating Type and Fuel Type

Fuel Type	Total		Baseload		Intermediate		Peaker		Wind Turbine	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	4	175	4	175	0	0	0	0	0	0
Hydro	5	64	0	0	4	14	1	50	0	0
Landfill Gas	0	0	0	0	0	0	0	0	0	0
Natural Gas	2	503	0	0	2	503	0	0	0	0
Natural Gas/Oil	6	2,217	0	0	4	1,801	2	416	0	0
Oil	1	14	0	0	0	0	1	14	0	0
Solar	3	16	0	0	0	0	3	16	0	0
Wind	26	2,043	0	0	0	0	0	0	26	2,043
Total	47	5,032	4	175	10	2,318	7	496	26	2,043

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 4

Resource Type	Resource Type	FCA 4	Proration		Annual Bilateral Period 1 for ARA 2		ARA 2		Annual Bilateral Period 2 for ARA 2		Annual Bilateral 3 Period		ARA 3	
		*CSO	CSO	**Change	ARA 2	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	2,051.536	1,860.060	-191.476	1,681.032	-179.028	1,482.357	-198.675	1,367.357	-115.000	1,021.146	-346.211	700.637	-320.509
	Passive Demand	1,297.906	1,154.626	-143.280	1,135.705	-18.921	1,163.465	27.760	1,163.465	0.000	1,123.515	-39.950	1,149.743	26.228
Demand Total		**3,349.442**	**3,014.686**	**-334.756**	**2,816.737**	**-197.949**	**2,645.822**	**-170.915**	**2,530.822**	**-115.000**	**2,144.661**	**-386.161**	**1,850.380**	-294.281
Generator	*Non-Intermittent*	31,161.623	27,655.394	-3,506.229	27,839.130	183.736	28,386.625	547.495	27,890.197	-496.428	28,354.572	464.375	28,812.896	458.324
	Intermittent	1,085.540	979.072	-106.468	972.075	-6.997	857.886	-114.189	865.064	7.178	841.517	-23.547	784.778	-56.739
Generator Total		**32,247.163**	**28,634.466**	**-3,612.697**	**28,811.205**	**176.739**	**29,244.511**	**433.306**	**28,755.261**	**-489.250**	**29,196.089**	**440.828**	**29,597.674**	401.585
Import Total		**1,992.600**	**1,726.449**	**-266.151**	**1,726.449**	**0.000**	**1,396.258**	**-330.191**	**1,396.258**	**0.000**	**1,296.258**	**-100.000**	**1,182.869**	-113.389
***Grand Total		**37,589.205**	**33,375.601**	**-4,213.604**	**33,354.391**	**-21.210**	**33,286.591**	**-67.800**	**32,682.341**	**-604.250**	**32,637.008**	**-45.333**	**32,630.923**	-6.085

* Real-time Emergency Generators (RTEG) CSO not capped at 600.000 MW

** Change columns contains the changes in CSO amount resulting from the specific FCM Event as well as adjustments for Delisted MW released according to MR 1, Section 13.2.5.2, and changes that occurred (terminations etc.) prior to the event reported in the column.

*** Grand Total reflects both CSO Grand Total and the net total of the Change Column.

Capacity Supply Obligation FCA 5

Resource Type	Resource Type	FCA 4	Proration		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	**Change	ARA 2	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	2,104.141	2,001.126	-103.015	1,385.670	-615.456	1,074.461	-311.21				
	Passive Demand	1,485.713	1,397.586	-88.127	1,345.283	-52.303	1,348.593	3.31				
Demand Total		**3,589.854**	**3,398.712**	**-191.142**	**2,730.953**	**-667.759**	**2,423.054**	-307.90				
Generator	*Non-Intermittent*	30,558.220	28,337.481	-2,220.739	27,917.690	-419.791	28,364.588	446.90				
	Intermittent	880.737	827.804	-52.933	778.165	-49.639	795.545	17.38				
Generator Total		**31,438.957**	**29,165.285**	**-2,273.672**	**28,695.855**	**-469.430**	**29,160.133**	464.28				
Import Total		**2,011.001**	**1,831.372**	**-179.629**	**1,831.372**	**0.000**	**1,635.835**	-195.54				
***Grand Total		**37,039.812**	**34,395.369**	**-2,644.443**	**33,258.180**	**-1,137.189**	**33,219.022**	-39.16				

* Real-time Emergency Generators (RTEG) CSO not capped at 600.000 MW

** Change columns contains the changes in CSO amount resulting from the specific FCM Event as well as adjustments for Delisted MW released according to MR 1, Section 13.2.5.2, and changes that occurred (terminations etc.) prior to the event reported in the column.

*** Grand Total reflects both CSO Grand Total and the net total of the Change Column.

Capacity Supply Obligation FCA 6

Resource Type	Resource Type	FCA	Proration		Annual Bilateral for ARA 1		ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	**Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	2,001.510	1,918.662	-82.848	1,368.608	-550.054	1,271.984	-96.624								
	Passive Demand	1,643.334	1,553.054	-90.280	1,521.535	-31.519	1,521.535	0.000								
Demand Total		**3,644.844**	**3,471.716**	**-173.128**	**2,890.143**	**-581.573**	**2,793.519**	-96.624								
Generator	*Non-Intermittent*	29,866.098	27,957.613	-1,908.485	28,121.731	164.118	28,343.440	221.709								
	Intermittent	891.069	840.563	-50.506	827.047	-13.516	828.252	1.205								
Generator Total		**30,757.167**	**28,798.176**	**-1,958.991**	**28,948.778**	**150.602**	**29,171.692**	222.914								
Import Total		**1,924.000**	**1,768.111**	**-155.889**	**1,768.111**	**0.000**	**1,641.821**	-126.290								
***Grand Total**		**36,326.011**	**34,038.003**	**-2,288.008**	**33,607.032**	**-430.971**	**33,607.032**	0.000								

* Real-time Emergency Generators (RTEG) CSO not capped at 600.000 MW

** Change columns contains the changes in CSO amount resulting from the specific FCM Event as well as adjustments for Delisted MW released according to MR 1, Section 13.2.5.2, and changes that occurred (terminations etc.) prior to the event reported in the column.

*** Grand Total reflects both CSO Grand Total and the net total of the Change Column.

Capacity Supply Obligation FCA 7

Resource Type	Resource Type	FCA	Proration		Annual Bilateral for ARA 1		ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	**Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	1,116.698	1,043.719	-72.979												
	Passive Demand	1,631.335	1,519.740	-111.595												
Demand Total		**2,748.033**	**2,563.459**	-184.574												
Generator	*Non-Intermittent*	30,704.578	28,146.837	-2,557.741												
	Intermittent	936.913	893.710	-43.203												
Generator Total		**31,641.491**	**29,040.547**	**-2,600.944**												
Import Total		**1,830.000**	**1,606.862**	**-223.138**												
***Grand Total**		**36,219.524**	**33,210.868**	**-3,008.656**												

* Real-time Emergency Generators (RTEG) CSO not capped at 600.000 MW

** Change columns contains the changes in CSO amount resulting from the specific FCM Event as well as adjustments for Delisted MW released according to MR 1, Section 13.2.5.2, and changes that occurred (terminations etc.) prior to the event reported in the column.

*** Grand Total reflects both CSO Grand Total and the net total of the Change Column.

RELIABILITY COSTS – NET COMMITMENT PERIOD COMPENSATION (NCPC) OPERATING COSTS

What are Daily NCPC Payments?

- “Make-whole” payments made to resources whose hourly commitment and dispatch by ISO-NE resulted in a shortfall between the resource’s offered value in the Energy and Regulation Markets and the revenue earned from output over the course of the day
- Typically, this is the result of some out-of-merit operation of resources occurring in order to protect the overall resource adequacy and transmission security of specific locations or of the entire control area

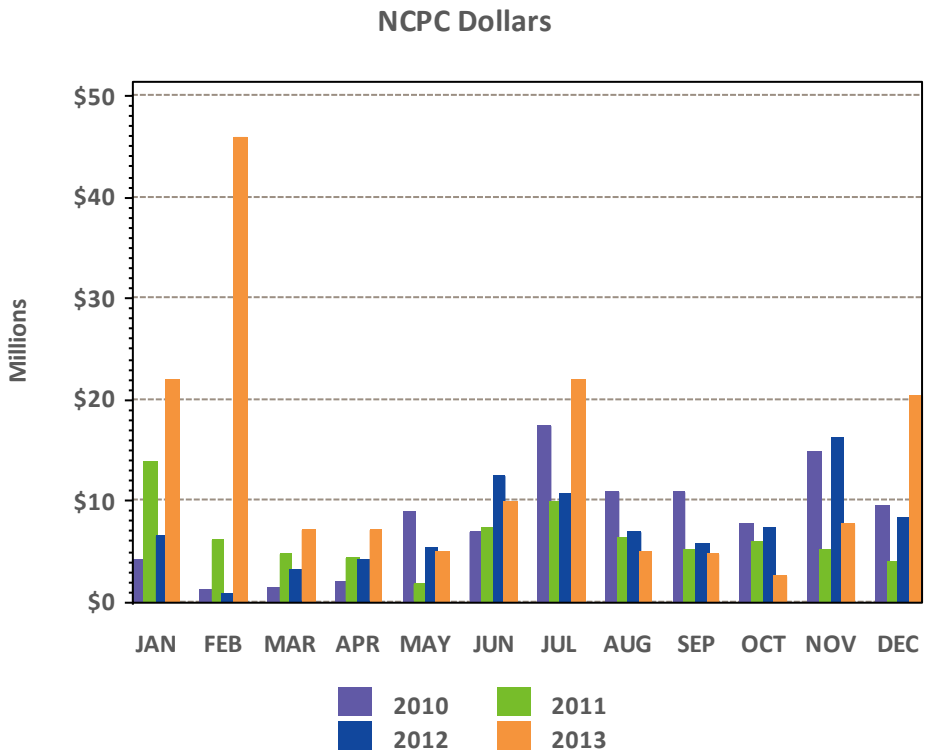
Definitions

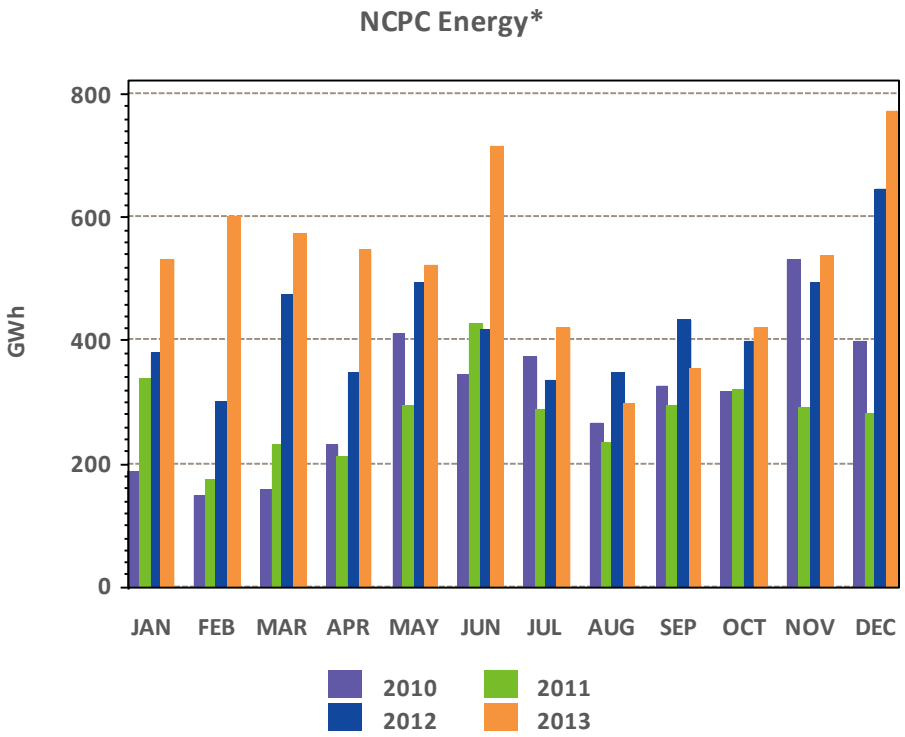
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally.
2nd Contingency NCPC Payments	Reliability costs paid to resources providing capacity in constrained areas to respond to a local second contingency. They are committed based on 2nd Contingency (2ndC) protocols, and are also known as Local Second Contingency Protection Resources (LSCPR).
Voltage NCPC Payments	Reliability costs paid to resources operated by ISO-NE to provide voltage support or control in specific locations.
Distribution NCPC Payments	Reliability costs paid to units dispatched at the request of local transmission providers for purpose of managing constraints on the low voltage (distribution) system. These requirements are not modeled in the DA Market software.
Delisted Units	Resources within the control area that have requested to be classified as a non-installed capacity (ICAP) resource, and as such, are not required to offer their capacity into the DA Energy Market.
OATT	Open Access Transmission Tariff.

Charge Allocation Key

Allocation Category	Market / OATT	Allocation
System 1st Contingency	Market	DA 1st C (excluding at external nodes) is allocated to system DALO. RT 1st C (at all locations) is allocated to System 'Daily Deviations'. Daily Deviations = sum of(generator deviations, load deviations, generation obligation deviations at external nodes, increment offer deviations)
External DA 1st Contingency	Market	DA 1st C at external nodes (from imports, exports, Incs and Decs) are allocated to activity at the specific external node or interface involved
Zonal 2nd Contingency	Market	DA and RT 2nd C NCPC are allocated to load obligation in the Reliability Region (zone) served
System Low Voltage	OATT	(Low) Voltage Support NCPC is allocated to system Regional Network Load and Open Access Same-Time Information Service (OASIS) reservations
Zonal High Voltage	OATT	High Voltage Control NCPC is allocated to zonal Regional Network Load
Distribution - PTO	OATT	Distribution NCPC is allocated to the specific Participant Transmission Owner (PTO) requesting the service

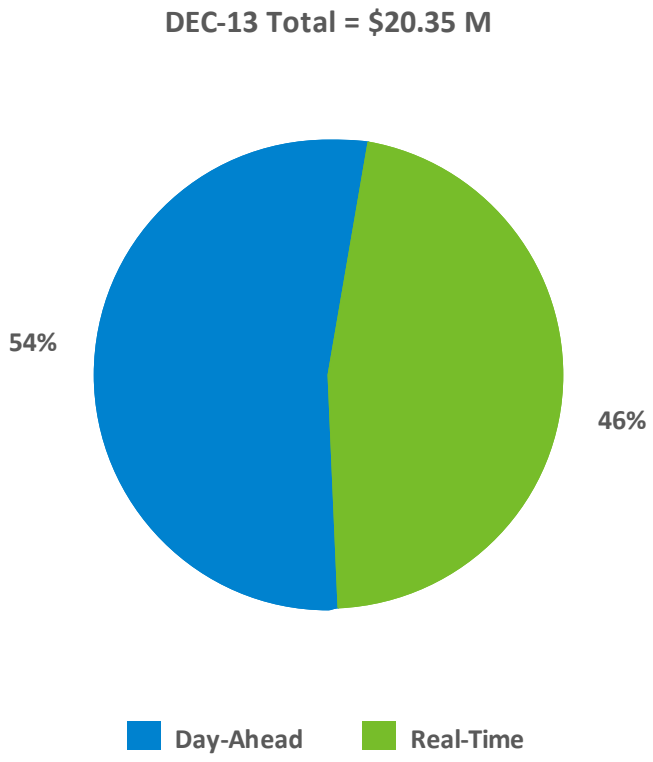
Year-Over-Year Total NCPC Dollars and Energy

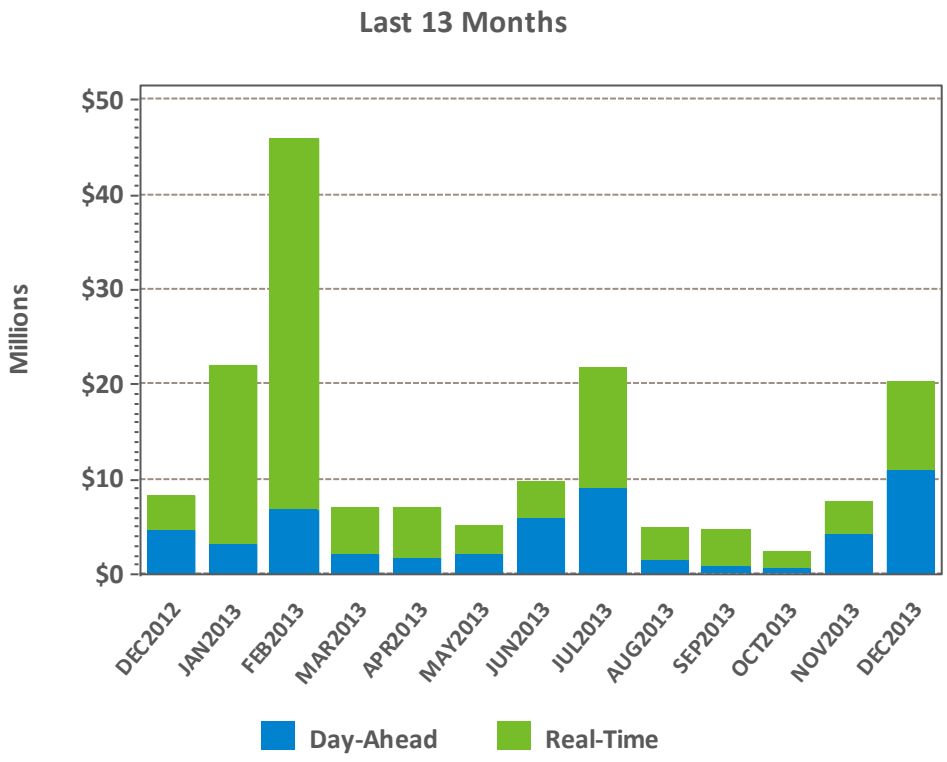




* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits, assessed during hours in which they are NCPC-eligible. All NCPC components (1st Contingency, 2nd Contingency, Voltage, and RT Distribution) are reflected.

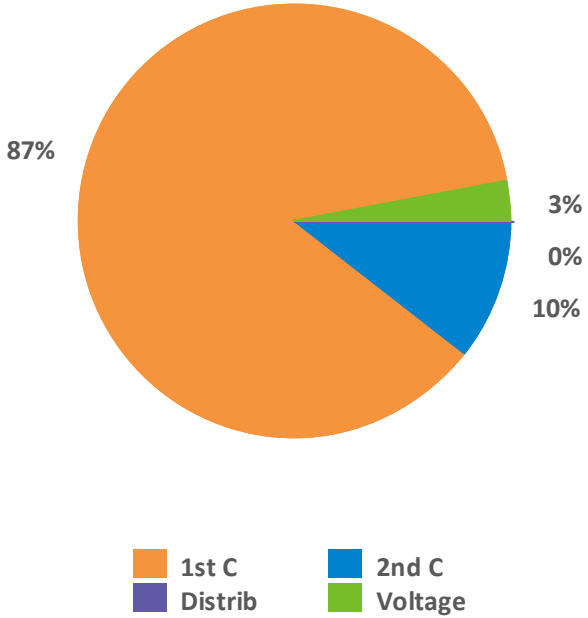
DA and RT NCPC Charges



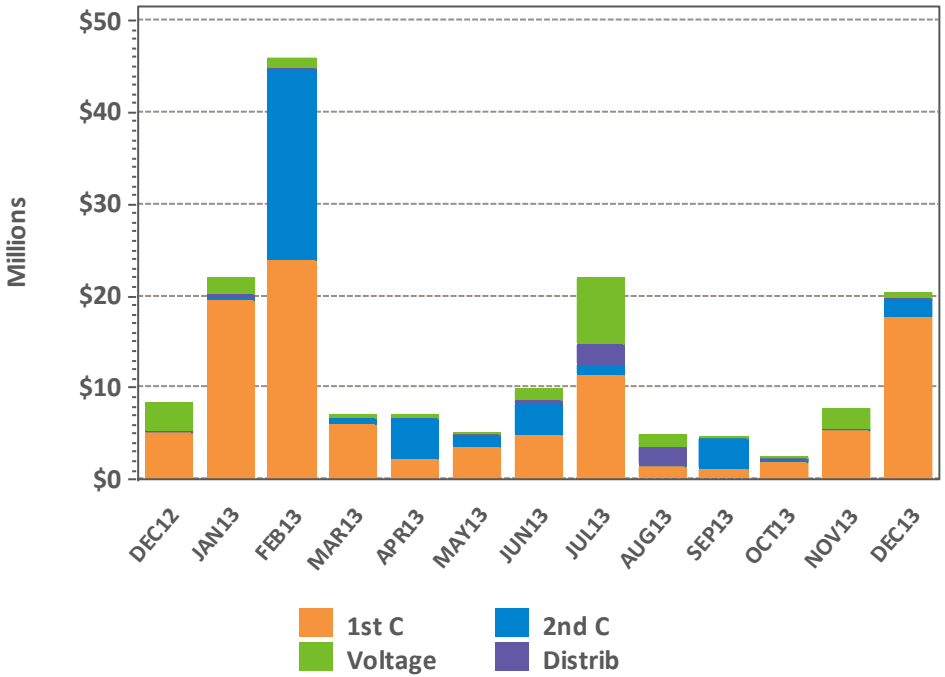


NCPC Charges by Type

DEC-13 Total = $20.35 M

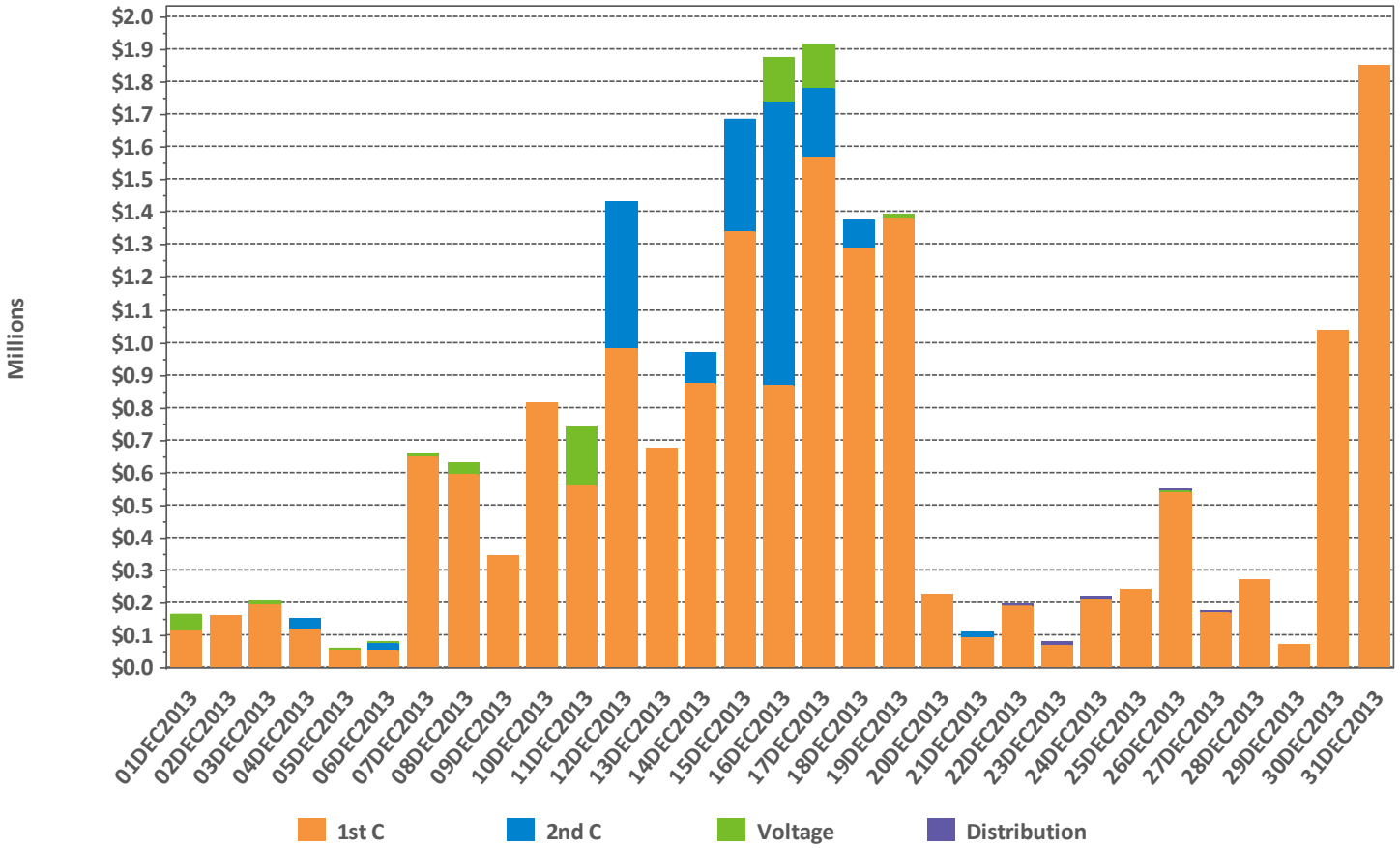


Last 13 Months

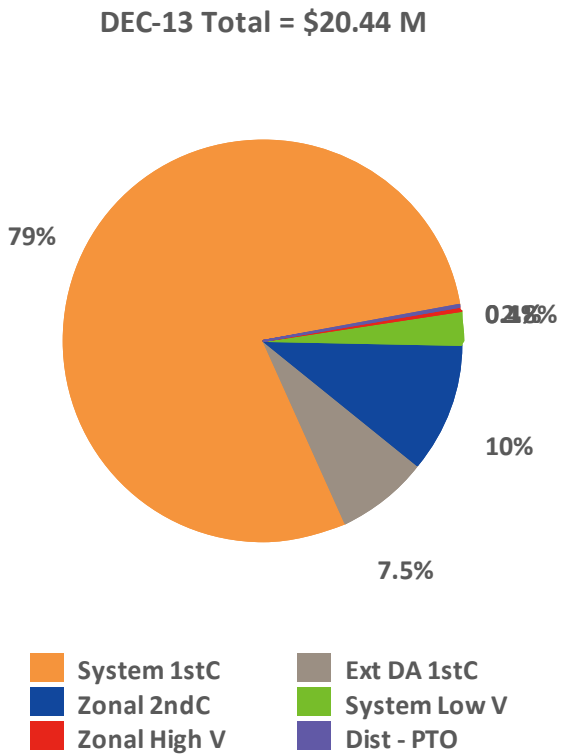


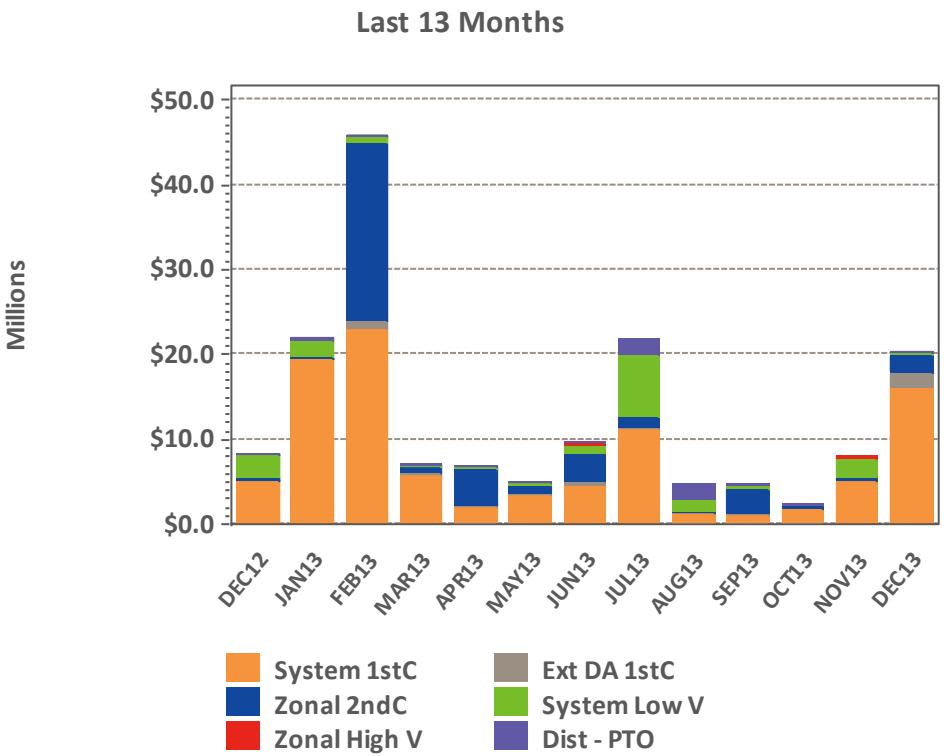
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type

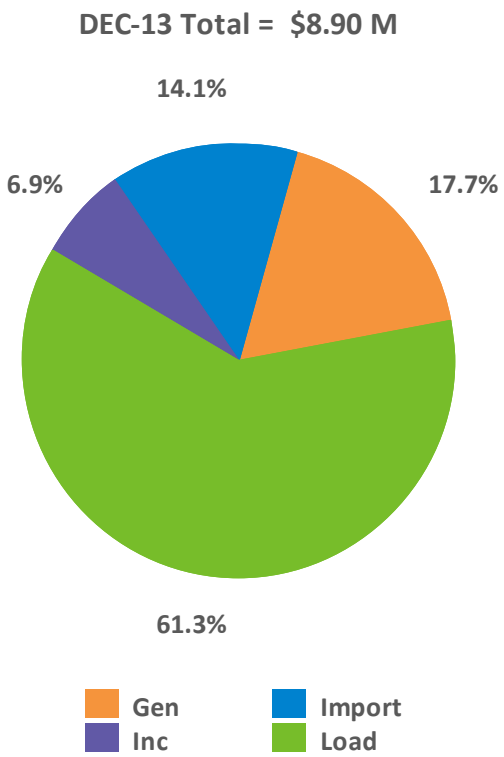


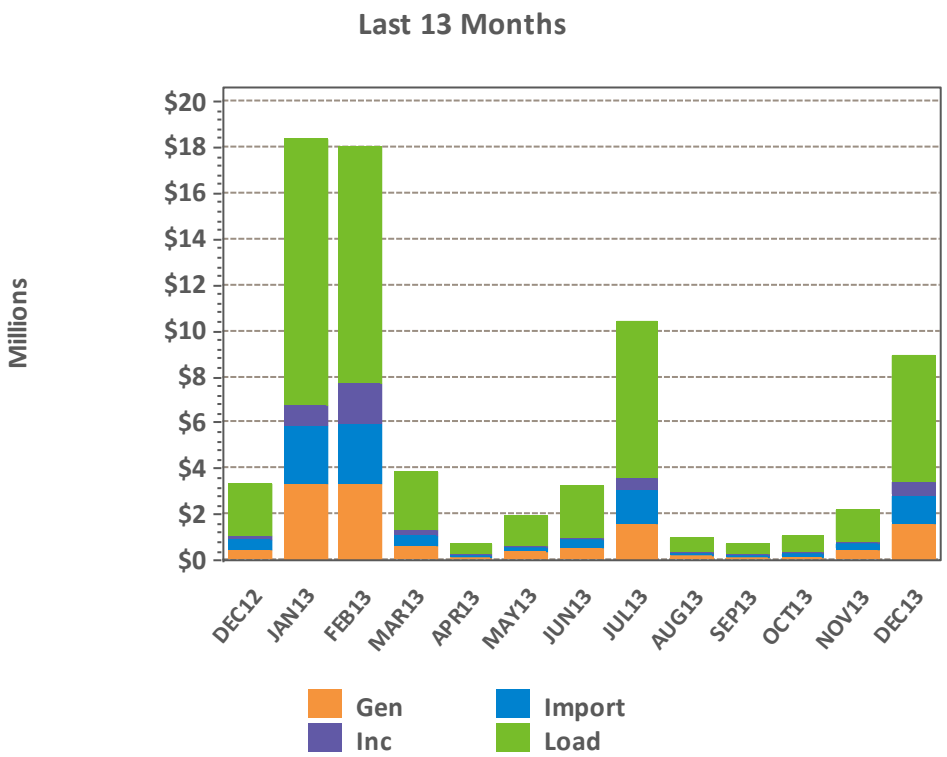
NCPC Charges by Allocation





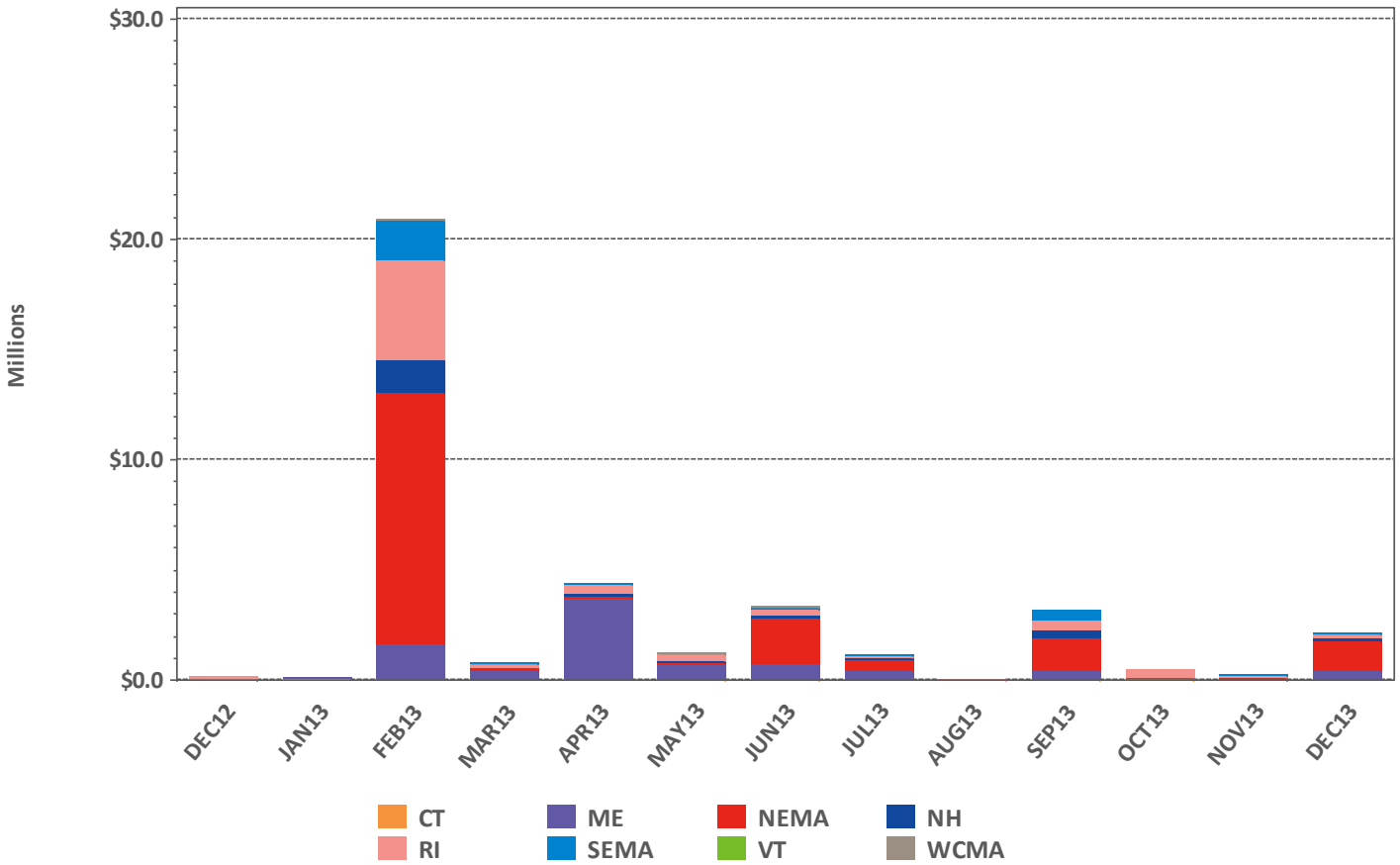
RT First Contingency Charges by Deviation Type





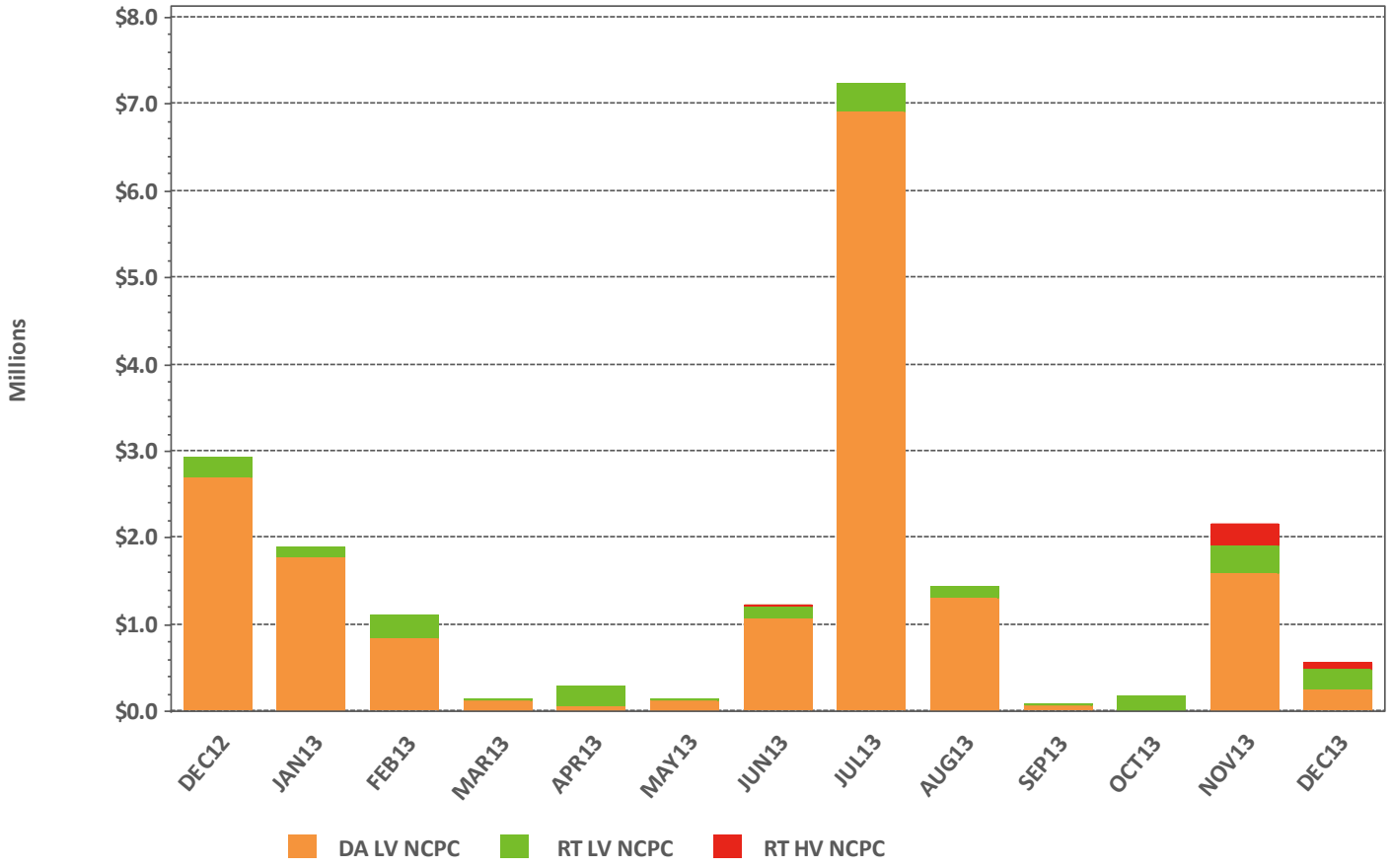
Gen – Generator deviations
Inc – Increment Offer deviations
Imp – Import deviations
Load – Load obligation deviations

LSCPR Charges by Zone

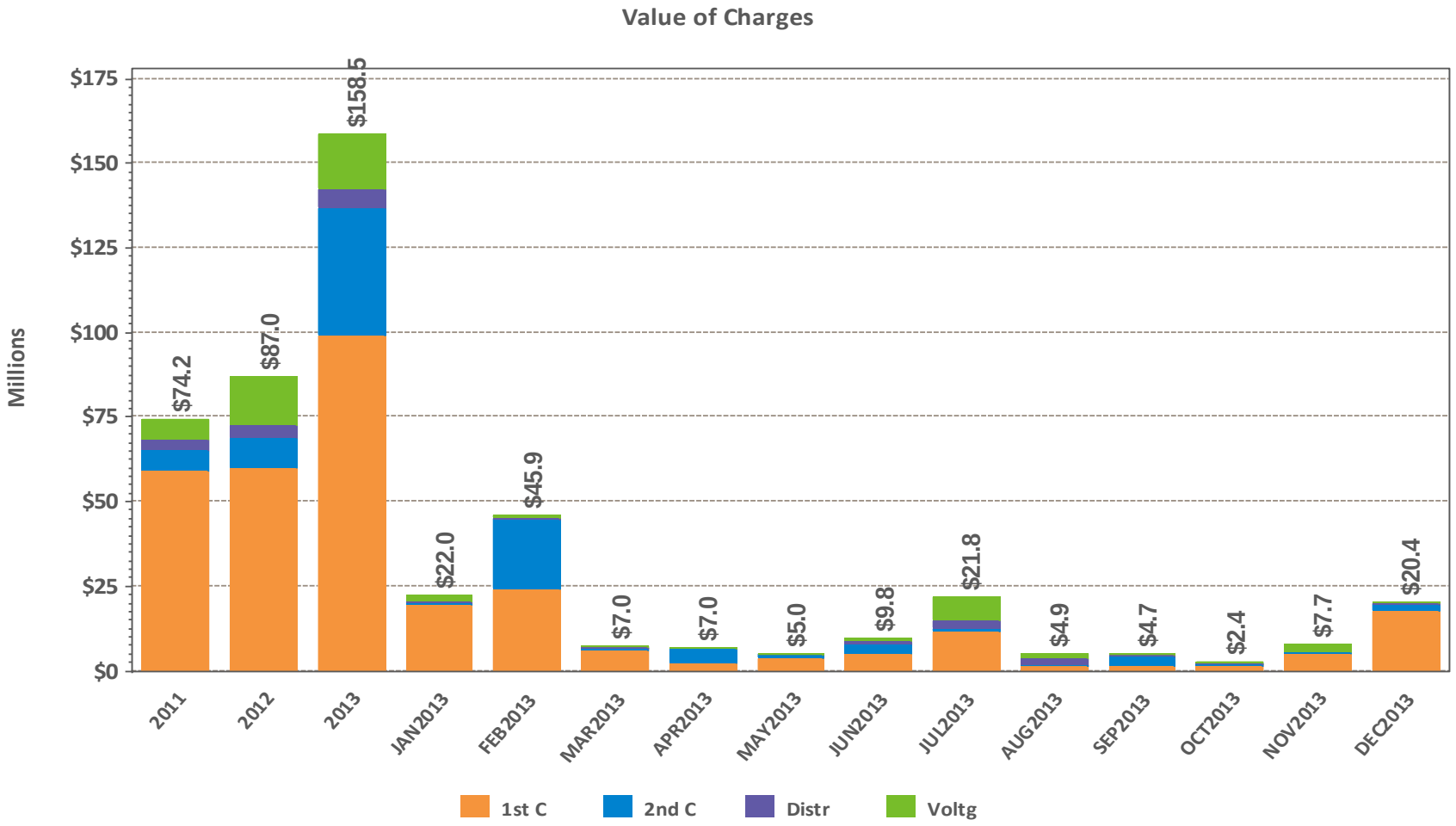


CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region
SEMA – Southeast Massachusetts Region
WCMA – Western/Central Massachusetts Region
NEMA – Northeast Massachusetts Region
EXT – External Locations

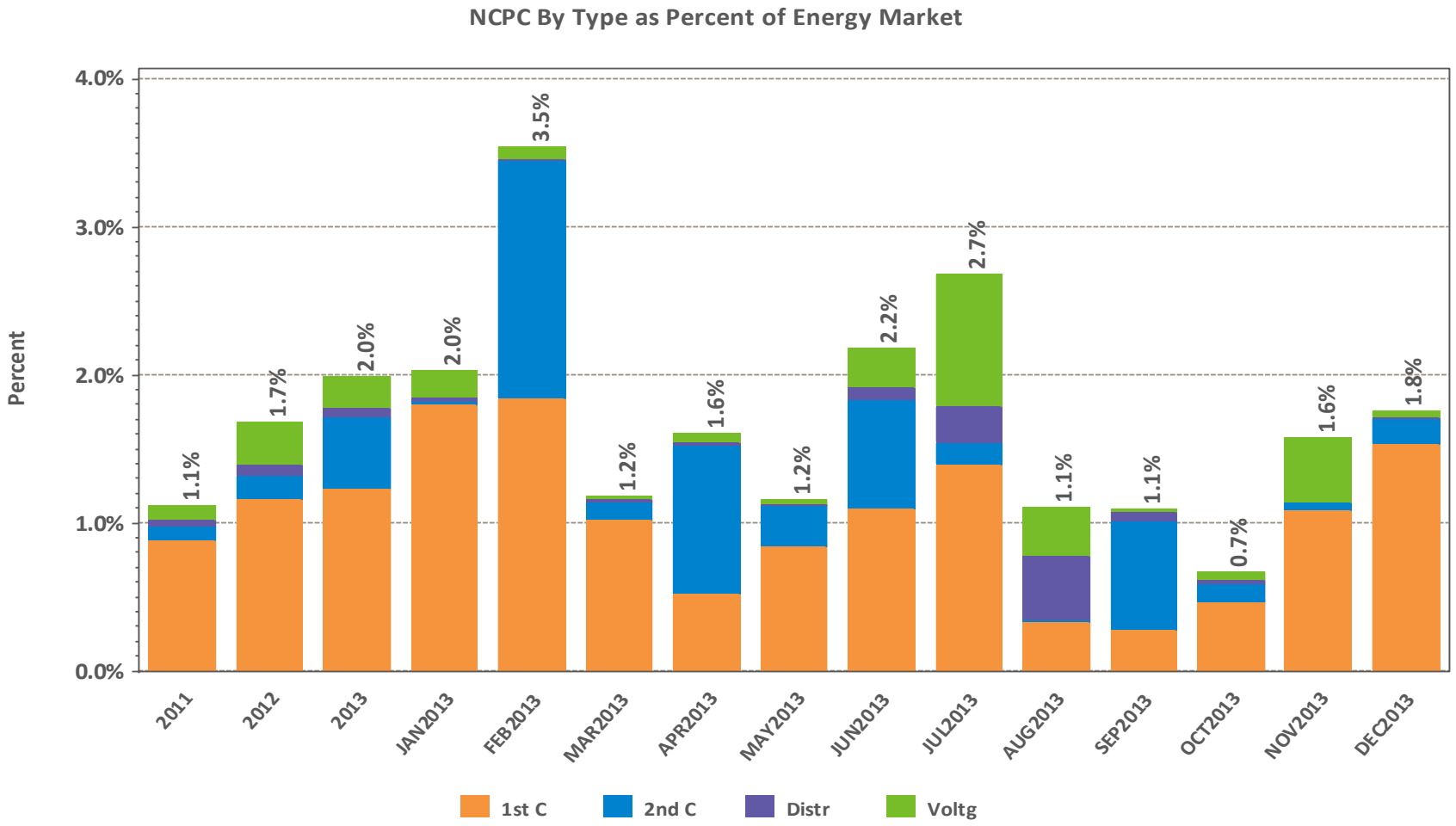
NCPC Charges for Voltage Support and High Voltage Control



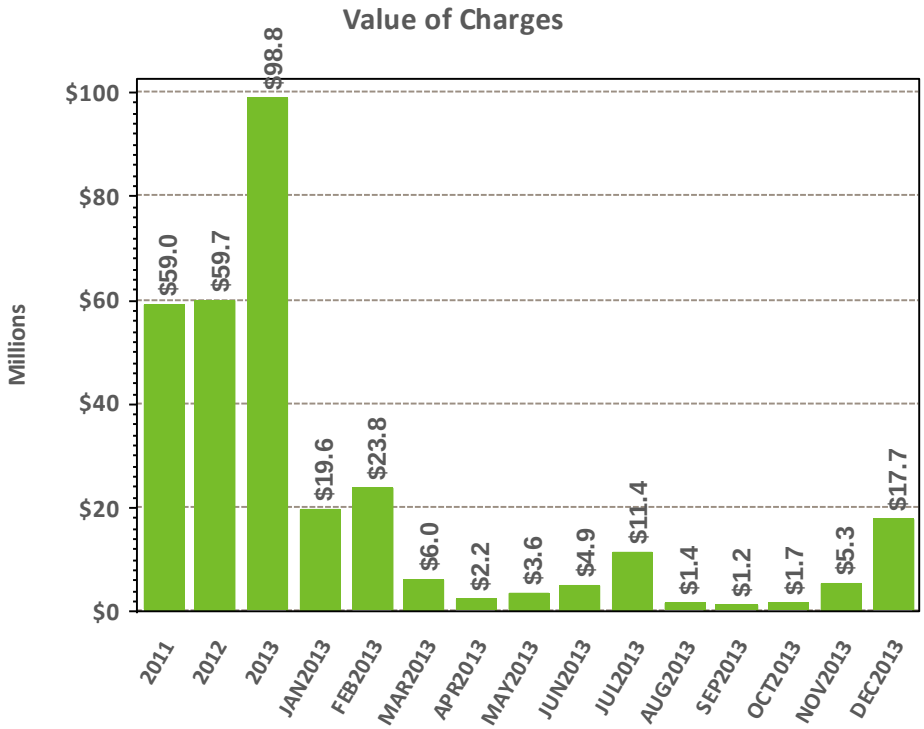
NCPC Charges by Type

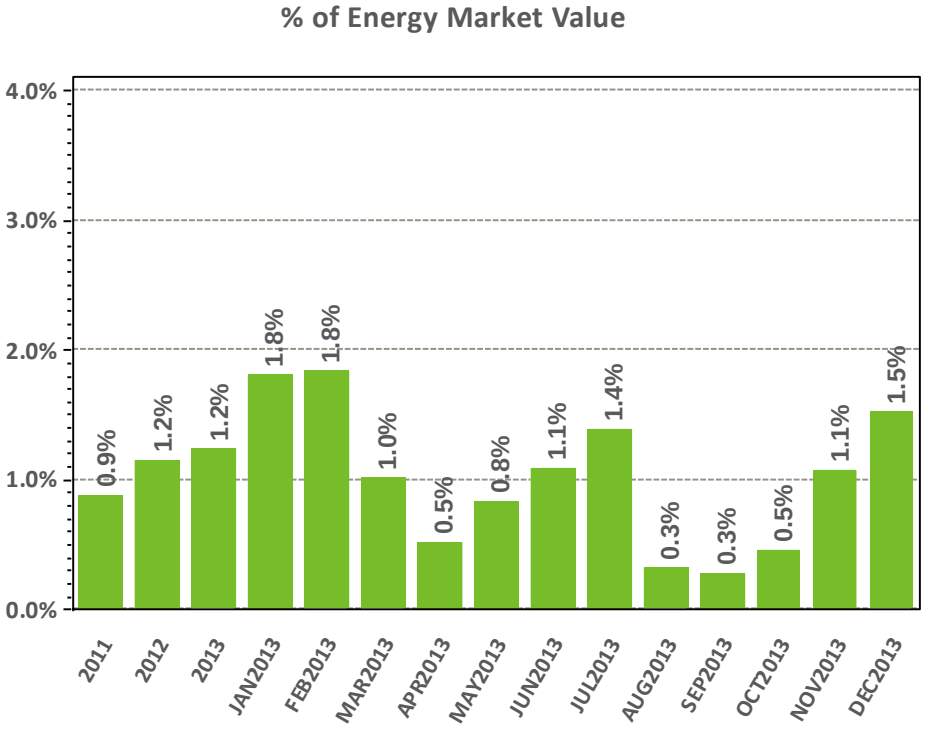


NCPC Charges as Percent of Energy Market



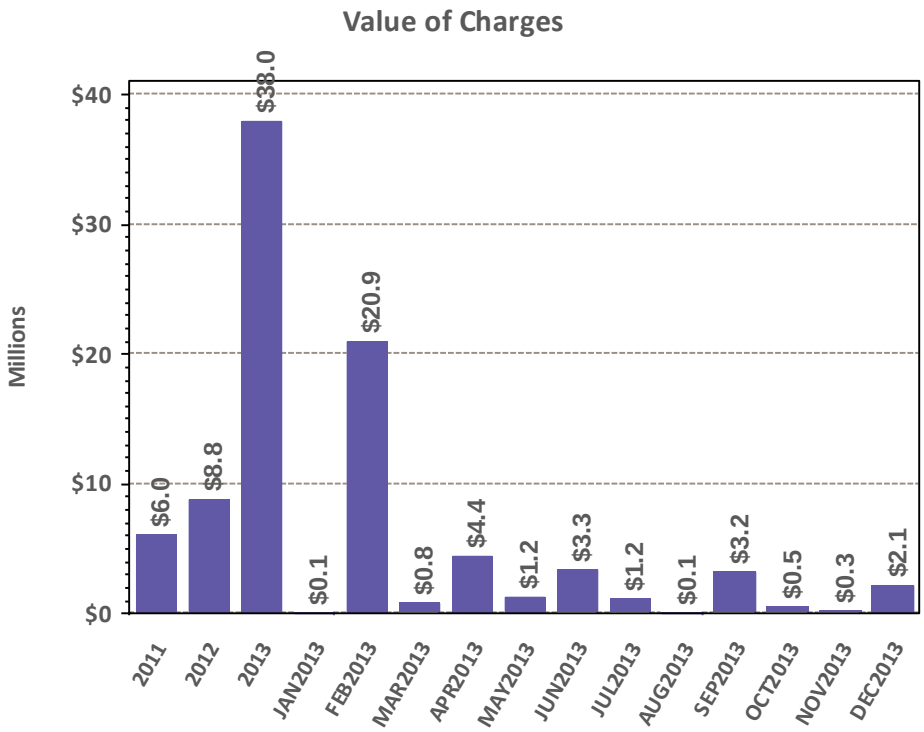
First Contingency NCPC Charges

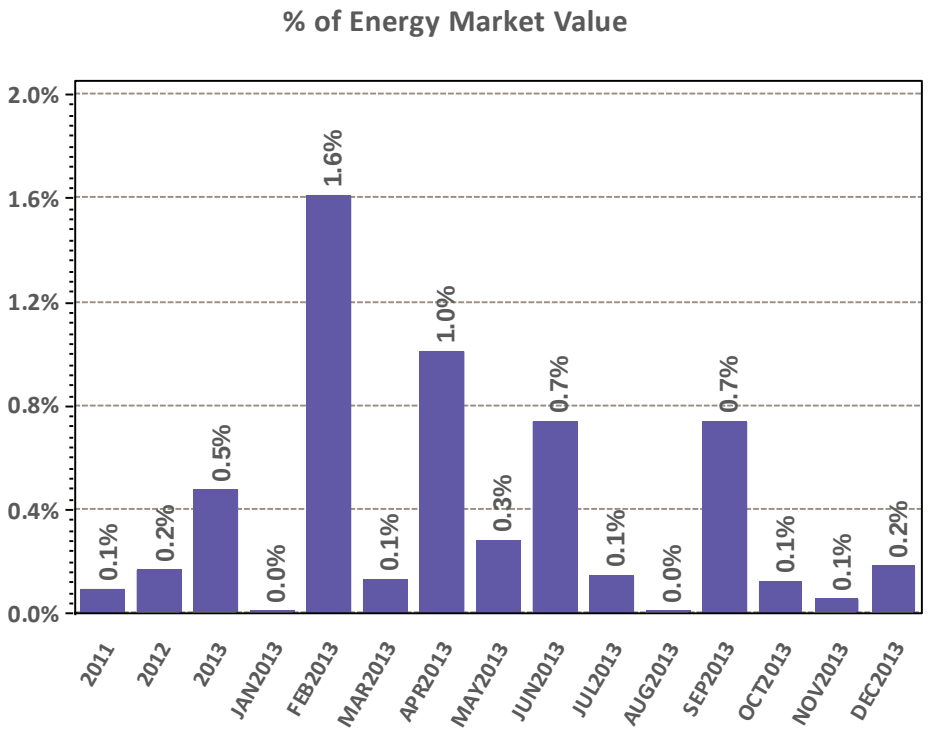




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

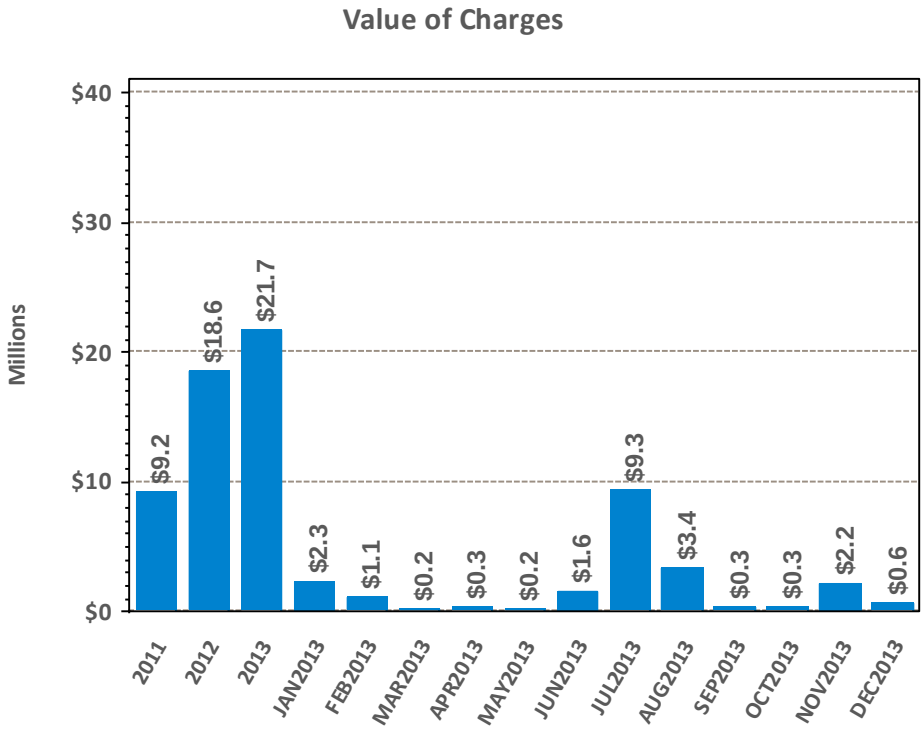
Second Contingency NCPC Charges

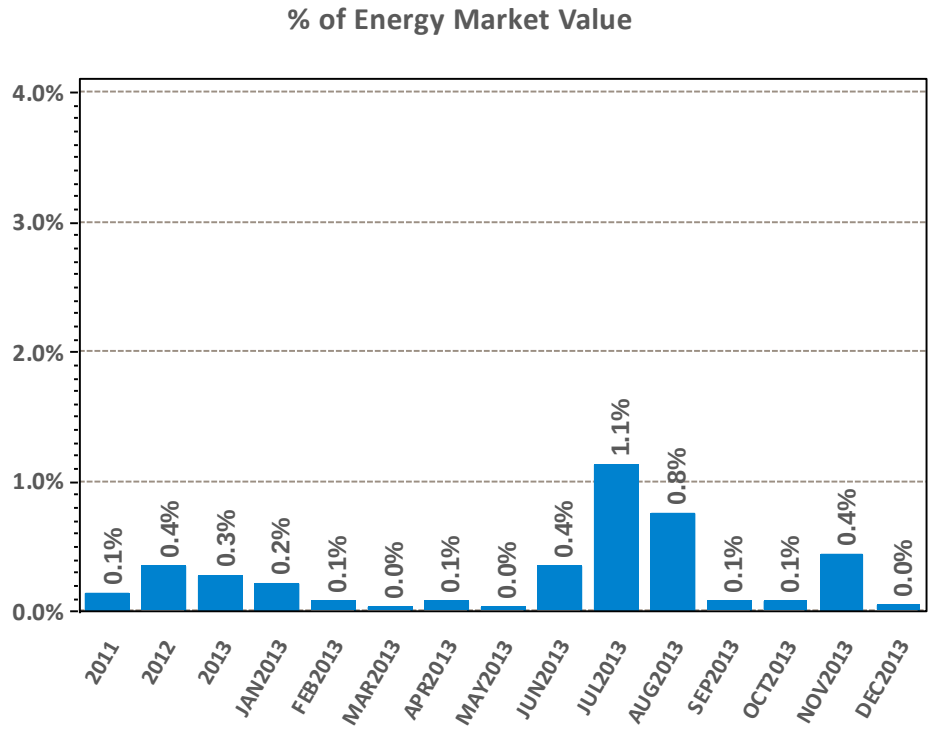




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

Voltage and Distribution NCPC Charges





Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

DA vs. RT Pricing

The following slides outline:

- This month vs. prior year's average LMPs and fuel costs
- Reserve Market results
- DA cleared load vs. RT load
- Zonal and total incs and decs
- Self-schedules
- DA vs. RT net interchange

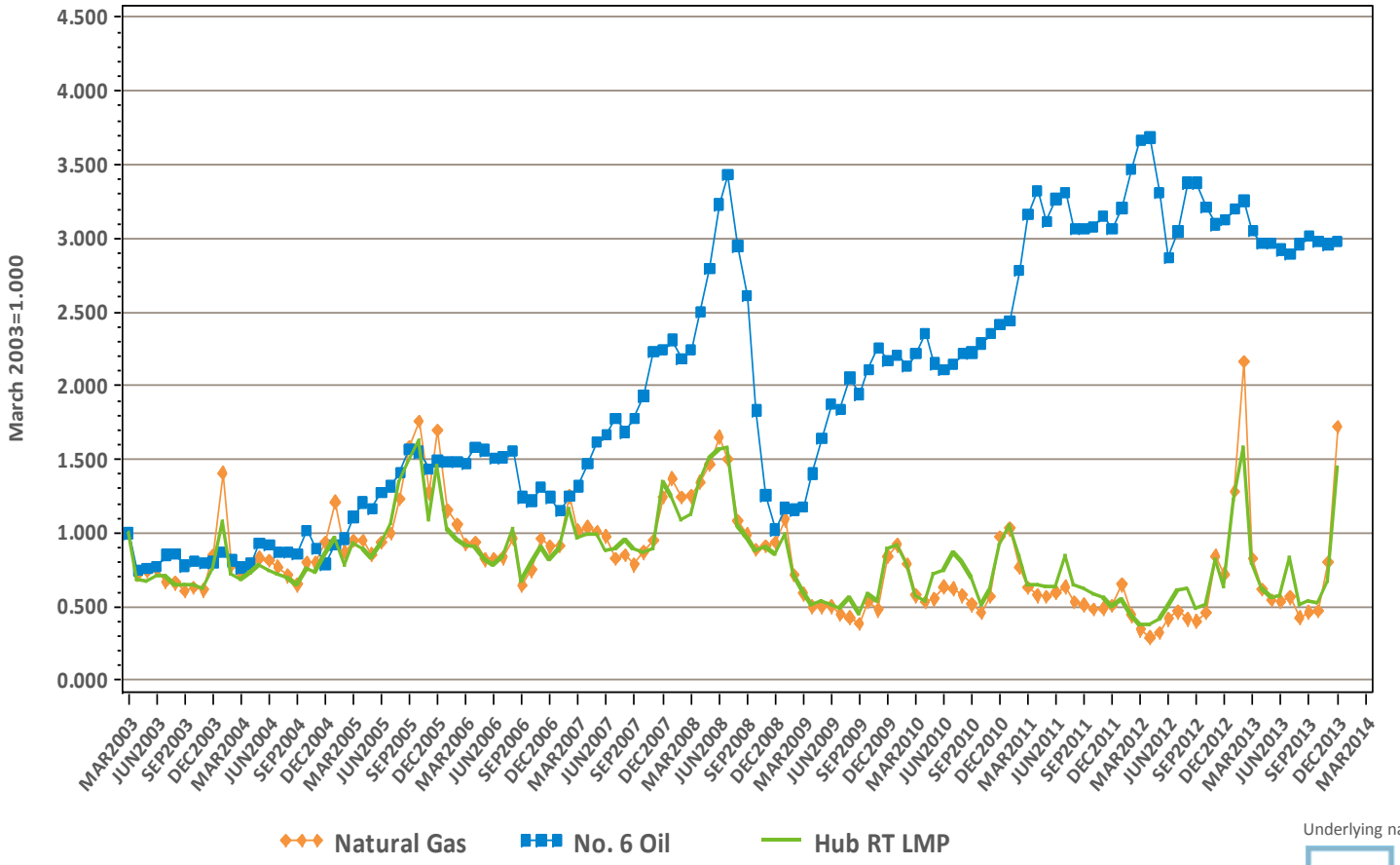
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 2011	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$46.14	$47.47	$45.58	$45.94	$46.67	$45.78	$46.19	$46.92	$46.38
Real-Time	$46.57	$47.95	$44.95	$46.07	$46.57	$46.14	$46.58	$47.23	$46.68
RT Delta %	0.9%	1.0%	-1.4%	0.3%	-0.2%	0.8%	0.9%	0.7%	0.6%
Year 2012	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Day-Ahead	$36.48	$37.09	$36.20	$36.24	$36.57	$36.56	$36.44	$37.29	$36.43
Real-Time	$36.22	$36.95	$35.25	$36.00	$36.22	$35.96	$36.22	$36.97	$36.17
RT Delta %	-0.7%	-0.4%	-2.6%	-0.7%	-0.9%	-1.7%	-0.6%	-0.8%	-0.7%

December-12	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$46.59	$45.51	$45.80	$46.03	$45.51	$46.03	$46.68	$46.35	$46.30
Real-Time	$43.78	$43.14	$42.94	$43.15	$42.73	$43.42	$43.97	$43.60	$43.63
RT Delta %	-6.0%	-5.2%	-6.2%	-6.3%	-6.1%	-5.7%	-5.8%	-5.9%	-5.8%
December-13	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Day-Ahead	$96.20	$88.01	$92.72	$94.32	$88.50	$94.93	$96.52	$92.59	$92.96
Real-Time	$99.34	$96.97	$94.69	$97.58	$96.26	$98.73	$99.72	$98.40	$98.53
RT Delta %	3.3%	10.2%	2.1%	3.5%	8.8%	4.0%	3.3%	6.3%	6.0%
Annual Diff.	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Yr over Yr DA	106.5%	93.4%	102.5%	104.9%	94.5%	106.2%	106.8%	99.7%	100.8%
Yr over Yr RT	126.9%	124.8%	120.5%	126.2%	125.3%	127.4%	126.8%	125.7%	125.9%

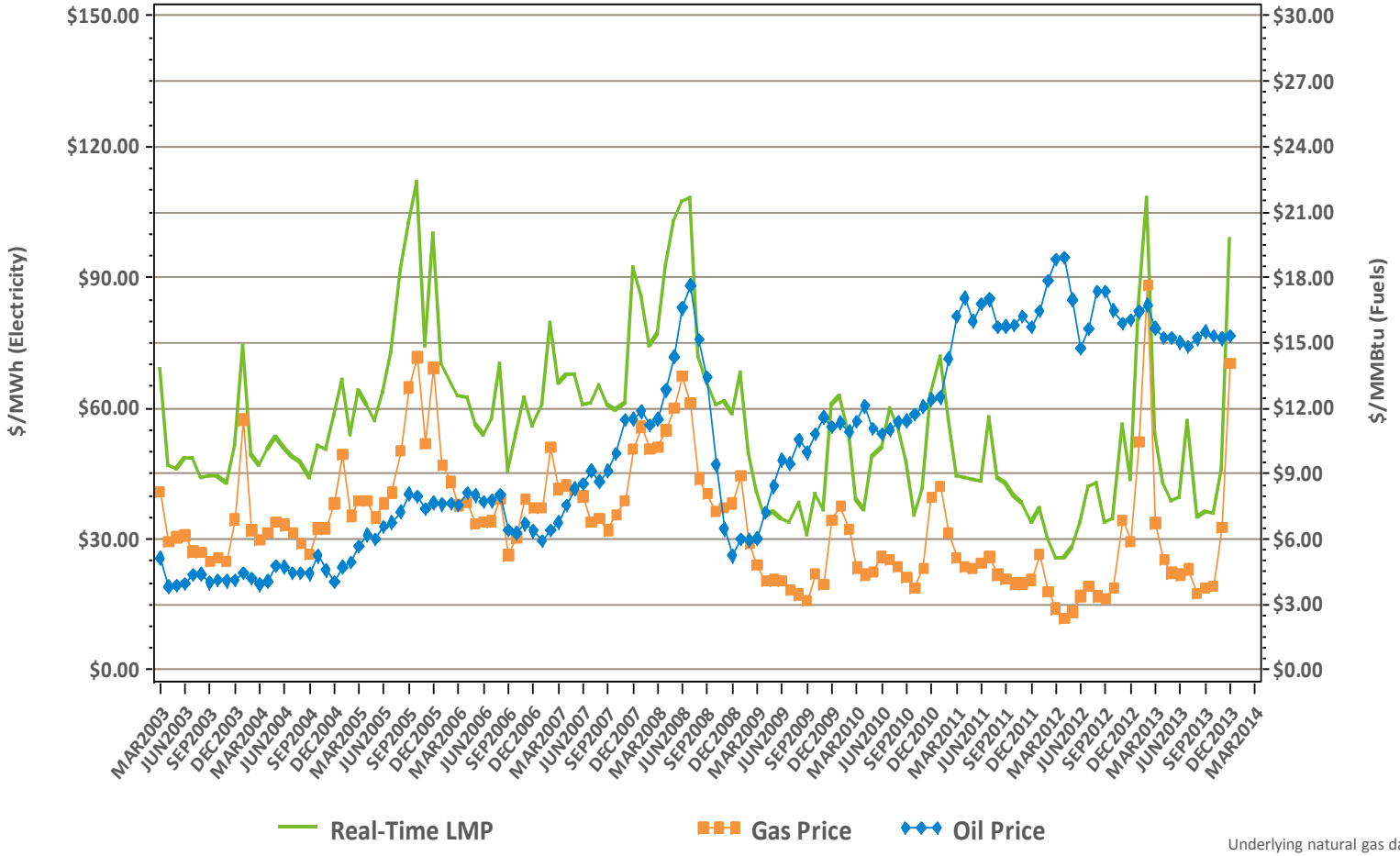
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ICE Global markets in clear view

Monthly Average Fuel Price and RT Hub LMP



Underlying natural gas data furnished by:

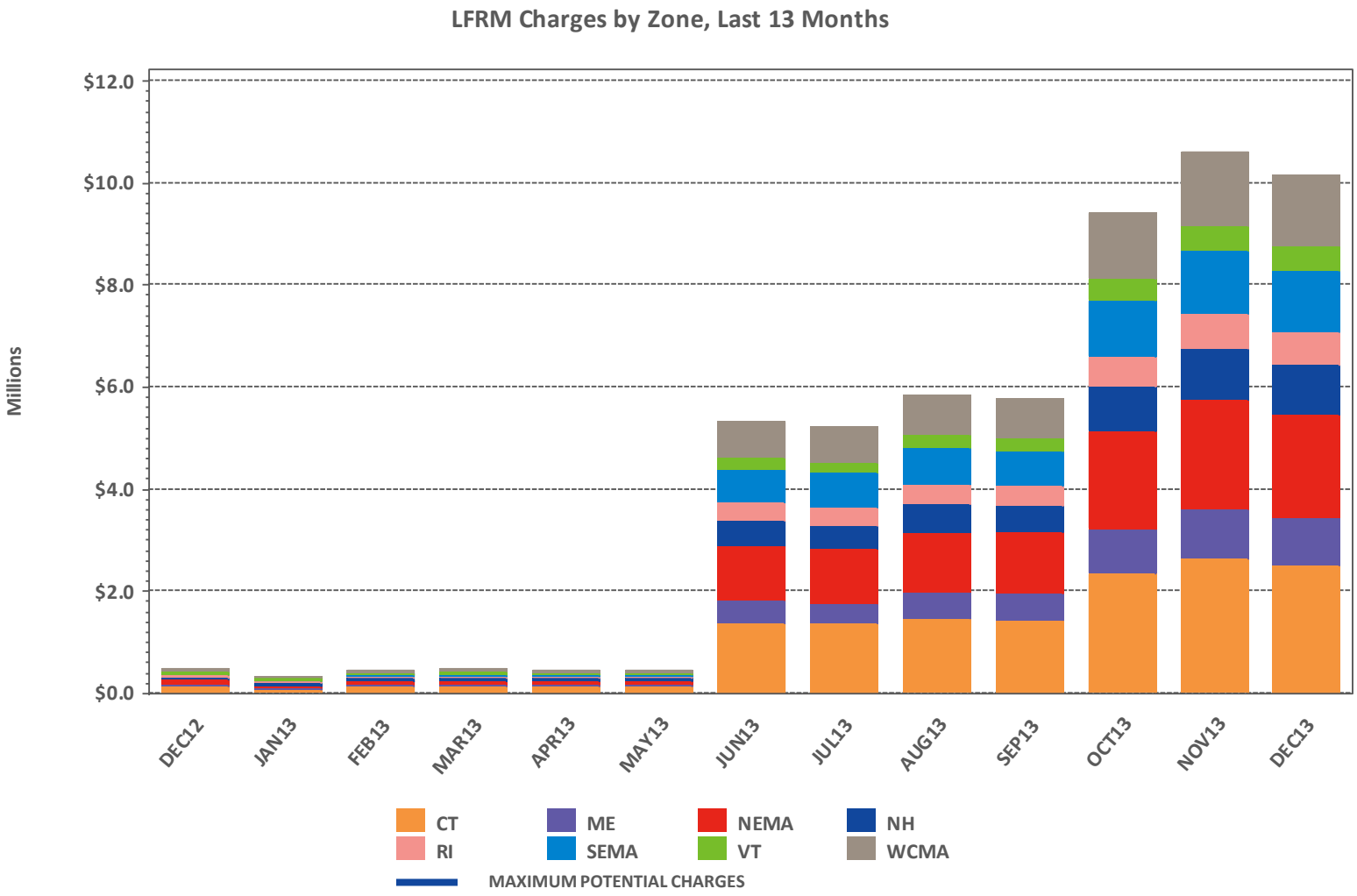
ICE Global markets in clear view

Reserve Market Results – December 2013

- Maximum potential Forward Reserve Market payments of $11.5M were reduced by credit reductions of $503K, failure-to-reserve penalties of $820K and failure-to-activate penalties of $0, resulting in a net payout of $10.2M or 89% of maximum
  - Rest of System: $6.1M/$7.1M (91%)
  - Southwest Connecticut: $604K/$657K (92%)
  - Connecticut: $3.1M/$4.1M (85%)
- $8.5M total Real-Time credits were reduced by $1.6M in Forward Reserve Energy Obligation Charges for a net of $6.8M in Real-Time Reserve payments
  - Rest of System: 179 hours, $3.7M
  - Southwest Connecticut: 179 hours, $1.9M
  - Connecticut: 179 hours, $864K
  - NEMA: 179 hours, $417K

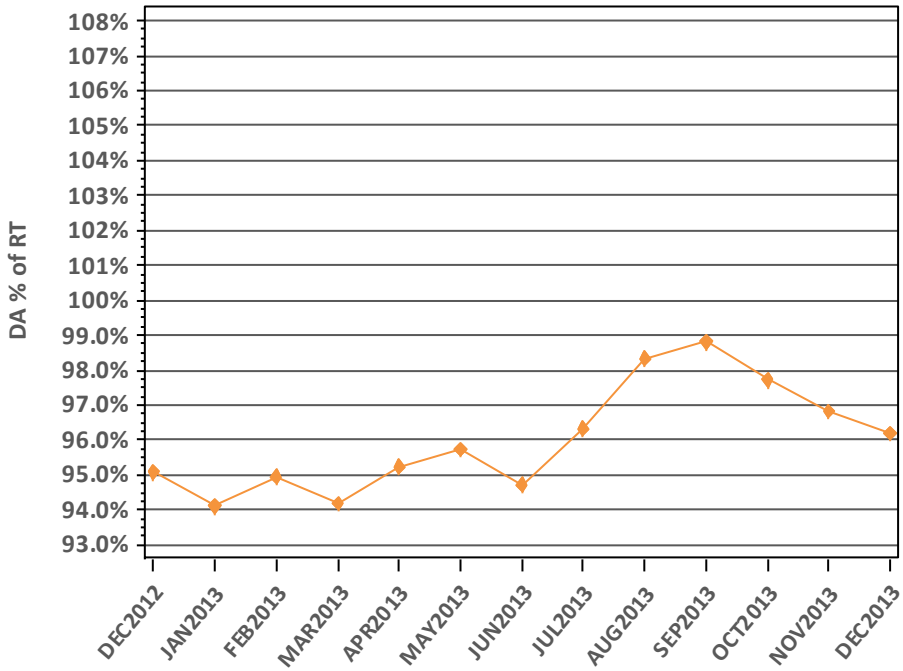
*** "Failure to reserve" results in both reductions in credits and penalties in the Locational Forward Reserve Market.**

LFRM Charges to Load by Load Zone ($)

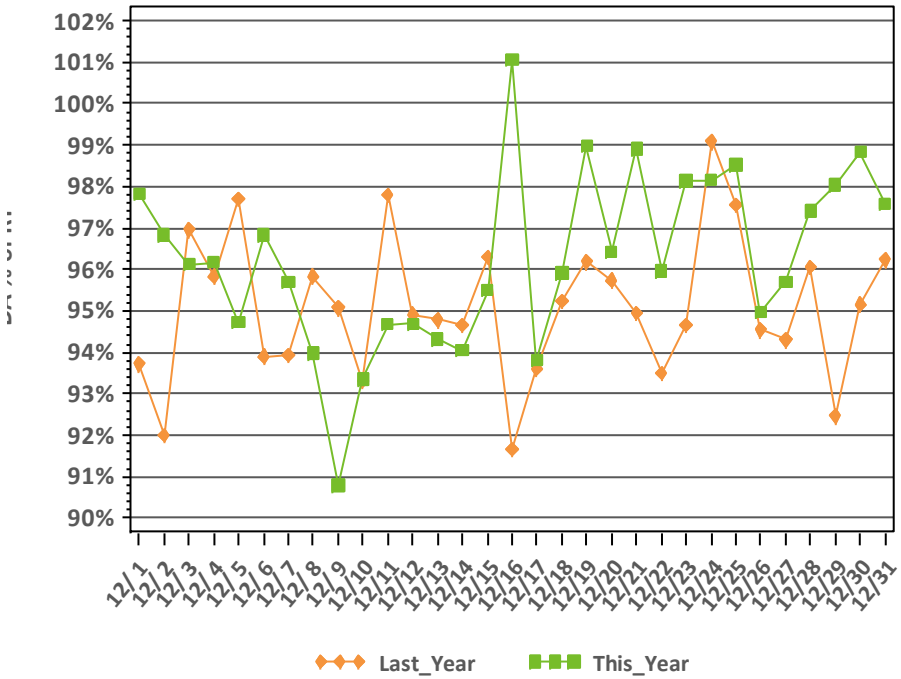


DA vs. RT Load Obligation: December, This Year vs. Last Year

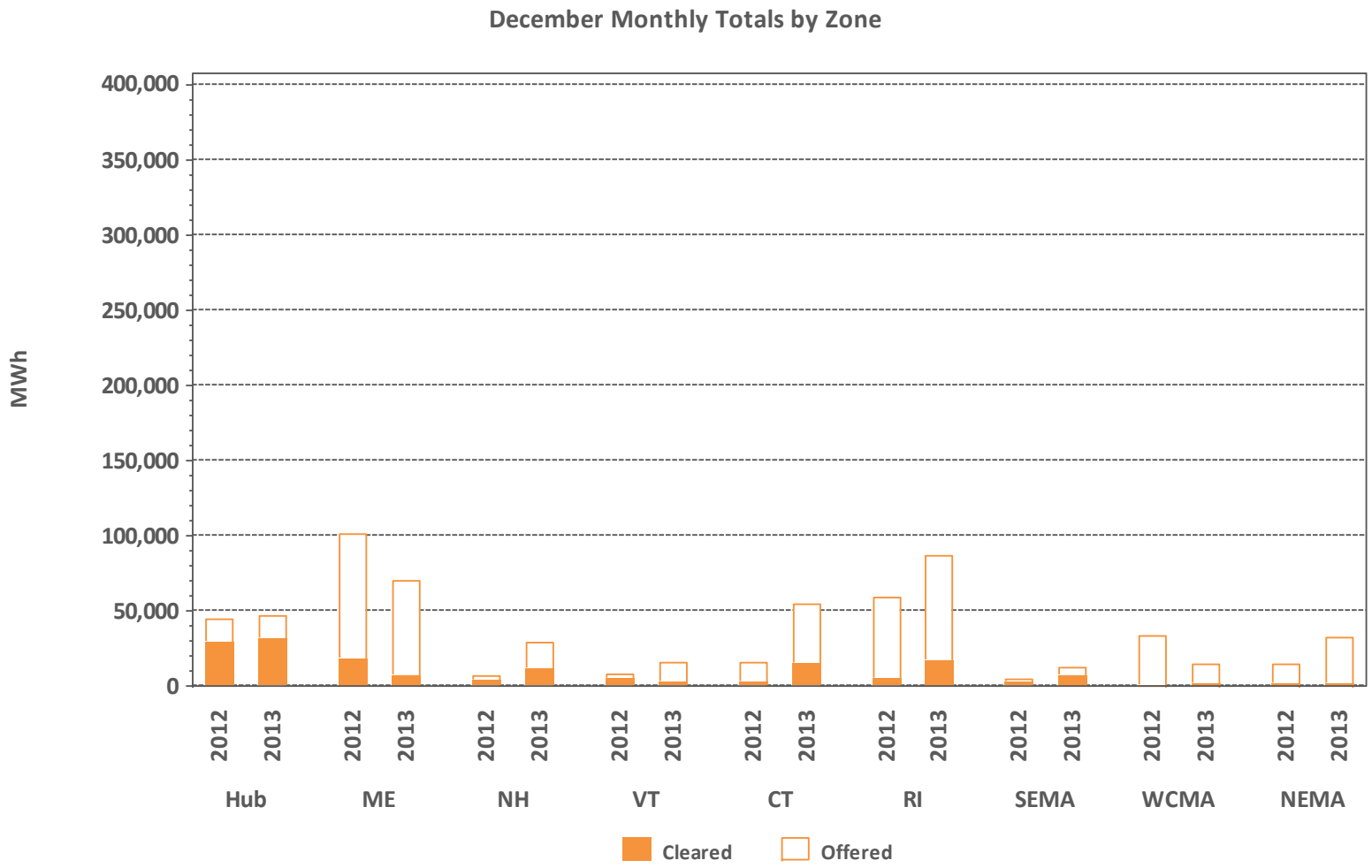
Monthly, Last 13 Months



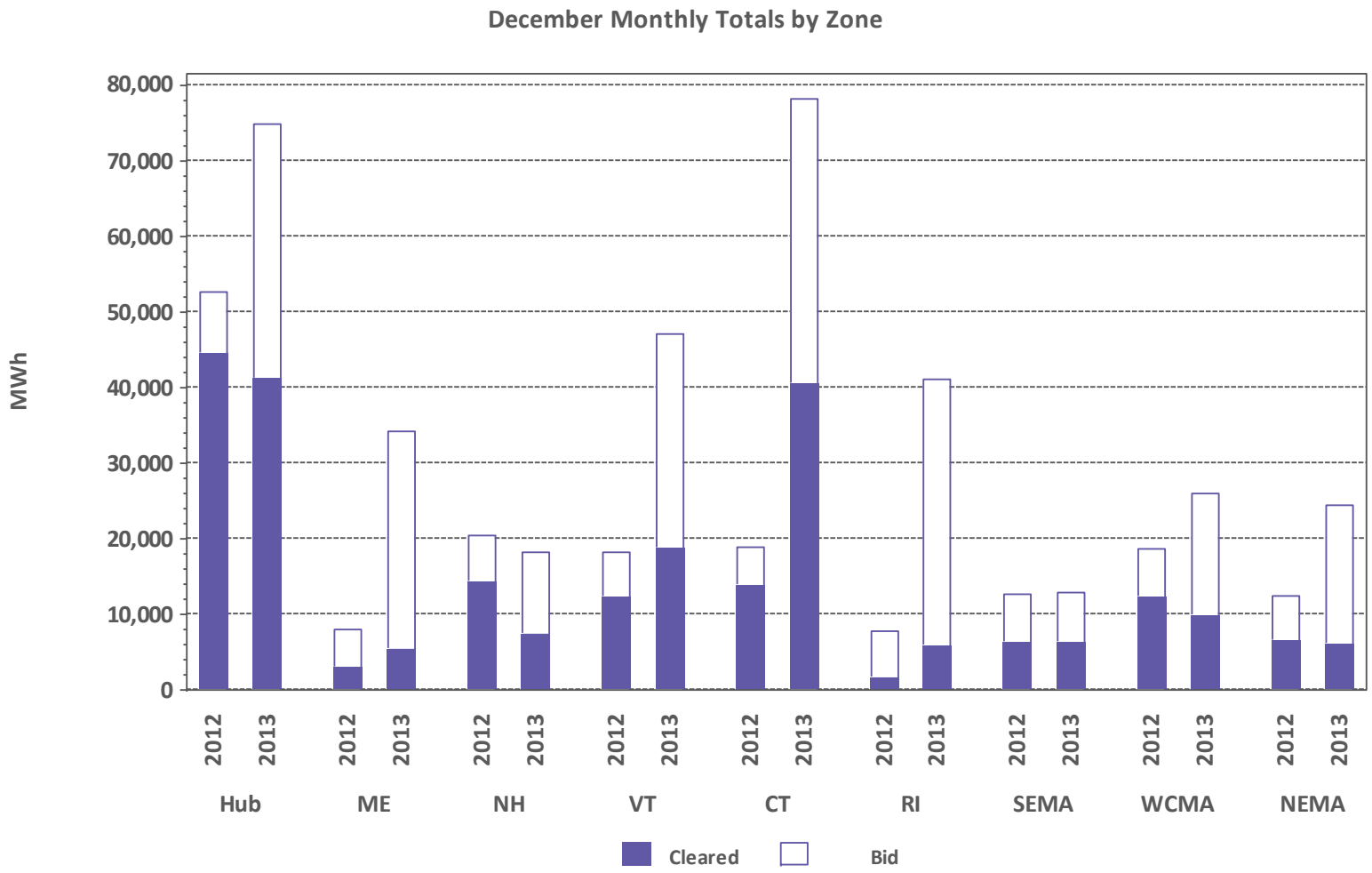
Daily, This Year vs. Last Year



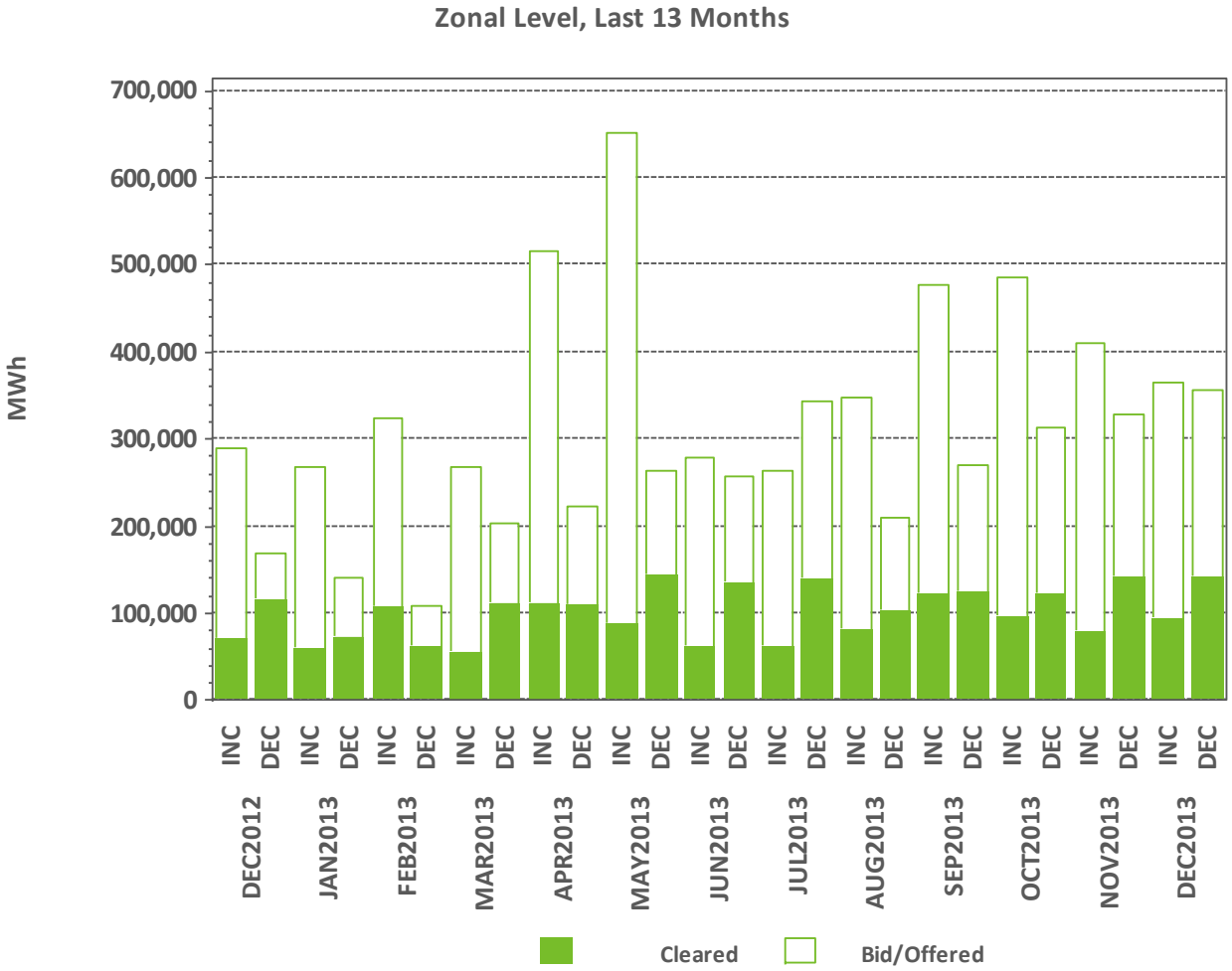
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

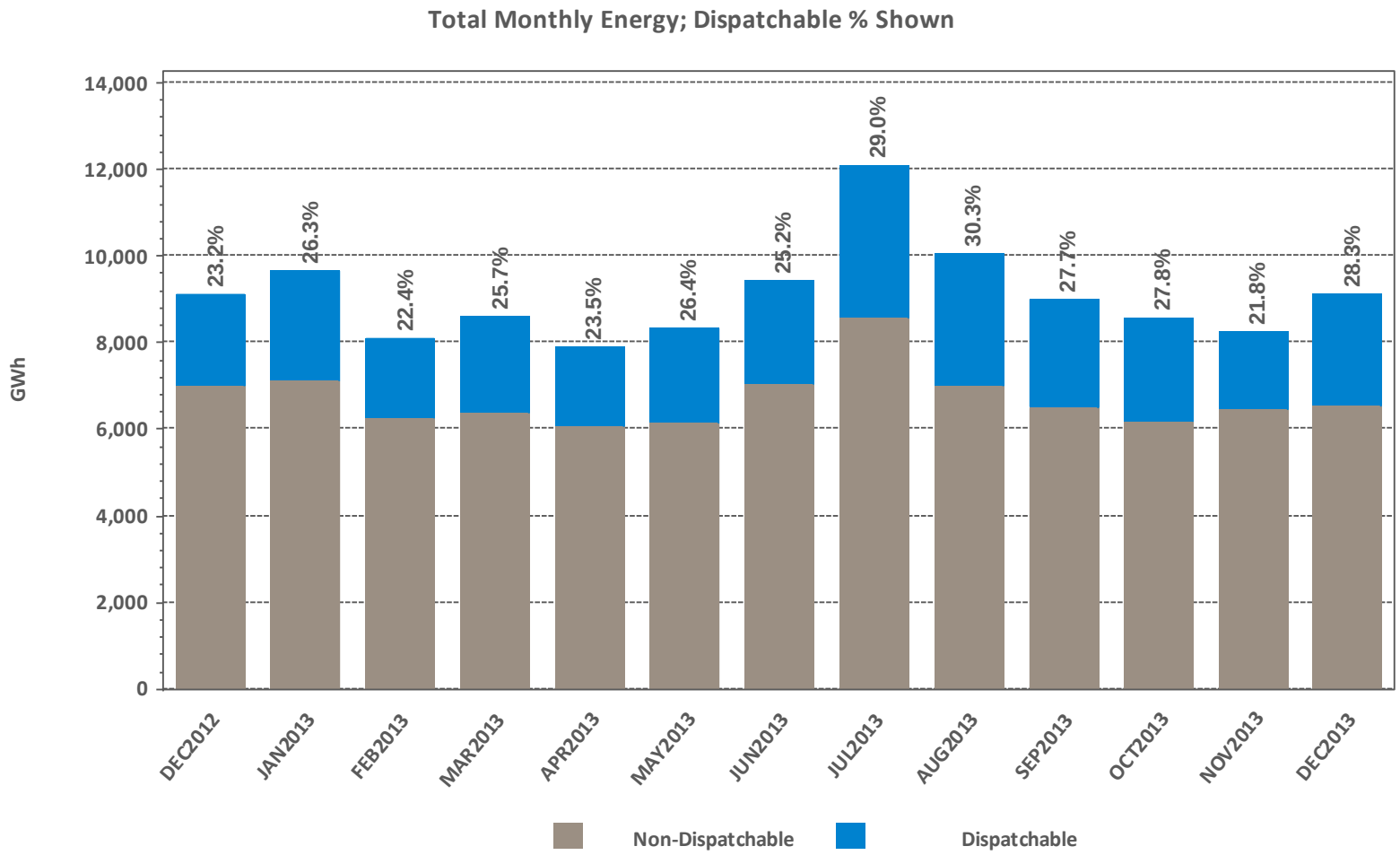


Total Increment Offers and Decrement Bids

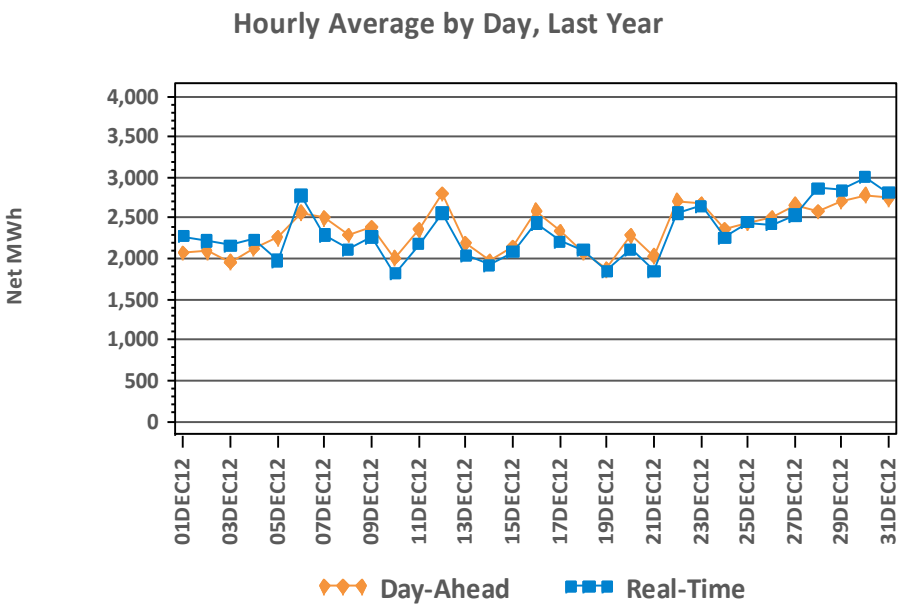


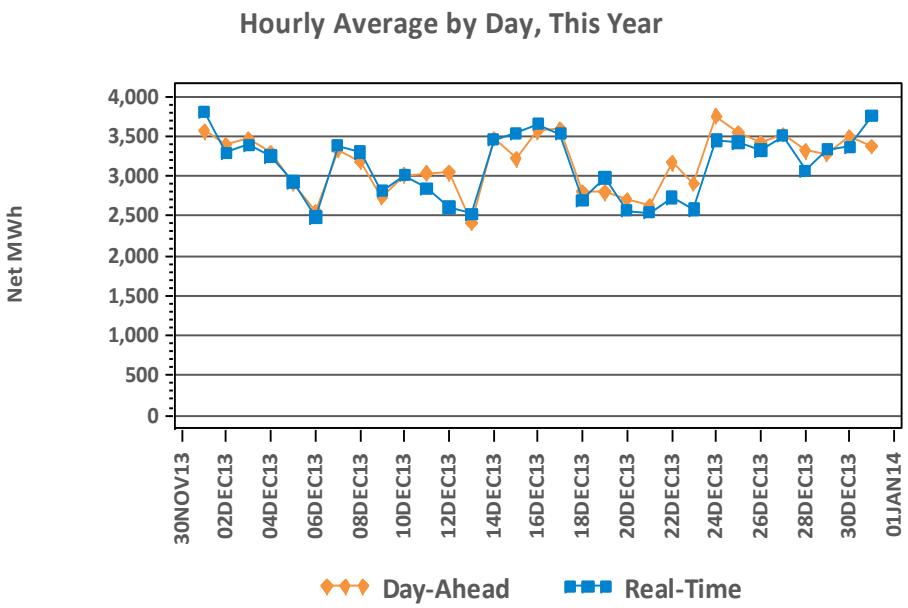
Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



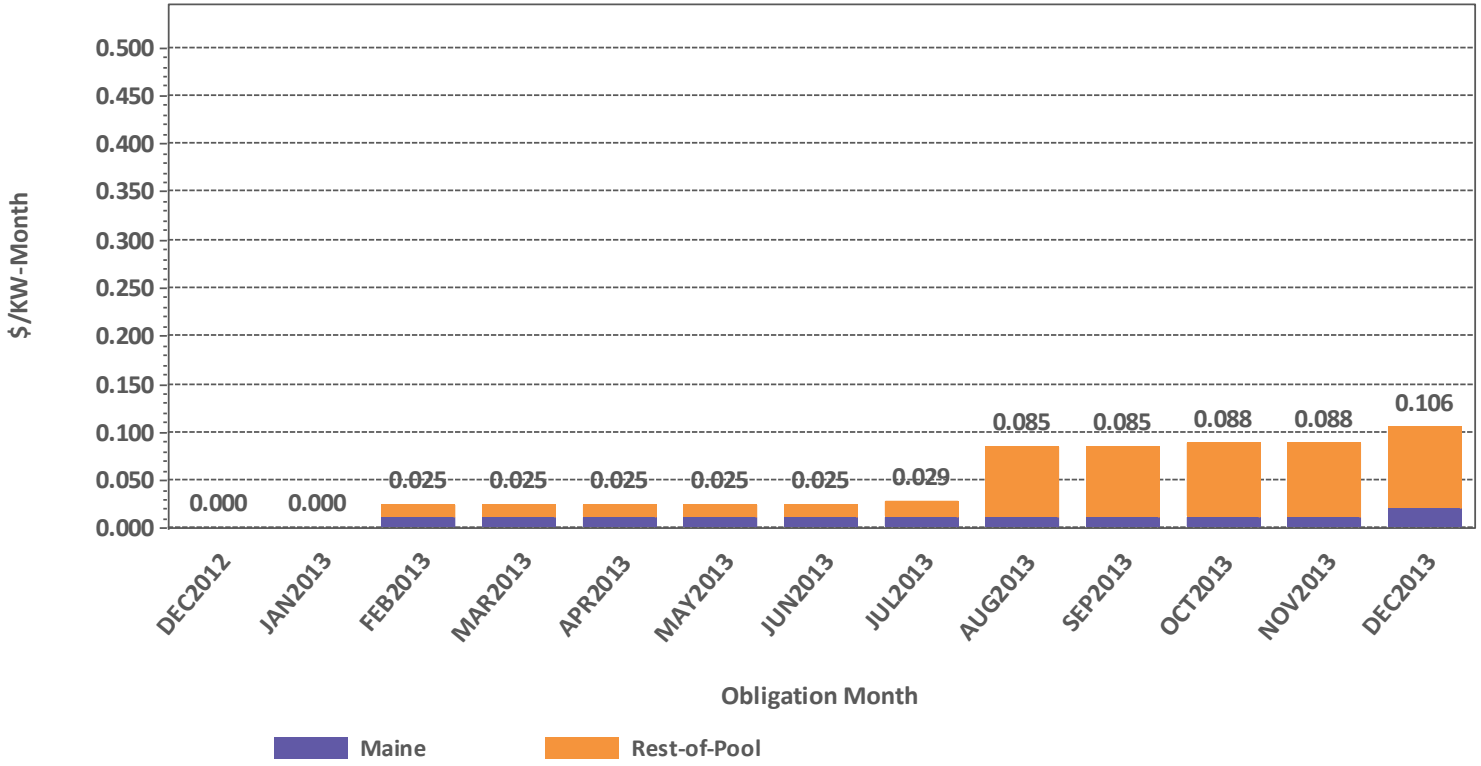
DA vs. RT Net Interchange
December 2013 vs. December 2012





Net Interchange is the sum of daily imports minus the sum of daily exports
Positive values are net imports

Rolling Average Peak Energy Rent (PER)



Rolling Average PER is currently calculated as a rolling twelve month average of individual monthly PER values for the twelve months preceding the obligation month.

Individual monthly PER values are published to the ISO web site here: Home > Markets > Other Markets Data > Forward Capacity Market > Reports and are subject to resettlement.

REGIONAL SYSTEM PLAN (RSP) AND INTERREGIONAL PLANNING

Planning Advisory Committee

- RSP14 overview of messages and scope of work is scheduled for January 22
- The draft 2011 Economic Study Report has been posted for PAC comment
  - Comments are due February 7
  - ISO will discuss comments with the PAC and then finalize the report
- The draft 2012 Economic Study Report will be posted soon for PAC comment
- January 22/23 PAC Agenda
  - EIPC Gas/Electric Interface Study and Non-grant Work Updates
  - Economic Update by Moody's Analytics
  - Load and Energy-Efficiency Forecast Update
  - RSP14 Zones Configuration and RSP14 Scope of Work
  - Economic Study Update
  - NH/VT 2022/2023 Solutions
  - Strategic Transmission Analysis/Unit Retirement Study Update
  - SWCT Needs Assessment II
  - Montville Autotransformer Replacement

Distributed Generation Forecast Working Group

- The preliminary photovoltaic forecast and interconnection issues were discussed at the December 16 DGFWG meeting
- Stakeholders comments on the draft interim photovoltaic forecast and interconnection issues are due by January 7
- Follow-up discussions will be discussed at the January 27 DGFWG meeting at the Doubletree in Westborough

Environmental Advisory Group

- Regulatory updates and discussions of environmental emissions were held at the December 20 meeting
- The Draft 2012 ISO New England Electric Generator Air Emissions Report has been posted for EAG and PSPC comments which are due by January 17
  - http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/eag/mtrls/2013/dec202013/draft_2012_emissions.pdf

RSP Project Stage Descriptions

Stage	Description
1	Planning and Preparation of Project Configuration
2	Pre-construction (e.g., material ordering, project scheduling)
3	Construction in Progress
4	In Service

North Shore Upgrades – Salem Harbor Non-Price Retirement

Status as of 1/6/14

Project Benefits: Allows for the Non-Price Retirement of the Salem Harbor Plant

Upgrade	Expected In-service	Present Stage
Reconductor Y-151 Tewksbury Jct. - West Methuen 115 kV	Feb-14	3
Reconductor B-154N King St. - South Danvers 115 kV	Feb-13	4
Reconductor C-155N King St. - South Danvers 115 kV	Feb-13	4
Reconductor S-145 Tewksbury - North Reading 115 kV	Aug-13	4
Reconductor T-146 Tewksbury - North Reading 115 kV	Aug-13	4

Lower Southeastern Massachusetts (SEMA) Proposed Long-term Upgrades

Status as of 1/6/14

Project Benefit: Improves system reliability for the Lower SEMA area

Upgrade	Expected In-service	Present Stage
Expand the Carver Substation	Jun-13	4
Build New 345 kV Line from Carver to Vicinity of Bourne Substation and connect to Line 120. Expand Bourne with one breaker position.	Jun-13	4*
Construct New 115 kV Substation with 345-115 kV Autotransformer and Loop Line 115 into the new substation	Dec-13	4
Upgrade the 115 kV Bell Rock to High Hill D21 Line	May-13	4
Separate the 345 kV (342 / 322) Double Circuit Tower Lines	Jun-13	4

Project approved by MA EFSB on 4/27/12

* The work is in service in a temporary configuration. The final in-service configuration will be completed May 2014.

NEEWS: Interstate Reliability Project

Status as of 1/6/14

Plan Benefit: Improves New England reliability by increasing transfer limits of three critical interfaces

Upgrade	Expected In-service	Present Stage
Build New 345 kV Line 3271 Card - Lake Road	Dec-15	2
Card 345 kV Substation Expansion	Dec-15	3
Lake Road 345 kV Substation Expansion	Dec-15	2
Build New 345 kV Line 341 Lake Road to CT/RI Border	Dec-15	2
Build New 345 kV Line 341 CT/RI Border to West Farnum	Dec-15	1
West Farnum 345 kV Substation Additions	Dec-15	1
New Sherman Road 345 kV Substation	Dec-15	1
West Farnum 115 kV Substation Upgrades	Dec-15	1
Reconductor 345 kV Line 328 West Farnum to Sherman Road	Dec-15	1
Riverside Substation Relay Upgrades	Dec-15	1
Woonsocket Substation Relay Upgrades	Dec-15	1
Hartford Avenue Substation Relay Upgrades	Dec-15	1
Build New 345 kV Line 366 West Farnum to MA/RI Border	Dec-15	1
Build New 345 kV Line 366 MA/RI Border to Millbury 3	Dec-15	1
Millbury 3 Substation Expansion	Dec-15	1
Carpenter Hill Substation Relay Upgrades	Dec-15	1

NEEWS: Central Connecticut Reliability Project

Status as of 1/6/14

Plan Benefit: Improves New England reliability by increasing transfer limits of three critical interfaces

Upgrade	Expected In-service	Present Stage
Central Connecticut Reliability Project (CCRP)*	Jun-17	1

* Combined with Greater Hartford Central Connecticut Study

Maine Power Reliability Program (MPRP)

Status as of 1/6/14

Project Benefit: Addresses long-term system needs of Bangor Hydro Electric and Central Maine Power, thermal and voltage issues in western Maine and supports load growth in southern Maine

New 345 kV Lines	Expected In-Service	Present Stage
Construct New Section 3023 Orrington to Albion Road	May-13	4
Construct New Section 3024 Albion Road to Coopers Mills	Jan-15	3
Construct New Section 3025 Coopers Mills to Larrabee Road	Mar-15	3
Construct New Section 3026 Larrabee Road to Surowiec	Dec-12	4
Construct New Section 3020 Surowiec to Raven Farm	Nov-13	4
Construct New Section 3021 South Gorham to Maguire Road	Mar-14	3
Construct New Section 3022 Maguire Road to Eliot	Jun-14	3

- The above listing focuses on major transmission line construction and rebuilding.

Maine Power Reliability Program, *cont.*

Status as of 1/6/14

Project Benefit: Addresses long-term system needs of Bangor Hydro Electric and Central Maine Power, thermal and voltage issues in western Maine and supports load growth in southern Maine

New 115 kV Lines	Expected In-Service	Present Stage
Construct New Section 254 Orrington to Coopers Mills	Feb-15	3
Construct New Section 243A Livermore Falls to Junction Section 243	Jun-14	3
Construct New Section 251 Livermore Falls to Larrabee Road	May-14	3
Construct New Section 255 Larrabee Road to Middle Street	Apr-15	3
Construct New Section 86A Tap to Belfast	Aug-14	3
Construct New Section 256 Middle Street to Lewiston Lower	April-15	1

- The above listing focuses on major transmission line construction and rebuilding.

Maine Power Reliability Program, *cont.*

Status as of 1/6/14

Project Benefit: Addresses long-term system needs of Bangor Hydro Electric and Central Maine Power, thermal and voltage issues in western Maine and supports load growth in southern Maine

115 kV Lines Rebuilds	Expected In-Service	Present Stage
Rebuild Section 66 Detroit to Wyman Hydro	May-11	4
Rebuild Section 67 Detroit to Albion Road	May-13	4
Rebuild Section 203 Detroit to Bucksport	Apr-12	4
Rebuild Section 257 (formerly 67) Coopers Mills to Albion Road	May-13	4
Rebuild Section 258 (formerly 84) Coopers Mills to Albion Road	Aug-13	4
Rebuild Section 166 Surowiec to Spring Street	Nov-11	4
Rebuild Section 167 Surowiec to Moshers	Nov-11	4

- The above listing focuses on major transmission line construction and rebuilding.

Maine Power Reliability Program, *cont.*

Status as of 1/6/14

Project Benefit: Addresses long-term system needs of Bangor Hydro Electric and Central Maine Power, thermal and voltage issues in western Maine and supports load growth in southern Maine

115 kV Lines Rebuilds (continued)	Expected In-Service	Present Stage
Rebuild Section 60 Coopers Mills to Bowman Street	Feb-15	3
Rebuild Section 88 Coopers Mills to Augusta East Side	Feb-15	3
Rebuild Section 89 Livermore Falls to Riley	Mar-14	3
Rebuild Section 229 Riley to Rumford IP	May-13	4
Rebuild Section 212 Monmouth to Larrabee Road	Feb-13	4
Rebuild Section 269 Bowman Street to Monmouth	May-12	4
Rebuild Section 238 Louden to Maguire Road	Feb-12	4
Rebuild Section 250 Maguire Road to Three Rivers	Dec-13	4

- The above listing focuses on major transmission line construction and rebuilding.

Maine Power Reliability Program, *cont.*

Status as of 1/6/14

Project Benefit: Addresses long-term system needs of Bangor Hydro Electric and Central Maine Power, thermal and voltage issues in western Maine and supports load growth in southern Maine

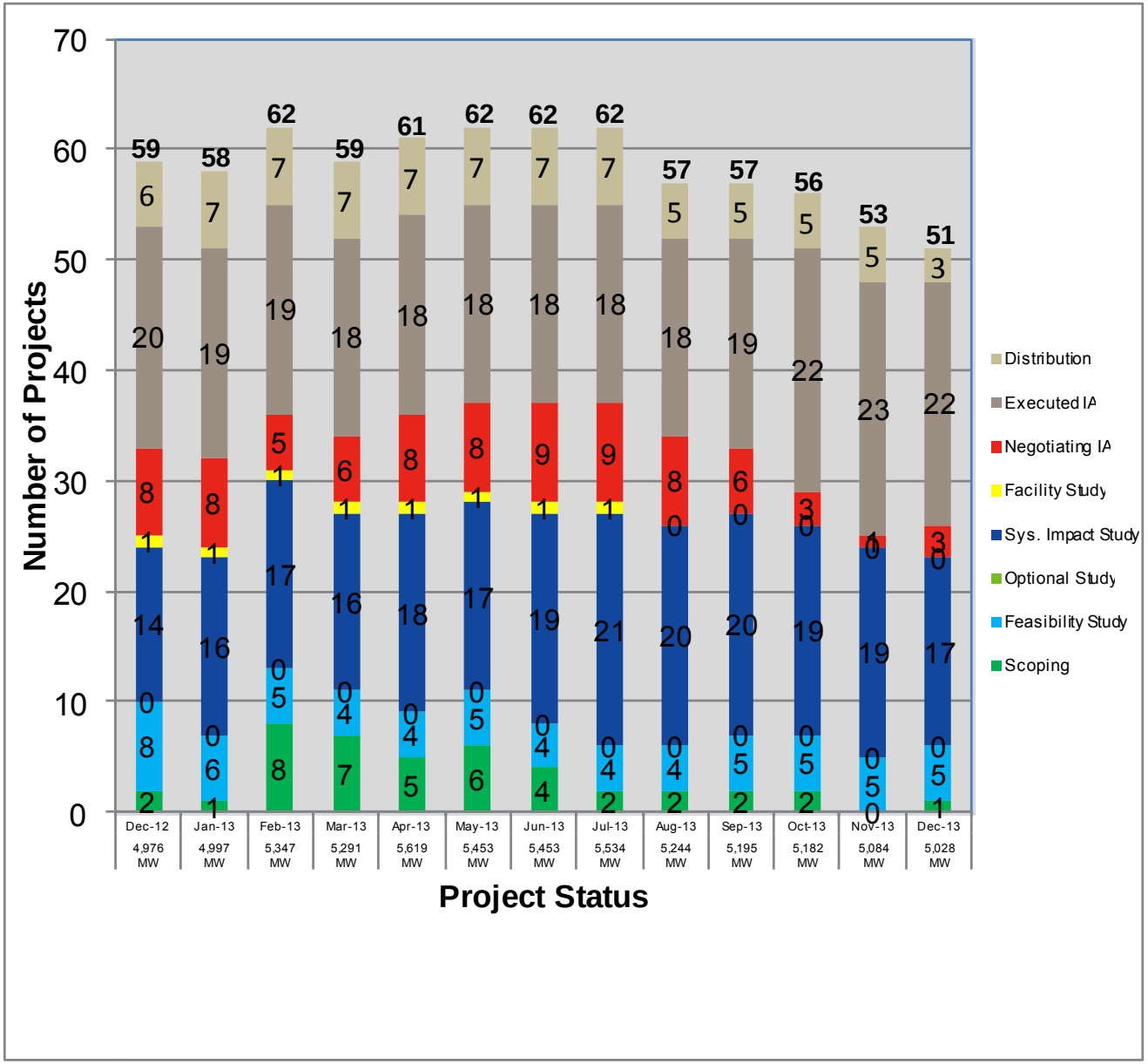
345/115 kV Autotransformers	Expected In-Service	Present Stage
Install One 345/115 kV Autotransformer at Albion Road	Apr-13	4
Install One 345/115 kV Autotransformer at Coopers Mills	Jan-15	3
Install One 345/115 kV Autotransformer at Larrabee Road	Dec-12	4
Install One 345/115 kV Autotransformer at Maguire Road	Jun-14	3
Install One 345/115 kV Autotransformer at South Gorham	Nov-09	4

- The above listing focuses on major transmission line construction and rebuilding.

Transmission Siting Update

- NEEWS
  - Rhode Island Reliability Project
    - Project completed
  - Greater Springfield Reliability Project
    - Project completed
  - Interstate Reliability Project
    - National Grid siting application was filed in MA on 6/21/12
    - National Grid siting application was filed in RI on 7/19/12
    - CL&P's siting hearings in CT were completed on 8/30/12
    - Received siting approval from CT on 1/2/13. The RI Energy Facilities Siting Board approved the project on 6/14/13. Siting proceeding in MA is ongoing.
- MPRP
  - Project filed with the Maine Public Utility Commission on 7/1/08
  - Maine PUC approved most of the project on 6/10/10
  - Hearings are complete - written order received on Lewiston Loop
  - Transmission Cost Allocations are being revised to reflect the new version of the project

Status of Tariff Studies



OPERABLE CAPACITY ANALYSIS

Winter 2014

Winter 2014 Operable Capacity Analysis

50/50 Load Forecast (Reference)	January-2014 [2] CSO	January-2014 [2] SCC
Generator Operable Capacity MW [1]	30,702	34,276
OP CAP From OP-4 RTDR (+)	282	282
OP CAP From OP-4 RTEG (+)	143	143
Operable Capacity Generator with OP-4 DR and RTEG	31,127	34,701
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	217	217
Non Commercial Capacity (+)	122	122
Non Gas-fired Planned Outage MW (-)	1139	1,199
Allowance for Unplanned Outages (-)	2,800	2,800
Gas Generator Outages MW (-)	1,402	1,476
Generation at Risk Due to Gas Supply (-) [4]	2,196	2,522
Net Capacity (NET OPCAP SUPPLY MW) [3]	23,929	27,043
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	21,299	21,299
Operating Reserve Requirement MW	2,375	2,375
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,674	23,674
Operable Capacity Margin [3]	255	3,369

[1] Generator Operable Capacity is based on data as of December 11th , 2013 and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity.

[2] Based on week with lowest Operable Capacity Margin, week beginning January 18th, 2014

[3] Includes OP4 actions associated with RTEG and RTDR

[4] Total of (Gas at Risk MW) – (Gas Gen Outages MW)

Winter 2014 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	January-2014[2] CSO	January-2014[2] SCC
Generator Operable Capacity MW [1]	30,702	34,276
OP CAP From OP-4 RTDR (+)	282	282
OP CAP From OP-4 RTEG (+)	143	143
Operable Capacity Generator with OP-4 DR and RTEG	31,127	34,701
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	217	217
Non Commercial Capacity (+)	122	122
Non Gas-fired Planned Outage MW (-)	1,139	1,199
Allowance for Unplanned Outages (-)	2,800	2,800
Gas Generator Outages MW (-)	1,402	1,476
Generation at Risk Due to Gas Supply (-) [4]	3,229	3,669
Net Capacity (NET OPCAP SUPPLY MW) [3]	22,896	25,896
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	21,934	21,934
Operating Reserve Requirement MW	2,375	2,375
Operable Capacity Required (NET LOAD OBLIGATION MW)	24,309	24,309
Operable Capacity Margin [3]	(1,413)	1,587

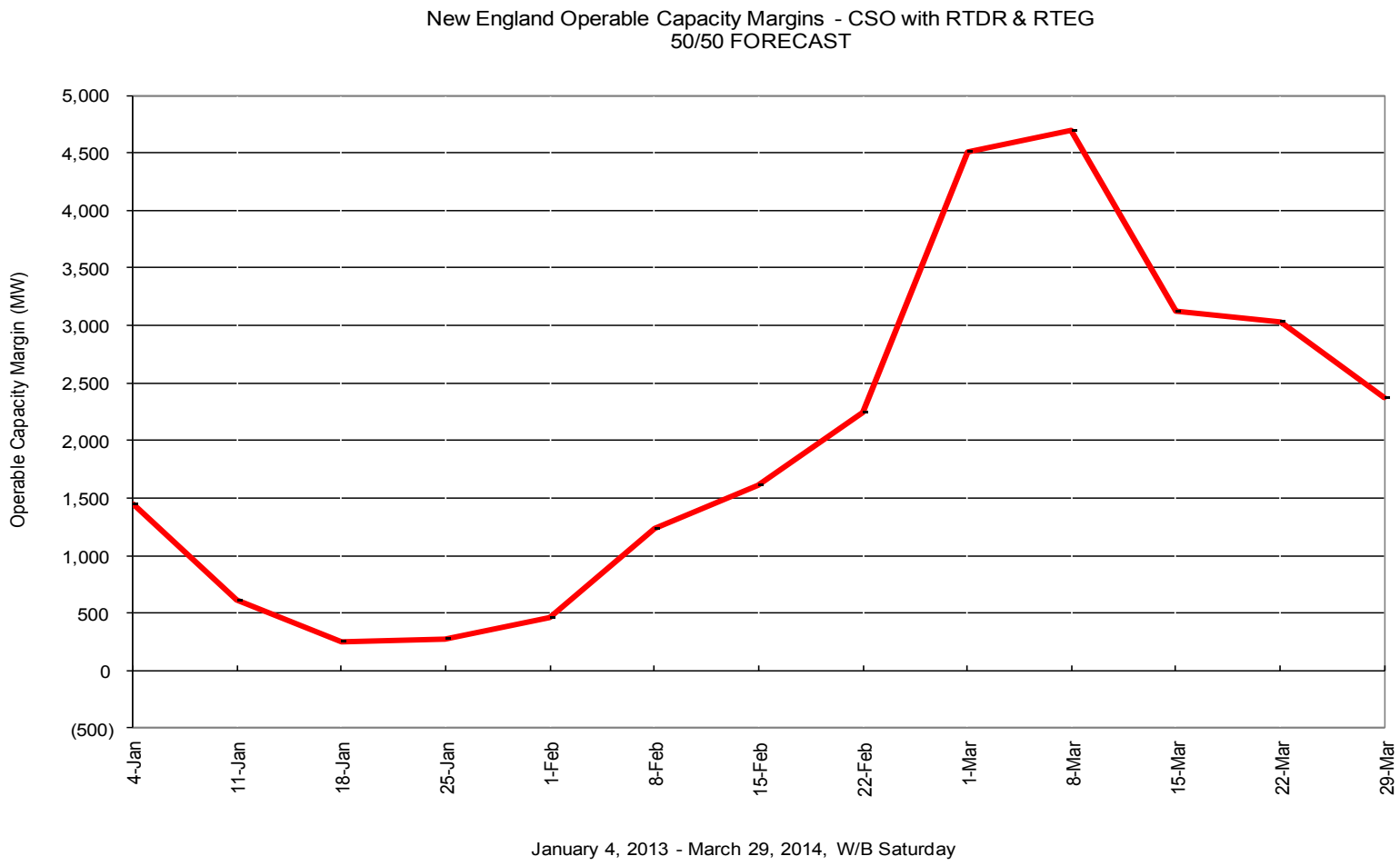
[1] Generator Operable Capacity is based on data as of December 11th , 2013 and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity.

[2] Based on week with lowest Operable Capacity Margin, week beginning January 18th, 2014.

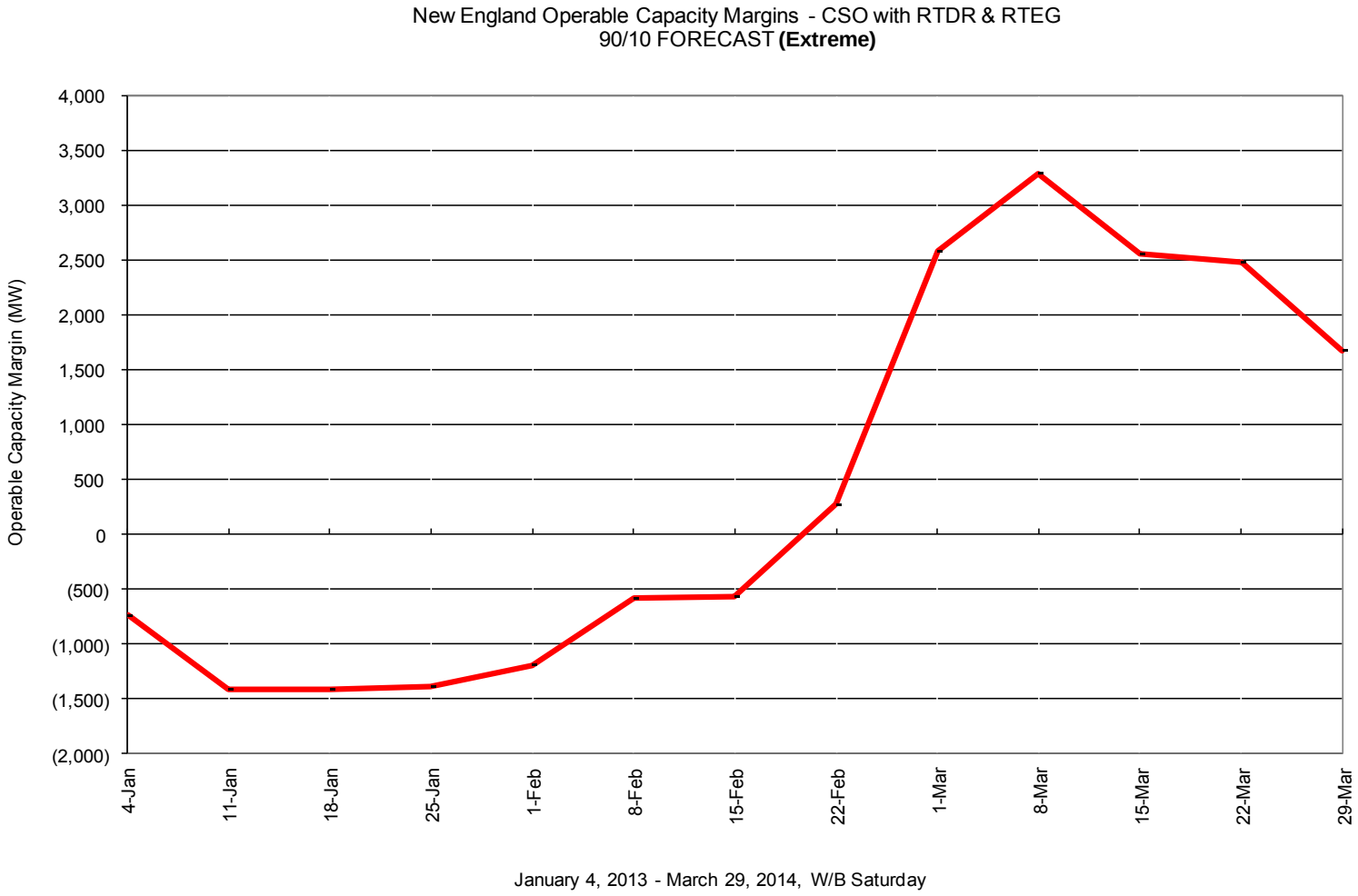
[3] Includes OP4 actions associated with RTEG and RTDR

[4] Total of (Gas at Risk MW) – (Gas Gen Outages MW)

Winter 2014 Operable Capacity Analysis(MW) 50/50 Forecast (Reference)



Winter 2014 Operable Capacity Analysis(MW) 90/10 Forecast (Extreme)



Winter 2014 Operable Capacity Analysis(MW)
50/50 Forecast (Reference)

ISO-NE 2014 OPERABLE CAPACITY ANALYSIS

January 10, 2014 - 50/50- FORECAST - CSO

This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, and August and Mid September.

	OPCAP SUPPLY								LOAD OBLIGATIONS			OPCAP MARGINS				
STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS GENERATOR OUTAGES CSO MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW	OPCAP FROM OP4 REAL-TIME EMER. GEN MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
1/4/2014	30,702	217	122	1,130	2,800	806	2,073	24,232	20,830	2,375	23,205	1,027	282	1,309	143	1,452
1/11/2014	30,702	217	122	1,139	2,800	928	2,310	23,864	21,299	2,375	23,674	190	282	472	143	615
1/18/2014	**30,702**	**217**	**122**	**1,139**	**2,800**	**1,402**	**2,196**	**23,504**	**21,299**	**2,375**	**23,674**	**(170)**	**282**	**112**	**143**	**255**
1/25/2014	30,702	217	122	1,116	2,800	208	3,390	23,527	21,299	2,375	23,674	(147)	282	135	143	278
2/1/2014	29,714	1,083	122	1,053	3,100	162	3,256	23,348	21,075	2,375	23,450	(102)	398	296	168	464
2/8/2014	29,714	1,083	122	1,093	3,100	162	2,717	23,847	20,805	2,375	23,180	667	398	1,065	168	1,233
2/15/2014	29,714	1,083	122	1,102	3,100	740	1,779	24,198	20,776	2,375	23,151	1,047	398	1,445	168	1,613
2/22/2014	29,714	1,083	122	1,095	3,100	273	1,886	24,565	20,511	2,375	22,886	1,679	398	2,077	168	2,245
3/1/2014	29,714	1,083	122	1,084	2,200	1,577	222	25,836	19,515	2,375	21,890	3,946	398	4,344	168	4,512
3/8/2014	29,714	1,083	122	1,478	2,200	1,577	0	25,664	19,162	2,375	21,537	4,127	398	4,525	168	4,693
3/15/2014	29,714	1,083	122	1,972	2,200	2,852	0	23,895	18,965	2,375	21,340	2,555	398	2,953	168	3,121
3/22/2014	29,714	1,083	122	2,936	2,200	2,341	0	23,442	18,597	2,375	20,972	2,470	398	2,868	168	3,036
3/29/2014	29,560	1,083	122	5,216	2,700	776	0	22,073	18,023	2,375	20,398	1,675	461	2,136	234	2,370

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
3. New resources that have acquired a CSO but have not become commercial.
4.Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.
5. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
8. Net OpCap Supply MW Available (1 + 2 + 3 - 4 - 5 - 6 - 7 = 8)
9. Peak Load Forecast as provided in the 2013 CELT Report and adjusted for Passive Demand Resources.
10. Operating Reserve Requirement based on 125% of first largest contingency plus 50% the second largest contingency.
11. Total Net Load Obligation per the formula(9 + 10 = 11)
12. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (8 - 11 = 12)
13. OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
14. OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (12 + 13 = 14)
15. OP 4 Action 6 Emergency Generation Response without the Voltage Reduction requiring > 10 Minutes based on OP4 Appendix A. Real Time Emergency Generation is capped at 600MW. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
16. OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (14 + 15 = 16); This does not include Emergency Energy Transactions (EETs).

Winter 2014 Operable Capacity Analysis(MW)
90/10 Forecast (Extreme)

ISO-NE 2014 OPERABLE CAPACITY ANALYSIS

January 10, 2014 - 90/10- FORECAST - CSO

This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, and August and Mid September.

	OPCAP SUPPLY								LOAD OBLIGATIONS			OPCAP MARGINS				
STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS GENERATOR OUTAGES CSO MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW	OPCAP FROM OP4 REAL-TIME EMER. GEN MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
1/4/2014	30,702	217	122	1,130	2,800	806	3,640	22,665	21,452	2,375	23,827	(1,162)	282	(880)	143	(737)
1/11/2014	**30,702**	**217**	**122**	**1,139**	**2,800**	**928**	**3,703**	**22,471**	**21,934**	**2,375**	**24,309**	**(1,838)**	**282**	**(1,556)**	**143**	**(1,413)**
1/18/2014	**30,702**	**217**	**122**	**1,139**	**2,800**	**1,402**	**3,229**	**22,471**	**21,934**	**2,375**	**24,309**	**(1,838)**	**282**	**(1,556)**	**143**	**(1,413)**
1/25/2014	30,702	217	122	1,116	2,800	208	4,423	22,494	21,934	2,375	24,309	(1,815)	282	(1,533)	143	(1,390)
2/1/2014	29,714	1,083	122	1,053	3,100	162	4,284	22,320	21,703	2,375	24,078	(1,758)	398	(1,360)	168	(1,192)
2/8/2014	29,714	1,083	122	1,093	3,100	162	3,913	22,651	21,426	2,375	23,801	(1,150)	398	(752)	168	(584)
2/15/2014	29,714	1,083	122	1,102	3,100	740	3,335	22,642	21,396	2,375	23,771	(1,129)	398	(731)	168	(563)
2/22/2014	29,714	1,083	122	1,095	3,100	273	3,246	23,205	21,124	2,375	23,499	(294)	398	104	168	272
3/1/2014	29,714	1,083	122	1,084	2,200	1,577	1,572	24,486	20,099	2,375	22,474	2,012	398	2,410	168	2,578
3/8/2014	29,714	1,083	122	1,478	2,200	1,577	831	24,833	19,737	2,375	22,112	2,721	398	3,119	168	3,287
3/15/2014	29,714	1,083	122	1,972	2,200	2,852	0	23,895	19,534	2,375	21,909	1,986	398	2,384	168	2,552
3/22/2014	29,714	1,083	122	2,936	2,200	2,341	0	23,442	19,155	2,375	21,530	1,912	398	2,310	168	2,478
3/29/2014	29,560	1,083	122	5,216	2,700	776	150	21,923	18,565	2,375	20,940	983	461	1,444	234	1,678

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
3. New resources that have acquired a CSO but have not become commercial.
4.Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.
5. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
8. Net OpCap Supply MW Available (1 + 2 + 3 - 4 - 5 - 6 - 7 = 8)
9. Peak Load Forecast as provided in the 2013 CELT Report and adjusted for Passive Demand Resources.
10. Operating Reserve Requirement based on 125% of first largest contingency plus 50% the second largest contingency.
11. Total Net Load Obligation per the formula(9 + 10 = 11)
12. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (8 - 11 = 12)
13. OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
14. OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (12 + 13 = 14)
15. OP 4 Action 6 Emergency Generation Response without the Voltage Reduction requiring > 10 Minutes based on OP4 Appendix A. Real Time Emergency Generation is capped at 600MW. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
16. OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (14 + 15 = 16); This does not include Emergency Energy Transactions (EETs).

OPERABLE CAPACITY ANALYSIS

Appendix

Possible Relief Under OP4 based on OP4 Appendix A

OP 4 Action Number	Page 1 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
1	Implement Power Caution and advise Resources with a CSO to prepare to provide capacity and notify "Settlement Only" generators with a CSO to monitor reserve pricing to meet those obligations. Begin to allow depletion of 30-minute reserve.	0 [1] 600
2	Dispatch real time Demand Resources.	Jan =282 [3] Feb-March =398 [3]
3	Voluntary Load Curtailment of Market Participants' facilities.	40 [2]
4	Implement Power Watch	0
5	Schedule Emergency Energy Transactions and arrange to purchase Control Area-to-Control Area Emergency	1,000
6	Voltage Reduction requiring > 10 minutes Dispatch real time Emergency Generation	134 [4] Jan =143 [3] Feb-March= 168 [3]
7	Request generating resources not subject to a Capacity Supply Obligation to voluntary provide energy for reliability purposes	0
8	Voltage Reduction requiring 10 minutes or less	267 [4]
9	Transmission Customer Generation Not Contractually Available to Market Participants during a Capacity Deficiency. Voluntary Load Curtailment by Large Industrial and Commercial Customers.	5 200 [2]

Possible Relief Under OP4 based on OP4 Appendix A

OP 4 Action Number	Page 2 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
10	Radio and TV Appeals for Voluntary Load Curtailment Implement Power Warning	200 [2]
11	Request State Governors to Reinforce Power Warning Appeals.	100 [2]
Total		Jan =2,971 MW Feb-Mar = 3,112 MW

NOTES:

1. Based on Summer Ratings. Assumes 25% of total MW Settlement Only units <5 MW will be available and respond.
2. The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
3. The RTDR and RTEG MW values are based on FCM results as of December 11th , 2013.
4. The MW values are based on a 26,690 MW system load and the most recent voltage reduction test % achieved.

JANUARY 3, 2014

Discussion of the 2014 Work Plan

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Objective and Highlights

- The primary objective of this presentation is to provide the highlights of the 2014 ISO work plan and seek stakeholder input
- 2013 comprised an intense set of market and planning based activities that required significant stakeholder involvement
- 2014 transitions to an 'implementation year' with several of the market and planning activities moving into implementation stage
- FERC's decision on FCM Performance Incentive, New England Governor's infrastructure initiative and other new FERC initiatives could all influence the timing of the various activities in the 2014 work plan

Objective and Highlights

- The Hourly Offers project, which includes NCPC redesign, will occupy a significant portion of the ISO resources
- Market activities are split into Market Design and Market Assessment activities
  - Market Assessment activities serve as a prelude to the Market Design activities

Planning/Operations Related Activities

2014				2015			
Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Transmission Planning Studies/Support State Siting (Slides 7-9)							
Eastern Interconnection Planning Collaborative (Slide 10)							
2013 Economic Studies (Slide 11)		2014 Economic Studies (Slide 11)				2015 Economic Studies	
Finalize 2014 Forecast of State EE		(Slide 12)		Finalize 2015 Forecast of State EE			
Interregional Planning (Slide 13)							
Transmission Cost Allocation (Slide 14)							
FERC Order 1000 - Implement Final Compliance Orders (Slide 15)							
		2018/19 ICR and LSR		(Slide 16)		2019/20 ICR and LSR	
FCA #8 / Annual Reconfig Auctions		(Slide 17)		FCA #9 / Annual Reconfig Auctions			
Generator Interconnection Studies / Review of Generator Interconnection Process (Slide 18)							
RSP 14 (Slide 19)				RSP 15			
2013/14 Winter Program (Slide 20)							
Gas - Electric Operations Coordination (Slide 21)							
NERC/FERC Compliance; Cyber Security (Slide 22)							
	Tariff Language on Elective Transmission Upgrades			(Slide 23)			
FCM Zones Filing	Implement the modeling Capacity Zones (Slide 24)						
Develop Distributed Generation Forecast				(Slide 25)			
Operating Guide Updates (Slide 26)							

Operations/Planning Activities

Markets Related Activities

2014				2015	
Q1	Q2	Q3	Q4	Q1	Q2
FCM Demand Curve (Slide 28)					
NCPC Cost Allocation Phase I (Slide 29)					
				NCPC Cost Allocation Phase II (Slide 29)	
Sub-hourly Settlement (Slide 30)					
	PRD: Energy and Reserves (Slide 31)				
Treatment of Resources Retained for Reliability		(Slide 32)			
3rd Party FTR Clearing (Slide 33)					
Monthly FRM Auction	(Slide 34)				
NPR Timeline	(Slide 34)				
	Wind Dispatch Rules / DARD Pumps (Slide 35)				
Energy Pricing Enhancements (Slide 37)					
Elective Transmission Upgrades (Slide 38)					

Market Assessment
Market Design Project

Capital Projects

2014				2015			
Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Energy Offer Flexibility / Hourly Offers (Slide 40)							
FCA 9 Implementation (Slide 41)					FCA 10 Implementation		
Backup Control Center (Slide 42)							
Generator Control Application (Slide 43)							
Coordinated Transaction Scheduling (Slide 44)							
Regulation Market Project (Slide 45)							
Web Enhancements Phase II	(Slide 46)						
Divisional Accounting (Slide 47)							
Wind Forecasting	(Slide 48)						
Market System Upgrade	(Slide 49)						
Business Continuity Plan Phase III (Slide 50)							
Various Database and Application Enhancements (Slides 51-53)							
Issue Resolution 2014 (Slide 54)							

Capital Projects

Transmission Planning Studies

- Updated Needs Assessments will be conducted in 2014 in accordance with the Planning Process
  - Updated regional load forecast and Energy-Efficiency (EE) forecast
  - Once developed, implement interim Distributed Generation forecast, primarily focused on solar photovoltaic resources
  - Resource mix will be adjusted for the results of the first eight Forward Capacity Market Auctions
    - New Resources
    - Non Price Retirements and de-list bids
    - Other resource attrition

Transmission Planning Studies, cont.

- Several studies are underway or nearing completion
  - Eastern Connecticut Study
  - Southwestern Connecticut Ten-Year Compliance Plan
  - Greater Boston Solutions Study
  - Updated regional transfer limit analysis, including stability limit analysis
  - Greater Hartford area
  - SEMA/RI area, including impact of Brayton Point retirement

Transmission Planning Studies, cont.

- Support state siting proceedings for major transmission projects, as necessary
  - Greater Boston Reliability Project (MA, NH)
  - VT/NH Reliability Project (VT, NH)
- Implementation of Order 1000 and any final compliance obligations will begin in 2014. These efforts are likely to continue into 2015 as we gain more experience with the new process

Eastern Interconnection Planning Collaborative (EIPC)

- EIPC analysis on Phase 1 and 2 of the DOE project was completed in 2012 and the ISO is supporting a Phase 3 effort for a DOE funded Gas/Electric Interface Study from 2013 through 2015
- EIPC initiated its non-grant transmission analysis work in 2013
  - 2013 EIPC non-Grant Work Plan focused on biennial Model Roll-up and Evaluation (contingency analysis and/or transfer analysis)
    - Select model years (for example, a 10-year case) and build roll-up models
    - Perform model evaluation (contingency and transfer analysis)
    - Identify any gaps and develop enhancements to address those gaps
    - With stakeholder input, develop resource expansion scenarios
  - 2014 ISO Planning staff effort
    - Continue support for and participation in Technical Team, Economic Analysis Working Group, Coordinating and Executive Committees

2013/2014 Attachment K Economic Studies

- 2013 economic study requests submitted by April 2013 for analysis of different levels of transfer over HQ Phase II to New England
  - Economic analysis nearing completion
  - Results to be reviewed in upcoming PAC meetings
- 2014 economic study requests to be submitted by April 1, 2014

State Sponsored Energy-Efficiency Programs

- The Regional Energy-Efficiency Initiative (REEI) efforts have highlighted New England states' activities and investments in energy efficiency
- Data has been gathered to support the development of the 2014 EE forecast, expected to be completed in Spring 2014
- ISO will continue working with the Energy-Efficiency Forecast Working Group to review and refine the EE forecast process
- Data gathering to support development of the 2015 EE forecast to begin in Q3 2014

Interregional Planning

- There are a number of forums and activities related to interregional planning efforts beyond EIPC
  - North American Electric Reliability Corporation (NERC)
  - Northeast Power Coordinating Council (NPCC)
  - Inter-Area Planning Stakeholder Committee (IPSAC)
  - Department of Energy (DOE) Congestion Study Support
  - Northeast Gas Association (NGA)
- ISO, NYISO and PJM will be working on implementation of the Inter-regional Planning portion of Order 1000 in 2014. These efforts are likely to continue into 2015 as we gain more experience with the new process

Transmission Cost Allocation (TCA)

Transmission Owner	Project	Pool Transmission Facilities (PTF) Cost Estimate	Target Date[1]
VELCO / NU	New Hampshire Solutions	~$450M	Potential 2014 TCA Submittal
NU	Greater Springfield Reliability Project – NEEWS	$754M (requested)	•2013 TCA Submitted •Determination to be issued Q1-2014
NU/NSTAR/NGRID	Advanced Boston Projects	~60M	•Potential 2014 TCA Submittal
NGRID	Auburn Area Upgrade Projects	~120M	•TCA Submitted Oct. 2013 •ISO Determination expected Q1-2014
NGRID	•Salem Harbor Retirement Reliability Upgrades •Salem Harbor Asset Condition •Salem Harbor Cable Replacement S145/T146 Project	•~$48M •~75M •~63M	TCA's expected to be submitted in 2014
NU / NGRID	Pittsfield / Greenfield	~$135M	Potential 2014 TCA Submittal

FERC Order 1000 – Implementation

- FERC Order 1000 compliance filings are complete. Awaiting any final compliance obligations for both Inter-regional and Intra-regional Planning from FERC
- ISO will be working on preparations for implementation of Order 1000 throughout 2014. These efforts will likely extend into 2015 as the new processes becomes refined with experience

2018/2019 Installed Capacity and Local Sourcing Requirements for FCA #9

- PSPC review of ISO recommendation of Installed Capacity Requirement (ICR) values – **June 2014**
- Reliability Committee (RC) review/vote – **August 2014**
- Participants Committee review/vote – **October 2014**
- File with FERC – **November 2014**
- Forward Capacity Auction #9 conducted – **February 2015**

FCM Auction Key Dates

- Commitment Period #5 (2014-2015)
  - ARA #3 – **March 2014**
- Commitment Period #6 (2015-2016)
  - ARA #2 – **August 2014**
- Commitment Period #7 (2016-2017)
  - ARA #1 – **June 2014**
- Commitment Period #8 (2017-2018)
  - Conduct Auction – **February 2014**
  - Results Filing – **February 2014**
- Commitment Period #9 (2018-2019)
  - Show of Interest Window – **February 18 – March 4, 2014**
  - FCA FERC Informational Filing – **November 2014**
  - Conduct Auction – **February 2015**

Generator Interconnection Queue as of December 1, 2013

- In total, 49 generation projects are currently being tracked by the ISO, totaling approximately 5,100 MW
  - 0 in scoping stage
  - 5 in feasibility study
  - 19 in system impact study/optional interconnection study
  - 0 in facilities study
  - 1 negotiating interconnection agreements
  - 23 with interconnection agreements
  - 5 distribution interconnections

Note: 3 projects require 2 studies each due to multiple interconnection requests and 1 project has no capacity increase

Regional System Plan (RSP) – 2014

- RSP14 and related key Planning Advisory Committee (PAC) meetings
  - RSP scope of work to be presented at the February PAC
  - Environmental and renewable resource updates provided to PAC and Environmental Advisory Group (EAG) on an ongoing basis
  - Initial draft report will be posted for stakeholder review in July
  - RSP review and comment meeting scheduled for August 14
- RSP14 Public Meeting scheduled for September 11

2013/14 Winter Reliability Program

- 2013/14 winter reliability program services for the period December 1, 2013 through February 28, 2014 :
  - Establishment of initial fuel oil inventory
  - Delivery of replenishment fuel inventory during the program period (dual fuel generators only)
  - Testing of dual fuel unit's ability to switch from gas fuel and operate on fuel oil.
  - Delivery of additional demand response
- ISO will provide monthly updates on the program at the NEPOOL Participants Committee meetings , and a final report after the completion of the program

Gas-Electric Coordination

- Implement changes to ISO Information Policy per FERC Order 787 to improve coordination and information sharing with gas pipelines
- Implement tools that mine data from various sources to estimate the availability of natural gas for energy purposes
- Run capacity analysis scenarios across different seasons based on information gathered from fuel surveys and pipelines
- Establish operating plans to deal with different system conditions
- Continue data gathering and analysis
- Communicate with stakeholders and regulators on a regular basis

NERC/FERC Compliance; Cyber Security

- Ensure compliance with new and existing NERC and FERC orders
  - Maintain compliance monitoring with required self-certifications
  - Work with NERC on its new Reliability Assurance Initiative
  - Increase focus on internal controls
  - Continued interaction with Participants on matters relating to NPCC's administration and auditing of NERC Standards
- Improving ISO programs for managing system models to support enhanced NERC modeling and planning requirements
- Enhance existing tools, processes and controls to provide better protection against current and emerging cyber security threats
- Preparation for NERC Audit scheduled for Q1, 2015

Elective Transmission Upgrades – ETU's

- There are a number of issues with the existing OATT language on the processing of requests for Elective Transmission Upgrades (ETU's)
- ISO has discussed the issues with stakeholders and hopes to present draft tariff language to address these issues in Q2 2014
- There are likely some corresponding changes in Market Rule 1 that will have to be reviewed for completeness of the process changes
- FERC filing anticipated in Q3/Q4 2014

Modeling Capacity Zones

- Existing four capacity zones (ME, NEMA/BOS, CT, ROP) will be modeled in FCA #8
- FERC compliance filing on tariff changes to provide automatic review trigger mechanism for modeling capacity zones to be made in Q1 2014
- The new mechanism is anticipated to be in place for FCA #9
- RSP14 to include a longer term forecast of anticipated capacity zones

Distributed Generation Forecast

- The Distributed Generation Forecast Working Group (DGFWG) formally started its work in September 2013
- Two sessions have been held to date with good participation from stakeholder and states
- ISO has created an draft interim DG Forecast that has been presented to the group
  - It is hoped this forecast can be used until a more robust forecast method is developed
  - How best to use this forecast information is still under review
- Critical technical issues have been identified regarding the interconnection and operability of solar photovoltaic resources, that will require more analysis and perhaps lead to changes in state interconnection standards

Operating Guides and Procedures Update

- Review and update Guides due to system transmission and generation changes
  - MPRP; Interstate; Lower SEMA; Addition of Renewable Generators
- Review and update real-time voltage limits
- Develop temporary operating guides for system modification during construction
- Integrate new wind dispatching process into review of system operating limits (this is tied to the Wind Integration Phase I project which is detailed on slide 48)

MARKET DESIGN

FCM Demand Curve

- The ISO will propose a system-wide demand curve for the region's capacity market.
  - The ISO will begin the stakeholder process in January 2014
  - ISO believes that the FERC filing for this activity should be scheduled for no later than summer 2014
  - The ISO is evaluating sub-regional demand curves specific to constrained zones as part of this project
- With a summer 2014 filing, implementation most likely would be for FCA #10

NCPC Cost Allocation

- The ISO is planning to address cost allocation in two phases
- During Phase I, the ISO will assess how real-time "first contingency" NCPC costs are allocated
  - The Phase I stakeholder process is underway
  - Implementation scheduled no earlier than Q4 2014
- Phase II will include a comprehensive review of cost allocation, identifying the cause or beneficiary of the commitment or dispatch that resulted in the NCPC costs
  - The Phase II stakeholder process is expected to begin after the implementation of the *Energy Market Offer Flexibility* hourly markets project

Sub-hourly Real-Time Settlement

- The real-time markets (energy, reserves and regulation) are all settled hourly, even though resources are dispatched at sub-hourly intervals
  - The hourly settlement approach, especially for resources that are able to respond quickly, can result in hourly compensation being inconsistent with how the resource performed on a 5-minute basis.
  - The ISO is evaluating allowing for sub-hourly settlement for the real-time markets for, at a minimum, generation, external transactions, dispatchable asset related demand, and demand response
- The stakeholder process is underway and implementation is scheduled after the *Energy Market Offer Flexibility* project

Price Responsive Demand (PRD): Energy and Reserves

- The ISO is evaluating updates to the PRD market rules to reflect the revised *NCPC Payment* rules, and to specify participation in the Forward Reserve and Regulation markets, and the rules for the provision of real-time reserve.
  - The ISO is planning to begin the stakeholder process in 2014
  - FERC filing is scheduled for Q1 2015
  - These changes are scheduled to be effective for June 1, 2017

Treatment of Resources Retained for Reliability

- The ISO is evaluating modifications to the auction treatment of resources retained for reliability in the Forward Capacity Auction. The ISO is proposing to remove the impact of these resources on auction clearing prices
  - The stakeholder process is underway
  - FERC filing is scheduled for Q2 2014
  - These changes are scheduled to be in place for FCA #9

3rd Party FTR Clearing

- The objective of this project is to replace ISO-NE financial assurance requirements for holding FTRs with margining by a third party clearing entity
  - This shifts FTR default risk from ISO New England Market Participants to the third party
- Address the financial assurance issues that have prevented implementation of Long Term FTRs and Balance of Planning Period auctions
- Facilitate secondary market trading
- Stakeholder process is currently underway and the ISO anticipates a stakeholder vote in Q3 2014

Other Market Design Projects

- The ISO intends to propose moving from a seasonal to a monthly Forward Reserve Auction
  - Stakeholder process will begin shortly and the change is intended to be effective for the October 2014 delivery month

- The ISO is proposing changes to the submission timing of Non-Price Retirement Requests so that if the request is retained for reliability, participant decisions can be completed before the FCA
  - The stakeholder process is underway
  - FERC filing on the items listed above scheduled for Q1 2014
  - These changes are scheduled to be effective for FCA #9

Other Market Design Projects (continued)

- The ISO is proposing to modify the dispatch rules as they apply to wind resources to ensure reliable system operation while efficiently using wind resources
  - The ISO is planning to begin the stakeholder process in 2014 with implementation scheduled for 2015

- The ISO is proposing to add intertemporal parameters for DARD pumps to improve the commitment and operation for pumping
  - The stakeholder process is expected to begin in 2014
  - The ISO is still evaluating when these changes can be effective

MARKET ASSESSMENTS

Energy Pricing Enhancements

- Significant improvements have been made in 2013 to improve energy price formation
- The objective of this project is to continue to works towards ensure that LMPs accurately reflect the incremental cost of supplying electric energy and maintaining operating reserves
- The ISO is evaluating the following additional items
  - Improved pricing algorithms for fast-start resources;
  - Improved methodologies for incorporating into real-time prices
    - the cost of slow-ramping generation units and
    - the costs incurred to re-dispatch the system when necessary to satisfy steep load ramps during the operating day
- The ISO will provide periodic updates to stakeholders in 2014, beginning in Q1

Elective Transmission Upgrades: Market Implications

- The ISO is evaluating operational and market impacts specific to new, merchant transmission projects
  - This assessment will review the integration of these transmission projects into the energy and capacity markets
- The ISO is planning to start the stakeholder process for these changes in 2014

CAPITAL PROJECTS

Energy Market Offer Flexibility / Hourly Offers

- This project will design and implement functionality that will allow resources to submit hourly energy offers into the Day-Ahead Energy Market, and to modify the commitment cost components and the incremental energy-offer component of supply offers during the operating day and submit negative offers in the energy markets
- This project also includes the implementation of the NCPC redesign
- The project is schedule to be implemented in December 2014

FCM Performance Incentives (FCA 9)

- This project proposes to implement the FERC order related to either the FCM Pay-for-Performance proposal or the alternate NEPOOL proposal
- The project is schedule to be implemented in Q1 2015

Backup Control Center Data Center Transition

- This project transitions/cuts over from the old Backup Control Center to the new Backup Control Center.
- The major activities include reliably switching over all energy management system and market system based applications, relocation of servers, purchasing and installation of network hardware, servers, client workstations
- With the cutover, Operations Training Staff will transition to the new BCC and it will be utilized as the Control Room training center
- The project is expected to be implemented in Q2 2014

Generation Control Application (GCA) Production Phase I

- This project will expand on previous functionality and provide the following
  - An enhanced version of the optimization engine for the commitment and shutdown of fast-start units
  - Enhance modeling of pump storage plants to allow unit switching between generation and pumping mode
  - Automatic detection/prediction for minimum generation conditions
  - Development of next hour interchange predictor for the New York North interface.
- The project is scheduled to be implemented in Q1 2015

Coordinated Transaction Scheduling

- The project will improve the economic efficiency of interchange scheduling between NYISO and ISO-NE by implementing software changes to enable the two ISOs to coordinate selection of the most economic transactions
- Participants will be able to submit spread interface bids with 15 minute granularity, and the ISOs will move to 15 minute scheduling
- The project is scheduled to be implemented in Q4 2015

Alternative Technologies and Regulation Market Project

- This project will implement modifications to the Regulation market resource selection process, Automatic Generation Control dispatch and settlement to comply with Order 755
- The project is currently scheduled to be implemented in Q2 2014

Web Enhancements Phase II

- The ISO is continuing improvements to the external website during the Phase II project, with a focus on significantly increasing user functionality and making information more accessible and usable to internal and external users
- This project will vastly improve the ability to organize content on ISO-NE's website across committees, issues, projects
- The site will be better organized as a customer service channel, handling critical inquiries and requests from stakeholders, and better equipped to broadcast outages and other notices.
- The project is schedule to be implemented in Q2 2014

Divisional Accounting

- This is a multi-phase project through 2014 and 2015 that will implement changes to various ISO NE systems to allow participants to create and maintain subaccounts and associate their resources and transactions to these subaccounts.
- These changes will increase market efficiency for participants by allowing them to evaluate their portfolio by business unit, division or generating facility.
- The project is scheduled to be implemented in Q4 2015

Wind Integration Phase I

- This ongoing project will incorporate wind forecasting and wind resources into ISO Processes, scheduling, and dispatch services
- This project will acquire external wind power forecasting services, create operator situational awareness displays, integrate wind into the real-time dispatch integration and maintain historical wind data for future use of the forecast service, auditing, and other analysis.
- The project is schedule to be implemented in Q1 2014

Simultaneous Feasibility Test (SFT) and Market System Upgrade

- This project will upgrade the SFT application to align with the Contingency Analysis and other security applications that were upgraded as part of the 2012 Energy Management System upgrade project
- The project is schedule to be implemented in Q2 2014

Business Continuity Plan Infrastructure Enhancements Phase III

- This is the final phase of the initiative that began in 2008.
- This project will expand the virtual environment to production and implement the four-way integration environment.
- The functionality will improve the ability for ISO personnel to conduct business remotely in the case of the unavailability of the Main Control Center.
- The project is schedule to be implemented in Q2 2015

Various Application Enhancements

- Control Room Visualization
  - This project will merge individual substation displays into a single system wide display allowing the operators to pan and zoom to gain a more detailed overview of the system. As part of this project, enhancements will be added to provide operators with access from the new display to Transmission Operating Guides
  - The project is schedule to be implemented in Q2 2014

- New voltage/reactive tool
  - Implement a new voltage tool that will be used by the Control Room in real-time

Various Application Enhancements

- Software Testing Tool
  - The purpose of this project is to automate the testing effort for various applications at the ISO, which will result in efficiencies in future project implementations
  - This project is scheduled for implementation in Q4 2014
- FCM Termination and Retirements
  - The project will improve the process for the termination and retirement of FCM resources through automation and create a centralized, automated solution to replace labor-intensive business processes
  - Eliminate the risk of errors across Capacity Commitment Periods due to manual database edits
  - The project is schedule to be implemented in Q3 2014

Various Application Enhancements

- Hardware Upgrades / Software Enhancements
  - These upgrades are intended to address various ISO hardware upgrade needs and implement software enhancements to various enterprise applications, market and reliability based applications and data bridges that connect these applications
  - These are implemented at various points during the course of the year, based on the schedule of major projects

2014 Issues Resolution Project

- Reduce Backlog in Issues Management
  - The 2014 Issue Resolution Project is intended to continue to improve the resolution pace of issues
  - This will increase operational efficiency and accuracy, provide for minor enhancements and reduce risk
  - This could include both software and hardware infrastructure enhancements
  - This will be implemented as multiple projects and they are scheduled for completion by the end of 2014

ACTIVITY DRIVERS

Wholesale Markets Activity Drivers

Activity	Driver	Reliability Impact	Market Efficiency Impact
FCM Demand Curve	ISO Initiative	Medium	High
NCPC Cost Allocation	ISO Initiative	Medium	Medium
PRD: Energy and Reserves	FERC Order 745	Medium	Medium
Sub-Hourly Settlement	Market Participants	Medium	Medium
3rd Party FTR Clearing	ISO Initiative	Low	Medium
Regulation Market	FERC Order 755	Low	Medium
Monthly FRM Auctions	Market Participants	Medium	Medium

Wholesale Markets Activity Drivers, cont.

Activity	Driver	Reliability Impact	Market Efficiency Impact
Wind Dispatch Rules	ISO Initiative/Public Policy	Medium	Medium
Treatment of Resources Retained for Reliability	ISO Initiative	Low	High
Non Priced Retirement Timeline	ISO Initiative	Low	High
Energy Pricing Enhancements	Market Participants, ISO	Medium	High
Elective Transmission Upgrades	Tariff Compliance	Medium	Medium

Planning/Operations Activity Drivers

Activity	Driver	Reliability Impact
Transmission Planning Studies	NERC and NPCC and Tariff Compliance	High
Eastern Interconnection Planning Collaborative	DOE Initiative	Low
2013 and 2014 Economic Studies	Tariff Compliance; Order 890	Low
Finalize 2014 / 2015 State EE Forecast	Public Policy	Medium
Interregional Planning	NERC, NPCC and Tariff Compliance	Medium
Transmission Cost Allocation	Tariff Compliance	Low
Implement FERC Order 1000	FERC Compliance	Medium
2018/19; 2019/20 ICR and LSR	NERC, NPCC and Tariff Compliance	High
FCA #8 / FCA #9 Annual Reconfig Auctions	Tariff Compliance	High

Planning/Operations Activity Drivers, cont.

Activity	Driver	Reliability Impact
Generator Interconnection Studies / Review of Interconnection Process	Tariff Compliance	Medium
RSP 14 /RSP 15 Publication	Tariff Compliance	Low
2013/14 Winter Program	ISO Initiative	High
Gas-Electric Coordination	ISO Initiative	High
NERC/FERC/NPCC Compliance; Cyber Security	NERC / FERC / NPCC Compliance	High
Implementation of new method for Modeling Capacity Zones	FERC Order	High
Develop a Distributed Generation (DG) forecast	Public Policy	Medium
Operating Guide Updates	ISO Operations	High

Capital Project Activity Drivers

Activity	Driver	Reliability Impact	Market Efficiency Impact	Estimated 2014 Implementation Cost*
Hourly Offers	ISO / Stakeholder Initiative	High	High	$10.2M
FCA 9 Implementation	Tariff Compliance	Medium	High	TBD
Backup Control Center	NERC Compliance	High	Medium	$612K
Generator Control Application	ISO Initiative	High	High	$3.3M
Coordinated Transaction Scheduling	Internal/External Market Monitor; FERC	High	High	$3.8M
Regulation Market	FERC Order 755	Low	Medium	$659K

* **Provides costs for chartered projects only; Projects could span multiple years**

Capital Project Activity Drivers, cont.

Activity	Driver	Reliability Impact	Market Efficiency Impact	Estimated 2014 Implementation Cost*
Web Enhancements Phase II	ISO, Market Participants	Low	Medium	$168K
Divisional Accounting	ISO Initiative	Low	Low	$1.2M
Wind Forecasting	ISO Initiative	Medium	Medium	$105K
Market System Upgrade	ISO Initiative	High	High	$436K
Business Continuity Plan Phase III	NERC Compliance	High	Medium	TBD
Various Database / Application Enhancements	ISO IT/Operations	Medium	Medium	TBD
Issue Resolution 2014	ISO Management	Medium	Medium	$1.5M

*** Provides costs for chartered projects only; Projects could span multiple years**

Capital Projects

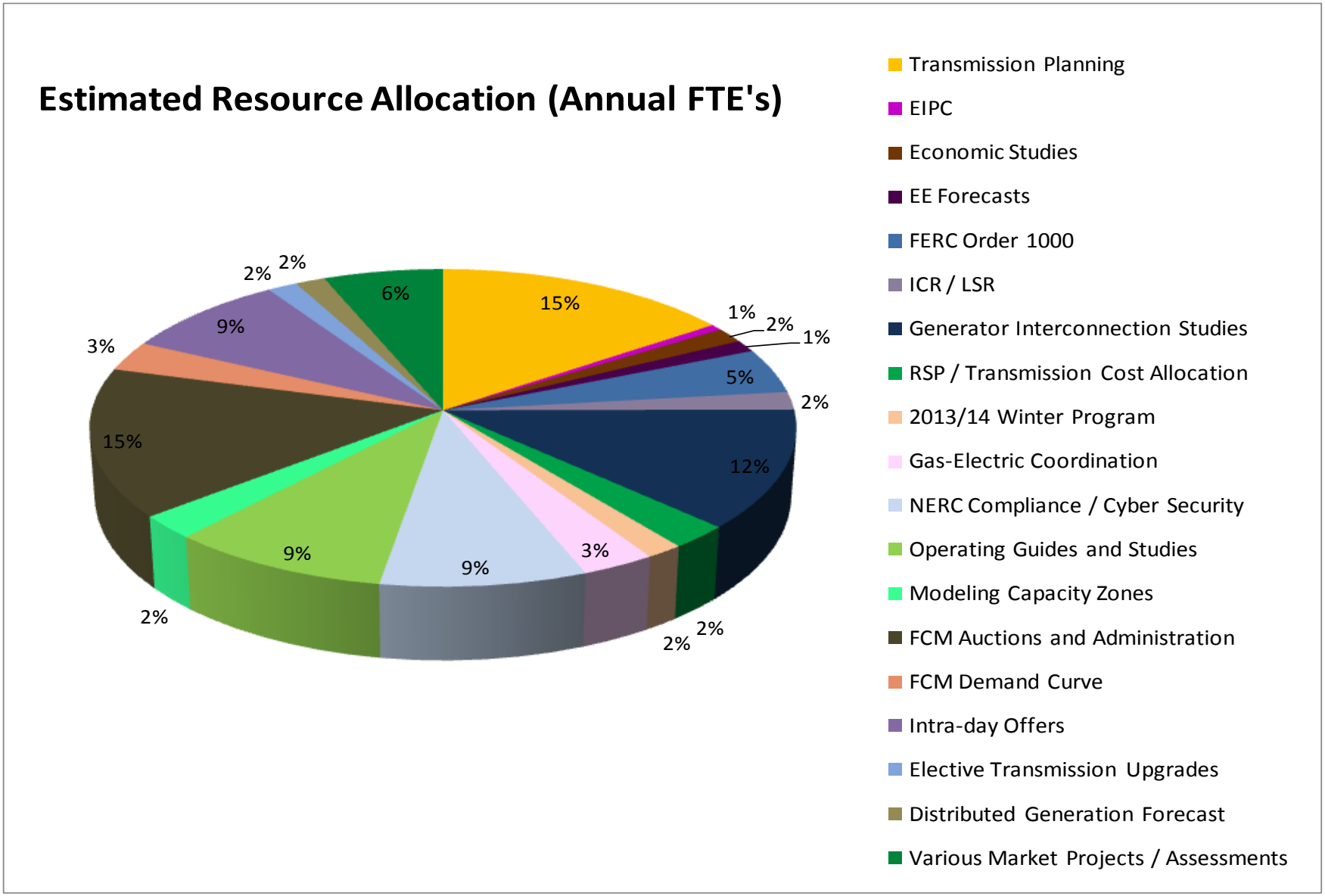
- The ISO discusses changes and updates to its capital budget each quarter (with stakeholders) and files an updated Capital Filing Tariff with the FERC
  - The quarterly CFT captures any changes in the cost of a project
  - The quarterly CFT also notes projects that are completed and new projects that are chartered
  - The most accurate quarterly costs are reflected in the ISO CFT
  - Please note that the resource estimates and costs contained in this presentation are approximations and intended to signal the current level of effort for each activity

Resource Estimate

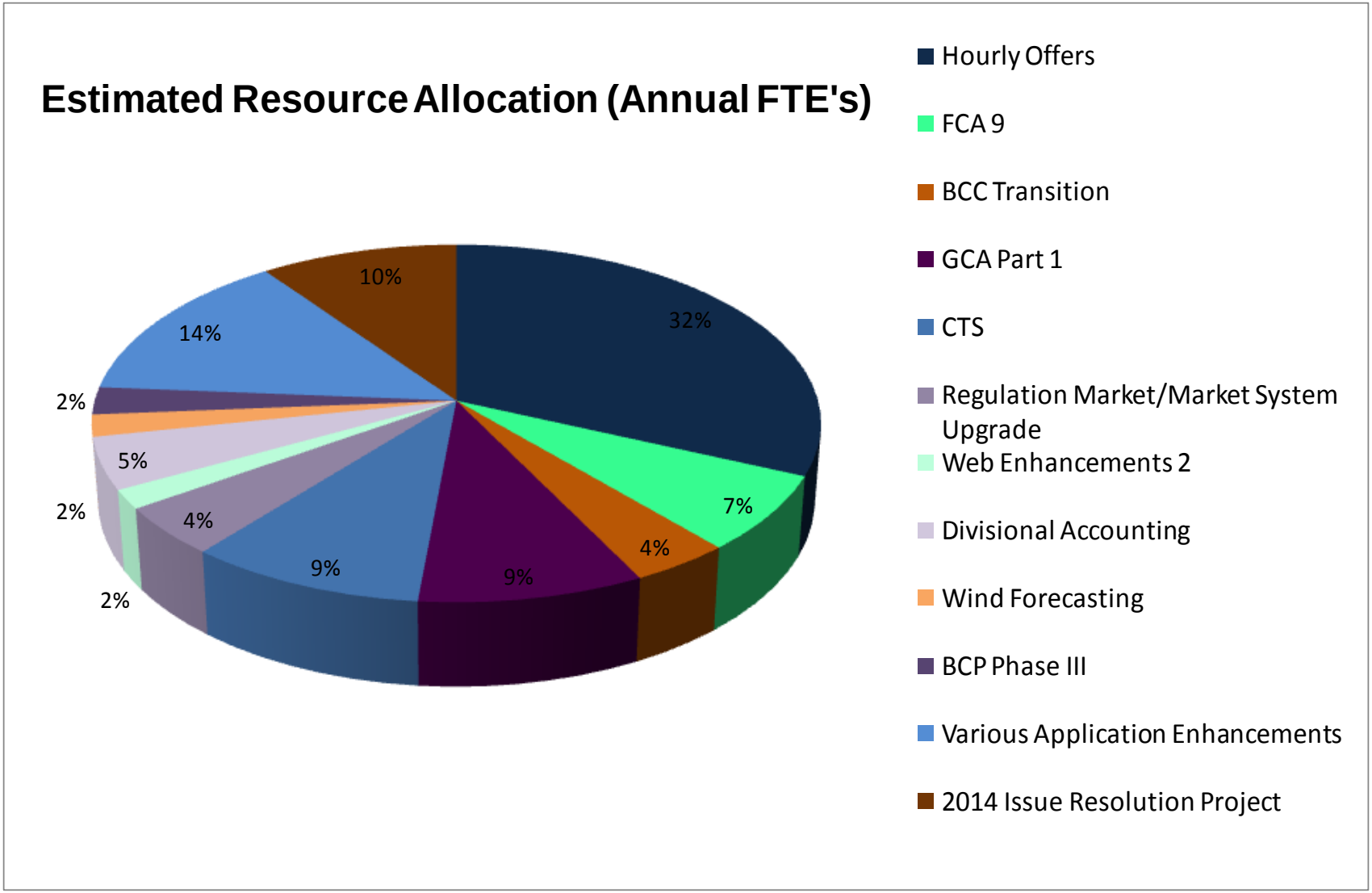
- For the activities identified in the work plan, the estimated ISO resource allocation is as follows:
  - For the capital projects identified in the work plan, the ISO expects an approximate allocation of 105 resources
  - For the non capital activities identified in the work plan, the ISO expects an approximate allocation of 160 resources

- Slides 64 and 65 illustrate the relative resource allocation across activities contained in the work plan
  - The resources are estimates and actual allocation of resources across all activities will change based on scope, schedule and emerging priorities
  - Costs associated with generator interconnection studies are mostly reimbursed by the study owner

Estimated Resource Allocation to Operating Activities



Estimated Resource Allocation to Capital Projects



M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Pat Gerity, NEPOOL Counsel

DATE: December 26, 2013

RE: *Order 787*-Related Information Policy Changes

At the January 10, 2014 Participants Committee meeting, you will be asked to consider supporting revisions to the Information Policy that (i) would allow the ISO, consistent with FERC Order No. 787,[1] to share Confidential Information with interstate natural gas pipelines and (ii) removes certain language related to information sharing with natural gas pipelines that is longer effective[2] and is not to be retained as part of the *Order 787*-related changes ("*Order 787 Changes*"). A copy of the *Order 787 Changes*, as well as background materials from the ISO describing the changes it initially proposed, have been included with this memorandum.

Initial changes proposed by the ISO in response to *Order 787* were unanimously recommended by the Markets Committee at its December 11 meeting. However, since that recommendation, additional changes, which would retain some, but not all, of the language accepted on an interim basis a little less than a year ago, were proposed by specifically-effected members in the Generation Sector and accepted by the ISO.[3] Accordingly, this matter has been included for discussion rather than listed on the Consent Agenda.

If there is no objection, the Committee may accept, as a friendly amendment, the additional changes proposed by effected Generators and agreed upon by the ISO. Otherwise, the Participants Committee's consideration of this matter would begin with the Markets Committee recommended changes. In either case, the following form of resolution may be used:

> RESOLVED, that the Participants Committee supports the revisions to the Information Policy to allow the ISO to share Confidential Information with interstate natural gas pipelines consistent with *Order 787*, as [provided to this Committee in advance of this meeting ***or*** recommended by the Markets Committee at its December 11, 2013 meeting], together with [those changes agreed to by the Committee at this meeting and] such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

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[1] *Communication of Operational Information Between Natural Gas Pipelines and Electric Transmission Operators*, Order No. 787, 145 FERC ¶ 61,134 (Nov. 15, 2013) ("*Order 787*").

[2] The prior pipeline information sharing changes, which became effective Jan. 24, 2013, expired Apr. 30, 2013. *See ISO New England Inc.*, 142 FERC ¶ 61,058 (Jan. 23, 2013).

[3] Changes proposed by the ISO and recommended by the Markets Committee as shown in the attached tariff sheets by underline and strikeout. The additional changes proposed by Generators and accepted by the ISO are highlighted and underlined.

ATTACHMENT D

ISO New England Information Policy

ISO as separate attachments via the Forward Capacity Tracking System, will be shared with subsequent Lead Market Participants or Project Sponsors for that resource.

Notwithstanding anything to the contrary in the ISO New England Information Policy, the ISO, the Participants Committee, or any Governance Participant may disclose *Confidential Information* as required or permitted to satisfy the "Minimum Criteria for Market Participation" set forth in Section II.A of the ISO New England Financial Assurance Policy.

Notwithstanding anything to the contrary in the ISO New England Information Policy and consistent with FERC Order No. 787, ~~from January 24, 2013 through April 30, 2013,~~ the ISO may disclose ~~confidential forecast~~Confidential Information ~~and real-time output information~~ concerning natural gas-fueled generation from resources located within the New England Control Area to the operating personnel of an interstate natural gas pipeline company that operates a pipeline provided that: (a) Confidential Information regarding specific generators will be shared only with the pipeline serving that generator directly and (b) the ISO has determined that it is operationally necessary to ensure reliability to disclose the Confidential Information. ~~that operates a pipeline, provided that: (a) Confidential Information regarding specific generators will be shared only with the pipeline serving that generator directly or serving the local distribution company that serves that generator; (b) the ISO has determined that it is operationally necessary to ensure reliability to disclose the Confidential Information; (c) the ISO and the interstate natural gas pipeline company have entered into a non-disclosure agreement substantially in the form attached hereto as Appendix D; (d) the ISO will provide a summary of any disclosed Confidential Information to the affected generator within 48 hours following disclosure; and (e) the ISO will discontinue the disclosure of Confidential Information to the interstate natural gas pipeline if (i) the gas pipeline breaches or threatens to breach its obligations under the non-disclosure agreement or (ii) the ISO determines that disclosure is no longer required for reliability purposes. The generator whose Confidential Information is disclosed pursuant to this provision shall be entitled to all rights and remedies, in law or equity, with respect to any breach of the pipeline company's obligation to maintain the disclosed data in confidence consistent with all applicable FERC orders and rules, including FERC Order No. 717, and FERC-approved gas pipeline tariffs, to the same extent as if the generator had provided the information directly to the interstate natural gas pipeline company.~~

2.3 Disclosure of Information Regarding Defaulting Governance Participants

Notwithstanding any provision herein to the contrary, the information for release to Governance Participants identified in this Section shall no longer be deemed "*Confidential Information*" pursuant to

APPENDIX D

FORM OF PIPELINE NON-DISCLOSURE AGREEMENT

This NON-DISCLOSURE AGREEMENT (the "Agreement") is made this ____ day of _____, 2013 (the "Effective Date") between _____ (the "Pipeline") and ISO NEW ENGLAND INC., a Delaware corporation ("ISO-NE") (the Pipeline and ISO-NE, individually, a "Party" and, collectively, the "Parties").

WHEREAS, the Parties are working to coordinate the sharing of relevant data regarding gas and electric operations in New England to ensure the reliability of both systems; and

WHEREAS, from January 24, 2013 through April 30, 2013, ISO-NE's Information Policy allows it to share forecast and real-time output information concerning natural gas-fueled generation from resources located within the New England Control Area to the operating personnel of the interstate natural gas pipeline companies that operate the pipeline that serves directly that generator or serves the local distribution company that serves that generator; and

WHEREAS, in furtherance thereof, the Parties may, but are in no way obligated to, deliver to each other certain information; and

WHEREAS this Agreement is entered into to ensure that Confidential Information is not disclosed to unauthorized recipients in violation of this Agreement.

NOW, THEREFORE, for good and valuable consideration, the receipt and adequacy of which are hereby acknowledged, the Parties agree as follows:

1. Definition of Confidential Information. (a) The following constitutes "Confidential Information": (i) information regarding forecast and real-time electric output of natural gas-fueled generating resources located within New England ("Affected Generators"); (ii) oral, written or recorded/electronic information about either Party, its vendors, agents and customers (including participants in the New England Power Pool) that is marked confidential" or "proprietary" if written or recorded/electronic; and (iii) all reports, summaries, compilations, analyses, notes or other information which contain any such information described in clause (i) or (ii).

~~**(b) This provision shall not apply to any information which:**~~

~~**(i) can be demonstrated to have been in the possession of the Party receiving the information (the "Receiving Party") prior to receipt thereof from the Party disclosing the information (the "Disclosing Party") without any obligation of confidentiality or to have been developed in the course of work entirely independent of any disclosure made hereunder or the subject matter of this Agreement;**~~

~~**(ii) is or becomes part of the public domain other than through breach of this Agreement or through the fault of the Receiving Party; or**~~

~~**(iii) has been independently acquired or developed by the Receiving Party or its officers, employees, consultants, advisers or attorneys without violating any obligations under this Agreement.**~~

~~**(c) The Parties acknowledge and agree that nothing in this Agreement is intended to create an obligation on a Party to disclose information of any kind to the other Party (including, without limitation, any information the disclosure of which, in the sole judgment of such Party, would violate any law or governmental regulation) or to take any action of any kind with respect to facilities that the Party owns or controls in response to any information that the Party receives from the other Party. The Disclosing Party shall have no liability to the Receiving Party for the Receiving Party's reliance on Confidential Information provided by the Disclosing Party or for any actions that the Receiving Party takes (or fails to take) with respect to such Confidential Information.**~~

~~2. Non-Disclosure.~~

~~**(a) The "Confidential Period," as used herein, shall mean the period of six months following the disclosure of the discrete piece of Confidential Information. During the Confidential Period, the Receiving Party shall not, in any manner, either directly or indirectly, divulge, disclose, or communicate to any person, firm, corporation or other entity, or use for any purposes other than those set forth herein, the relevant Confidential Information acquired from the Disclosing Party, without the express prior written consent of the Disclosing Party and any Affected Generators. During the Confidential Period, ISO-NE shall not disclose the relevant Confidential Information of the Pipeline to anyone except to officers and employees of ISO-NE responsible for reliable electric operations and to the outside consultants, advisers and/or attorneys who advise those responsible employees, in each case who have a need to know to ensure the reliability of electric operations in New England and who have been advised of the confidential nature of the Confidential Information and who have agreed to abide by the terms of this Agreement. During the Confidential Period, the Pipeline shall not disclose the relevant Confidential Information of ISO-NE or any Affected Generator to anyone except the Pipeline's transmission function employees, as defined by the Federal Energy Regulatory Commission, and to the outside consultants, advisers and/or attorneys who advise those transmission function employees, in each case who have a need to know to ensure the reliability of gas operations in New England and who have been advised of the confidential nature of the Confidential Information and who have agreed to abide by the terms of this Agreement. Subject to the limitations of liability contained**~~

~~**herein, the Receiving Party agrees that it shall be liable for any breach of this Agreement by its officers, employees, consultants, advisers and attorneys.**~~

~~**(b) Upon execution of this Agreement, each Party shall advise the other Party in writing of its disclosure procedures (i.e., individuals within the categories described above to be called, or email addresses to be used for the delivery of electronic information) to be followed in sharing Confidential Information pursuant to this Agreement. Such procedures may be revised from time to time by either Party at its sole discretion by providing written notice to the other Party. Each Party agrees to provide the Confidential Information only to the individuals specified in the procedures, if any.**~~

~~**(c) If the Receiving Party or one of its representatives is required to disclose Confidential Information by subpoena, law or other directive of a court, administrative agency, legislative or judicial body, governing tribunal or commission, or arbitration panel, the Receiving Party hereby agrees to provide the Disclosing Party with prompt notice of such request or requirement. Moreover, if the Pipeline is the Receiving Party, it shall also give notice to ISO, which shall in turn give notice to any Affected Generator. The Disclosing Party and any Affected Generators shall jointly (i) seek an appropriate protective order or other remedy, (ii) consult with the Receiving Party with respect to taking steps to resist or narrow the scope of such request or legal process, or (iii) waive compliance, in whole or in part, with the terms of this Agreement. In the event that such protective order or other remedy is not obtained, or that the Disclosing Party and Affected Generators, if any, waive compliance with the provisions hereof, the Receiving Party hereby agrees to furnish only that portion of the Confidential Information which the**~~

~~Receiving Party's counsel advises is legally required and to request that confidential treatment will be accorded such Confidential Information.~~

~~3. Ownership and Return of Confidential Information.~~

~~(a) All Confidential Information shall remain the property of the Disclosing Party or the Affected Generator, as applicable.~~

~~(b) If the Disclosing Party, in its sole discretion, so requests, the Receiving Party will promptly deliver to the Disclosing Party all Confidential Information, including all copies, reproductions, summaries, compilations, or extracts thereof in the Receiving Party's possession or in the possession of any representative of the Receiving Party, but excluding documents, memoranda, notes and other writings prepared by the Receiving Party or by the Receiving Party's representatives to whom the Receiving Party has delivered the Confidential Information, which contain the Confidential Information. All documents, memoranda, notes and other writings prepared by the Receiving Party, or by the Receiving Party's representatives to whom the Receiving Party has delivered the Confidential Information, which contain the Confidential Information (including recorded/electronic versions thereof) shall be destroyed by the Receiving Party (such destruction to be confirmed in writing to the Disclosing Party). Notwithstanding anything herein to the contrary, the Receiving Party may retain one archival copy of the Confidential Information as required to meet its legal obligations. If an archival copy is retained, it will be treated by the Receiving Party the same way Receiving Party treats its own confidential business information. Also, the Receiving Party shall not be obligated to search for and destroy, delete or erase or return Confidential Information, or any analyses, compilations, studies or other documents which have been prepared and which contain any Confidential Information, if such are maintained as part of a back-up or archival system or records in electronic information and storage systems, including but not limited to such systems as any recording media for analog or digital information, PDA's, smart phones or cell phones, computers, phone systems, instant messages, e-mail or voice mail, as part of the routine maintenance and operation of such systems. The Receiving Party will treat Confidential Information in its electronic information and storage systems the same way the Receiving Party treats its own confidential business information.~~

~~4. Equitable Relief; Damages. Without prejudice to the rights and remedies otherwise available, the Disclosing Party shall be entitled to seek direct damages and (subject to the court's~~

~~requirements for bonding and burden of proof) equitable relief by way of injunction or otherwise if the Receiving Party or any of the Receiving Party's representatives breach or threaten to breach any of the provisions of this Agreement. The Receiving Party reserves all rights to oppose, and defenses to, such relief.~~ ~~**ANYTHING IN THIS AGREEMENT TO THE CONTRARY NOTWITHSTANDING, IN NO EVENT SHALL EITHER PARTY BE LIABLE FOR INDIRECT, SPECIAL, EXEMPLARY, PUNITIVE, CONSEQUENTIAL (INCLUDING LOST OPPORTUNITY OR PROFIT) DAMAGES OR FOR DAMAGES IN TORT.**~~

~~5. Term; Survival. This Agreement terminates May 1, 2013. The obligations of the Parties with respect to Confidential Information disclosed hereunder prior to the date of such termination shall survive as specified herein. The following provisions shall survive the termination of this Agreement for the purposes of any claim brought under or relating to this Agreement: Section 4 (Equitable Relief; Damages); Section 5 (Survival); and Section 7 (Governing Law; Venue; Jury Trial).~~

~~6. No Waiver. Each Party understands and agrees that no failure or delay by the other Party in exercising any right, power or privilege hereunder shall operate as a waiver thereof, nor shall any single or partial exercise thereof preclude any other or further exercise thereof or the exercise of any right, power or privilege hereunder.~~

~~7. **GOVERNING LAW; VENUE; JURY TRIAL. THIS AGREEMENT SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE COMMONWEALTH OF MASSACHUSETTS WITHOUT REGARD TO ITS CONFLICTS OF LAWS PRINCIPLES. VENUE FOR ANY ACTION HEREUNDER SHALL BE WITHIN MASSACHUSETTS. EACH PARTY HEREBY IRREVOCABLY WAIVES ANY RIGHT TO TRIAL BY JURY.**~~

~~8. Assignment Prohibited. Any assignment of a Party's rights, obligations or duties under this Agreement without the other Party's prior written consent shall be void. ISO-NE shall give the Affected Generators notice of a proposed assignment by the Pipeline.~~

~~9. Entire Agreement. This Agreement contains the entire agreement between the Parties concerning the confidentiality of the Confidential Information and supercedes all previous agreements, and no modification of this Agreement or waiver of the terms and conditions hereof shall be binding upon the parties, unless approved in writing by each of them.~~

~~10. Severability. If any provision or provisions of this Agreement shall be held to be invalid, illegal or unenforceable, the validity, legality and enforceability of the remaining provisions shall not in any way be affected or impaired thereby.~~

~~11. Due Authorization. Each Party represents and warrants that (a) it has full power and authority to enter into this Agreement, (b) execution of this Agreement will not violate any other agreement with a third party, and (c) the person signing this Agreement on its behalf has been properly authorized and empowered to enter into this Agreement.~~

~~12. No Warranty. The Parties acknowledge that, while it is their intention to provide to each other Confidential Information which is accurate and complete, no Party makes any express or implied representation or warranty as to the accuracy or completeness of the Confidential Information. Notwithstanding the foregoing, no Party shall disclose to the other Confidential Information about which it has direct knowledge of its inaccuracy or incompleteness. No Party shall have an obligation hereunder to amend or update Confidential Information once it has been disclosed.~~

~~13. No Third-Party Beneficiaries. The Parties do not confer any rights or remedies upon any person other than the Parties to this Agreement and their respective successors and permitted assigns.~~

~~IN WITNESS WHEREOF, the parties hereto have executed this Non-Disclosure Agreement as of the date first written above.~~

~~ISO NEW ENGLAND INC. _____~~

~~By_____ By_____~~
~~Title: Title:~~

ISO new england

memo

To: Markets Committee

From: John Norden and Kevin Flynn – ISO New England Inc.

Date: December 4, 2013

Subject: ISO New England Information Policy Changes to Conform with FERC Order on Gas/Electric Information Sharing

On November 15, 2013, the Federal Energy Regulatory Commission ("FERC" or "Commission") issued a final rule providing explicit authority for interstate natural gas pipelines and electric transmission operators to share non-public information for the purpose of promoting reliable service or operational planning ("Order No. 787").[1] In Order No. 787, the Commission stated that the final rule will help maintain system reliability by permitting the sharing of information that operators of the gas and electric transmission systems deem necessary to promote the reliability and integrity of their systems.[2] The Commission also stated that it "is intentionally permitting the communication of a broad range of non-public, operational information to provide flexibility to individual transmission operators, who have the most insight and knowledge of their systems, to share that information which they deem necessary to promote reliable service on their system."[3]

The currently-effective ISO New England Information Policy (the "Information Policy") [4] does not permit the broad range of communications authorized under Order No. 787. Therefore, ISO New England Inc. (the "ISO") is proposing changes to the Information Policy that will allow the ISO to share non-public (*i.e.*, confidential) information with interstate natural gas pipelines as authorized under Order No. 787 ("Information Policy Changes"). The Information Policy Changes also remove language related to information sharing with interstate pipelines that was effective last winter (January 24, 2013-April 30, 2013) and has since expired.

The attached Information Policy Changes permit the communications authorized by the Commission in Order No. 787. Given the region's reliance on natural gas for electric generation, communication and coordination with the interstate pipelines is important. Therefore, the ISO is seeking to make the Information Policy Changes effective as soon as possible. As such, the ISO will be seeking a vote on the changes at the December 11, 2013 NEPOOL Markets Committee meeting and the January 10, 2014 NEPOOL Participants Committee meeting.

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[1] 145 FERC ¶ 61,134 (2013).
[2] Order No. 787 at P 1.
[3] Order No. 787 at PP 41, 123.
[4] The Information Policy is Attachment D to the ISO New England Transmission, Markets and Services Tariff.

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Pat Gerity, NEPOOL Counsel

DATE: January 3, 2014

RE: Proposed Clarifications to Offer Flexibility Changes

At the January 10, 2014 Participants Committee meeting, you will be asked to consider supporting clarifications to the application of the Energy Market Offer Flexibility Changes proposed in response to the FERC's October 3, 2013 order[1] originally accepting those changes (the "Clarifications"). The Clarifications are recommended by the Markets Committee. Materials from the ISO providing background on the Clarifications, as well as a marked copy of Market Rule 1 reflecting the proposed Clarifications, have been included with this memo.

By way of background, on July 1, 2013, the ISO and NEPOOL jointly filed energy market enhancements to provide Market Participants greater flexibility in structuring and modifying their Supply Offers in the Day-Ahead and Real-Time Energy Markets (the "Offer Flexibility Changes"). Included in the Offer Flexibility Changes were corresponding revisions to Appendix A on market power mitigation. More specifically, the Offer Flexibility Changes allow Resources to submit energy offers using price information from the market that is not necessarily reflected in the daily indices which were the basis for bid reference prices developed by the ISO's internal market monitor ("IMM"). Per these rule changes, if a Resource chooses to provide such offers, that Resource would be required to provide verification substantiating their offers after the fact. Market Participants failing to submit the required verification would be prevented in the future from using this more flexible offer scheme (per the "lock-out" provisions set forth in Appendix A). In accepting the Offer Flexibility Changes, the FERC directed two modifications: (1) the IMM must calculate Reference Levels for locked-out Resources based on updated information, instead of using the Day-Ahead Energy Market price index; and (2) the Tariff must clarify that the IMM will make hourly Reference Levels available to individual Resources.

At its December 10 meeting, the Markets Committee voted to recommend Participants Committee support for the Clarifications by a vote of 65.33% in favor (Generation - 0%; Transmission - 19.6%; Supplier - 6.53%; AR - 0% (12.17% reallocated to the other 5 Sectors), Publicly Owned Entity - 19.6%), and End User - 19.6%), and with a significant number of abstentions. Under the circumstances, this item is presented for individual action at the January meeting.

The following resolution can be used for Participants Committee action on this matter:

> RESOLVED, that the Participants Committee support the revisions to Market Rule 1 Appendix A proposed in response to the compliance requirements contained in the FERC's October 16, 2013 Order conditionally accepting the Energy Market Offer Flexibility Changes (Docket No. ER13-1877-000), as recommended by the Markets Committee at its December 10-11, 2013 meeting, together with [any changes agreed to at this meeting, and] such other non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

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[1] *ISO New England Inc. and New England Power Pool*, 145 FERC ¶ 61,014 (2013).

SECTION III

MARKET RULE 1

APPENDIX A
MARKET MONITORING,
REPORTING AND MARKET POWER MITIGATION

submitted by a Market Participant, and all consultations must be completed, no later than 5:00 p.m. of the second business day prior to the Operating Day for which the Reference Level will be effective. Adjustments to fuel prices after this time must be submitted in accordance with the fuel price adjustment provisions in Section III.A.3.4.

III.A.3.1. Consultation Prior to Offer.

If an event occurs within the 24 hour period prior to the Operating Day that a Market Participant, including a Market Participant that is not permitted to submit a fuel price adjustment pursuant to Section III.A.3.4(e), believes will cause the operating cost of a Resource to exceed the level that would violate one of the conduct tests specified in Section III.A.5 of this ***Appendix A***, the Market Participant may contact the Internal Market Monitor to provide an explanation of the increased cost. In order for the information to be considered for the purposes of the Day-Ahead Energy Market, the Market Participant must contact the Internal Market Monitor at least one hour prior to the close of the Day-Ahead Energy Market. In order for the information to be considered for purposes of the first commitment analysis performed following the close of the Re-Offer Period, the Market Participant must contact the Internal Market Monitor at least one hour prior to the close of the Re-Offer Period. Cost information submitted thereafter shall be considered in subsequent commitment and dispatch analyses if received between 8:00 a.m. and 5:00 p.m. and at least one hour prior to the close of the next hourly Supply Offer submittal period. ~~by 6:00 p.m. the day prior to the Operating Day.~~ If the Internal Market Monitor determines that there is an increased cost, the Internal Market Monitor will either update the Reference Level or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for the Operating Day for which the offer is submitted. Any request and all supporting cost data and other verifiable supporting information must be submitted to the Internal Market Monitor prior to the Market Participant's submission of the offer.

~~Any changes to fuel prices shall not be subject to the consultation provisions of this Section III.A.3.1.~~ If a Market Participant believes that the fuel price determined under Section III.A.7.5(e) should be modified, it may contact the Internal Market Monitor to request a change to the fuel price and provide an explanation of the basis for the change. Any request to change the fuel price determined under Section III.A.7.5(e) must be received between the hours of 8:00 a.m. and 5:00 p.m. on any day.

III.A.3.2. Dual Fuel Resources.

In evaluating bids or offers under this ***Appendix A*** for dual fuel Resources, the Internal Market Monitor shall utilize the fuel type specified in the Supply Offer for the calculation of cost-based Reference Levels

pursuant to Section III.A.7.5 below. If a Market Participant specifies a fuel type in the Supply Offer that, at the time the Supply Offer is submitted, is the higher priced fuel available to the Resource, then within five business days the Market Participant must:

(a) provide the Internal Market Monitor with written verification as to the cause for the use of the higher cost fuel.

(b) provide the Internal Market Monitor with evidence that the higher cost fuel was used.

If the Market Participant fails to provide supporting information within five business days of the Operating Day, then the Reference Level based on the lower cost fuel will be used in place of the Supply Offer for settlement purposes.

III.A.3.3. Market Participant Access to its Reference Levels.

The Internal Market Monitor will make available to the Market Participant the Reference Levels applicable to that Market Participant's Supply Offers through the MUI. Updated ~~The~~ Reference Levels will be made available whenever calculated. ~~on a daily basis.~~ The Market Participant shall not modify such Reference Levels in the ISO's or Internal Market Monitor's systems.

III.A.3.4. Fuel Price Adjustments.

(a) A Market Participant may submit a fuel price, to be used in calculating the Reference Levels for a Resource's Supply Offer, whenever the Market Participant's expected price to procure fuel for the Resource will be greater than that used by the Internal Market Monitor in calculating the Reference Levels for the Supply Offer. A fuel price may be submitted for Supply Offers entered in the Day-Ahead Energy Market, the Re-Offer Period, or for a Real-Time Offer Change. A fuel price is subject to the following conditions:

(i) In order for the submitted fuel price to be utilized in calculating the Reference Levels for a Suply Offer, the fuel price must be submitted prior to the applicable Supply Offer deadline,

(ii) The submitted fuel price must reflect the price at which the Market Participant expects to be able to procure fuel to supply energy under the terms of its Supply Offer, exclusive of resource-specific transportation costs. Modifications to Reference Levels based on changes to transportation costs must be addressed through the consultation process specified in Seciton III.A.3.1.

(iii) The submitted fuel price may be no lower than the lesser of (1) 110% of the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer or (2) the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer plus $2.50/MMbtu.

(b) Within five business days following submittal of a fuel price, a Market Participant must provide the Internal Market Monitor with (i) an invoice for the fuel utilized or (ii) a quote from a named supplier or (iii) a price from a publicly available trading platform or price reporting agency, demonstrating that the submitted fuel price reflects the cost at which the Market Participant expected to purchase fuel for the operating period covered by the Supply Offer, as of the time that the Supply Offer was submitted, under an arm's length fuel purchase transaction. Any amount to be added to the quote from a named supplier, or to a price from a publicly available trading platform or price reporting agency, must be submitted and approved using the provision for consultations prior to the determination of Reference Levels in Section III.A.3. The submitted fuel price may be no greater than 110% of the fuel price reflected on the submitted invoice for the fuel utilized, the quote from a named supplier or the price from a publicly available trading platform or price reporting agency, plus any approved adder.

(c) The Supply Offers for the associated Resource may be no greater than 110% and no less than 90% of the Reference Level calculated with the submitted fuel price.

(d) If, within a 12 month period, the requirements in sub-sections (b) or (c) are not met for a Resource, then a fuel price adjustment pursuant to Section III.A.3.4 shall not be permitted for that Resource for up to six months. The following table specifies the number of months for which a Market Participant will be precluded from using the fuel price adjustment, based on the number of times the requirements in sub-sections (b) or (c) are not met within the 12 month period. The 12 month period excludes any previous days for which the Market Particpant was precluded from using the fuel price adjustment. The period of time for which a Market Participant is precluded from using the fuel price adjustment begins two weeks after the most-recent incident occurs.

Number of Incidents	Months Precluded (starting from most-recent incident)
1	2
2 or more	6

NOVEMBER 13, 2013

Compliance Filing: Consultation under Offer Flexibility Rules

Presentation to the NEPOOL Markets Committee

Bob Laurita and Mario DePillis

INTERNAL MARKET MONITORING

Agenda

1. Summary of Commission's October 3, 2013 Order
2. Review of the proposed Market Rules related to Participant Fuel Price Adjustment and the "Lock Out" Provision
3. Proposed Market Rule Changes to Comply with the Commission's Order

Commission Order (Summary)

- On October 3, 2013, the Commission issued an order on offer flexibility.
- The Commission accepted the majority of the ISO's and IMM's proposed Market Rule changes
- The Commission ordered two modifications:
  - "The IMM must calculate the Reference Levels for locked-out resources based on updated information, instead of using the day-ahead price index." (From Paragraph 35)
  - "ISO-NE must submit a compliance filing with Tariff language clarifying that the IMM will make the hourly Reference Levels available to individual resources. ISO-NE must submit a compliance filing with Tariff language clarifying that the IMM will make the hourly Reference Levels available to individual resources."(From Paragraph 36)

Review of Fuel Price Adjustment Market Rule

- Prior to the Supply Offer deadline for any market (i.e., day-ahead market, Re-Offer Period and each hour in real-time), a Market Participant may enter a fuel price for the IMM to use in calculating a Resource's reference level if the Market Participant believes its actual fuel costs will exceed the IMM's index-based fuel price by a large enough margin to put the Resource at risk of inappropriate mitigation.
- Market Participants can enter their requested fuel price through an interface in eMarket at any time.
- The IMM will use two *ex post* tests to review Fuel Price Adjustment requests :
  - Supply Offer Consistency and
  - Fuel Price Consistency

Review of Fuel Price Adjustment

- **Supply Offer Consistency Test**
  - The Market Participant must enter a Supply Offer that is within 10% of the requested fuel price adjustment.
- **Fuel Price Consistency Test**
  - In addition, a Market Participant that enters a fuel price adjustment must submit documentation after the fact verifying that the submitted fuel price is based on a fuel price quote, contract or price from an electronic trading system.
- **Failure to Meet Two Requirements Results In "Lock Out"**
  - If a Market Participant fails either test above the Market Participant will be excluded from submitting a fuel price adjustment through the eMarket user interface for a two - to six-month period.

Gas Price Information In New England

- Intra-day trading is primarily OTC.
  - Trading is illiquid.
  - Little public price information
  - Prices are time and generator specific, e.g., large generators may pay more due to larger volumes.
- Gas prices can vary significantly from generator to generator, particularly during the Operating Day. Applying price received by Generator "A" to Generator "B" would increase probability of error.
- IMM's primary source of intra-day price is from individual generators

Solution Requirements for "Locked-Out" Generators

- Compliance with FERC Order requires that locked-out generators must be able to inform IMM of fuel cost changes.

- Compliance with FERC Order requires up-to-date fuel cost information in absence of real-time fuel price indices

- IMM is restricted to generator-specific fuel cost information, especially during the Operating Day.

Proposed Market Rule Changes to Comply with the Commission's Order

- The IMM will clarify in the Market Rule that a "locked-out" Market Participant can contact the IMM using the consultation process defined in Section III.A.3.1 of the tariff to request a change to the fuel price.
- Section III.A.3.1 will allow Market Participants to consult during the Operating Day for intra-day fuel price changes.
- The normal rules for consultation will continue to apply:
  - The "locked-out" Market Participant will be required to provide *ex ante* documentation of their expected fuel cost.
  - The Market Participant's request must be received between the hours of 8:00 a.m. and 5:00 p.m.

Proposed Market Rule Changes to Comply with the Commission's Order (Continued)

- The proposed Section III.A.3.1 ex ante approach allows the IMM to review the Market Participant's documentation.
- A "Locked-Out" Market Participant can pro-actively request a fuel price adjustment through the consultation process for a future time period (i.e., over-night gas price.)
- Section III.A.3.3. will clarify that Reference Levels will be available to Market Participants when the Reference Levels are calculated.

OCTOBER 3, 2013 ORDER EXCERPTS

Paragraph 34

- *"We agree with NEPOOL that the proposed Offer Flexibility Changes represent a balance of interests.* ***Because the fuel price adjustment mechanism provides market participants with the latitude to increase a resource's Reference Level without prior review, it is appropriate for a market participant to be subject to a lock-out period if the IMM determines that the participant cannot substantiate or justify its fuel price adjustment"***

Paragraph 35

- *We note, however, that there are a few potential inconsistencies between ISONE's intended application of the proposed revisions, including the lock-out provisions, and the actual proposed Tariff language. Accordingly, our acceptance is conditioned upon ISO-NE submitting revised tariff records in a compliance filing that reconciles the proposed Tariff language with ISO-NE's statements. In its answer, ISO-NE states that, during the lock-out period, "the Reference Levels for the resource would be determined by the IMM based on a published day-ahead fuel price index." The provisions, however, do not specify what type of pricing information the IMM will use to calculate the hourly Reference Levels for resources that are locked-out – i.e., whether the IMM would use a day-ahead price index or real-time (or operating day) price information. We find that, since the IMM will be calculating hourly Reference Levels that incorporate updated information,* ***the IMM also should calculate the Reference Levels for locked-out resources based on updated information, instead of using the day-ahead price index.*** *Accordingly, ISO-NE must submit clarifying Tariff revisions reflecting that approach.*

Paragraph 36

- *Further, while ISO-NE states that the IMM "must develop hourly Reference Levels rather than Reference Levels that are fixed for an Operating Day," proposed Tariff section III.A.3.3 as drafted states that "Reference Levels will be made available on a daily basis."* ***ISO-NE must submit a compliance filing with Tariff language clarifying that the IMM will make the hourly Reference Levels available to individual resources.*** *The proposed Tariff revisions, as modified, should use updated information for Reference Levels for locked-out resources to help prevent inaccurate market price signals.*

145 FERC ¶ 61,014
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
Cheryl A. LaFleur, and Tony Clark.

ISO New England Inc. and New England Power Pool Docket No. ER13-1877-000

ORDER CONDITIONALLY ACCEPTING TARIFF REVISIONS

(Issued October 3, 2013)

1. On July 1, 2013, ISO New England Inc. (ISO-NE) and the New England Power Pool (NEPOOL) Participants Committee (together, the Filing Parties) submitted proposed changes to the ISO-NE Transmission, Markets and Services Tariff (Tariff) involving energy market enhancements intended to provide greater flexibility for market participants to structure and modify their supply offers in the day-ahead and real-time markets (Offer Flexibility Changes). We will conditionally accept the Offer Flexibility Changes, subject to a compliance filing, to become effective December 3, 2014, as requested.

I. The Filing

2. The Filing Parties state that the New England region has experienced a marked increase in the proportion of its electric power that is generated by natural gas-fired resources.[1] The Filing Parties note that this increased dependence on natural gas-fired generation has challenged the existing gas and electric market structures and necessitated discussion at the regional and national levels about how best to address those challenges. The Filing Parties explain that the Offer Flexibility Changes are another step in a series

[1] For example, according to ISO-NE, in 1990, natural gas-fired generators produced approximately five percent of the electricity consumed in New England. In 2010, that figure was at 34 percent. ISO-NE's 2010 Annual Markets Report at 78. By 2012, the figure had grown to 51 percent. ISO-NE July 2012 paper, *Addressing Gas Dependence*, at 3.

of operational and market improvements that ISO-NE is working on with stakeholders to address these concerns.

3. The proposed Offer Flexibility Changes have six components.

A. Real-Time Offer Changes

4. Under the current Tariff, market participants finalize and submit offers for the day-ahead energy market by no later than 10:00 a.m. on the day before a particular operating day. After the day-ahead market is cleared and the results posted, market participants may modify their offers during a half-hour period between 1:30 p.m. and 2:00 p.m. (known as the Re-Offer Period) on the day before the operating day. There is no opportunity to change the cost-related parameters of an offer after the Re-Offer Period. Some non-cost related offer parameters can be re-declared by a market participant in real-time to accurately reflect the physical characteristics of a resource.

5. Under the proposed Offer Flexibility Changes, market participants will be able to modify the cost-related parameters of a supply offer up until 30 minutes prior to the hour during the operating day and will be able to modify the energy blocks, start-up fee, no-load fee, fuel type, and the regulation supply offer price and quantity.[2] Dispatchable Asset Related Demand (DARD)[3] units will be able to modify the energy blocks (price and quantity of energy) of the demand bid. The Filing Parties state that being able to update an offer in real time means that, when a resource's operating costs have changed to reflect real-time fuel or other costs, the operating costs can be reflected in the new offer, which makes it more likely that market participants' financial incentives and the requirement for resources to follow dispatch instructions are aligned.

B. Offers That Vary By Hour

6. Under the current market rules, the cost-based parameters of offers generally are the same for every hour of a particular operating day. The proposed Offer Flexibility

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[2] Market participants may do so after the initial Reserve Adequacy Analysis process is completed; ISO-NE conducts the initial Reserve Adequacy Analysis process to determine whether it is necessary from a reliability perspective to commit more resources in addition to those that were committed through the clearing of the day-ahead market.

[3] Capitalized terms not defined herein are intended to have the meaning given to those terms in the Tariff.

Changes would allow market participants to submit cost-related parameters of a supply offer, or a demand bid for a DARD, that may vary by hour, rather than requiring these parameters to be the same for all hours of an operating day. The Filing Parties state that allowing the cost-related parameters to vary by hour will have the same general benefits as being able to change offers in real time.

C. Negative Offers

7. Under the current rules, an offer in the energy market may not be less than $0/MWh. The proposed Offer Flexibility Changes would allow market participants to submit offers as low as negative $150/MWh (referred to as the energy offer floor) for external transactions and the energy blocks for a supply offer, demand bid, increment offer, and decrement bid. The Filing Parties state that the lower offer floor accommodates the needs of market participants with resources that can operate economically (or can increase consumption) at very low energy prices and better reflects the full range of prices at which different types of resources become uneconomic. The Filing Parties explain that, from a market efficiency perspective, lowering the energy offer floor will allow resource output to be set through an economic dispatch process.[4]

D. Self-Scheduling

8. Currently, a market participant self-schedules a generating resource by re-declaring the resource's Economic Minimum Limit to reflect the desired minimum output level of the resource. The proposed Offer Flexibility Changes eliminate the use of the Economic Minimum Limit as the mechanism through which a market participant indicates a desired minimum output level of a generating resource and instead use the term as a more static value based upon the physical design characteristics, environmental regulations, and licensing limits of the generating resource.[5] Under the proposed Offer Flexibility Changes, a market participant will be able to self-schedule a generating resource by submitting a request for a resource to be dispatched at a specific output level.

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[4] Under the current rules, the output of all resources with a $0/MWh offer is modified administratively when necessary, rather than through an economic dispatch process. The Filing Parties state that setting the energy offer floor at a sufficiently low level will provide a strong incentive for all generating resources to follow dispatch down to their Emergency Minimum Limit to avoid excess generation conditions (a Minimum Generation Emergency).

[5] *See* Ethier/Parent Testimony at 13.

The Filing Parties state that, from an operational perspective, the existing practice of modifying a resource's Economic Minimum Limit has the disadvantage of reducing the resource's dispatchable range,[6] sometimes artificially creating a Minimum Generation Emergency and requiring system operators to take administrative actions and/or implement administrative pricing to resolve the situation. The proposed change would prevent resources from moving the Economic Minimum Limit when self-scheduling and, thus, would allow system operators to dispatch a resource to its Economic Minimum Limit before declaring a Minimum Generation Emergency.

E. Appendix A/Mitigation Rules[7]

9. The Filing Parties propose conforming changes to the Appendix A mitigation rules, which they state are required to maintain consistency with the proposed changes that allow market participants to submit offers that vary by hour, change offers in real time, and submit offers as low as negative $150/MWh. As the proposed Offer Flexibility Changes would allow participants to submit offers that vary by hour and modify the cost-related parameters throughout the operating day, the Filing Parties propose that the Internal Market Monitor (IMM) develop hourly Reference Levels rather than Reference Levels that are fixed for an operating day.

10. As proposed, the hourly Reference Levels will incorporate fuel price information from market participants. Specifically, Reference Levels will be calculated using the lower of either a submitted fuel price from a market participant, or a price calculated by the IMM. Participant-submitted fuel price changes for the Reference Levels will not be reviewed by the IMM prior to submitting the change. The Filing Parties also propose three mechanisms intended to prevent market participants from entering fuel price adjustments as a means to avoid mitigation: (1) the IMM will set a limit on the fuel price it will use in calculating a resource's Reference Level based on available fuel price indices and market conditions and that is independent of any fuel price adjustment submitted by a market participant; (2) if a market participant enters a fuel price adjustment and simultaneously enters a new offer, the new offer must be within 10 percent of the Reference Level calculated based on the new fuel price; and (3) a market participant that enters a fuel price adjustment must submit documentation verifying that

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[6] The dispatchable range is the difference between the resource's Economic Minimum Limit and the Economic Maximum Limit.

[7] Market Monitoring, Reporting and Market Power Mitigation of Market Rule 1 of the Tariff.

the submitted fuel price is based on a fuel price quote, contract, or price from an electronic trading system. The Filing Parties state that a market participant that fails to submit verification will be excluded from submitting a fuel price adjustment for the applicable resource for two months for the first failure and six months for the second failure (lock-out provisions).

11. However, as explained in the testimony of Dr. Mario DePillis, Jr., an economist with the IMM,[8] a market participant can request a value to be added to the quote or price that reflects its expected fuel costs. The "adder" value must be submitted and approved by the IMM in advance using the consultation process described in section III.A.3 of the proposed Tariff changes. ISO-NE states that, if, for example, the market participant does not have an updated quote from a natural gas supplier, it could instead include an adder to its fuel quote or price that reflects the volatility observed in the intra-day natural gas market on the public trading platforms. In addition, ISO-NE notes that the market participant could apply the adder to reflect different natural gas purchase quantities.

12. The Filing Parties propose additional conforming changes to Appendix A. First, they propose making the period for which mitigation applies, once triggered, more flexible. Under the existing rules, mitigation continues until the end of an operating day, but, under the proposed revisions, mitigation may end before the end of an operating day under appropriate conditions. Second, they propose modifying certain mitigation calculations to reflect the potential variation in the period during which a resource may be mitigated. Third, they also seek to modify the local reliability commitment mitigation threshold so that it is only based on the existing 10 percent of low load cost threshold. The current $80/MWh threshold is proposed to be eliminated because, according to the Filing Parties, high and volatile fuel prices could otherwise result in mitigation being triggered inappropriately. Fourth, they plan to introduce limits, based on fuel prices, to the amount that start-up fees and no-load fees may be increased in real-time. Finally, they seek to eliminate the requirement that market participants with dual-fuel resources must submit offers based on the resource's least cost fuel, so that these market participants instead can manage the delivery and price risk associated with natural gas based on oil costs and can conserve oil by offering based on natural gas costs.

F. <u>Clarifying Changes</u>

13. The Filing Parties propose clarification and clean-up changes, including: removing defined terms that are no longer applicable; adding defined terms for supply

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[8] DePillis Testimony at 15-17.

offer parameters; and clarifying language related to supply offers, demand bids, and external transactions.

14. The Filing Parties request an effective date of December 3, 2014, and waiver of the 120-day advance notice requirement of 18 C.F.R. § 35.3 (2013). However, the Filing Parties seek a Commission determination by October 1, 2013, before stakeholders consider any proposed changes to other market rules related to the Offer Flexibility Changes at ISO-NE's October 8, 2013 stakeholder meeting.

II. Notice of Filings and Responsive Pleadings

15. Notice of the filing was published in the *Federal Register*, 78 Fed. Reg. 45,051 (2013), with interventions and protests due on or before July 22, 2013.

16. Brookfield Energy Marketing LP; Calpine Corporation; Entergy Nuclear Power Marketing, LLC; Exelon Corporation; GDF SUEZ Energy North America, Inc.; H.Q. Energy Services (U.S.) Inc.; Northeast Utilities Service Company; PSEG Energy Resources & Trade LLC and PSEG Power Connecticut LLC filed timely motions to intervene. The NRG Companies filed a motion to intervene out-of-time.[9] Capital Power;[10] Electric Power Supply Association (EPSA); New England Power Generators Association Inc. (NEPGA); and New England States Committee on Electricity (NESCOE) filed timely motions to intervene and comments. Massachusetts Department of Public Utilities (Mass DPU) filed a notice of intervention and comments. On July 31, 2013, ISO-NE filed an answer, and on August 6, 2013, NEPOOL filed an answer.

A. Comments/Protests

17. NEPGA states that the Offer Flexibility Changes, and specifically the ability to vary and modify offers by hour, will significantly improve day-ahead and real-time price formation and efficiency. However, NEPGA and others[11] challenge the proposed

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[9] The NRG Companies are NRG Power Marketing LLC; GenOn Energy Management, LLC; Connecticut Jet Power LLC; Devon Power LLC; Middletown Power LLC; Montville Power LLC; Norwalk Power LLC; NRG Canal LLC; and NRG Kendall.

[10] Capital Power is CP Energy Marketing (US) Inc.; Bridgeport Energy, LLC; Rumford Power Inc.; and Tiverton Power LLC.

[11] Capital Power and EPSA support NEPGA's comments.

Appendix A mitigation revisions, arguing that they are unjustly and unreasonably punitive and could suppress market prices below the marginal cost of energy, thereby penalizing all resources, rather than enhancing operational reliability through improved price formation.

18. NEPGA asserts that denying market participants the ability to reflect actual fuel price exposure for real-time dispatch for a two- or six-month period based on a single failure to verify an anticipated fuel price is inefficient and punitive to the rest of the competitive market supply. NEPGA states that, if a market participant does not have an updated quote for a quantity greater than that quoted by a supplier or on a publicly-traded platform, or cannot obtain a quote for a price at the quantity the resource needs, the quote available to the market participant may not reflect its actual fuel costs. NEPGA states that, while allowing a value to be added to the quote or price that reflects its expected fuel costs is helpful, it is not a sufficient safeguard against penalizing market participants for basing their supply offers on their anticipated actual fuel costs. NEPGA asserts that it is unreasonable to expect that a market participant can predict with absolute precision all of the adders or adder methodologies that may be necessary to account for the myriad of possible reasons (and combination of reasons) described by the IMM for how a quote or trading platform price may differ from actual fuel costs. NEPGA states that instead a market participant might choose not to increase its supply offer to reflect its actual fuel costs if it has not predicted its need for an adder (and received approval from the IMM) in advance, potentially suppressing marginal prices and disrupting efficient economic dispatch – resulting in some of the harmful consequences the Offer Flexibility Changes are intended to remedy. NEPGA asserts that the proposed Appendix A revisions are unjust and unreasonable, because they effectively force market participants to choose between basing their supply offers on their actual fuel costs or risk a severe penalty for a single failure to document a fuel price consistent with an actual fuel price.

19. NEPGA also challenges the magnitude of the proposed penalty, noting that a two-month prohibition denies a market participant the opportunity to change its supply offer in 1,500 consecutive re-offer periods (25 opportunities per operating day) due to a market participant's one-time inability to document expected fuel costs, which can be extremely unpredictable. NEPGA states that none of the penalty provision triggers are acts of malice or attempts to exercise undue market power to avoid mitigation, but are instead a reflection of the limitations of the IMM's proposed mitigation scheme.

20. Finally, NEPGA states that, according to the IMM, the two- and six-month exclusion penalties are reasonable, in part, because "they correspond to a similar exclusion used in the New York market for participant-submitted fuel prices." NEPGA argues, however, that the New York Independent System Operator, Inc.'s (NYISO) market power mitigation measures differ significantly from those proposed by the IMM. Specifically, NEPGA states that the NYISO market monitor may impose two- and

six- month penalties where a market participant has, over a time period of at least one week, submitted inaccurate fuel type or fuel price information that was biased in the market participant's favor. NEPGA states that the Appendix A revisions would impose the same penalties as NYISO but for only a single transgression.[12] NEPGA states that the NYISO tariff exclusion penalties are not a proper benchmark for the IMM's proposed penalties because the NYISO exclusion penalties are intended to discourage and penalize more egregious supply offer behavior with a greater likelihood of adversely affecting efficient markets.

21. NEPGA and others argue that the Commission should require ISO-NE to change the proposed penalty provisions, with Capital Power adding that ISO-NE should submit compliance filings reporting how often the penalty provisions are triggered and how mitigation determinations are being handled.

22. NESCOE[13] states that it generally supports the Offer Flexibility Changes, positing that the revisions will ensure that the marginal cost of electricity is more closely aligned with the actual cost of production, by reflecting real-time fuel prices and other changes to operating costs. NESCOE states that the added flexibility will provide the region with another tool to address concerns related to New England's growing reliance on natural gas as a fuel source for electric generation, stating that the ability to vary and modify offers by hour will help bridge the timing gaps between the natural gas and electric markets.

23. NESCOE also asserts that the proposed changes should help address concerns expressed in *Dominion Energy Marketing, Inc.* that the Tariff lacks "flexibility to allow for cost recovery by resources that respond under extraordinary circumstances."[14] NESCOE states that, by providing an opportunity to revise offers to reflect the price of procuring fuel in real-time and other changed costs, the Offer Flexibility Changes should reduce the burden placed on resources to make section 205 filings to recover costs associated with dispatch for reliability reasons.

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[12] NEPGA Comments at 8.

[13] The Mass DPU states that it supports the Offer Flexibility Changes and concurs with NESCOE's comments, stating that these changes should enhance market efficiency and system reliability.

[14] *Dominion Energy Marketing, Inc.*, 143 FERC ¶ 61,233, at P 28 (2013).

24. Finally, NESCOE encourages and appreciates the commitment by ISO-NE to continue to monitor offer behavior to determine if a reduction to the negative offer floor price is warranted in the future.

B. Answers

25. ISO-NE responds that the lock-out provisions will not result in over-mitigation or harm to the market. ISO-NE explains that, under the proposed provisions, a resource is only mitigated when a supply offer is well above a resource's Reference Level and the IMM finds that the market participant possesses market power.[15] Specifically, the IMM must determine that the market participant submitting the offers is a pivotal supplier, has a resource that is located in a constrained area or is dispatched for local reliability purposes, and has a price that exceeds its Reference Level by a specified amount.

26. ISO-NE also asserts that generators should not have unlimited authority to set References Levels for their resources. ISO-NE explains that generators are able to submit fuel price adjustments based on their fuel price expectations that will increase their Reference Levels, provided that their expectations can be substantiated by providing some reasonable explanation as to why they believe the expected fuel price will exceed the published fuel price index. ISO-NE contends that mitigation is intended to assure that market outcomes are competitive and that generators are responsible for knowing their own costs, developing reasonable estimates of expected costs, and reflecting those costs in their offers.[16]

27. ISO-NE further states that the lock-out provisions affect the ability of market participants to submit fuel prices used to determine Reference Levels, not those used by a market participant to formulate supply offers. ISO-NE explains that the Reference Level for a resource that will apply during a lock-out period will be based on published fuel price indices that reflect actual market data, trading volumes and prices submitted to the organizations that develop and publish the fuel indices.[17] In addition, "locked out" market participants are not precluded from engaging in prior consultation with the IMM to determine appropriate fuel prices to be used to calculate Reference Levels.

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[15] *See* ISO-NE Answer at 6.

[16] ISO-NE Answer at 11.

[17] ISO-NE Answer at 6.

28. ISO-NE posits that imposing a two- to six-month lockout period is an appropriate consequence for having submitted unsupported fuel price adjustments since the potential harm from unjustified fuel price adjustments in the form of inappropriately high Locational Marginal Prices (LMP) is substantial. ISO-NE suggests that a lock-out is unlikely to impact overall market efficiency, explaining that day-ahead and intra-day fuel prices typically affect multiple market participants receiving fuel from the same sources (e.g., the same natural gas pipeline). ISO-NE theorizes that some market participants are likely to submit supply offers and fuel price adjustments reflecting those market conditions; this would result in LMPs being substantially the same as they would have been if a market participant subject to the lockout period had itself submitted higher supply offers that were not mitigated.[18]

29. In its answer, NEPOOL suggests that the package of mitigation provisions reasonably requires market participants to substantiate offers based on actual fuel price, and if there is an unjustified rejection of that substantiation by the IMM, the market participant has the opportunity to seek relief from the Commission by filing a complaint under Federal Power Act section 206.[19] NEPOOL requests the Commission approve the mitigation measures to minimize the risk for bidding conduct that could raise consumer costs to unreasonable or unjustified levels. NEPOOL also states that it was clear in stakeholder discussions that the dramatically increased flexibility to permit market participants to update their energy offers intra-day would be unacceptable to many NEPOOL members unless accompanied by meaningful mitigation measures.

III. Discussion

A. Procedural Matters

30. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2013), the notice of intervention and timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

31. Pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d) (2013), the Commission will grant the late-filed motion to intervene given the party's interest in the proceeding, the early stage of the proceeding, and the absence of undue prejudice or delay.

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[18] *See* ISO-NE Answer at 8.

[19] NEPOOL Answer at 5 (referencing 16 U.S.C. § 824e (2006)).

32. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2013), prohibits an answer to a protest unless otherwise ordered by the decisional authority. We will accept ISO-NE's and NEPOOL's answers because they have provided information that assisted us in our decision-making process.

B. Commission Determination

33. We will conditionally accept the Offer Flexibility Changes, subject to ISO-NE submitting revised tariff records in a compliance filing, to become effective December 3, 2014. We find that the proposed revisions, modified as discussed below, will significantly improve flexibility for market participants to structure and modify supply offers in the energy markets, as well as provide ISO-NE with the tools to better manage the electric system and thereby help ensure reliability.

34. In rendering our determination, we note that NEPGA, Capital Power, and EPSA generally support the proposed Offer Flexibility Changes; they dispute only the proposed lock-out provisions. These parties assert that the two- and six-month lock-out penalties are disproportionate in magnitude, and the consequences of mitigation would not be limited to the specific market participant and commensurate with the specific supply offer behavior. We disagree. The proposed lock-out provisions do not prohibit a market participant from reflecting a more current fuel price in its supply offer, or prevent the market participant from consulting with the IMM. The lock-out provisions are intended to incentivize market participants to submit fuel price adjustments for their Reference Levels only when there is a reasonable explanation or documentation supporting the adjustment. We agree with NEPOOL that the proposed Offer Flexibility Changes represent a balance of interests. Because the fuel price adjustment mechanism provides market participants with the latitude to increase a resource's Reference Level without prior review, it is appropriate for a market participant to be subject to a lock-out period if the IMM determines that the participant cannot substantiate or justify its fuel price adjustment.

35. We note, however, that there are a few potential inconsistencies between ISO-NE's intended application of the proposed revisions, including the lock-out provisions, and the actual proposed Tariff language. Accordingly, our acceptance is conditioned upon ISO-NE submitting revised tariff records in a compliance filing that reconciles the proposed Tariff language with ISO-NE's statements. In its answer, ISO-NE states that, during the lock-out period, "the Reference Levels for the resource would be determined by the IMM based on a published day-ahead fuel price index."[20] The proposed Tariff

[20] ISO-NE Answer at 5.

provisions, however, do not specify what type of pricing information the IMM will use to calculate the hourly Reference Levels for resources that are locked-out – i.e., whether the IMM would use a day-ahead price index or real-time (or operating day) price information. We find that, since the IMM will be calculating hourly Reference Levels that incorporate updated information, the IMM also should calculate the Reference Levels for locked-out resources based on updated information, instead of using the day-ahead price index. Accordingly, ISO-NE must submit clarifying Tariff revisions reflecting that approach.

36. Further, while ISO-NE states that the IMM "must develop hourly Reference Levels rather than Reference Levels that are fixed for an Operating Day,"[21] proposed Tariff section III.A.3.3 as drafted states that "Reference Levels will be made available on a daily basis." ISO-NE must submit a compliance filing with Tariff language clarifying that the IMM will make the hourly Reference Levels available to individual resources. The proposed Tariff revisions, as modified, should use updated information for Reference Levels for locked-out resources to help prevent inaccurate market price signals.

37. As to NEPGA's comparison of the NYISO market mitigation measures with the Filing Parties' proposed mitigation measures, such comparisons are irrelevant here. It is well-established that there can be more than one just and reasonable process,[22] and we see no reason to require NYISO and ISO-NE to implement the same mitigation mechanisms. Having found that the Filing Parties have proposed mitigation rules that appropriately accommodate the needs and characteristics of the ISO-NE region, we need not analyze how the rules compare with those implemented by NYISO.[23]

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[21] ISO-NE Transmittal at 14.

[22] *See, e.g., Midwest Independent Transmission System Operator, Inc.*, 127 FERC ¶ 61,109, at P 20 (2009); *New York Indep. Sys. Operator, Inc*., 126 FERC ¶ 61,320, at P 40 (2009) ("there can be more than one just and reasonable planning process and RTOs and ISOs [Independent System Operators] are not required to have identical planning processes").

[23] *See ISO New England Inc.*, 114 FERC ¶ 61,315, at P 33 (2006) ("Under the FPA, if we find that ISO-NE has successfully supported the justness and reasonableness of its [filing], we must approve it. We cannot, under those circumstances, consider alternatives to what is proposed by ISO-NE") (citing *Cities of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir.), *cert. denied*, 469 U.S. 917 (1984)).

38. With respect to Capital Power's request that the Commission require ISO-NE to submit reports to the Commission on how the penalty provisions are being implemented, we will not impose such a reporting requirement at this time. However, we expect ISO-NE to monitor the effects of the Offer Flexibility Changes and to be prepared to report to the Commission how these changes have improved or not improved the ISO-NE market.

The Commission orders:

(A) The Commission hereby conditionally accepts the Offer Flexibility Changes, subject to a compliance filing, to become effective on December 3, 2014, as requested, as discussed in the body of this order.

(B) ISO-NE is hereby directed to submit revised tariff records in a compliance filing within sixty (60) days of the date of this order, as discussed in the body of this order.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

MEMORANDUM

TO: NEPOOL Participants Committee

FROM: Eric Runge, NEPOOL Counsel

DATE: January 3, 2014

RE: Capacity Zones Vote

At the January 10, 2014 meeting of the Participants Committee, you will be asked to vote on revisions to Sections II and III of the ISO New England Inc. (the "ISO") Transmission, Markets and Services Tariff ("ISO Tariff") in response to the FERC's May 31, 2013 order in Docket No. ER12-953-002 regarding the Forward Capacity Market ("FCM") and the development of Capacity Zones ("May 31 Order"). Capacity Zone related-revisions to the ISO Tariff were considered and voted on by each of the three Technical Committees. The only recommendation of Participants Committee support is from the Markets Committee, which recommends support for a Participant-sponsored revision to Section III.13 of the ISO Tariff, as discussed further below.

The May 31 Order was an order on the compliance filing in response to a prior FCM-related order that addressed, in part, Capacity Zones used in the FCM. The May 31 Order allowed the ISO to retain four Capacity Zones for use in FCM while it conducted further stakeholder process regarding the development of Capacity Zones. The order required the ISO to consider the following during that further stakeholder process: "(1) the appropriate level of zonal modeling going forward; (2) the appropriate rules to govern intra- and inter-zonal transactions; and (3) whether objective criteria by which zones may automatically be created in response to rejected delist bids, generation retirements or other changes in system conditions would be appropriate in New England, or if not, why not."[1] The May 31 Order directed the ISO to: "[explain] how it has addressed these items in its stakeholder process, and it must: (i) develop and file with the Commission revisions to the ISO Tariff that articulate appropriate objective criteria to revise the number and boundaries of capacity zones automatically as the relevant conditions change, or (ii) file with the Commission an explanation as to why such criteria are unnecessary."[2] The May 31 Order also required the ISO file within thirty days of the Order a schedule by which it would carry out the further FCM Capacity Zone filing.

The Reliability Committee began discussing the Capacity Zone topic in response to the May 31 Order in July and the ISO began presenting its proposal in August. That proposal includes using the eight existing Load Zones as a starting point for the Capacity Zones commencing with FCA-9. The proposal includes a mechanism for using objective criteria to change zonal boundaries in the future based in part on the analysis of interface transfer limits that

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[1] May 31 Order at P 35.

[2] *Id.*

is done as part of the annual Region System Planning process.[3] Much of the ISO's proposal is reflected in revisions to Section III.12 of the ISO Tariff. The Reliability Committee reviewed and provided advisory input on those proposed revisions due to their reliability implications. Because the ISO's proposal includes revisions to the Regional System Planning Revisions of Attachment K of the ISO Open Access Transmission Tariff ("OATT"), the Transmission Committee also reviewed and voted on the ISO proposal. During the NEPOOL discussions of the ISO's Capacity Zone proposal, NRG presented an alternative proposal that included revisions to Section III.13 of the ISO Tariff as well as to Sections II (Attachment K of the OATT) and III.12. Changes to Market Rules in Section III.13 are considered and voted on by the Markets Committee, and thus the Markets Committee reviewed and voted on those proposed changes by NRG.[4]

On December 17, 2013, the Markets, Reliability and Transmission Committees met jointly and voted separately on the proposed Capacity Zone revisions. The Reliability Committee considered and voted on the Capacity Zone revisions to Section III.12 of the ISO Tariff. Several amendments to the ISO proposal were offered but none passed.[5] The ISO's unamended proposal also did not pass with a Vote of approximately 28.6% in favor. The Transmission Committee considered and voted on the Capacity Zone revisions to Attachment K of the ISO OATT. One amendment was offered to the ISO proposal but did not pass. The ISO's unamended proposal also did not pass with a Vote of approximately 42.9% in favor. Finally, the Markets Committee considered and voted on the NRG proposed revisions to Section III.13 of the ISO Tariff. The NRG proposed revisions to Section III.13 were supported by the Markets Committee with a Vote of 74.2% in favor.[6]

The following resolutions could be used for Participants Committee consideration of this matter.

For the Markets Committee recommendation:

> RESOLVED, that the Participants Committee supports the recommendation of the Markets Committee to revise Section III.13 of the ISO Tariff, proposed by NRG as a change to the ISO Capacity Zone proposal and reflected in the materials distributed to the Participants Committee for its January 10, 2014 meeting, together with any changes agreed to at the meeting and such non-substantive

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[3] More detail on the ISO's proposal is contained in the ISO presentation included with this memo.

[4] The ISO's Capacity Zones proposal did not include any revisions to Section III.13 of the ISO Tariff.

[5] We understand that a number of those amendments will also be offered at the January 10 meeting and have accordingly included with this memorandum the corresponding materials from the December 17 joint meeting, other than those supporting UI's amendments. UI has indicated that it will not offer its amendments at the January meeting.

[6] The Notices of Actions for the December 17 joint meeting of the three Technical Committees are included with this memo.

changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Markets Committee.

For the ISO proposal for revisions to Section III.12 of the ISO Tariff related to Capacity Zones:

> RESOLVED, that the Participants Committee supports the ISO proposal for Capacity Zones to revise Section III.12 of the ISO Tariff in response to the May 31 Order, as reflected in the materials distributed to the Participants Committee for its January 10, 2014 meeting, together with any changes agreed to at the meeting and such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.

For the ISO proposal for revisions to Attachment K of Section II of the ISO Tariff related to Capacity Zones:

> RESOLVED, that the Participants Committee supports the ISO proposal for Capacity Zones to revise Attachment K of Section II of the ISO Tariff in response to the May 31 Order, as reflected in the materials distributed to the Participants Committee for its January 10, 2014 meeting, together with any changes agreed to at the meeting and such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Transmission Committee.

If you have any questions about this memo or the Capacity Zone effort, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Dave Doot (860-275-0102; dtdoot@daypitney.com).

DECEMBER 17, 2013 | WESTBOROUGH, MA

NEPOOL PARTICIPANTS COMMITTEE
JAN 10, 2014 MEETING, AGENDA ITEM #8

Capacity Zone Modeling

Reliability Committee & Transmission Committee & Markets Committee

Al McBride

MANAGER, AREA TRANSMISSION PLANNING

Presentation Objectives

- Describe the zone modeling discussions to date
- Describe the ISO proposal for modeling zones in the Forward Capacity Market
- Provide examples of the ISO proposal
- Identify clarifying language that has been added to the Tariff red lines
- Request vote on the ISO proposal

Stakeholder Process

As defined by FERC

- FERC has required the ISO to consider the following during the Stakeholder Process:

  "…(1) **the appropriate level of zonal modeling** going forward; (2) the appropriate **rules to govern intra- and inter-zonal transactions**; and (3) whether **objective criteria by which zones may automatically be created** in response to rejected delist bids, generation retirements or other changes in system conditions would be appropriate in New England, or if not, why not."

Docket No. ER12-953-002: Order Issued May 31, 2013

Subsequent Filing

As defined by FERC

- FERC has required the ISO to make an additional filing at a later time to address:

  "…how it has addressed these items in its stakeholder process, and it must: (i) **develop and file with the Commission revisions to the ISO-NE tariff** that ***articulate appropriate objective criteria to revise the number and boundaries of capacity zones automatically as the relevant conditions change***, **or** (ii) file with the Commission **an explanation as to why such criteria are unnecessary**."

Docket No. ER12-953-002: Order Issued May 31, 2013

Summary of Stakeholder Discussions

- At the July 7, 2013 Special Reliability Committee (RC) meeting we discussed:
  - The requirements of the FERC order
  - The constraints observed and expected on the New England system
  - The methodologies in place to calculate requirements
  - Considerations in the design of Capacity Zones
  - The timeline challenges associated with making changes for FCA-9
- At the July 22 and 23, 2013 Summer RC meeting we discussed:
  - The possibility of making some changes in time for FCA-9
- At the August 19, 2013 Special RC meeting we discussed:
  - The Capacity Zone creation methodologies in place in PJM and New York
  - The Transmission Security Analysis (TSA) that has been performed in New England for the 8 energy Load Zones
  - The transmission transfer capability analysis processes in place in New England
  - Possible ways forward to model Capacity Zones

Summary of Stakeholder Discussions, cont'd

- At the September 3, 2013 Special RC meeting we discussed:
  - The ISO proposal at a high level
  - Examples of the Capacity Zone models in place in PJM and NY
  - Possible objective criteria (triggers) for the creation of Capacity Zones (with examples)
  - Export-constrained zones
  - The proposed process for the analysis of transfer limits and interfaces in the RSP process
  - What is proposed for FCA-9 and FCA-10 (and beyond)
- At the September 26, 2013 Special RC meeting
  - The ISO presented the proposed objective criteria (trigger) for the creation of Capacity Zones (with examples)
- At the October 15, 2013 RC meeting
  - The ISO presented Attachment K and MR1, Section 12 redline tariff language
- At the November 19, 2013 RC meeting
  - The ISO presented Attachment K and MR1, Section 12 redline tariff language
  - An alternative proposal was presented by NRG

The ISO proposal is a two step process

- **Step 1:** Identify the potential zonal boundaries and associated transfer limits to be tested for modeling in the FCM
- **Step 2:** Use objective criteria to determine whether or not the zone should be modeled for the Capacity Commitment Period
  - Import-constrained zone: trigger to model the zone is based on the quantity of surplus resources in the zone above the zonal requirement
  - Export-constrained zone: trigger to model the zone is based on the quantity of existing and proposed new resources in the zone
  - Zones that are neither import- or export-constrained are collapsed into the rest-of-pool zone

What is the proposed zonal modeling timeline?

Pursuant To Attachment K:
- Conduct Transfer Analysis
- Identify Zones & Boundaries to be evaluated in FCM preparation
- Discuss with PAC
- Present to RC
- Document in RSP

File New Capacity Zone Boundary at FERC – if proposed

Published RSP includes forecast of future years zones & boundaries

Pursuant To Tariff Section III.12:
- ICR, LSR & Tie Benefits calculations
- Calculate whether the zones identified pursuant to Attachment K should be modeled using the objective criteria
- Discuss with PSPC
- Present to RC for vote

Retirements requests that are received in this time-frame would be captured in the zone-modeling calculation

SOI

File Capacity Zones and Requirements at FERC

FCA

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb

Will the ISO proposal change the amount of capacity to be purchased in a zone?

- No
  - The proposed zonal modeling process only determines whether the zone will be separately modeled (as import- or export-constrained)
- The Local Sourcing Requirements (LSR) calculations for import-constrained zones are unchanged by the ISO proposal
- The Maximum Capacity Limit (MCL) calculations for export-constrained zones are unchanged by the ISO proposal

What is the proposed trigger to model an import-constrained zone?

- An import-constrained zone would be modeled when there is insufficient surplus above the required amount of capacity in the zone to allow for the removal of the largest station from the zone
- Example:
  - If the required capacity in zone is 4,000 MW and the largest station in the zone is 1,000 MW, then the zone will be modeled if the Existing Qualified Capacity in the zone is less than 5,000 MW

What is the purpose of the surplus in the import-constrained zone trigger?

- A zone may start out with more than enough resources to meet its requirement
- However, retirements and delists could be submitted for the commitment period that would reduce the existing capacity in the zone
  - Potentially causing the zone to become short of its requirement
- Modeling the zone allows the auction process to prevent the zone from becoming short of the requirement
  - The price in the auction would be used to identify which existing resources (or replacement new resources) be selected to meet the requirement of the zone
  - The need to reject such delist bids for reliability is avoided

Why is the trigger based on the largest station in the zone?

- New England has experienced multiple occurrences of full station retirements
  - Salem Harbor (4 Resources)
  - Brayton Point (4 Resources)
  - Norwalk Harbor (3 Resources)

What are the largest stations by Load Zone?

Largest Station List	Connecticut	NEMA/Boston	New Hampshire	Rhode Island	SEMASS	WCMASS	Vermont
Largest Station	Millstone 2&3	Mystic 7,8&9	Seabrook	RISE	Canal	Northfield	McNeill
Largest Station MW	2100	1972	1245	548	1092	1168	52

How does the use of the largest station compare with the surplus used in PJM?

- PJM will separately model a zone if there is less than 15% surplus import capability into the zone being tested
- Using the largest station (in the ISO-NE proposal) will result in surplus percentages greater than 15% in modeled zones in New England
  - Example: using Millstone 2 & 3 for the Connecticut Load Zone will mean that Connecticut will be modeled as a zone if there is less than 2,100 MW of surplus capacity in the zone above the requirement
    - 2,100 MW is approximately 29% of the FCA-8 requirement in CT

What is the proposed trigger to model an export-constrained zone?

- An export-constrained zone would be modeled when the maximum amount of resources that can be purchased in the zone (the Maximum Capacity Limit) is less than the total of the existing and proposed new resources in the zone
- Example:
  - If the MCL for zone is 4,000 MW and there are 3,000 MW of existing resources and 2,000 MW of proposed new resources that could qualify, then the zone would be modeled as export constrained

Why is the ISO not proposing to model all Load Zones all of the time?

- Modeling zones that don't need to be modeled would be an unnecessary administrative and implementation burden
- The boundaries of several of the existing Load Zones do not correspond to constraints on the real operating system
  - Load Zones are used for energy market settlement aggregation
    - They are not used to manage system dispatch
- Several Load Zone boundaries do not have established interface transfer capabilities
  - Do not provide meaningful information regarding the location of resources

Do PJM and New York model all zones all of the time?

- No - In PJM and New York, all parts of the system are tested, but only those portions of the system that trigger the objective criteria are separately modeled as zones in the capacity market

A newly created zone would be filed at FERC

- Capacity Zones that are consistent with the boundaries of existing Load Zones or Capacity Zones will be identified in the pre-FCA ICR filing
  - (i.e. the process would be unchanged from the current process)
- Proposed potential Capacity Zones that differ from the boundaries of existing Load Zones or Capacity Zones would be filed at FERC early in the qualification timeline for the given FCA
  - So that qualification and requirements calculations can be conducted with a FERC-approved zone

What will be analyzed for FCA-9?

- For FCA-9 Capacity Zones would be created by implementing the objective criteria (automatic trigger) using the existing 8 energy Load Zones as the starting point
  - Energy Load Zones that do not exceed the automatic trigger will be collapsed into the Rest-of-Pool Capacity zone

What will be analyzed for FCA-10 and beyond?

- For FCA-10 and beyond, incorporate the analysis of appropriate zonal boundaries into the annual process used to calculate transfer limits for RSP and NERC statutory requirements
  - The automatic trigger would continue to define whether the zone would be created

How are bilateral trading rules affected?

- Once a zone is modeled in the FCA, it will persist in the subsequent reconfiguration auctions and bilateral transaction windows for that Capacity Commitment Period
  - No change to bilateral trading rules

EXAMPLES OF THE ZONE MODELING PROCESS

Examples

- Two examples are provided to give a sense of how the proposal will work
  - NEMA/Boston
  - New Hampshire
- See also the Special RC presentation on September 26 for several additional examples of zonal modeling calculations

NEMA/Boston example (FCA-8 values)

- Line-line TSA requirement 2,788 MW
- Largest station 1,972 MW
- Total 4,760 MW

- There were 3,685 MW of Existing Qualified Capacity in Boston - so the objective criteria would be triggered and the zone would be modeled for the commitment period

New Hampshire example (FCA-8 values)

- Line-line TSA requirement* 3,101 MW
- Largest Station 1,245 MW
- Total 4,346 MW

- There were 4,396 MW of Existing Qualified Capacity in New Hampshire – so the zone would not be modeled

*Assuming zero import capability

Questions

January 3, 2014

Memorandum

To: NEPOOL Participants Committee
From: Pete Fuller, NRG

RE: NRG Proposal Regarding Capacity Zones

At its January 10, 2014 meeting, the Participants Committee will be considering ISO-proposed changes to Section 12 and Attachment K to the ISO-NE Tariff related to modeling capacity zones in FCM.[1] NRG is proposing amendments to each of these sections, which are described briefly below.

Attachment K

ISO proposes to modify Attachment K to the Tariff, governing the Regional System Planning Process, to incorporate an assessment each year of "potential future transmission system weaknesses and limiting facilities that could impact the transmission system's ability to reliably transfer energy in the planning horizon," including consideration of resource retirement requests and Permanent Delist Bids that were submitted, and Static and Dynamic Delist Bids that were rejected for reliability, from the most recent FCA to determine potential interfaces or zonal boundaries that may be appropriately modeled in the upcoming FCA.

NRG proposes incremental changes to the ISO's proposed Attachment K language to accomplish four things:

- Comply with the Commission's direction in several orders to 'model all zones all the time.' Rather than establishing boundaries 'that should be considered in the assessment of Capacity Zones to be modeled' NRG proposes that all boundaries established pursuant to the Attachment K planning process 'should be modeled as Capacity Zones in the Forward Capacity Market.'

- Incorporate all marketplace information from existing resources in identifying zonal interfaces. Rather than including only retirement and delist bid information from the most recent FCA, NRG proposes that the planning process will consider all retirement requests and all delist bids submitted in all previous FCAs as well as in the current FCA, to the extent known, when assessing the topology of the system and identifying zonal boundaries.

[1] These proposals are separate from the changes recommended to the PC by the Markets Committee regarding the ability of participants to enter into bilateral capacity transactions between resources in different Capacity Zones.

- Take a pro-active approach to zonal interface identification by including 'at risk' resources in the assessment of system topology. Similar to the approach ISO-NE took in the 2012 'Retirement Study,'[2] NRG proposes that the process consider, among other things, resources likely to be facing extensive capital upgrade requirements for environmental compliance or otherwise, resources not designed as peaking units but with low utilization factors, and resources more than 20 years old.

- Comply with the Commission's direction with respect to 'automatic' creation of capacity zones when delist bids are rejected for reliability. NRG's proposed language creates a presumption, consistent with the Commission's directive, that such zones would be created in the following FCA, unless ISO affirmatively determines that such a zone would be detrimental to system reliability or market efficiency.

Section 12

NRG's proposed language for Section 12 of the Tariff, "Calculation of Capacity Requirements," adds a new Section 12.4A dealing specifically with Capacity Zones for FCA9, and modifies Section 12.4 in similar ways for all FCAs starting with FCA10. The process for establishing FCA9 system and zonal capacity requirements needs to start very soon, and it is not reasonable to expect that the revised Attachment K planning process for identifying zonal boundaries can be completed early in 2014 to support that effort. Therefore, NRG's proposed Section 12.4A proposes that the zones for FCA9 start with the current eight load zones as capacity zone boundaries, augmented, to the extent possible, by any additional or modified boundaries that are identified as part of the Attachment K planning process.

NRG's proposed language in Section 12.4 makes explicit the goal of moving the FCA to a more sophisticated structure such that it can evaluate and clear the auction in the presence of "bi-directional and mesh network constraints." Despite the desirable characteristics of the descending clock auction, its inability to handle the actual topology and interconnectedness of the New England system make it inadequate for the long term. Recognizing the limitation that the descending clock auction imposes, NRG's proposed language in both Sections 12.4 and 12.4A provides that, while that auction mechanism remains in place, capacity zones will only be modeled to the extent they can be identified as definitively import-constrained or export-constrained, and provides modified language for establishing that determination for each zone. Most importantly, the proposed language for establishing that a zone is import-constrained parallels NRG's Attachment K revisions, such that in addition to the largest generating station in the zone, all retirement and delist bids from all prior and current auctions would be assumed out-of-service, as well as all 'at risk' resources, in determining if the existing capacity within a zone is less than the line-line Transmission Security Analysis requirement.[3]

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[2] http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2012/dec132012/retirements_redacted.pdf

[3] In both Section 12.4 and 12.4A, the proposed language regarding the 'at risk' resources was not part of the proposal considered by the RC at its December 17 meeting, but was added to the proposal to be considered by the PC based on feedback received at that meeting.

Once the descending clock auction has been replaced, only proposed Section 12.4(d) will be operative, providing that "Beginning with the Forward Capacity Auction in which bi-directional and mesh network constraints can be evaluated in clearing the auction, all interfaces identified in the annual assessment of transmission transfer capability pursuant to ISO Tariff Section II, Attachment K will be modeled." In order to be compliant with the series of Commission orders leading to the instant proposals, and to support an efficient locational mechanism for procuring and valuing capacity resources, this must be the goal for the region and its stakeholders.

Thanks for your consideration.

III.12 Calculation of Capacity Requirements

III.12.1 Installed Capacity Requirement.

Prior to each Forward Capacity Auction, the ISO shall calculate the Installed Capacity Requirement for the New England Control Area for each upcoming Capacity Commitment Period through the Capacity Commitment Period associated with that Forward Capacity Auction in accordance with this Section III.12.1.

The ISO shall determine the Installed Capacity Requirement such that the probability of disconnecting non-interruptible customers due to resource deficiency, on the average, will be no more than once in ten years. Compliance with this resource adequacy planning criterion shall be evaluated probabilistically, such that the Loss of Load Expectation ("LOLE") of disconnecting non-interruptible customers due to resource deficiencies shall be no more than 0.1 day each year. The forecast Installed Capacity Requirement shall meet this resource adequacy planning criterion for each Capacity Commitment Period. The Installed Capacity Requirement shall be determined assuming all resources pursuant to Sections III.12.7 and III.12.9 will be deliverable to meet the forecasted demand determined pursuant to Section III.12.8.

If the Installed Capacity Requirement shows a consistent bias over time, either high or low, the ISO shall make adjustments to the modeling assumptions and/or methodology through the stakeholder process to eliminate the bias in the Installed Capacity Requirement. The modeling assumptions used in determining the Installed Capacity Requirement are specified in Sections III.12.7, III.12.8 and III.12.9. For the purpose of this Section III.12, a "resource" shall include generating resources, demand resources, and import capacity resources eligible to receive capacity payments in the Forward Capacity Market.

III.12.2 Local Sourcing Requirements and Maximum Capacity Limits.

Prior to each Forward Capacity Auction, the ISO shall calculate the capacity requirements and limitations, accounting for relevant transmission interface limits which shall be determined pursuant to Section III.12.5, for each modeled Capacity Zone (as described in Section III.12.4) for each upcoming Capacity Commitment Period through the Capacity Commitment Period associated with that Forward Capacity Auction. The Local Sourcing Requirement shall represent the minimum amount of capacity that must be procured within an import-constrained ~~Load~~ Capacity Zone. The Maximum Capacity Limit shall represent the maximum amount of capacity that can be procured in an export-constrained ~~Load~~ Capacity Zone to meet the Installed Capacity Requirement.

The ISO shall use consistent assumptions and standards to establish a resource's electrical location for purposes of qualifying a resource for the Forward Capacity Market and for purposes of calculating Local Sourcing Requirements. ~~Load Zones will be reconfigured as necessary pursuant to Section III.2.7(g) of Market Rules~~. The methodology used in determining the Local Sourcing Requirements and the Maximum Capacity Limits are specified in Sections III.12.2.1 and III.12.2.2, respectively. The modeling assumptions used in determining the Local Sourcing Requirements and the Maximum Capacity Limits are specified in Sections III.12.5, III.12.6, III.12.7, III.12.8 and III.12.9.

III.12.2.1 Calculation of Local Sourcing Requirements for Import-Constrained Capacity~~Load~~ Zones.

For each import-constrained ~~Load~~ Capacity Zone, the Local Sourcing Requirement shall be the amount needed to satisfy the higher of: (i) the Local Resource Adequacy Requirement as determined pursuant to Section III.12.2.1.1; or (ii) the Transmission Security Analysis as determined pursuant to Section III.12.2.1.2.

III.12.2.1.1 Local Resource Adequacy Requirement.

The Local Resource Adequacy Requirement shall be calculated as follows:

(a) Two areas shall be modeled: (i) the ~~Load~~ Capacity Zone under study which includes all load and all resources electrically located within the ~~Load~~ Capacity Zone, including external Control Area support from tie benefits on the import-constrained side of the interface, if any; and (ii) the rest of the New England Control Area which includes all load and all resources electrically located within the rest of the New England Control Area, including external Control Area support from tie benefits on the unconstrained side of the interface, if any.

(b) The only transmission constraint to be modeled shall be the transmission interface limit between the ~~Load~~ Capacity Zone under study and the rest of the New England Control Area as ~~determined~~ identified pursuant to Section III.12.5.

(c) Any proxy units that are required in the New England Control Area pursuant to Section III.12.7.1 shall be modeled as specified in Section III.12.7.1, in order to ensure that the New England Control Area meets the resource adequacy planning criterion specified in Section III.12.1. If the system LOLE is less than 0.1 days/year, firm load is added (or unforced capacity is subtracted) so that the system LOLE equals 0.1 days/year.

(d) The Local Resource Adequacy Requirement for the import-constrained ~~Load~~ Capacity Zone Z shall be determined in accordance with the following formula:

$$LRA_Z = Resources_z + Proxy\ Units_z - (Proxy\ Units\ Adjustment_z(1-FOR_z)) - (Firm\ Load\ Adjustment_z(1-FOR_z))$$

In which:

LRA_Z	=	MW of Local Resource Adequacy Requirement for ~~Load~~ Capacity Zone Z;
$Resources_z$	=	MW of resources electrically located within ~~Load~~ Capacity Zone Z, including import Capacity Resources on the import-constrained side of the interface, if any;
$Proxy\ Units_z$	=	MW of proxy unit additions in Load Zone Z;
Firm Load $Adjustment_z$	=	MW of firm load added (or subtracted) within ~~Load~~ Capacity Zone Z to make the LOLE of the New England Control Area equal to 0.105 days per year; and
FOR_z	=	Capacity weighted average of the forced outage rate modeled for all resources within ~~Load~~ Capacity Zone Z, including and proxy unit additions to ~~Load~~ Capacity Zone Z.
Proxy Units Adjustment	=	MW of firm load added to (or unforced capacity subtracted from) ~~Load~~ Capacity Zone Z until the system LOLE equals 0.1 days/year.

To determine the Local Resource Adequacy Requirement, the firm load is adjusted within ~~Load~~ Capacity Zone Z until the LOLE of the New England Control Area reaches 0.105 days per year. The LOLE of 0.105 days per year includes an allowance for transmission related LOLE of 0.005 days per year associated with each interface. As firm load is added to (or subtracted from) ~~Load~~ Capacity Zone Z, an equal amount of firm load is removed from (or added to) the rest of New England Control Area.

III.12.2.1.2 Transmission Security Analysis Requirement.

A Transmission Security Analysis shall be used to determine the requirement of the ~~Load Zone~~zone being studied, and shall include the following features:

(a) The ISO shall perform a series of transmission load flow studies and/or a deterministic operable capacity analysis targeted at determining the performance of the system under stressed conditions, and at developing a resource requirement sufficient to allow the system to operate through those stressed conditions.

(b) The Transmission Security Analysis requirement shall be set at a level sufficient to cover most reasonably anticipated events, but will not guarantee that every combination of obligated resources within the zone will meet system needs.

(c) In performing the Transmission Security Analysis, the ISO ~~shall~~ may establish static transmission interface transfer limits, as identified pursuant to Section III.12.5, as a reasonable representation of the transmission system's capability to serve load with available existing resources.

(d) The Transmission Security Analysis may model the entire New England system and individual ~~Load Zones~~zones, for both the first contingency (N-1) and second contingency (N-1-1) conditions. First contingency conditions (N-1) shall include the loss of the most critical generator or most critical transmission element with respect to the ~~Load Zone~~zone. Second contingency conditions (N-1-1) shall include both: (i) the loss of the most critical generator with respect to the ~~Load Zone~~zone followed by the loss of the most critical transmission element ("Line-Gen"); and (ii) the loss of the most critical transmission element followed by the loss of the next most critical transmission element ("Line-Line") with respect to the ~~Load Zone~~zone.

III.12.2.2 Calculation of Maximum Capacity Limit for Export-Constrained ~~Load~~ Capacity Zones.

For each export-constrained ~~Load~~ Capacity Zone, the Maximum Capacity Limit shall be calculated using the following method:

(a) Two areas shall be modeled: (i) the ~~Load~~ Capacity Zone under study which includes all load and all resources electrically located within the ~~Load~~ Capacity Zone, including external Control Area support from tie benefits on the export-constrained side of the interface, if any; and (ii) the rest of the New England Control Area, which includes all load and all resources electrically located within the rest of the New England Control Area, including external Control Area support from tie benefits to the rest of the New England Control Area, if any.

(b) The only transmission constraint to be modeled shall be the transmission interface limit between the ~~Load~~ Capacity Zone under study and the rest of the New England Control Area as ~~determined~~ identified pursuant to Section III.12.5.

(c) Any proxy units that are required in the New England Control Area pursuant to Section III.12.7.1 shall be modeled as specified in Section III.12.7.1, in order to ensure that the New England Control Area meets the resource adequacy planning criterion specified in Section III.12.1. If the system LOLE is less than 0.1 days/year, firm load is added (or unforced capacity is subtracted) so that the system LOLE equals 0.1 days/year.

(d) The Maximum Capacity Limit for the export-constrained ~~Load~~ Capacity Zone Y shall be determined in accordance with the following formula:

$$\text{Maximum Capacity Limit}_Y = \text{ICR} - \text{LRA}_{\text{RestofNewEngland}}$$

In which:

Maximum Capacity Limit$_Y$ = Maximum MW amount of resources , including Import Capacity Resources on the export-constrained side of the interface, if any, that can be procured in the export-constrained ~~Load~~ Capacity Zone Y to meet the Installed Capacity Requirement;

ICR = MW of Installed Capacity Requirement for the New England Control Area, determined in accordance with Section III.12.1; and

$LRA_{RestofNewEngland}$ = MW of Local Sourcing Requirement for the rest of the New England Control Area, which for the purposes of this calculation is treated as an import-constrained region, determined in accordance with Section III.12.2.1.

III.12.3 Consultation and Filing of Capacity Requirements.

At least two months prior to filing the Installed Capacity Requirements and Local Sourcing Requirements for each upcoming Capacity Commitment Period through the relevant Capacity Commitment Period with the Commission, the ISO shall review the modeling assumptions and resulting Installed Capacity Requirements and the Local Sourcing Requirements with the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies. Following consultation with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies, the ISO shall file the Installed Capacity Requirements and Local Sourcing Requirements**~~,~~ ~~including identification of any new Capacity Zone(s),~~** for each upcoming Capacity Commitment Period through the relevant Capacity Commitment Period with the Commission pursuant to Section 205 of the Federal Power Act ~~no later than~~ 90 days prior to the Forward Capacity Auction for the Capacity Commitment Period**. The ISO shall file with the Commission pursuant to Section 205 of the Federal Power Act, the proposed identification of a potential new Capacity Zone when the boundary of the potential new Capacity Zone differs from the boundaries of existing Load Zones or Capacity Zones. In order to be used in a given FCA, any new Capacity Zone must have received approval from the Commission prior to the Existing Capacity Qualification Deadline of the applicable FCA.**

III.12.4 Capacity Zones.

For each Forward Capacity Auction, the ISO shall, using the results of the most recent annual assessment of transmission transfer capability conducted pursuant to ISO Tariff Section II, Attachment K, determine ~~model the four~~ the Capacity Zones to model as described below, and will include such designations in its filing with the Commission pursuant to Section III.13.8.1:

(a) The ISO shall model in the Forward Capacity Auction, as separate export-constrained Capacity Zones, those zones identified in the most recent annual assessment of transmission transfer capability pursuant to ISO Tariff Section II, Attachment K, for which the Maximum Capacity Limit is less than sum of the existing qualified capacity and proposed new capacity that could qualify to be procured in the export constrained Capacity Zone, including existing and proposed new Import Capacity Resources on the export-constrained side of the interface.~~The Maine Load Zone shall be modeled as a separate export-constrained Capacity Zone in the Forward Capacity Auction~~.

(b) The ISO shall model in the Forward Capacity Auction, as separate import-constrained Capacity Zones, those zones identified in the most recent annual assessment of transmission transfer capability pursuant to ISO Tariff Section II, Attachment K, for which the~~re is insufficient~~ second contingency transmission capability **results in a** ~~**to serve the associated**~~ line-line Transmission Security Analysis requirement, calculated pursuant to Section III.12.2.1.2 and pursuant to ISO New England Planning Procedures, ~~**along**~~ **that is greater than the Existing Qualified Capacity in the zone,** with the largest ~~Resource~~generating station in the zone modeled as out-of-service. Each assessment will model out-of-service all Non-Price Retirement Requests **(including any received for the current FCA at the time of this calculation)** and Permanent De-List Bids as well as rejected for reliability Static De-List Bids from the most recent previous Forward Capacity Auction and rejected for reliability Dynamic De-List Bids from the most recent previous Forward Capacity Auction.~~The Connecticut Load Zone shall be modeled as a separate import-constrained Capacity Zone in the Forward Capacity Auction~~.

~~(c) The Northeastern Massachusetts Load Zone shall be modeled as a separate import-constrained Capacity Zone in the Forward Capacity Auction.~~

(c~~d~~) ~~The remaining system Load Zones (Western/Central Massachusetts, Southeastern Massachusetts, Vermont, New Hampshire, and Rhode Island)~~ Adjacent Load Zones that are neither export-constrained nor import-constrained shall be modeled together as the Rest-of-~~-~~Pool Capacity Zone in the Forward Capacity Auction.

III.12.5 Transmission Interface Limits.

Transmission interface limits, used in the determination of Local Sourcing Requirements, shall be determined pursuant to ISO Tariff Section II, Attachment K using network models that include all resources, existing transmission lines and proposed transmission lines that the ISO determines, in accordance with Section III.12.6, will be in service no later than the first day of the relevant Capacity Commitment Period. ~~Load modeling assumptions used in determining the transmission interface limits are specified in Section III.12.8. Each target transmission interface limit shall be calculated assuming simultaneous imports from directly connected Control Areas up to the transmission interface limits that may be assumed over the other interfaces. Prior to each Forward Capacity Auction, the ISO shall update the transmission interface limits for each internal and external interface for each upcoming Capacity Commitment Period through the Capacity Commitment Period associated with that Forward Capacity~~

~~Auction. This update shall take into account any additional transmission projects and elements of transmission projects that are added to the network model pursuant to Section III.12.6.~~ The transmission interface limits shall be established, using deterministic analyses, at levels that provide acceptable thermal, voltage and stability performance of the system both with all lines in service and after any criteria contingency occurs as specified in ISO New England Manuals and ISO New England Administrative Procedures.

III.12.6 Modeling Assumptions for Determining the Network Model.

The ISO shall determine, in accordance with this Section III.12.6, the generating units and transmission infrastructure to include in the network model that: (i) are expected to be in service no later than the first day of the relevant Capacity Commitment Period; and (ii) may have a material impact on the network model, a potential interface constraint, or on one or more Local Sourcing Requirements. The network model shall be used, among other purposes, (i) for the Forward Capacity Market qualification process and (ii) to calculate transmission interface limits in order to forecast the Local Sourcing Requirements. The network model shall include generating units and associated Interconnection Facilities as specified in subsection (a) and Transmission Upgrades as specified in subsection (b).

(a) Generating units and associated Interconnection Facilities that shall be included in the network model for the relevant Capacity Commitment Period shall include:

(i) all existing resources that have not been approved to be retired for the relevant Capacity Commitment Period, as described in Section III.13.2.5.2.5.3;

(ii) all generating units that are resources cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period that have a valid Interconnection Request for which a draft Interconnection System Impact Study report has been submitted to the Interconnection Customer; and

iii. any generating unit that has a valid Interconnection Request for which a draft Interconnection Feasibility Study report has been submitted to the Interconnection Customer and is reasonably expected to declare commercial operation no later than the first day of the relevant Capacity Commitment Period whether or not such unit is participating in the Forward Capacity Market qualification process.

(b) Prior to each Forward Capacity Auction and each annual reconfiguration auction, the ISO shall determine and publish a list of the transmission projects and elements of transmission projects that will be included in the network model. During the process of making the transmission infrastructure determinations, as described in Section III.12.6.1, the ISO shall consult with the Governance Participants, the Transmission Owners, any transmission project proponents, the state utility regulatory agencies in New England and, as appropriate, other state agencies.

III.12.6.1 Process for Establishing the Network Model

(a) The ISO shall establish an initial network model prior to the Forward Capacity Auction that only includes transmission infrastructure that is already in service at the time that the initial network model is developed.

(b) After establishing the initial network model, the ISO shall compile a preliminary list of the transmission projects or elements of transmission projects in the ~~Transmission Project Listing~~RSP Project List, individually or in combination with each other, as appropriate, to identify transmission projects that may achieve an in-service date no later than the first day of the relevant Capacity Commitment Period and that will have a material impact on the network model, on a potential interface constraint or one or more Local Sourcing Requirements.

(c) For the transmission projects or elements of transmission projects in the ~~Transmission Project Listing~~RSP Project List that are included in the preliminary list developed pursuant to subsection (b), the ISO shall determine whether the transmission projects or elements of transmission projects meet all of the initial threshold milestones specified in Section III.12.6.2 and will be considered for further evaluation pursuant to subsection (d).

(d) For those transmission projects or elements of transmission projects that meet the initial threshold milestones in subsection (c), the ISO shall use the evaluation criteria specified in Section III.12.6.3, and any other relevant information, to determine whether to include a transmission project or element of a transmission project in the final network model.

(e) If after completing its evaluation pursuant to Sections III.12.6.1 through III.12.6.3 and conferring with the transmission project proponents, the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies, the ISO determines that the transmission project or a portion of the transmission project is reasonably expected to be in service no later than the first day

for the relevant Capacity Commitment Period, then such transmission project or portion of transmission project shall be considered in service in the finalized network model to calculate the transmission interface limits pursuant to Section III.12.5.

III.12.6.2 Initial Threshold to be Considered In-Service.

The ISO shall determine whether transmission projects or elements of transmission projects meet all of the following initial threshold milestones:

(a) A critical path schedule for the transmission project has been furnished to ISO showing that the transmission project or the element of the transmission project will be in-service no later than the first day of the relevant Capacity Commitment Period. The critical path schedule must be sufficiently detailed to allow the ISO to evaluate the feasibility of the schedule.

(b) At the time of the milestone review, siting and permitting processes, if required, are on schedule as shown on the critical path schedule.

(c) At the time of the milestone review, engineering is on schedule as shown on the critical path schedule.

(d) At the time of the milestone review, land acquisition, if required, is on schedule as shown on the critical path schedule.

(e) Corporate intent to build the transmission project has been furnished to the ISO. An officer of the host Transmission Owner has submitted to the ISO a statement verifying that the officer has reviewed the proposal and critical path schedule submitted to the ISO, and the Transmission Owner concurs that the schedule is achievable, and it is the intent of the Transmission Owner to build the proposed transmission project in accordance with that schedule. The Transmission Owner may develop alternatives or modifications to the transmission project during the course of design of the transmission project that accomplish at least the same transfer capability. Such alternatives or modifications are acceptable, so long as the ISO determines that the alternative or modification is reasonably expected to achieve an in-service date no later than the first day of the relevant Capacity Commitment Period. The provision of an officer's statement shall be with the understanding that the statement shall not create any liability on the officer and that any liability with respect to the Transmission Owner's obligations shall be as set forth in the Transmission Operating Agreement and shall not be affected by such officer's statement.

III.12.6.3 Evaluation Criteria.

For a transmission project or element of a transmission project that meets the initial threshold milestones specified in Section III.12.6.2, the ISO shall consider the following factors and any other relevant information to determine whether to include the transmission project or element of the transmission project in the network model for the relevant Capacity Commitment Period.

(a) Sufficient engineering to initiate construction is on schedule as shown on the critical path schedule.

(b) Approval under Section I.3.9 of the Transmission, Markets and Services Tariff, if required, has been obtained or is on schedule to be obtained as shown on the critical path schedule.

(c) Significant permits, including local permits, if required to initiate construction have been obtained or are on schedule consistent with the critical path schedule.

(d) Easements, if required, have been obtained or are on schedule consistent with the critical path schedule. Needed land purchases, if required, have been made or are on schedule consistent with the critical path schedule.

(e) Any contracts required to procure or construct a transmission project are in place consistent with the critical path schedule. The ISO's analysis may also take into account whether such contracts contain incentive and/or penalty clauses to encourage third parties to advance the delivery of material services to conform with the critical path schedule.

(f) Physical site work is on schedule consistent with the critical path schedule.

(g) The transmission project is in a designated National Interest Electric Transmission Corridor in accordance with Section 216 of the Federal Power Act, 16 U.S.C. §§ 824p.

III.12.7 Resource Modeling Assumptions.

III.12.7.1 Proxy Units.

When the available resources are insufficient for the unconstrained New England Control Area to meet the resource adequacy planning criterion specified in Section III.12.1, proxy units shall be used as

additional capacity to determine the Installed Capacity Requirement and the Local Resource Adequacy Requirements. The proxy units shall reflect resource capacity and outage characteristics such that when the proxy units are used in place of all other resources in the New England Control Area, the reliability, or LOLE, of the New England Control Area does not change. The outage characteristics are the summer capacity weighted average availability of the resources in the New England Control Area as determined in accordance with Section III.12.7.3. The capacity of the proxy unit is determined by adjusting the capacity of the proxy unit until the LOLE of the New England Control Area is equal to the LOLE calculated while using the capacity assumptions described in Section III.12.7.2.

When modeling transmission constraints for the determination of Local Resource Adequacy Requirements, the same proxy units may be added to the import-constrained ~~Load Zone~~zone or elsewhere in the rest of the New England Control Area depending on where system constraints exist.

III.12.7.2 Capacity.

The resources included in the calculation of the Installed Capacity Requirement and the Local Sourcing Requirements shall include:

(a) all Existing Generating Capacity Resources,

(b) resources cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period,

(c) all Existing Import Capacity Resources backed by a multiyear contract to provide capacity in the New England Control Area, where that multiyear contract requires delivery of capacity for the Commitment Period for which the Installed Capacity Requirement is being calculated, and

(d) Existing Demand Resources that are qualified to participate in the Forward Capacity Market and New Demand Resources that have cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period,

but shall exclude:

(e) capacity associated with Export Bids cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period, and

(f) resources for which Permanent De-list Bids cleared in previous Forward Capacity Auctions or for which Non-Price Retirement Requests have been received.

The rating of Existing Generating Capacity Resources and Existing Import Capacity Resources used in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements and Maximum Capacity Limits shall be the summer Qualified Capacity value of such resources for the relevant ~~Load Zone~~zone. The rating of Demand Resources shall be the summer Qualified Capacity value reduced by any reserve margin adjustment factor that is otherwise included in the summer Qualified Capacity value. The rating of resources, except for Demand Resources, cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period shall be based on the amount of Qualified Capacity that cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period. Resources are located within the ~~Load~~ Capacity Zones in which they are electrically located as determined during the qualification process.

III.12.7.2.1 [Reserved.]

III.12.7.3 Resource Availability.

The Installed Capacity Requirement and the Local Sourcing Requirements shall be calculated taking resource availability into account and shall be determined as follows:

For Existing Generating Capacity Resources:

(a) The most recent five-year moving average of EFORd shall be used as the measure of resource availability used in the calculation of the Installed Capacity Requirement and the Local Resource Adequacy Requirements. The most recent five-year moving average of EFORd shall be used as the measure of resource availability for non-peaking resources used in the calculation of Transmission Security Analysis Requirements. A deterministic adjustment factor, based on the operational experience of the ISO, shall be used as the measure of resource availability for peaking resources used in the calculation of Transmission Security Analysis Requirements, and will be reviewed periodically.

(b) [Reserved.]

(c) Once sufficient data are collected under the availability incentives in the Forward Capacity Market, a resource availability metric, which reflects resource availability in a manner that is consistent with the availability incentives in the Forward Capacity Market, shall be developed and reviewed with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other

state agencies and used in the calculation of the Installed Capacity Requirement and the Local Sourcing Requirements.

For resources cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period that do not have sufficient data to calculate an availability metric as defined in subsections (a) or (c) above, class average data for similar resource types shall be used. For Demand Resources, including Real-Time Emergency Generation, historical performance data for those resources will be used to develop an availability metric for use in the calculation of the Installed Capacity Requirement and Local Sourcing Requirements.

III.12.7.4 Load and Capacity Relief.

Load and capacity relief expected from system-wide implementation of the following actions during a capacity deficiency (Operating Procedure No. 4) shall be included in the calculation of the Installed Capacity Requirement and the Local Sourcing Requirements. The Installed Capacity Requirements and Local Sourcing Requirements shall reflect the impact of the following actions during a capacity deficiency which are specified in the ISO New England Manuals and ISO New England Administrative Procedures:

(a) **Implement voltage reduction**. The MW value of the load relief shall be equal to the percentage load reduction achieved in the most applicable voltage reduction tests multiplied by the forecasted seasonal peak loads.

(b) **Arrange for available Emergency energy from Market Participants or neighboring Control Areas.** These actions are included in the calculation through the use of tie benefits to meet system needs. The MW value of tie benefits is calculated in accordance with Section III.12.9.

(c) **Maintain an adequate amount of ten-minute synchronized reserves**. The amount of system reserves included in the Installed Capacity Requirement shall be consistent with those needed for reliable system operations during Emergency Conditions. When modeling transmission constraints, the reserve requirement for a ~~Load Zone~~zone shall be the ~~Load Zone~~zone's pro rata share of the forecasted system peak load multiplied by the system reserves needed for reliable system operations during Emergency Conditions.

III.12.8 Load Modeling Assumptions.

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III.12 Calculation of Capacity Requirements

III.12.1 Installed Capacity Requirement.

Prior to each Forward Capacity Auction, the ISO shall calculate the Installed Capacity Requirement for the New England Control Area for each upcoming Capacity Commitment Period through the Capacity Commitment Period associated with that Forward Capacity Auction in accordance with this Section III.12.1.

The ISO shall determine the Installed Capacity Requirement such that the probability of disconnecting non-interruptible customers due to resource deficiency, on the average, will be no more than once in ten years. Compliance with this resource adequacy planning criterion shall be evaluated probabilistically, such that the Loss of Load Expectation ("LOLE") of disconnecting non-interruptible customers due to resource deficiencies shall be no more than 0.1 day each year. The forecast Installed Capacity Requirement shall meet this resource adequacy planning criterion for each Capacity Commitment Period. The Installed Capacity Requirement shall be determined assuming all resources pursuant to Sections III.12.7 and III.12.9 will be deliverable to meet the forecasted demand determined pursuant to Section III.12.8.

If the Installed Capacity Requirement shows a consistent bias over time, either high or low, the ISO shall make adjustments to the modeling assumptions and/or methodology through the stakeholder process to eliminate the bias in the Installed Capacity Requirement. The modeling assumptions used in determining the Installed Capacity Requirement are specified in Sections III.12.7, III.12.8 and III.12.9. For the purpose of this Section III.12, a "resource" shall include generating resources, demand resources, and import capacity resources eligible to receive capacity payments in the Forward Capacity Market.

III.12.2 Local Sourcing Requirements and Maximum Capacity Limits.

Prior to each Forward Capacity Auction, the ISO shall calculate the capacity requirements and limitations, accounting for relevant transmission interface limits which shall be determined pursuant to Section III.12.5, for each modeled Capacity Zone (as described in Section III.12.4) for each upcoming Capacity Commitment Period through the Capacity Commitment Period associated with that Forward Capacity Auction. The Local Sourcing Requirement shall represent the minimum amount of capacity that must be procured within an import-constrained ~~Load~~ Capacity Zone. The Maximum Capacity Limit shall represent the maximum amount of capacity that can be procured in an export-constrained ~~Load~~ Capacity Zone to meet the Installed Capacity Requirement.

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The ISO shall use consistent assumptions and standards to establish a resource's electrical location for purposes of qualifying a resource for the Forward Capacity Market and for purposes of calculating Local Sourcing Requirements. ~~Load Zones will be reconfigured as necessary pursuant to Section III.2.7(g) of Market Rules~~. The methodology used in determining the Local Sourcing Requirements and the Maximum Capacity Limits are specified in Sections III.12.2.1 and III.12.2.2, respectively. The modeling assumptions used in determining the Local Sourcing Requirements and the Maximum Capacity Limits are specified in Sections III.12.5, III.12.6, III.12.7, III.12.8 and III.12.9.

III.12.2.1 Calculation of Local Sourcing Requirements for Import-Constrained Capacity~~Load~~ Zones.

For each import-constrained ~~Load~~ Capacity Zone, the Local Sourcing Requirement shall be the amount needed to satisfy the higher of: (i) the Local Resource Adequacy Requirement as determined pursuant to Section III.12.2.1.1; or (ii) the Transmission Security Analysis as determined pursuant to Section III.12.2.1.2.

III.12.2.1.1 Local Resource Adequacy Requirement.

The Local Resource Adequacy Requirement shall be calculated as follows:

(a) Two areas shall be modeled: (i) the ~~Load~~ Capacity Zone under study which includes all load and all resources electrically located within the ~~Load~~ Capacity Zone, including external Control Area support from tie benefits on the import-constrained side of the interface, if any; and (ii) the rest of the New England Control Area which includes all load and all resources electrically located within the rest of the New England Control Area, including external Control Area support from tie benefits on the unconstrained side of the interface, if any.

(b) The only transmission constraint to be modeled shall be the transmission interface limit between the ~~Load~~ Capacity Zone under study and the rest of the New England Control Area as ~~determined~~ identified pursuant to Section III.12.5.

(c) Any proxy units that are required in the New England Control Area pursuant to Section III.12.7.1 shall be modeled as specified in Section III.12.7.1, in order to ensure that the New England Control Area meets the resource adequacy planning criterion specified in Section III.12.1. If the system LOLE is less than 0.1 days/year, firm load is added (or unforced capacity is subtracted) so that the system LOLE equals 0.1 days/year.

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(d) The Local Resource Adequacy Requirement for the import-constrained ~~Load~~ Capacity Zone Z shall be determined in accordance with the following formula:

LRA_Z = $Resources_z$ + $Proxy\ Units_z$ – (Proxy Units $Adjustment_z(1-FOR_z)$)-(Firm Load $Adjustment_z(1-FOR_z)$)

In which:

LRA_Z	=	MW of Local Resource Adequacy Requirement for ~~Load~~ Capacity Zone Z;
$Resources_z$	=	MW of resources electrically located within ~~Load~~ Capacity Zone Z, including import Capacity Resources on the import-constrained side of the interface, if any;
$Proxy\ Units_z$	=	MW of proxy unit additions in Load Zone Z;
Firm Load $Adjustment_z$	=	MW of firm load added (or subtracted) within ~~Load~~ Capacity Zone Z to make the LOLE of the New England Control Area equal to 0.105 days per year; and
FOR_z	=	Capacity weighted average of the forced outage rate modeled for all resources within ~~Load~~ Capacity Zone Z, including and proxy unit additions to ~~Load~~ Capacity Zone Z.
Proxy Units Adjustment	=	MW of firm load added to (or unforced capacity subtracted from) ~~Load~~ Capacity Zone Z until the system LOLE equals 0.1 days/year.

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To determine the Local Resource Adequacy Requirement, the firm load is adjusted within ~~Load~~ Capacity Zone Z until the LOLE of the New England Control Area reaches 0.105 days per year. The LOLE of 0.105 days per year includes an allowance for transmission related LOLE of 0.005 days per year associated with each interface. As firm load is added to (or subtracted from) ~~Load~~ Capacity Zone Z, an equal amount of firm load is removed from (or added to) the rest of New England Control Area.

III.12.2.1.2 Transmission Security Analysis Requirement.

A Transmission Security Analysis shall be used to determine the requirement of the ~~Load Zone~~zone being studied, and shall include the following features:

(a) The ISO shall perform a series of transmission load flow studies and/or a deterministic operable capacity analysis targeted at determining the performance of the system under stressed conditions, and at developing a resource requirement sufficient to allow the system to operate through those stressed conditions.

(b) The Transmission Security Analysis requirement shall be set at a level sufficient to cover most reasonably anticipated events, but will not guarantee that every combination of obligated resources within the zone will meet system needs.

(c) In performing the Transmission Security Analysis, the ISO ~~shall~~ may establish static transmission interface transfer limits, as identified pursuant to Section III.12.5, as a reasonable representation of the transmission system's capability to serve load with available existing resources.

(d) The Transmission Security Analysis may model the entire New England system and individual ~~Load Zones~~zones, for both the first contingency (N-1) and second contingency (N-1-1) conditions. First contingency conditions (N-1) shall include the loss of the most critical generator or most critical transmission element with respect to the ~~Load Zone~~zone. Second contingency conditions (N-1-1) shall include both: (i) the loss of the most critical generator with respect to the ~~Load Zone~~zone followed by the loss of the most critical transmission element ("Line-Gen"); and (ii) the loss of the most critical transmission element followed by the loss of the next most critical transmission element ("Line-Line") with respect to the ~~Load Zone~~zone.

III.12.2.2 Calculation of Maximum Capacity Limit for Export-Constrained ~~Load~~ Capacity Zones.

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For each export-constrained ~~Load~~ Capacity Zone, the Maximum Capacity Limit shall be calculated using the following method:

(a) Two areas shall be modeled: (i) the ~~Load~~ Capacity Zone under study which includes all load and all resources electrically located within the ~~Load~~ Capacity Zone, including external Control Area support from tie benefits on the export-constrained side of the interface, if any; and (ii) the rest of the New England Control Area, which includes all load and all resources electrically located within the rest of the New England Control Area, including external Control Area support from tie benefits to the rest of the New England Control Area, if any.

(b) The only transmission constraint to be modeled shall be the transmission interface limit between the ~~Load~~ Capacity Zone under study and the rest of the New England Control Area as ~~determined~~ identified pursuant to Section III.12.5.

(c) Any proxy units that are required in the New England Control Area pursuant to Section III.12.7.1 shall be modeled as specified in Section III.12.7.1, in order to ensure that the New England Control Area meets the resource adequacy planning criterion specified in Section III.12.1. If the system LOLE is less than 0.1 days/year, firm load is added (or unforced capacity is subtracted) so that the system LOLE equals 0.1 days/year.

(d) The Maximum Capacity Limit for the export-constrained ~~Load~~ Capacity Zone Y shall be determined in accordance with the following formula:

$$\text{Maximum Capacity Limit}_Y = \text{ICR} - \text{LRA}_{\text{RestofNewEngland}}$$

In which:

Maximum Capacity Limit$_Y$ = Maximum MW amount of resources , including Import Capacity Resources on the export-constrained side of the interface, if any, that can be procured in the export-constrained ~~Load~~ Capacity Zone Y to meet the Installed Capacity Requirement;

ICR = MW of Installed Capacity Requirement for the New England Control Area, determined in accordance with Section III.12.1; and

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$LRA_{RestofNewEngland}$ = MW of Local Sourcing Requirement for the rest of the New England Control Area, which for the purposes of this calculation is treated as an import-constrained region, determined in accordance with Section III.12.2.1.

III.12.3 Consultation and Filing of Capacity Requirements.

At least two months prior to filing the Installed Capacity Requirements and Local Sourcing Requirements for each upcoming Capacity Commitment Period through the relevant Capacity Commitment Period with the Commission, the ISO shall review the modeling assumptions and resulting Installed Capacity Requirements and the Local Sourcing Requirements with the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies. Following consultation with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies, the ISO shall file the Installed Capacity Requirements and Local Sourcing Requirements~~, including identificiation of any new Capacity Zone(s),~~ for each upcoming Capacity Commitment Period through the relevant Capacity Commitment Period with the Commission pursuant to Section 205 of the Federal Power Act ~~no later than~~ 90 days prior to the Forward Capacity Auction for the Capacity Commitment Period. **The ISO shall file with the Commission pursuant to Section 205 of the Federal Power Act, the proposed identification of a potential new Capacity Zone when the boundary of the potential new Capacity Zone differs from the boundaries of existing Load Zones or Capacity Zones. In order to be used in a given FCA, any new Capacity Zone must have received approval from the Commission prior to the Existing Capacity Qualification Deadline of the applicable FCA.**

III.12.4 Capacity Zones.

For each Forward Capacity Auction beginning with the auction for the 2019/2020 Capacity Commitment Period, the ISO shall, using the results of the most recent annual assessment of transmission transfer capability conducted pursuant to ISO Tariff Section II, Attachment K, ~~determine~~designate ~~model the four~~ the Capacity Zones to model as described below, and will include such designations in its filing with the Commission pursuant to Section III.13.8.1:

(a) Until such time as the Forward Capacity Market can evaluate bi-directional and mesh network constraints in clearing the auction, t~~T~~he ISO shall ~~model~~designate in the Forward Capacity Auction, as separate export-constrained Capacity Zones, those zones identified in the most recent annual assessment of transmission transfer capability pursuant to ISO Tariff Section II, Attachment K, for which the Maximum Capacity Limit is less than the sum of the existing qualified capacity and proposed incremental new capacity that could reasonably be expected to qualify to ~~be procured~~participate in the Forward

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Capacity Auction in the export constrained Capacity Zone, including existing and proposed new Import Capacity Resources on the export-constrained side of the interface. ~~The Maine Load Zone shall be modeled as a separate export-constrained Capacity Zone in the Forward Capacity Auction~~.

(b) Until such time as the Forward Capacity Market can evaluate bi-directional and mesh network constraints in clearing the auction, t~~T~~he ISO shall ~~model~~designate in the Forward Capacity Auction, as separate import-constrained Capacity Zones, those zones identified in the most recent annual assessment of transmission transfer capability pursuant to ISO Tariff Section II, Attachment K, for which the~~re is insufficient~~ second contingency transmission capability **results in a** ~~to serve the associated~~ line-line Transmission Security Analysis requirement, calculated pursuant to Section III.12.2.1.2 and pursuant to ISO New England Planning Procedures, ~~along~~ **that is greater than the Existing Qualified Capacity in the zone** with the largest ~~Resource~~ generating station in the zone modeled as out-of-service. Each assessment will model out-of-service all Non-Price Retirement Requests **(including any received for the current FCA at the time of this calculation)** and Permanent De-List Bids submitted for the current or any previous Forward Capacity Auction, as well as ~~rejected for reliability~~ submitted Static De-List Bids from the current or any ~~most recent~~ previous Forward Capacity Auctions and ~~rejected for reliability~~ submitted Dynamic De-List Bids from ~~the most recent~~ any previous Forward Capacity Auction, plus, to the extent not the subject of a Non-Price Retirement Request, Permanent De-List Bid, Static De-List Bid or Dynamic De-List Bid, all resources determined by ISO-NE, pursuant to Section 3.1 of ISO Tariff Section II, Attachment K, to be 'at risk.' ~~.The Connecticut Load Zone shall be modeled as a separate import-constrained Capacity Zone in the Forward Capacity Auction~~.

~~(c) The Northeastern Massachusetts Load Zone shall be modeled as a separate import-constrained Capacity Zone in the Forward Capacity Auction.~~

(c~~d~~) ~~The remaining system Load Zones (Western/Central Massachusetts, Southeastern Massachusetts, Vermont, New Hampshire, and Rhode Island)~~ Until such time as the Forward Capacity Market can evaluate bi-directional constraints in clearing the auction, ~~A~~adjacent Load Zones that are neither export-constrained nor import-constrained shall be modeled together as the Rest-of-Pool Capacity Zone in the Forward Capacity Auction.

(d) Beginning with the Forward Capacity Auction in which bi-directional and mesh network constraints can be evaluated in clearing the auction, all interfaces identified in the annual assessment of transmission transfer capability pursuant to ISO Tariff Section II, Attachment K will be modeled.

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III.12.4A Capacity Zones for the Ninth Forward Capacity Auction

For the Forward Capacity Auction for the 2018/2019 Capacity Commitment Period, the ISO shall designate the eight existing Load Zones, supplemented by findings from the most recent annual assessment of transmission transfer capability conducted pursuant to ISO Tariff Section II, Attachment K as appropriate, as Capacity Zones to model in the auction, and will include such designations in its filing with the Commission pursuant to Section III.13.8.1.

(a) the ISO shall designate in the Forward Capacity Auction, as separate export-constrained Capacity Zones, those zones identified in the most recent annual assessment of transmission transfer capability pursuant to ISO Tariff Section II, Attachment K, for which the Maximum Capacity Limit is less than the sum of the existing qualified capacity and proposed incremental new capacity that could reasonably be expected to qualify to participate in the Forward Capacity Auction in the export constrained Capacity Zone, including existing and proposed new Import Capacity Resources on the export-constrained side of the interface.

(b) the ISO shall designate in the Forward Capacity Auction, as separate import-constrained Capacity Zones, those zones identified in the most recent annual assessment of transmission transfer capability pursuant to ISO Tariff Section II, Attachment K, for which the second contingency transmission capability results in a line-line Transmission Security Analysis requirement, calculated pursuant to Section III.12.2.1.2 and pursuant to ISO New England Planning Procedures, that is greater than the total of the existing resources in the zone with the largest generating station in the zone modeled as out-of-service. Each assessment will model out-of-service all Non-Price Retirement Requests, Permanent De-List Bids, Static De-List Bids and Dynamic De-List Bids submitted in the current or any previous Forward Capacity Auction, plus, to the extent not the subject of a Non-Price Retirement Request, Permanent De-List Bid, Static De-List Bid or Dynamic De-List Bid, all resources determined by ISO-NE, pursuant to Section 3.1 of ISO Tariff Section II, Attachment K, to be 'at risk.'

(c) adjacent Load Zones that are neither export-constrained nor import-constrained shall be modeled together as the Rest-of-Pool Capacity Zone in the Forward Capacity Auction.

III.12.5 Transmission Interface Limits.

Transmission interface limits, used in the determination of Local Sourcing Requirements, shall be determined pursuant to ISO Tariff Section II, Attachment K using network models that include all resources, existing transmission lines and proposed transmission lines that the ISO determines, in accordance with Section III.12.6, will be in service no later than the first day of the relevant Capacity Commitment Period. ~~Load modeling assumptions used in determining the transmission interface limits~~

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~~are specified in Section III.12.8. Each target transmission interface limit shall be calculated assuming simultaneous imports from directly connected Control Areas up to the transmission interface limits that may be assumed over the other interfaces. Prior to each Forward Capacity Auction, the ISO shall update the transmission interface limits for each internal and external interface for each upcoming Capacity Commitment Period through the Capacity Commitment Period associated with that Forward Capacity Auction. This update shall take into account any additional transmission projects and elements of transmission projects that are added to the network model pursuant to Section III.12.6.~~ The transmission interface limits shall be established, using deterministic analyses, at levels that provide acceptable thermal, voltage and stability performance of the system both with all lines in service and after any criteria contingency occurs as specified in ISO New England Manuals and ISO New England Administrative Procedures.

III.12.6 Modeling Assumptions for Determining the Network Model.

The ISO shall determine, in accordance with this Section III.12.6, the generating units and transmission infrastructure to include in the network model that: (i) are expected to be in service no later than the first day of the relevant Capacity Commitment Period; and (ii) may have a material impact on the network model, a potential interface constraint, or on one or more Local Sourcing Requirements. The network model shall be used, among other purposes, (i) for the Forward Capacity Market qualification process and (ii) to calculate transmission interface limits in order to forecast the Local Sourcing Requirements. The network model shall include generating units and associated Interconnection Facilities as specified in subsection (a) and Transmission Upgrades as specified in subsection (b).

(a) Generating units and associated Interconnection Facilities that shall be included in the network model for the relevant Capacity Commitment Period shall include:

(i) all existing resources that have not been approved to be retired for the relevant Capacity Commitment Period, as described in Section III.13.2.5.2.5.3;

(ii) all generating units that are resources cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period that have a valid Interconnection Request for which a draft Interconnection System Impact Study report has been submitted to the Interconnection Customer; and

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iii. any generating unit that has a valid Interconnection Request for which a draft Interconnection Feasibility Study report has been submitted to the Interconnection Customer and is reasonably expected to declare commercial operation no later than the first day of the relevant Capacity Commitment Period whether or not such unit is participating in the Forward Capacity Market qualification process.

(b) Prior to each Forward Capacity Auction and each annual reconfiguration auction, the ISO shall determine and publish a list of the transmission projects and elements of transmission projects that will be included in the network model. During the process of making the transmission infrastructure determinations, as described in Section III.12.6.1, the ISO shall consult with the Governance Participants, the Transmission Owners, any transmission project proponents, the state utility regulatory agencies in New England and, as appropriate, other state agencies.

III.12.6.1 Process for Establishing the Network Model

(a) The ISO shall establish an initial network model prior to the Forward Capacity Auction that only includes transmission infrastructure that is already in service at the time that the initial network model is developed.

(b) After establishing the initial network model, the ISO shall compile a preliminary list of the transmission projects or elements of transmission projects in the ~~Transmission Project Listing~~RSP Project List, individually or in combination with each other, as appropriate, to identify transmission projects that may achieve an in-service date no later than the first day of the relevant Capacity Commitment Period and that will have a material impact on the network model, on a potential interface constraint or one or more Local Sourcing Requirements.

(c) For the transmission projects or elements of transmission projects in the ~~Transmission Project Listing~~RSP Project List that are included in the preliminary list developed pursuant to subsection (b), the ISO shall determine whether the transmission projects or elements of transmission projects meet all of the initial threshold milestones specified in Section III.12.6.2 and will be considered for further evaluation pursuant to subsection (d).

(d) For those transmission projects or elements of transmission projects that meet the initial threshold milestones in subsection (c), the ISO shall use the evaluation criteria specified in Section III.12.6.3, and

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any other relevant information, to determine whether to include a transmission project or element of a transmission project in the final network model.

(e) If after completing its evaluation pursuant to Sections III.12.6.1 through III.12.6.3 and conferring with the transmission project proponents, the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies, the ISO determines that the transmission project or a portion of the transmission project is reasonably expected to be in service no later than the first day for the relevant Capacity Commitment Period, then such transmission project or portion of transmission project shall be considered in service in the finalized network model to calculate the transmission interface limits pursuant to Section III.12.5.

III.12.6.2 Initial Threshold to be Considered In-Service.

The ISO shall determine whether transmission projects or elements of transmission projects meet all of the following initial threshold milestones:

(a) A critical path schedule for the transmission project has been furnished to ISO showing that the transmission project or the element of the transmission project will be in-service no later than the first day of the relevant Capacity Commitment Period. The critical path schedule must be sufficiently detailed to allow the ISO to evaluate the feasibility of the schedule.

(b) At the time of the milestone review, siting and permitting processes, if required, are on schedule as shown on the critical path schedule.

(c) At the time of the milestone review, engineering is on schedule as shown on the critical path schedule.

(d) At the time of the milestone review, land acquisition, if required, is on schedule as shown on the critical path schedule.

(e) Corporate intent to build the transmission project has been furnished to the ISO. An officer of the host Transmission Owner has submitted to the ISO a statement verifying that the officer has reviewed the proposal and critical path schedule submitted to the ISO, and the Transmission Owner concurs that the schedule is achievable, and it is the intent of the Transmission Owner to build the proposed transmission project in accordance with that schedule. The Transmission Owner may develop alternatives or modifications to the transmission project during the course of design of the transmission project that

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accomplish at least the same transfer capability. Such alternatives or modifications are acceptable, so long as the ISO determines that the alternative or modification is reasonably expected to achieve an in-service date no later than the first day of the relevant Capacity Commitment Period. The provision of an officer's statement shall be with the understanding that the statement shall not create any liability on the officer and that any liability with respect to the Transmission Owner's obligations shall be as set forth in the Transmission Operating Agreement and shall not be affected by such officer's statement.

III.12.6.3 Evaluation Criteria.

For a transmission project or element of a transmission project that meets the initial threshold milestones specified in Section III.12.6.2, the ISO shall consider the following factors and any other relevant information to determine whether to include the transmission project or element of the transmission project in the network model for the relevant Capacity Commitment Period.

(a) Sufficient engineering to initiate construction is on schedule as shown on the critical path schedule.

(b) Approval under Section I.3.9 of the Transmission, Markets and Services Tariff, if required, has been obtained or is on schedule to be obtained as shown on the critical path schedule.

(c) Significant permits, including local permits, if required to initiate construction have been obtained or are on schedule consistent with the critical path schedule.

(d) Easements, if required, have been obtained or are on schedule consistent with the critical path schedule. Needed land purchases, if required, have been made or are on schedule consistent with the critical path schedule.

(e) Any contracts required to procure or construct a transmission project are in place consistent with the critical path schedule. The ISO's analysis may also take into account whether such contracts contain incentive and/or penalty clauses to encourage third parties to advance the delivery of material services to conform with the critical path schedule.

(f) Physical site work is on schedule consistent with the critical path schedule.

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(g) The transmission project is in a designated National Interest Electric Transmission Corridor in accordance with Section 216 of the Federal Power Act, 16 U.S.C. §§ 824p.

III.12.7 Resource Modeling Assumptions.

III.12.7.1 Proxy Units.

When the available resources are insufficient for the unconstrained New England Control Area to meet the resource adequacy planning criterion specified in Section III.12.1, proxy units shall be used as additional capacity to determine the Installed Capacity Requirement and the Local Resource Adequacy Requirements. The proxy units shall reflect resource capacity and outage characteristics such that when the proxy units are used in place of all other resources in the New England Control Area, the reliability, or LOLE, of the New England Control Area does not change. The outage characteristics are the summer capacity weighted average availability of the resources in the New England Control Area as determined in accordance with Section III.12.7.3. The capacity of the proxy unit is determined by adjusting the capacity of the proxy unit until the LOLE of the New England Control Area is equal to the LOLE calculated while using the capacity assumptions described in Section III.12.7.2.

When modeling transmission constraints for the determination of Local Resource Adequacy Requirements, the same proxy units may be added to the import-constrained ~~Load Zone~~zone or elsewhere in the rest of the New England Control Area depending on where system constraints exist.

III.12.7.2 Capacity.

The resources included in the calculation of the Installed Capacity Requirement and the Local Sourcing Requirements shall include:

(a) all Existing Generating Capacity Resources,

(b) resources cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period,

(c) all Existing Import Capacity Resources backed by a multiyear contract to provide capacity in the New England Control Area, where that multiyear contract requires delivery of capacity for the Commitment Period for which the Installed Capacity Requirement is being calculated, and

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(d) Existing Demand Resources that are qualified to participate in the Forward Capacity Market and New Demand Resources that have cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period,

but shall exclude:

(e) capacity associated with Export Bids cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period, and

(f) resources for which Permanent De-list Bids cleared in previous Forward Capacity Auctions or for which Non-Price Retirement Requests have been received.

The rating of Existing Generating Capacity Resources and Existing Import Capacity Resources used in the calculation of the Installed Capacity Requirement, Local Sourcing Requirements and Maximum Capacity Limits shall be the summer Qualified Capacity value of such resources for the relevant ~~Load Zone~~zone. The rating of Demand Resources shall be the summer Qualified Capacity value reduced by any reserve margin adjustment factor that is otherwise included in the summer Qualified Capacity value. The rating of resources, except for Demand Resources, cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period shall be based on the amount of Qualified Capacity that cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period. Resources are located within the ~~Load~~ Capacity Zones in which they are electrically located as determined during the qualification process.

III.12.7.2.1 [Reserved.]

III.12.7.3 Resource Availability.

The Installed Capacity Requirement and the Local Sourcing Requirements shall be calculated taking resource availability into account and shall be determined as follows:

For Existing Generating Capacity Resources:

(a) The most recent five-year moving average of EFORd shall be used as the measure of resource availability used in the calculation of the Installed Capacity Requirement and the Local Resource Adequacy Requirements. The most recent five-year moving average of EFORd shall be used as the measure of resource availability for non-peaking resources used in the calculation of Transmission Security Analysis Requirements. A deterministic adjustment factor, based on the operational experience

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of the ISO, shall be used as the measure of resource availability for peaking resources used in the calculation of Transmission Security Analysis Requirements, and will be reviewed periodically.

(b) [Reserved.]

(c) Once sufficient data are collected under the availability incentives in the Forward Capacity Market, a resource availability metric, which reflects resource availability in a manner that is consistent with the availability incentives in the Forward Capacity Market, shall be developed and reviewed with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies and used in the calculation of the Installed Capacity Requirement and the Local Sourcing Requirements.

For resources cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period that do not have sufficient data to calculate an availability metric as defined in subsections (a) or (c) above, class average data for similar resource types shall be used. For Demand Resources, including Real-Time Emergency Generation, historical performance data for those resources will be used to develop an availability metric for use in the calculation of the Installed Capacity Requirement and Local Sourcing Requirements.

III.12.7.4 Load and Capacity Relief.

Load and capacity relief expected from system-wide implementation of the following actions during a capacity deficiency (Operating Procedure No. 4) shall be included in the calculation of the Installed Capacity Requirement and the Local Sourcing Requirements. The Installed Capacity Requirements and Local Sourcing Requirements shall reflect the impact of the following actions during a capacity deficiency which are specified in the ISO New England Manuals and ISO New England Administrative Procedures:

(a) **Implement voltage reduction**. The MW value of the load relief shall be equal to the percentage load reduction achieved in the most applicable voltage reduction tests multiplied by the forecasted seasonal peak loads.

(b) **Arrange for available Emergency energy from Market Participants or neighboring Control Areas.** These actions are included in the calculation through the use of tie benefits to meet system needs. The MW value of tie benefits is calculated in accordance with Section III.12.9.

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(c) **Maintain an adequate amount of ten-minute synchronized reserves**. The amount of system reserves included in the Installed Capacity Requirement shall be consistent with those needed for reliable system operations during Emergency Conditions. When modeling transmission constraints, the reserve requirement for a ~~Load Zone~~zone shall be the ~~Load Zone~~zone's pro rata share of the forecasted system peak load multiplied by the system reserves needed for reliable system operations during Emergency Conditions.

III.12.8 Load Modeling Assumptions.

The ISO shall forecast load for the New England Control Area and for each Load Zone within the New England Control Area. The load forecasts shall be based on appropriate models and data inputs. Each year, the load forecasts and underlying methodologies, inputs and assumptions shall be reviewed with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies. If the load forecast shows a consistent bias over time, either high or low, the ISO shall propose adjustments to the load modeling methodology to the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies to eliminate the bias. Demand Resources shall be reflected in the load forecast as specified below:

(a) Expected reductions from an installed or forecast Demand Resource not qualifying for or not participating in the Forward Capacity Auction shall be reflected as a reduction in the load forecast and resultant Installed Capacity Requirement for the relevant Capacity Commitment Period. The expected reduction from these resources will be included in the load forecast to the extent that they meet the qualification process rules, including monitoring and verification plan and financial assurance requirements. If no qualification process rules are in place for the expected reductions from these resources, they shall not be included within the load forecast.

(b) Expected reductions from an installed or forecast Demand Resource that qualifies to participate in the Forward Capacity Market, participates but does not clear in the Forward Capacity Auction, or has cleared in a previous Forward Capacity Auction and is expected to continue in the Forward Capacity Market shall not be reflected as a reduction in the load forecast and the resultant Installed Capacity Requirement for the relevant Capacity Commitment Period.

(c) [Reserved.]

Proposed Modification to Zonal Modeling Trigger

NEPOOL Reliability Committee Meeting

December 17, 2013

On behalf of Exelon Generation

SIGMA CONSULTANTS, INC

Concern

- ISO's proposal to trigger modeling of a zone essentially says "model the zone only if delist of the largest station puts the zone short of requirements."
- Two concerns:
  - There are no provisions to deal with reasonable levels of small, additional delists
    - It is unrealistic to believe that a large station would delist out of a zone, but there would be zero other small delist requests.
  - Zones without a single large station fail to be modeled when delist of several small units could cause a problem
    - Vermont is an example – 52 MW is largest station.

Historic Example

- Some history
  - In FCA-4 the entire Salem Harbor Station requested delist
  - In that same auction, at least 28 other, small projects in NEMA delisted (64 MW total)
  - Under ISO's proposal, if Salem were the largest NEMA station, and NEMA was long only by Salem Harbor's capacity, the zone would not be modeled, *and every one of these 28 delist requests would be rejected for reliability* as necessary to meet an (unmodeled) TSA need.
    - This would significantly disrupt proper functioning of the auction.
    - New capacity that wanted to build inside NEMA would see no signal to do so, and their offers could not be accepted unless they cleared at the Pool-wide price

Another Example

- FCA-8 status
  - EquiPower requested delist of Brayton Point Station.
  - In addition, we know at least 14 other small facilities (101 MW total) also requested NPRs in the SEMARI zone.
  - We don't know how many actual (non-Brayton) delists will be offered in SEMARI, but is seems unrealistic to say 0
  - Under ISO's proposal, if SEMARI was long by only Brayton's capacity, then the zone would not be modeled, all pending delists would be rejected, the other NPRs would be requested to stay for reliability (and potentially be paid under RMR's), and the zone would face reliability problems to the extent those resources left anyway
    - Any retained resources would disrupt proper functioning of the auction.
    - New capacity that wanted to build inside SEMARI would see no price signal to do so, and their offers could not be accepted unless they cleared at the Pool-wide price.

Solution

- Provide an additional buffer to model the zone so as to capture realistic delist requests that will come irrespective of a large station's decision to delist.
- Propose that this buffer be 15% of the LSR
- No downside – if you model the zone and indeed those additional delists don't show up, then there is no price separation, and result is the same as if the zone was not modeled
  - Inverse is not true. Failing to model a zone when you should have can have major disruptive impacts to the market.

Proposed Language

- Using ISO's proposed language:
  - MR1 Section 12.4(b) insert two words:

- (b) The ISO shall model in the Forward Capacity Auction, as separate import-constrained Capacity Zones, those zones identified in the most recent annual assessment of transmission transfer capability pursuant to ISO Tariff Section II, Attachment K, for which the second contingency transmission capability results in a line-line Transmission Security Analysis requirement, calculated pursuant to Section III.12.2.1.2 and pursuant to ISO New England Planning Procedures, that is greater than **85% of the** Existing Qualified Capacity in the zone, with the largest generating station in the zone modeled as out-of-service. Each assessment will model out-of-service all Non-Price Retirement Requests and Permanent De-List Bids as well as rejected for reliability Static De-List Bids from the most recent previous Forward Capacity Auction and rejected for reliability Dynamic De-List Bids from the most recent previous Forward Capacity Auction.

NU Amendment

III.12.4 Capacity Zones.

For each Forward Capacity Auction, the ISO shall, using the results of the most recent annual assessment of transmission transfer capability conducted pursuant to ISO Tariff Section II, Attachment K, determine the Capacity Zones to model as described below, and will include such designations in its filing with the Commission pursuant to Section III.13.8.1:

(a) The ISO shall model in the Forward Capacity Auction, as separate export-constrained Capacity Zones, those zones identified in the most recent annual assessment of transmission transfer capability pursuant to ISO Tariff Section II, Attachment K, for which the Maximum Capacity Limit is less than sum of the existing qualified capacity and proposed new capacity that could qualify to be procured in the export constrained Capacity Zone, including existing and proposed new Import Capacity Resources on the export-constrained side of the interface..

(b) The ISO shall model in the Forward Capacity Auction, as separate import-constrained Capacity Zones, those zones identified in the most recent annual assessment of transmission transfer capability pursuant to ISO Tariff Section II, Attachment K, for which the~~**re is insufficient**~~ second contingency transmission capability **results in a** ~~**to serve the associated**~~ line-line Transmission Security Analysis requirement **times 115%,** calculated pursuant to Section III.12.2.1.2 and pursuant to ISO New England Planning Procedures, ~~**along**~~ **that is greater than the Existing Qualified Capacity in the zone,** ~~with the largest generating station in the zone modeled as out-of-service.~~ Each assessment will model out-of-service all Non-Price Retirement Requests **(including any received for the current FCA at the time of this calculation)** and Permanent De-List Bids as well as rejected for reliability Static De-List Bids from the most recent previous Forward Capacity Auction and rejected for reliability Dynamic De-List Bids from the most recent previous Forward Capacity Auction..

(c) Adjacent Load Zones that are neither export-constrained nor import-constrained shall be modeled together as the Restof-Pool Capacity Zone in the Forward Capacity Auction.

To: Markets, Reliability and Transmission Committee Members and Alternates

From: Gary Will
Massachusetts Municipal Wholesale Electric Company

Date: December 17, 2013

Subject: Import Capacity Zone Modeling

MMWEC is concerned that the calculation for modeling import constrained zones in the FCM proposed by ISO New England, overstates the requirement. ISO proposes that an import constrained zone will be modeled if the N-1-1 import capability < capacity requirement – (zonal capacity – largest station).

We believe the PJM methodology to separately model a zone if there is less than 15% surplus import capability into the zone being tested is sufficient but provide for contingency coverage when a generator contingency or transmission element remains that is greater than 15% of the surplus import capability.

MMWEC Proposal

MMWEC proposes that an import constrained zone will be modeled if the N-1-1 import capability < capacity requirement – (zonal capacity – (the greater of the largest generator or transmission element or 15%).

ISO new england

memo

To: Participants Committee

From: Marc Lyons, Secretary – Reliability Committee

Date: December 17, 2013

Subject: **ACTIONS OF THE RELIABILITY COMMITTEE**

This memo is to notify the Participants Committee ("PC") of the actions taken by the Reliability Committee ("RC") at its Joint RC/TC/MC December 17, 2013 meeting.

(Agenda Item 2.1) Market Rule 1, Section 12 – Capacity Zonal Modeling

Resolved, that the Reliability Committee recommends that the Participants Committee support the revisions to Section III.12 of the New England Transmission, Markets and Services Tariff as proposed by ISO New England Inc as part of its response to the May 31, 2013 order in Docket No. ER12-953-002 and as circulated for the December 17, 2013 Joint Reliability, Transmission and Markets Committees meeting, together with any changes agreed to at the meeting and such non-substantive changes as may be agreed to after the meeting by the Chair and Vice Chair of the Reliability Committee.

The ISO New England main motion was moved and seconded. The following amendments were then put forward:

NRG Power Marketing, LLC ("NRG") reviewed their proposed amendment to MR 1 Section III.12.

A motion to approve the **NRG** amendment to the main motion was moved and seconded. A roll call vote was taken with 47.492% in favor (Generation Sector 20.64% in favor, 0.0% opposed, 2 abstentions; Transmission Sector 4.13% in favor, 16.51% opposed, 0 abstentions; Supplier Sector 13.76% in favor, 6.88% opposed, 7 abstentions; Alternative Resource Sector 8.97% in favor, 8.07% opposed, 5 abstentions; Publicly Owned Sector 0.0% in favor, 20.64% opposed, 0 abstentions; End User Sector 0.0% in favor, 0.41% opposed, 0 abstentions). Motion failed.

Exelon Generation Company ("Exelon") reviewed their proposed amendment to MR 1 Section III.12.

A motion to approve the **Exelon** amendment to the main motion was moved and seconded. A roll call vote was taken with 57.656% in favor (Generation Sector 17.17% in favor, 0.0% opposed, 2 abstentions; Transmission Sector 3.43% in favor, 13.73% opposed, 0 abstentions; Supplier Sector 14.31% in favor, 2.86% opposed, 4 abstentions; Alternative Resource 14.17% in favor, 0.0% opposed, 5 abstentions; Publicly Owned 0.0% in favor, 17.17% opposed, 0 abstentions; End User Sector 8.58% in favor, 8.58% opposed, 1 abstentions). Motion failed.

United Illuminating Company ("UI") reviewed their proposed amendment to MR 1 Section III.12.

ISO New England Inc.
One Sullivan Road, Holyoke, MA 01040-2841
www.iso-ne.com **T** 413 540-4517 **F** 413 535-4343

A motion to approve the **United Illuminating** amendment to the main motion was moved and seconded. A roll call vote was taken with 25.75% in favor (Generation Sector 0.0% in favor, 17.17% opposed, 2 abstentions; Transmission Sector 8.58% in favor, 8.58% opposed, 1 abstentions; Supplier Sector 0.0% in favor, 17.17% opposed, 2 abstentions; Alternative Resource 0.0% in favor, 14.17% opposed, 6 abstentions; Publicly Owned 17.17% in favor, 0.0% opposed, 0 abstentions; End User Sector 0.0% in favor, 17.17% opposed, 3 abstentions). Motion failed.

Northeast Utilities Service Company ("NU") reviewed their proposed amendment to MR 1 Section III.12.

A motion to approve the **NU** amendment to the main motion was moved and seconded. A roll call vote was taken with 30.9% in favor (Generation Sector 0.0% in favor, 17.17% opposed, 2 abstentions; Transmission Sector 13.73% in favor, 3.43% opposed, 0 abstentions; Supplier Sector 0.0% in favor, 17.17% opposed, 2 abstentions; Alternative Resource 0.0% in favor, 14.17% opposed, 6 abstentions; Publicly Owned 17.17% in favor, 0.0% opposed, 7 abstentions; End User Sector 0.0% in favor, 17.17% opposed, 2 abstentions). Motion failed.

Massachusetts Municipal Wholesale Electric Company ("MMWEC") reviewed their proposed amendment to MR 1 Section III.12.

A motion to approve the **MMWEC** amendment to the main motion was moved and seconded. A roll call vote was taken with 34.333% in favor (Generation Sector 0.0% in favor, 17.17% opposed, 1 abstentions; Transmission Sector 17.17% in favor, 0.0% opposed, 1 abstentions; Supplier Sector 0.0% in favor, 17.17% opposed, 2 abstentions; Alternative Resource 0.0% in favor, 14.1% opposed, 6 abstentions; Publicly Owned 17.17% in favor, 0.0% opposed, 0 abstentions; End User Sector 0.0% in favor, 17.17% opposed, 2 abstentions). Motion failed.

The un-amended **ISO-NE** main motion was moved and seconded. A roll call vote was taken with 28.611% in favor (Generation Sector 0.0% in favor, 17.17% opposed, 4 abstentions; Transmission Sector 11.44% in favor, 5.72% opposed, 2 abstentions; Supplier Sector 0.0% in favor, 17.17% opposed, 8 abstentions; Alternative Resource 0.0% in favor, 14.17% opposed, 7 abstentions; Publicly Owned 0.0% in favor, 17.17% opposed, 1 abstentions; End User Sector 17.17% in favor, 0.0% opposed, 1 abstentions). Motion failed.

ATTACHMENT K
REGIONAL SYSTEM PLANNING PROCESS

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2.5 Local System Planning Process

The LSP process described in Appendix 1 to this Attachment applies to the transmission system planning for the Non-PTF in the New England Transmission System. The PTOs will utilize interested members of the Planning Advisory Committee for advisory stakeholder input in the LSP process that will meet, as needed, at the conclusion of, or independent of, scheduled Planning Advisory Committee meetings. The LSP meeting agenda and meeting materials will be developed by representatives of the pertinent PTOs and PTO representatives will chair the LSP meeting. The ISO will post the LSP agenda and materials for LSP.

3. RSP: Principles, Scope, and Contents

3.1 Description of RSP

The ISO shall develop the RSP based on periodic comprehensive assessments (conducted not less than every third year) of the PTF systemwide needs to maintain the reliability of the New England Transmission System while accounting for market efficiency, economic, environmental and other considerations, as agreed upon from time to time. The ISO shall update the RSP to reflect the results of ongoing Needs Assessments conducted pursuant to Section 4.1 of this Attachment. The RSP shall also account for projected improvements to the PTF that are needed to maintain system reliability in accordance with national and regional standards and the operation of efficient markets under a set of planning assumptions.

The RSP shall, among other things:

(i) describe, in a consolidated manner, the assessment of the PTF system needs, the results of such assessments, and the projected improvements;

(ii) provide the projected annual and peak demands for electric energy for a five-to ten-year horizon, the needs for resources over this period and how such resources are expected to be provided;

(iii) specify the physical characteristics of the physical solutions that can meet the needs defined in the Needs Assessments and include information on market responses that can address them; and

(iv) provide sufficient information to allow Market Participants to assess the quantity, general locations, operating characteristics and required availability criteria of the type of incremental supply or demand-side resources, or merchant transmission projects, that

would satisfy the identified needs or that may serve to modify, offset or defer proposed regulated transmission upgrades.

The RSP shall also include a description of proposed regulated transmission solutions that, based on the Solutions Studies described in Section 4.2 of this Attachment, may meet the needs identified in the Needs Assessments. To this end, as further described in Section 3.6 below, the ISO shall develop and maintain a RSP Project List, a cumulative listing of proposed regulated transmission solutions classified, to the extent known, as Reliability Transmission Upgrades and Market Efficiency Transmission Upgrades that may meet those needs. The RSP shall also provide reasons for any new regulated transmission solutions or Transmission Upgrades included in the RSP Project List, any change in status of a regulated transmission solution or Transmission Upgrade in the RSP Project List, or for any removal of regulated transmission solutions or Transmission Upgrades from the RSP Project List that are known as of that time.

The RSP shall also include the results of the annual assessment of transmission transfer capability, conducted pursuant to applicable NERC, NPCC and ISO New England standards and criteria and the identification of potential future transmission system weaknesses and limiting facilities that could impact the transmission system's ability to reliably transfer energy in the planning horizon. Each annual assessment will identify those portions of the New England system, along with the associated interface boundaries, that should be considered in the assessment of Capacity Zones to be modeled in the Forward Capacity Market pursuant to ISO Tariff Section III.12. Each annual assessment will model out-of-service all Non-Price Retirement Requests and Permanent De-List Bids as well as rejected for reliability Static De-List Bids and rejected for reliability Dynamic De-List Bids from the most recent Forward Capacity Auction.

Each RSP shall be built upon the previous year's RSP.

3.2 Baseline of RSP

The RSP shall account for: (i) all projects that have met milestones, including market responses and regulated transmission solutions (e.g., planned demand-side projects, generation and transmission projects, Merchant Transmission Facilities, and Elective Transmission Upgrades) as determined by the ISO, in collaboration with the Planning Advisory Committee, pursuant to Sections 4.1 and 4.2 of this Attachment; and (ii) the requirements for system operation and restoration services, not including the development of a system operations or restoration plan, which is outside the scope of the regional system planning process.

NRG Redlines to Attachment K for Capacity Zones highlighted in yellow

ATTACHMENT K
REGIONAL SYSTEM PLANNING PROCESS

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NRG Redlines to Attachment K for Capacity Zones highlighted in yellow

Commission pursuant to the Commission's regulations governing access to CEII. To the extent a requestor seeks access to planning-related material that is not filed with the Commission, such requestor shall comply with the requirements provided in the CEII procedures of the ISO, available on the ISO's website, prior to receiving access to CEII information. Upon compliance with the ISO's CEII procedures, the ISO shall grant the requestor access to the planning-related CEII document through direct distribution or access to the ISO password-protected website.

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The LSP process described in Appendix 1 to this Attachment applies to the transmission system planning for the Non-PTF in the New England Transmission System. The PTOs will utilize interested members of the Planning Advisory Committee for advisory stakeholder input in the LSP process that will meet, as needed, at the conclusion of, or independent of, scheduled Planning Advisory Committee meetings. The LSP meeting agenda and meeting materials will be developed by representatives of the pertinent PTOs and PTO representatives will chair the LSP meeting. The ISO will post the LSP agenda and materials for LSP.

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The ISO shall develop the RSP based on periodic comprehensive assessments (conducted not less than every third year) of the PTF systemwide needs to maintain the reliability of the New England Transmission System while accounting for market efficiency, economic, environmental and other considerations, as agreed upon from time to time. The ISO shall update the RSP to reflect the results of ongoing Needs Assessments conducted pursuant to Section 4.1 of this Attachment. The RSP shall also account for projected improvements to the PTF that are needed to maintain system reliability in accordance with national and regional standards and the operation of efficient markets under a set of planning assumptions.

The RSP shall, among other things:

(i) describe, in a consolidated manner, the assessment of the PTF system needs, the results of such assessments, and the projected improvements;

(ii) provide the projected annual and peak demands for electric energy for a five-to ten-year horizon, the needs for resources over this period and how such resources are expected to be provided;

NRG Redlines to Attachment K for Capacity Zones highlighted in yellow

(iii) specify the physical characteristics of the physical solutions that can meet the needs defined in the Needs Assessments and include information on market responses that can address them; and

(iv) provide sufficient information to allow Market Participants to assess the quantity, general locations, operating characteristics and required availability criteria of the type of incremental supply or demand-side resources, or merchant transmission projects, that would satisfy the identified needs or that may serve to modify, offset or defer proposed regulated transmission upgrades.

The RSP shall also include a description of proposed regulated transmission solutions that, based on the Solutions Studies described in Section 4.2 of this Attachment, may meet the needs identified in the Needs Assessments. To this end, as further described in Section 3.6 below, the ISO shall develop and maintain a RSP Project List, a cumulative listing of proposed regulated transmission solutions classified, to the extent known, as Reliability Transmission Upgrades and Market Efficiency Transmission Upgrades that may meet those needs. The RSP shall also provide reasons for any new regulated transmission solutions or Transmission Upgrades included in the RSP Project List, any change in status of a regulated transmission solution or Transmission Upgrade in the RSP Project List, or for any removal of regulated transmission solutions or Transmission Upgrades from the RSP Project List that are known as of that time.

The RSP shall also include the results of the annual assessment of transmission transfer capability, conducted pursuant to applicable NERC, NPCC and ISO New England standards and criteria and the identification of potential future transmission system weaknesses and limiting facilities that could impact the transmission system's ability to reliably transfer energy in the planning horizon. Each annual assessment will identify those portions of the New England system, along with the associated interface boundaries, that should be ~~considered in the assessment of~~modeled as Capacity Zones ~~to be modeled~~ in the Forward Capacity Market pursuant to ISO Tariff Section III.12. Each annual assessment will model out-of-service all Non-Price Retirement Requests, ~~and~~ Permanent De-List Bids, ~~as well as rejected for reliability~~ Static De-List Bids and ~~rejected for reliability~~ Dynamic De-List Bids ~~from the most recent~~ submitted in any previous Forward Capacity Auction plus, to the extent not the subject of a Non-Price

NRG Redlines to Attachment K for Capacity Zones highlighted in yellow

Retirement Request, Permanent De-List Bid, Static De-List Bid or Dynamic De-List Bid, all resources considered by ISO-NE to be 'at risk,' including but not limited to:

i) resources potentially subject to major capital expenditures to comply with existing or anticipated environmental regulations,

ii) resources greater than twenty years old, and

iii) non-quick-start resources with low capacity factors.

Any rejected Non-Price Retirement Request, Permanent De-List Bid, Static De-List Bid or Dynamic De-List Bid from the most recent Forward Capacity Auction shall result in the definition of an interface to be modeled in future Forward Capacity Auctions unless ISO determines that an additional interface would have an adverse impact on the reliability of the system or the efficiency of the Forward Capacity Market, and provides a detailed explanation of that determination in the stakeholder discussions pursuant to Section III.12 and in its filing with the Commission pursuant to Section III.13.8.1.

Each RSP shall be built upon the previous year's RSP.

3.2 Baseline of RSP

The RSP shall account for: (i) all projects that have met milestones, including market responses and regulated transmission solutions (e.g., planned demand-side projects, generation and transmission projects, Merchant Transmission Facilities, and Elective Transmission Upgrades) as determined by the ISO, in collaboration with the Planning Advisory Committee, pursuant to Sections 4.1 and 4.2 of this Attachment; and (ii) the requirements for system operation and restoration services, not including the development of a system operations or restoration plan, which is outside the scope of the regional system planning process.

3.3 RSP Planning Horizon and Parameters

The RSP shall be based on a five-to ten-year planning horizon, and reflect five-to ten-year capacity and load forecasts.

The RSP shall conform to: Good Utility Practice; applicable Commission compliance requirements related to the regional system planning process; applicable reliability principles, guidelines, criteria, rules, procedures and standards of the ERO, NPCC, and any of their successors; planning criteria adopted and/or developed by the ISO; Transmission Owner criteria, rules, standards, guides and policies developed by the Transmission Owner for its facilities consistent with the ISO planning criteria, the applicable criteria of the

ISO new england

memo

To: NEPOOL Participants Committee

From: Erin Wasik-Gutierrez, Secretary
NEPOOL Transmission Committee

Date: December 18, 2013

Subject: **ACTIONS OF THE TRANSMISSION COMMITTEE**

This memo serves as notification to the Participants Committee (PC) of the actions taken by the Transmission Committee at the Joint RC/ TC/ MC December 17, 2013 meeting. The following actions were taken, with oppositions and abstentions noted:

Agenda Item No. 2.2: Attachment K to Section II of the ISO New England Transmission, Market and Services Tariff – Capacity Zone Modeling

The Main Motion for Attachment K Revisions was moved and seconded:

Resolved, that the Transmission Committee recommends that the Participants Committee support the revisions to Attachment K to Section II of the ISO New England Transmission, Markets and Services Tariff as proposed by ISO New England Inc. as part of its response to the May 31, 2013 order in Docket No. ER12-953-002 and as circulated for the December 17, 2013 Joint Reliability, Transmission and Markets Committees meeting, together with any changes agreed to at the meeting and such non-substantive changes as may be agreed to after the meeting by the Chair and Vice Chair of the Transmission Committee.

NRG Power Marketing, LLC Motion to Amend the Main Motion was reviewed, moved and seconded:

NRG Power Marketing, LLC's motion to amend the main motion failed based on a roll call vote with a vote of 51.36% in favor. The individual Sector votes were Generation (17.17% in favor, none ("0%") opposed and two ("2") abstentions), Transmission (2.86% in favor, 14.31% opposed and no ("0") abstentions), Supplier (17.17% in favor, none ("0%") opposed and seven ("7") abstentions), Publicly Owned (none ("0%") in favor, 17.17% opposed and no ("0") abstentions) and End User (none "0%" in favor, 17.17% opposed and one ("1") abstention), Alternative Resource (14.17% in favor, none ("0%") opposed and eight ("8") abstentions).

The United Illuminating Company Motion to Amend the Main Motion was reviewed, Moved and seconded:

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The United Illuminating Company's motion to amend the main motion failed based on a roll call vote with a vote of 30.04% in favor. The individual Sector votes were Generation (none ("0%") in favor, 17.17% opposed and two ("2") abstentions), Transmission (12.87% in favor, 4.29% opposed and two ("2") abstentions), Supplier (none ("0%") in favor, 17.17% opposed and three ("3") abstentions), Publicly Owned (17.17% in favor, none ("0%") opposed and no ("0") abstentions) and End User (none ("0%") in favor, 17.17% opposed and three ("3") abstentions), Alternative Resource (none ("0%") in favor, 14.17% opposed and eight ("8") abstentions).

The Main Motion was voted:

ISO-NE's main motion failed based on a roll call vote with a vote of 42.92% in favor. The individual Sector votes were Generation (none ("0%") in favor, 17.17% opposed and six ("6") abstentions), Transmission (8.58% in favor, 8.58% opposed and four ("4") abstentions), Supplier (none ("0%") in favor, 17.17% opposed and eight ("8") abstentions), Publicly Owned (17.17% in favor, none ("0%") opposed and no ("0") abstentions) and End User (17.17% in favor, none ("0%") opposed and one ("1") abstention), Alternative Resource (none ("0%") in favor, 14.17% opposed and nine ("9") abstentions).

NRG Proposed Amendment in this color

III.13.5. Bilateral Contracts in the Forward Capacity Market.

Market Participants shall be permitted to enter into Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals and Supplemental Availability Bilaterals in accordance with this Section III.13.5, with the ISO serving as Counterparty in each such transaction. Market Participants may not offset a Capacity Load Obligation with a Capacity Supply Obligation.

III.13.5.1. Capacity Supply Obligation Bilaterals.

A resource having a Capacity Supply Obligation seeking to shed that obligation ("Capacity Transferring Resource") may enter into a bilateral transaction to transfer its Capacity Supply Obligation, in whole or in part ("Capacity Supply Obligation Bilateral"), to a resource, or portion thereof, having Qualified Capacity for that Capacity Commitment Period that is not already obligated ("Capacity Acquiring Resource"), subject to the following limitations

(a) A monthly Capacity Supply Obligation Bilateral must be coterminous with a calendar month, and an annual Capacity Supply Obligation Bilateral must be coterminous with a Capacity Commitment Period.

(b) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the lowest monthly Capacity Supply Obligation of the Capacity Transferring Resource during the period covered by the Capacity Supply Obligation Bilateral. A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation amount that is greater than the lowest monthly amount of unobligated Qualified Capacity (that is, Qualified Capacity as determined in the most recent Forward Capacity Auction or reconfiguration auction qualification process that is not subject to a Capacity Supply Obligation for the relevant time period) of the Capacity Acquiring Resource during the period covered by the Capacity Supply Obligation Bilateral, as determined in the qualification process for the most recent Forward Capacity Auction or annual reconfiguration auction prior to the submission of the Capacity Supply Obligation Bilateral to the ISO.

(c) A Capacity Supply Obligation Bilateral may not transfer a Capacity Supply Obligation to a Capacity Acquiring Resource where that Capacity Acquiring Resource's unobligated Qualified Capacity is unobligated as a result of an Export Bid or Administrative Export De-List Bid that cleared in the Forward Capacity Auction.

NRG Proposed Amendment in this color

(d) A Real-Time Emergency Generation Resource may participate in a Capacity Supply Obligation Bilateral as either a Capacity Transferring Resource or a Capacity Acquiring Resource, provided, however, that where a Real-Time Emergency Generation Resource participates in a Capacity Supply Obligation Bilateral as a Capacity Acquiring Resource, the Capacity Transferring Resource must also be a Real-Time Emergency Generation Resource.

(e) [Reserved.]

(f) [Reserved.] ~~The Capacity Transferring Resource and the Capacity Acquiring Resource that are parties to a Capacity Supply Obligation Bilateral must be located in the same Capacity Zone, or the path from the Capacity Transferring Resource to the Capacity Acquiring Resource must flow across adjacent Capacity Zones in the direction of the modeled interface constraint(s), as such Capacity Zones and interface constraints are defined following the Forward Capacity Auction conducted for the Capacity Commitment Period to which the transferred Capacity Supply Obligation applies.~~

(g) If the Capacity Acquiring Resource is an Import Capacity Resource, then the Capacity Transferring Resource must also be an Import Capacity Resource on the same external interface.

(h) A resource, or a portion thereof, that has been designated as a Self-Supplied FCA Resource may transfer the self-supplied portion of its Capacity Supply Obligation by means of Capacity Supply Obligation Bilateral. In such a case, however, the Capacity Acquiring Resource shall not become a Self-Supplied FCA Resource as a result of the transaction.

(i) A monthly Capacity Supply Obligation may not be acquired by any resource on an approved outage for the relevant Capacity Commitment Period month.

(j) A resource that has not achieved Commercial Operation by the submission deadline for a monthly Capacity Supply Obligation Bilateral may not submit a transaction as a Capacity Acquiring Resource for that Capacity Commitment Period month, unless the resource has a negative Capacity Supply Obligation, in which case it may submit a Capacity Supply Obligation Bilateral in an amount up to the absolute value of its Capacity Supply Obligation.

III.13.5.1.1. Process for Approval of Capacity Supply Obligation Bilaterals.

NRG Proposed Amendment in this color

III.13.5.1.1.1. Timing.

The Lead Market Participant or Project Sponsor for either the Capacity Transferring Resource or the Capacity Acquiring Resource may submit a Capacity Supply Obligation Bilateral to the ISO during submittal windows, as defined in the ISO New England Manuals and ISO New England Operating Procedures. The ISO will issue a submission schedule for annual Capacity Supply Obligation Bilaterals as soon as practicable after the issuance of Forward Capacity Auction results. Monthly Capacity Supply Obligation Bilaterals may only be submitted and confirmed after the results of the third annual reconfiguration auction have been issued (except as described in Section III.13.4.2.1.3(c)) and prior to the closing of the monthly Capacity Supply Obligation Bilateral window, which will occur prior to the monthly reconfiguration auction. ISO New England will review all confirmed monthly Capacity Supply Obligation Bilaterals for each upcoming Obligation Month for reliability needs immediately preceding the monthly reconfiguration auction. A Capacity Supply Obligation Bilateral must be confirmed by the party other than the party submitting the Capacity Supply Obligation Bilateral to the ISO during the same submittal window and no later than the same deadline that applies to submission of the Capacity Supply Obligation Bilateral.

III.13.5.1.1.2. Application.

The submission of a Capacity Supply Obligation Bilateral to the ISO shall include the following: (i) the resource identification number of the Capacity Transferring Resource; (ii) the amount of the Capacity Supply Obligation being transferred in MW amounts up to three decimal places; (iii) the term of the transaction; and (iv) the resource identification number of the Capacity Acquiring Resource. If the parties to a Capacity Supply Obligation Bilateral so choose, they may also submit a price, in $/kW-month, to be used by the ISO in settling the Capacity Supply Obligation Bilateral. If no price is submitted, the ISO shall use a default price of $0.00/kW-month.

III.13.5.1.1.3. ISO Review.

(a) The ISO shall review the information provided in support of the Capacity Supply Obligation Bilateral, and shall reject the Capacity Supply Obligation Bilateral if any of the provisions of this Section III.13.5.1 are not met.

(b) Each Capacity Supply Obligation Bilateral shall be subject to a reliability review by the ISO to determine whether the transaction would result in a violation of any NERC or NPCC (or their successors) criteria, or ISO New England System Rules, during the Capacity Commitment Period associated with the transaction. Capacity Supply Obligation Bilaterals shall be reviewed by the ISO to ensure the regional and

NRG Proposed Amendment in this color

local adequacy achieved through the Forward Capacity Auction and other reliability needs are maintained. The ISO's review will consider the location and operating and rating limitations of resources associated with the Capacity Supply Obligation Bilateral to ensure reliability standards and Capacity Zone interface limits will remain satisfied if the capacity associated with the Capacity Transferring Resource is withdrawn and the capacity associated with the Capacity Acquiring Resource is accepted. The ISO's reliability reviews will assess transactions based on operable capacity needs while considering any approved or interim approved transmission outage information and any approved generation or Demand Response Resource outage information, and will include transmission security studies. For a monthly Capacity Supply Obligation Bilateral, the ISO shall obtain and consider information from the Local Control Center regarding whether the Capacity Supply Obligation of the Capacity Transferring Resource is needed for local system conditions and whether it is adequately replaced by the Acquiring Resource. The ISO will approve or reject Capacity Supply Obligation Bilaterals based on the order in which they are confirmed. If multiple Capacity Supply Obligation Bilaterals are submitted between the same resources, they may be reviewed together as one transaction and the most recent confirmation time among the related transactions will be used to determine the review order of the grouped transaction. Transactions that cannot meet the applicable reliability needs will only be accepted or rejected in their entirety and the resources will not be accepted or rejected in part for purposes of that transaction. Where the ISO has determined that a Capacity Supply Obligation Bilateral must be rejected for reliability reasons the Lead Market Participant or Project Sponsor, as appropriate, for the Capacity Transferring Resource and the Capacity Acquiring Resource shall be notified as soon as practicable of the rejection and of the reliability need prompting such rejection.

(c) Each Capacity Supply Obligation Bilateral shall be subject to a financial assurance review by the ISO. If the Capacity Transferring Resource and the Capacity Acquiring Resource are not both in compliance with all applicable provisions of the ISO New England Financial Assurance Policy, including those regarding Capacity Supply Obligation Bilaterals, the ISO shall reject the Capacity Supply Obligation Bilateral.

III.13.5.1.1.4. Approval.

Upon approval of a Capacity Supply Obligation Bilateral, the Capacity Supply Obligation of the Capacity Transferring Resource shall be reduced by the amount set forth in the Capacity Supply Obligation Bilateral, and the Capacity Supply Obligation of the Capacity Acquiring Resource shall be increased by the amount set forth in the Capacity Supply Obligation Bilateral.

Capacity Market Zones and Related MR1 and Tariff Changes

Pete Fuller
NEPOOL Markets Committee/Reliability Committee/Transmission Committee
December, 2013

Today's Discussion

- Proposal for complying with FERC Orders to 'model all zones all the time'
- Proposed changes to:
  - Attachment K, Sec 3.1 (TC)
  - MR1, Section 12 (RC)
  - MR1, Section 13.5.1 (MC)

Qualifier

- As currently structured and administered, FCM is deeply flawed:
  - Mitigation policies should provide the marginal existing resource a reasonable opportunity to recover all of its annual fixed costs
  - A demand curve that recognizes the incremental value of additional capacity is essential, especially in the absence of a supply curve based on long-run costs
  - Reliability reviews of existing resource offers (delist bids) should be eliminated; all constraints that are to be enforced through planning or operability criteria should be specified in the auction requirements

FERC Proceedings on Capacity Zones

- In the April 13, 2011 Order on Paper Hearing, FERC approved:
  - "ISO-NE's proposal to use the eight energy load zones as initial capacity zones. …we see no reason to further delay the modeling of all zones all the time." (P.272)
  - "ISO-NE's proposal to develop any future zones through ISO-NE's system planning stakeholder process." (P.283)
  - "ISO-NE's proposal to allow static and dynamic de-list bids from all resources to establish zonal prices." (P.290)
  - "ISO-NE's approach of reviewing … rejected de-list bids in the zonal development process for subsequent FCAs to determine if additional zones are needed" (P.292)
  - "changes to the clearing mechanism used in ISO-NE's descending clock auction structure [similar to a locational marginal pricing (LMP) clearing mechanism … recognizing bi-directional and mesh network constraints]" (P.293, 297)

- In the 1/19/12 Order on Rehearing, FERC approved and affirmed:
  - "we maintain that ISO-NE's proposal to model all zones all the time is appropriate" (P.107)
  - "We are … not persuaded by arguments that modeling zones is inappropriate in instances in which small zones may develop in highly congested urban and suburban areas." (P.108)
  - With respect to the treatment of rejected delist bids, "[t]he better solution is to establish more zones. While ISO-NE has stated that it would be burdensome to model additional zones in the current auction in which a de-list bid is rejected, ISO-NE has indicated that it is amenable to developing additional zones for subsequent FCAs." (P.109)

- In the 2/12/13 Order on the Compliance Filing, FERC found:
  - "We deny ISO-NE's request to waive the Commission's prior directive that ISO-NE model eight zones for FCA 8" (P.117)
    - "this does not preclude ISO-NE from making an additional filing providing adequate support for the modeling of fewer than eight zones in FCA 8" (P.117)
  - "We recognize that the reduction in constraints to which Mr. Rourke refers may justify future zonal modeling with fewer than eight zones. Alternatively, binding constraints and local reliability problems that prove intractable, or that are not present now but arise in the future, may dictate an even larger number of zones." (P.122)

- Summing it all up in the 5/31/13 Order, the FERC noted:
  - "As relevant here, the FCM design incorporates locational pricing, in which capacity zones are modeled in order to permit zonal price separation when binding constraints arise." (P.3)
  - "The Commission remains concerned, however, that despite having addressed zonal issues since 2010, ISO-NE has not developed an adequate process for determining the appropriate number of, and boundaries of, capacity zones in the New England region over time as conditions change." (P.35)
  - "we will require ISO-NE to consider during that process: (1) the appropriate level of zonal modeling going forward; (2) the appropriate rules to govern intra- and inter-zonal transactions; and (3) whether objective criteria by which zones may automatically be created in response to rejected delist bids, generation retirements or other changes in system conditions would be appropriate in New England, or if not, why not." (P.35)

Comparison

1) "The appropriate level of zonal modeling going forward"

ISO Proposal	NRG Proposal
Develop interfaces defining the boundaries of zones through PAC/planning process, considering NPRR, PDB and rejected SDB and DDB, from the most recent FCA	Develop interfaces defining the boundaries of zones through PAC/planning process, considering all NPRR, PDB, SDB and DDB, submitted in all previous FCAs, plus 'at risk' resources
"trigger" for modeling zones in each FCA	Model all zones all the time
No change to auction clearing methodology	Explicitly plan for bi-directional and mesh network constraints

2) "appropriate rules to govern intra- and inter-zonal transactions"

ISO Proposal	NRG Proposal
No change proposed	Eliminate restriction limiting capacity transactions to within the same zone (13.5.1(f))

Comparison

3) "Automatic creation of zones in response to rejected delist bids, retirements or other changes"

ISO Proposal	NRG Proposal
Develop interfaces defining the boundaries of zones through PAC/planning process	Rejected delist bid in FCA(n) requires definition of a zonal interface in FCA(n+1); or detailed explanation why an interface would harm the market

Roadmap

- The key purpose of modeling zones is to reflect binding constraints 'when they arise'
  - The constraints must all be modeled in order to show up as binding within an auction
- The goal of defining capacity zones should be to identify the interfaces that <u>might</u> bind if the generation/DR mix changes
  - SEMA is a case in point. Recently, ISO was suggesting SEMA as export-constrained. A large retirement can change everything.
- Bilateral trading of capacity lowers suppliers' risk, leading to lower overall costs in the market
  - Reconfiguration auctions would continue to be available after the bilateral trading period

NRG Proposal

- Zones for FCA9:
  - Model eight load zone interfaces, plus any others developed through the planning process, 'all the time'
  - Designate zones as import or export based on the balance of existing resources vs. TSA, including all delists/retirements (or MCL, including new resources likely to qualify)
- Zones for FCA10 and beyond:
  - Refresh the list of interfaces through the planning process
  - Model all zones all the time
- As soon as possible, revise the auction to handle bi-directional and mesh network constraints
- Capacity Bilaterals:
  - Along with modeling all zones all the time, eliminate restriction on bilateral trades between zones (III.13.5.1(f))
  - Add 'Capacity Zone interface limits' to criteria ISO must honor in their reliability review of capacity bilaterals

Proposed Tariff Language

- Accompanying tariff language for:
  - Attachment K, Section 3.1
  - Market Rule 1, Section 12.4 and new Section 12.4A
  - Market Rule 1, Section 13.5.1 and Section 13.5.1.1.3

Comments and suggestions are welcome prior to the Committee votes.

Thanks for your consideration.

ISO new england

memo

To: Participants Committee

From: Alex Kuznecow, Secretary, Markets Committee

Date: December 17, 2013

Subject: **ACTIONS OF THE MARKETS COMMITTEE**

This memo is notification to the Participants Committee (PC) of the following actions taken by the Markets Committee (MC) at the December 17, 2013 Joint RC/TC/MC meeting. All Sectors had a quorum.

1. (Agenda Item 2.3) **CAPACITY ZONE MODELING**
(NRG's proposed revisions to Section III.13 of Market Rule 1)
ACTION: RECOMMEND SUPPORT

The following motion was moved and seconded by the Markets Committee:

> RESOLVED, that the Markets Committee recommends that the Participants Committee support the revisions to Section III.13 of Market Rule 1 to eliminate the restriction on Capacity Supply Obligation ("CSO") bilateral trades between zones and to add Capacity Zone interface limits to criteria the ISO must honor in their reliability review of CSO bilaterals as proposed by NRG Power Marketing, LLC ("NRG") and as circulated for this meeting together with any changes agreed to at the meeting and such further non-substantive changes as the Chair and Vice-Chair approve.

The motion was then voted. The motion passed with a vote of 74.25% in favor. The individual Sector votes were Generation (17.17% in favor, 0% opposed, 5 abstentions), Transmission (0% in favor, 17.17% opposed, 4 abstentions), Supplier (17.17% in favor, 0% opposed, 12.3 abstentions), Alternative Resources (14.17% in favor, 0% opposed, 2 abstentions), Publicly Owned Entity (17.17% in favor, 0% opposed, 27 abstentions), and End User (8.58% in favor, 8.59% opposed, 3 abstentions).

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Pat Gerity, NEPOOL Counsel

DATE: January 8, 2014

RE: FCM PI Jump Ball Filing Schedule – Additional Time (5 Days) to be Requested for Initial Comments on the Filings

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We write to provide you with a further update as to the proposed schedule for the upcoming Jump Ball filings with respect to Market Rule changes to improve performance incentives for capacity resources (FCM PI). In order to allow interested parties extra time to provide their comments on the filings beyond the February 7, 2014 comment date the FERC will otherwise provide, ISO and NEPOOL counsel plan to file a joint request to extend that comment date to February 12. If granted, all interested entities would have until then to file comments on or protests to the January 17 Jump Ball filings. We intend to indicate in that joint motion that the Participants Committee members and alternates have all been advised of the proposed extension and were requested to raise any concerns ahead of our filing. We will advise the FERC of any concerns with the proposed extension that we receive, and if we receive none, will so advise the FERC of that fact as well.

Accordingly, if you have any concerns with the planned request for a February 12 comment date on the FCM PI Jump Ball filings to be submitted on January 17, please let Ray Hepper, me (860-275-0533; pmgerity@daypitney.com), or any other NEPOOL counsel know before close of business next Wednesday, January 15.

Many thanks.

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings as of January 8, 2014

The following activity, as more fully described in the attached litigation report, has occurred since the report dated December 4, 2013 was circulated. New matters/proceedings since the last report are preceded by an asterisk '*'. Page numbers precede the matter description.

I. Complaints

*	1	NEPGA FCA8 NPRR Complaint (EL14-17)	Jan 8	NEPGA files complaint, requesting 13-day comment period (ending Jan 21) and FERC order by Jan 27 either addressing the merits of its complaint or delaying FCA8 to Mar 24 to allow for a FERC order by Mar 17; NEPOOL intervenes
	1	FCM Administrative Pricing Rules Complaint (EL14-7)	Dec 16	NEPGA, NextEra answer ISO's Nov 27 Answer; Energy New England and Participating Municipal Systems submit comments opposing Complaint; EPSA submits comments supporting Complaint
			Dec 31	NESCOE files answer to NEPGA Dec 16 Answer
	2	NEPGA Resource Performance Obligations Complaint (EL13-66)	Dec 6	FERC denies rehearing but grants clarification requested of Aug 27, 2013 *NEPGA Order*

II. Rate, ICR, FCA, Cost Recovery Filings

	4	ICR-Related Values and HQICCs - 2014/2015 ARA3, 2015/2016 ARA2, 2016/2017 ARA1 (ER14-510)	Dec 18-20	Exelon, NRG, NU intervene
	5	FCA8 Qualification Informational Filing (ER14-329)	Dec 6	ISO files answer to NEPGA comments, PSEG and Exelon protests
			Dec 23	Exelon, PSEG respond to ISO Dec 6 answer
			Dec 27	FERC grants waiver of QDN deadlines requested by NGrid, Blue Sky West, Brookfield, and CSG
	5	ICR, HQICCs and Related Values - 2017/2018 Power Year (ER14-328)	Dec 30	FERC accepts 2017/2018 Capability Year ICR, HQICCs and related values
	6	2014 ISO-NE Administrative Costs and Capital Budgets (ER14-90)	Dec 19	FERC accepts ISO 2014 Budgets

III. Market Rule and Information Policy Changes, Interpretations and Waiver Requests

*	8	Demand Response Baseline Changes (ER14-727)	Dec 20	ISO and NEPOOL jointly file changes; comment date Jan 10
			Jan 7-9	Exelon, NRG, NU intervene
*	8	eTariff Corrections: Section III.13.5 (ER14-713)	Dec 19	ISO files conforming corrections to eTariff; comment date Jan 9
			Dec 27	NEPOOL intervenes
			Jan 7	ISO files amendment to correct tariff record; comment date Jan 17
*	8	Dual-Fuel Switching Provisions Move to Market Rule 1 (ER14-707)	Dec 19	ISO and NEPOOL jointly file changes that move existing dual-fuel switching provisions from Appendix K to Market Rule 1
			Jan 7	Exelon, NRG intervene
*	8	FCM Offer Review Trigger Price Revisions (ER14-616)	Dec 13	ISO files ORTP Changes
			Dec 18	NEPGA requests extension of comment date to Jan 8, 2014
			Dec 26	FERC grants extension of comment date requested by NEPGA
			Dec 18-Jan 8	Brookfield, Deepwater Wind, Dominion, PSEG, NRG, NU, UI intervene
			Jan 3-8	NEPOOL, First Wind, NESCOE submit comments; EMCOS, EnerNOC, Exelon, National Grid, NEPGA/EPSA, NextEra, Protesting Parties, NH PUC protest filing

*	9	LSCPR Cost Allocation Changes (ER14-584)	Dec 9 Dec 18-27	ISO and NEPOOL jointly file changes Exelon, NRG, NU intervene
*	9	Demand Resource Commercial Operation Auditing Revisions (ER14-581)	Dec 9 Dec 18-30	ISO and NEPOOL jointly file changes CMEEC, Exelon, NU intervene
	9	Exigent Circumstances Filing – FCM Admin. Pricing Rules (ER14-463)	Dec 5-16 Dec 16 Jan 6	MPUC, HQUS, ConEd, NRG, Exelon, Verso, Calpine intervene NEPOOL, EPSA, NICC, Public Systems submit comments; Connecticut, ENE and Participating Municipals, GDF Suez, MA AG, MA DPU, NECPUC, NESCOE, NextEra, NU and UI, and PSEG submit protests. Dominion intervenes out-of-time
	10	Waiver Request - Capacity Qualification Deadlines: Brookfield (ER14-442)	Dec 12 Dec 13 Dec 27	ISO submits comments indicating it does not oppose request; NEPOOL intervenes FERC grants requested waiver
	10	Waiver Request - Capacity Qualification Deadlines: Blue Sky West (ER14-364)	Dec 27	FERC grants Blue Sky West waiver request
	10	Waiver Request - Capacity Qualification Deadlines: CSG (ER14-356)	Dec 27	FERC grants CSG waiver request
	11	Waiver Request - Capacity Qualification Deadlines: National Grid (ER14-311)	Dec 27	FERC grants National Grid waiver request
	11	CSO Termination: Pawtucket (ER14-270)	Dec 23	FERC accepts termination of the Pawtucket CSO
	11	CSO Termination: Entergy (ER14-266)	Dec 12	FERC accepts termination of a portion of the Entergy CSO
	11	eTariff Corrections: Sections I.2, III.1, and III.F (ER14-172)	Dec 23	FERC accepts corrections

IV. OATT Amendments / TOAs / Coordination Agreements

*	15	*Order 784* Compliance Filing (ER14-877)	Dec 27 Dec 31	ISO submits Order 784 compliance filing NEPOOL intervenes
	16	*Order 1000* Compliance Filing (ER13-193; ER13-196)	Dec 10 Dec 16 Dec 18 Jan 7	NEPOOL submits comments, including NEPOOL Alternative CLF/Sustainable FERC Project, EMCOS/Participating Municipals, Environmental Parties, MA DPU, MMWEC/NHEC, NHT, NESCOE, VT/RI Parties submit comments and/or protests ISO and PTO AC request 15-day extension of time (to Jan 15) to respond to comments and protests LSP Transmission submits protest

V. Financial Assurance/Billing Policy Amendments

	18	FCM Non-Commercial Capacity Changes to Financial Assurance Policy (ER14-487)	Dec 19-23 Jan 7	NU, NRG intervene ISO amends Dec 4 filing to correct eTariff viewer errors; comment date Jan 17

VI. Schedule 20/21/22/23 Changes

*	18	Schedule 21-UI: LCSAs (Bridgeport Energy) (ER14-691; ER14-690)	Dec 18	UI files Emera LCSA and termination of Capital Power LCSA related to Bridgeport Energy
*	18	Schedule 21-UI: LCSA (Wallingford) (ER14-650)	Dec 17	UI files Wallingford LCSA

	19	Schedule 21-NU: LCRAs (CTMEEC, Wallingford) (ER14-324 et al.)	Dec 20	FERC accepts LCRA filings, effective Jan 1, 2014, subject to a further compliance filing
	19	Schedule 21-NU: Elimination of Unreserved Use Penalties (ER14-258)	Dec 17	FERC accepts elimination of unreserved use penalties language, effective Jan 1, 2014
	19	LGIA – BHE/Oakfield Wind Farm (ER14-63)	Dec 5 Dec 12	FERC accepts revised LGIA
	19	Schedule 21-GMP: Merger Revisions; Cancellation of Schedule 21-CVPS (ER12-2304	Dec 13 Dec 18	FERC staff files comments on settlement agreement Settlement Judge Johnson issues status report

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

	20	Quarterly Reports Regarding Non-Generating Resource Regulation Market Participation (ER08-54)	Dec 19	ISO files its 21st quarterly report

IX. Membership Filings

*	21	January 2014 Membership Filing (ER14-490)	Dec 31	***New Members***: Eligo Energy, Emera Energy Services Subsidiary Nos. 6-8, Genbright, Mid-Maine Waste Action Corporation, Oasis Energy, and Yes Energy; ***Termination***: Exelon New England Holdings; comment date Jan 21
	21	December 2013 Membership Filing (ER14-497)	Dec 23	FERC accepts BTG Pactual Commodities membership; AEP Energy termination

X. Misc. - ERO Rules, Filings; Reliability Standards

*	21	FFT Report: December 2013 (NP14-14)	Dec 30	NERC files Report
*	21	Revisions to BES Definition (RD14-2)	Dec 13	NERC proposes revisions to the definition of Bulk Electric System; comment date Jan 17, 2014
*	21	Revised Reliability Standards: PRC-023 and -025 (RM14-2; RM13-19)	Dec 17	NERC files revisions to PRC-023
	22	NOPR: Revised TOP and IRO Reliability Standards (RM13-15, RM13-14, RM13-12)	Dec 20 Jan 6	NERC requests FERC defer action in this proceeding until Jan 31, 2015 ISO/RTO Council, NRECA support requested deferral
	25	*Order 793*: Revised Reliability Standard: PRC-005-2 (RM13-7)	Dec 19	FERC issues final rule approving revised Reliability Standard
	26	*Order 791*: Version 5 CIP Reliability Standards (-002 through -011) (RM13-5)	Dec 20	APPA/NRECA, EEI/EPSA, Brian Evans-Mongeon request rehearing and/or clarification of *Order 791*
	26	2014 NERC/NPCC Business Plans and Budgets (RR13-9)	Jan 3	FERC accepts Nov 22 NERC compliance filing

XI. Misc. - of Regional Interest

	27	203 Application: NRG Kendall / Veolia ENH (EC14-33)	Dec 13 Dec 18 Dec 20 Dec 23 Jan 7	NSTAR intervenes and protest filing NSTAR withdraws protest FERC requests additional information NRG responds to Dec 20 FERC request FERC authorizes sale of NRG Kendall to Veolia ENH
	28	203 Application: Edison Mission / NRG (EC14-14)	Dec 5 Dec 9 Dec 11 Dec 23 Jan 2 Jan 7	FERC requests additional information Additional parties intervene; PJM IMM submits comments NRG submits requested information NRG answers Dec 9 comments by PJM IMM PJM IMM submits additional comments NRG answers Jan 2 additional comments by PJM IMM
	29	SGIA – CMP/MMWAC (ER14-451)	Dec 23	FERC accepts non-conforming SGIA, effective Jan 1, 2014
	29	NSTAR/HQUS Use Rights Transfer Agreement (ER14-244)	Dec 12	FERC accepts Agreement, effective Jan 1, 2014
	29	Bangor Hydro (Emera Maine) Notice of Succession to MPS OATT (ER14-218)	Dec 23	FERC accepts notice of succession
*	31	Termination of PURPA Purchase Obligation: Fitchburg from Pinetree QF(QM14-1)	Dec 17	Fitchburg seeks termination of its obligation to purchase the output from Pinetree's 16MW QF; comment date Jan 14, 2014

XII. Misc. - Administrative & Rulemaking Proceedings

31	Zero Rate Reactive Power Rate Schedules (AD14-1)	Dec 11 Dec 17	FERC staff holds workshop FERC issues notice inviting comments on the mechanics of filing reactive power rate schedules for which there is no compensation; comment date Jan 24, 2014.
31	RTO/ISO Centralized Capacity Markets (AD13-7)	Dec 11 – Jan 8	Parties file comments

XIII. Natural Gas Proceedings

35	*Order 787*: Gas/Electric Operational Info Sharing (RM13-17)	Dec 16 Dec 23	Enable Interstate Pipelines and NGA/Process Gas Consumers Group/NW Industrial Gas Users request clarification and/or rehearing of *Order 787* *Order 787* becomes effective

XIV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XV. Federal Courts

37	Orders 1000 and 1000-A (12-1232)	Dec 13	Final Briefs filed; Petitioners submit motion proposing oral argument format. Respondent-Intervenors file response to Petitioners' motion and cross-motion for the allocation of additional, separate time

M E M O R A N D U M

TO: NEPOOL Participants Committee Member and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: January 9, 2014

RE: Status Report on Current Regional Wholesale Power and Transmission Arrangements Pending Before the Regulators, Legislatures, and Courts

We have summarized below the status of key ongoing proceedings relating to NEPOOL matters before the Federal Energy Regulatory Commission ("FERC"), state regulatory commissions, and the Federal Courts and legislatures through December 4, 2013. If you have questions, please contact us.[1]

I. Complaints

- **NEPGA FCA8 NPRR Complaint (EL14-17)**

On January 8, 2014, the New England Power Generators Association ("NEPGA") filed a Complaint urging the FERC (i) to order the ISO to revise the Tariff to provide that Resources whose Non-Price Retirement Requests ("NPRRs") were rejected for reliability reasons from FCA8 will not be counted towards the ICR; and (ii) to issue an order on the merits of the Complaint on or before January 27, 2014, or if it cannot issue an order on the merits by that date, to issue an order by January 27 directing the ISO to delay the commencement of FCA8 until five (5) business days after the issuance of an order on the merits, which it requested by issued by March 17, 2014. The date by which comments and the ISO's response must be filed has not yet been noticed, but NEPGA requested a shortened comment period that would end on January 21, 2014. A copy of the Complaint can be downloaded from the FERC's eLibrary at http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13434042. If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **FCM Administrative Pricing Rules Complaint (EL14-7)**

As previously reported, the New England Power Generators Association ("NEPGA") filed, on October 31, 2013, a complaint asking the FERC (i) to determine that the Tariff provisions that set capacity prices during Insufficient Competition and Inadequate Supply and the Capacity Carry Forward Rule are creating unreasonable and unduly discriminatory price disparities between new and existing capacity resources; and (ii) to direct that the recommended revisions to the ISO Tariff be implemented ("Complaint"). The substance of the Complaint (the Exelon Proposal) was considered, but not supported, at the October 4, 2013 Participants Committee meeting. NEPGA requested that the proposed Market Rule revisions be made effective so that they are in place prior to FCA8 (or February 3, 2014). At the request of the ISO, and following comments by NEPOOL, supporting comments by CMEEC/MMWEC/NHEC, NGrid, and NU, and a protest by NEPGA, the FERC granted a one week extension of time, to November 27, for the ISO's answer to and any comments on the Complaint.

The ISO filed its response to the Complaint on November 27. Comments were filed by NEPOOL and jointly by Algonquin & Maritimes Pipelines. Protests were filed by CMEEC/MMWEC/NHEC, CT AG, CT Agencies, CT OCC, MA AG, NECPUC, NESCOE, NGrid, and NU. Calpine, EnerNOC, EPSA, Exelon, and

[1] Capitalized terms used but not defined in this filing are intended to have the meanings given to such terms in the Second Restated New England Power Pool Agreement (the "Second Restated NEPOOL Agreement"), the Participants Agreement, or the ISO New England Inc. Transmission, Markets and Services Tariff (the "ISO Tariff").

PSEG filed comments supporting the Complaint. On December 16, NEPGA and NextEra submitted answers to the ISO's November 27 answer, EPSA submitted additional comments supporting the Complaint, and Energy New England ("ENE") and Participating Municipals[2] submitted comments opposing the Complaint. On December 31, NESCOE filed an answer to NEPGA's December 16 answer. This matter is pending before the FERC.

If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **NEPGA Resource Performance Obligations Complaint (EL13-66)**

On December 6, the FERC denied rehearing but granted clarification[3] of its August 27 order that itself granted in part and denied in part the resource performance obligations complaint originally filed by NEPGA.[4] As previously reported, the May 17, 2013 complaint by NEPGA alleged that the ISO impermissibly re-interpreted the Tariff to impose a firm fuel obligation on all capacity resources. In the *NEPGA Order*, the FERC found that the Tariff imposes a strict performance obligation on capacity resources and that capacity resources may not take economic outages, including outages based on economic decisions not to procure fuel or transportation. The *NEPGA Order* also found that "a demonstrated inability to obtain natural gas or transportation may legitimately affect whether a resource is physically available," where lack of physical availability is not a Tariff violation. Addressing related enforcement matters, the FERC indicated that it would not pursue any pending enforcement referrals from the ISO that are based solely on an alleged inability to procure natural gas.

In the *NEPGA Rehearing Order*, the FERC rejected NEPGA's assertion that the ISO should have been required to submit under Section 205 its filing containing the non-exhaustive list of factors the IMM typically will consider in analyzing whether fuel was available to a capacity resource, finding that "the IMM's list merely provides examples of the types of information, from the broad range of information that could be pertinent to such a fact-specific analysis, that the IMM will consider in determining whether a resource has met the standard set forth in the Tariff." In addition, the FERC rejected NEPGA's argument that the *NEPGA Order* allowed "confiscatory" rates to continue without identifying a remedy. With respect to fuel procurement, however, the FERC granted NEPGA's requested clarifications that (i) if a resource is asked to operate at levels above its Day-Ahead Energy Market schedule, "it must do everything in its control to procure fuel for the additional request, but it is not a Tariff violation if the resource is unable to obtain fuel or transportation using intra-day measures"; and (ii) a capacity resource is not required to guarantee fuel availability for the resource's entire Capacity Supply Obligation ("CSO") in Real-Time when dispatch exceeds its Day-Ahead Energy Market schedule and fuel is unavailable. The FERC stated that "the Tariff does not require capacity resources to guarantee that fuel will be available; rather, it requires them to purchase the fuel and transportation necessary to satisfy a [CSO] if the fuel and transportation are available. This finding neither alters the performance obligations the Tariff imposes on capacity resources nor expands the limited circumstances under which the Tariff may excuse non-performance."

The *NEPGA Rehearing Order* was not challenged and is final and unappealable, concluding this proceeding. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com), Harold Blinderman (860-275-0357; hblinderman@daypitney.com) or Dave Doot (860-275-0102; dtdoot@daypitney.com).

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[2] "Participating Municipals" are Braintree, Concord, Groveland, Hingham, Littleton (MA), Merrimac, Middleton, Rowley, Taunton, and Wellesley.

[3] *New England Power Generators Assoc., Inc. v. ISO New England Inc.*, 145 FERC ¶ 61,206 (2013) ("*NEPGA Rehearing Order*").

[4] *New England Power Generators Assoc., Inc. v. ISO New England Inc.*, 144 FERC ¶ 61,157 (2013) ("*NEPGA Order*"), *order on reh'g and clarification*, 145 FERC ¶ 61,206 (2013).

- **NESCOE FCM Renewables Exemption Complaint (EL13-34)**

Rehearing of the FERC's February 12, 2013 order denying NESCOE's FCM Renewable Exemption Complaint[5] was requested and remains pending before the FERC. As previously reported, NESCOE instituted this December 28, 2012 complaint in response to the ISO's December 3, 2012 FCM compliance filing (*see* ER12-953 in Section III below) that implemented buyer-side mitigation without an exemption for state-sponsored public policy resources. NESCOE asserted that the ISO's proposed Minimum Offer Price Rule ("MOPR") would likely exclude from the FCM new renewable resources developed pursuant to state statutes and regulations, and thereby result in customers being forced to purchase more capacity than is necessary for resource adequacy and proposed an alternative renewables exemption (the "Renewables Exemption Proposal"). In denying the Complaint, the FERC found that "NESCOE has failed to meet its burden under section 206 to demonstrate that ISO-NE's MOPR is unjust, unreasonable or unduly discriminatory" as applied to the New England Capacity Market.[6] The FERC declined to set the case for hearing, and therefore denied the motion to consolidate this proceeding with the FCA8 Revisions Compliance Filing proceeding (ER12-953),[7] on which it concurrently issued an order conditionally accepting in part and dismissing in part the ISO's proposed compliance filing (*see* Section III below). Rehearing was requested by NESCOE, the CT PURA, and the MA DPU on March 14. On March 29, NEPGA filed an answer challenging NESCOE's request for rehearing. On April 15, the FERC issued a tolling order affording it additional time to consider the rehearing requests, which remain pending before the FERC. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com), Harold Blinderman (860-275-0357; hblinderman@daypitney.com) or Dave Doot (860-275-0102; dtdoot@daypitney.com).

- **Base ROE Complaint (2012) (EL13-33)**

This Complaint, as well as all of the answers and comments submitted in this proceeding, remain pending before the FERC. As previously reported, Environment Northeast ("ENE"), Greater Boston Real Estate Board, National Consumer Law Center, and the NEPOOL Industrial Customer Coalition ("NICC", and together, the "2012 Complainants") filed an additional complaint regarding the return on equity ("Base ROE") used in calculating formula rates for transmission service in the ISO's Open Access Transmission Tariff ("OATT"), seeking to reduce the Base ROE from the still effective 11.14% to 8.7%. 2012 Complainants acknowledged that the Base ROE is already the subject of ongoing hearing procedures in EL11-66 (see below) but offered the following six reasons for the docketing of a further complaint addressing the Base ROE: (1) the FERC has held that the pendency of a section 206 investigation into a public utility's ROE does not immunize that ROE from investigation through a second section 206 complaint proceeding; (2) promoting the Congressionally-directed symmetry of remedies as between FPA §§ 205 and 206 (i.e. a fair symmetry requires that 2012 Complainants be free to file a complaint requesting further rate decreases based on later common equity cost data without regard to the status of prior complaints since TOs could file at any time for an increase); (3) this complaint would ensure the FERC could set an ROE below the 9.2% requested in EL11-66 if the evidence leads there; (4) to reset the New England Transmission Owners ("TOs")[8] zone of reasonableness through updated proxy group analysis; (5) greater assurance that their consent would be required to complete an ROE settlement; and (6) to establish a further 15-month refund period.

Interventions were filed by NEPOOL, AIM, CT AG, CT OCC, CT PURA, EMCOS,[9] MA AG, MOPA, MPUC, TEC, and the VT DPS. On January 16, the TOs filed their answer, asserting that the FERC

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[5] *New England States Comm. on Elec. v. ISO New England Inc.*, 142 FERC ¶ 61,108 (2013), *reh'g requested.*

[6] *Id.* at P 32.

[7] *Id.* at P 30.

[8] TOs are Bangor Hydro, CMP, National Grid, New Hampshire Transmission ("NHT"), NSTAR, NUSCO on behalf of its operating company affiliates CL&P, WMECO, and PSNH, UI, Unitil and Fitchburg, and Vermont Transco.

[9] EMCOS or the "Eastern Massachusetts Consumer-Owned Systems" are Braintree, Hingham, Reading, and Taunton.

should dismiss the Complaint as contrary to Section 206's 15-month refund limitation and that the Complaint failed to show that the TOs' Base ROE is unjust and unreasonable. TOs argue that evidence relevant to their cost of capital for 2013 and beyond will only be relevant to this Complaint. MMWEC and NHEC filed joint comments supporting the complaint and urging the FERC to grant the relief requested therein and establish the earliest possible refund effective date. Substantively, MMWEC/NHEC provided additional evidence to counter TO arguments that they face substantial payment "risks" in connection either with the provision of transmission service or the construction of new facilities. On January 31, 2013, 2012 Complainants answered the TOs January 16 answer. The request to consolidate this proceeding with EL11-66, as well as the complaint, answers, and comments are pending before the FERC. If you have any questions concerning this matter, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Base ROE Complaint (2011) (EL11-66)**

As previously reported, Trial Judge Cianci issued his initial decision on August 6, 2013 finding unjust and unreasonable the 11.14% ROE currently used in calculating formula rates for transmission service in the OATT, and finding that the ROE should be 10.6% for the October 2011 through December 2012 "locked in/refund period" and 9.7% from January 2013 forward, subject to further updating or modification by the FERC.[10] By way of reminder, the FERC established hearing and settlement judge procedures[11] following a complaint by a number of State, consumer, and consumer advocate parties (the "2011 Complainants")[12] seeking a FERC order reducing the 11.14% Base ROE to 9.2% "due to changes in the capital markets since the *Bangor Hydro* proceeding."[13] After settlement judge procedures before Judge Judith A. Dowd were ultimately unsuccessful and terminated, these proceedings proceeded to now-completed hearings before Judge Cianci. Briefs on exceptions to the initial decision were filed by Complainants, TOs, EMCOS, and FERC Trial Staff on September 20. Briefs opposing exceptions were filed by the same parties on October 24, 2013.[14] If you have any questions concerning this matter, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Eric Runge (617-345-4735; ekrunge@daypitney.com).

II. Rate, ICR, FCA, Cost Recovery Filings

- **ICR-Related Values and HQICCs - 2014/2015 ARA3, 2015/2016 ARA2, and 2016/2017 ARA1 (ER14-510)**

On December 3, 2013, the ISO and NEPOOL jointly filed materials that identify the Installed Capacity Requirement ("ICR"), Local Sourcing Requirements ("LSR"), Maximum Capacity Limits ("MCL") (collectively, the "ICR-Related Values") and Hydro Quebec Interconnection Capability Credits ("HQICCs") for the third annual reconfiguration auction ("ARA") for the 2014/2015 Capability Year to be held March 1, 2014, the second ARA for the 2014/2015 Capability Year to be held in August 2014, and the first ARA for the 2015/2016 Capability Year to be held in June 2014. The ICR-Related Values and HQICCs were supported by the Participants Committee through the approval of the November 8, 2013 Consent Agenda. A

[10] *Martha Coakley, Mass. Att'y Gen. et al.*, 144 FERC ¶ 61,012 (2013) ("*2011 Base ROE Initial Decision*").

[11] *Martha Coakley, Mass. Att'y Gen et al.*, 139 FERC ¶ 61,090 (2012) ("*Base ROE Complaint Order*"). The *Base ROE Complaint Order* was not challenged and is final.

[12] Complainants are Martha Coakley, Mass. Att'y Gen. ("MA AG"), the Conn. Public Utilities Regulatory Authority ("CT PURA"), Mass. Dep't of Pub. Utils. ("MA DPU"), New Hampshire Pub. Utils. Comm. ("NH PUC"), George Jepsen, Conn. Att'y Gen. ("CT AG"), CT OCC, Maine Off. of the Pub. Advocate ("ME OPA"), New Hampshire Off. of the Consumer Advocate, ("NH OCA"), Rhode Island Div. of Pub. Utils. and Carriers ("RI PUC"), Vermont Dep't of Pub. Srvc ("VT DPS"), MMWEC, AIM, TEC, Power Options, and the IECG.

[13] *See Bangor Hydro-Elec. Co. et al.*, 117 FERC ¶ 61,129 (2006) ("*Opinion 489*") at PP 79-81, *order on reh'g, Bangor Hydro-Elec. Co. et al.*, 122 FERC ¶ 61,265 (2008) at PP 30-34.

[14] Errata to the Table of Authorities were filed by Complainants and the TOs on Oct. 25 and 29, respectively.

February 1, 2014 effective date was requested. Interventions were filed by Exelon, NRG and NU, but no comments were submitted. This matter is now pending before the FERC. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **FCA8 Qualification Informational Filing (ER14-329)**

On November 5, 2013, the ISO submitted its informational filing (the "FCA8 Informational Filing") for qualification in FCA8. The ISO is required under Market Rule Section 13.8.1 to submit an informational filing with the FERC containing the determinations made by the ISO for the upcoming Forward Capacity Auction ("FCA") at least 90 days prior to each auction. FCA8 is scheduled to begin February 3, 2014. The Informational Filing contained the ISO's determinations that four Capacity Zones, Maine, Connecticut, NEMA, and Rest of Pool, will be modeled for FCA8. The Informational Filing reported that there will be 35,877 MW of existing capacity in FCA8 competing with 2,126 MW of new capacity under a procurement limit of 33,855 MW (ICR minus HQICCs). The ISO reported also that there were a total of 7,851 MW of de-list bids, 1,907 MW of which were later converted into Non-Price Retirement Requests. A list of the 98 Resources for which a Non-Price Retirement Request was submitted, and the status of the associated reliability review, is included in the transmittal letter. The identity of the de-list bids accepted and those rejected for reliability purposes was included in a privileged Attachment E.

Interventions were filed by NEPOOL, NESCOE, NRG, NU, Blue Sky West, CPV Towantic, Dominion, and GDF Suez. NEPGA submitted comments (i) stating that the IMM mitigated a significant percentage of FCA8 generator static de-list bids, suggesting a disconnect between the actual costs and risk thresholds necessary for a Market Participant to assume a CSO and those that, in the IMM's opinion should, be allowed in a de-list bid, and (ii) asking that the ISO "explain its reasons for each rejected de-list bid after the … FCA8 auction consistent with its obligation to do so under the ISO-NE Tariff." PSEG protested the filing (i) requesting that, in light of its October 17 memo identifying the possibility of "a deficiency of 1,547 MW below [the Net Installed Capacity Requirement] ("NICR")" due to the number of retirement notices received, the ISO be directed to supplement the Information Filing to give Participants a clearer picture of available capacity in FCA8, and (ii) requesting that the ISO be directed to revise its Tariff provisions governing the treatment of resources retained for reliability for FCA8, rather than waiting for FCA9 as discussed with Participants. Exelon protested the IMM's determination with respect to Mystic 7's static de-list bid and requested that its de-list bid be re-set in accordance with the information provided in its protest. On December 6, the ISO filed an answer to the comments and protests filed by NEPGA, PSEG, and Exelon. On December PSEG and Exelon responded to the ISO's December 6 answer.

With respect to the QDN deadlines for FCA8, National Grid submitted in this proceeding, out of an abundance of caution, its November 5 request, filed in ER14-311, for a limited waiver of the QDN deadlines. Additional requests for waiver of the QDN Deadlines were filed by Blue Sky West, Brookfield, and CSG. Each of the requests was granted on December 27, 2013 (*See* Section III below).

The FCA8 Informational Filing is pending before the FERC. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **ICR-Related Values and HQICCs - 2017/2018 Power Year (ER14-328)**

On December 30, the FERC accepted the 2017/2018 Capability Year ICRs, HQICCs and related values (Local Sourcing Requirements ("LSR") and Maximum Capacity Limits "MCL") jointly filed by the ISO and NEPOOL on November 5, 2013. Those values will be used in FCA8. With a 2017/2018 ICR of 34,923 MW (reflecting tie benefits of 1,870 MW) and HQICCs of 1,068/mo., the net amount of capacity to be purchased in FCA8 to meet the ICR will be 33,855 MW. The LSR for the Connecticut and NEMA/Boston Load Zones are 7,319 MW and 3,428 MW, respectively; the MCL for the Maine export-constrained Load Zone is 3,960 MW. Unless the December 30 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **2014 ISO-NE Administrative Costs and Capital Budgets (ER14-90)**

On December 19, the FERC accepted the ISO's 2014 Administrative and Capital Budgets.[15] As previously reported, the ISO reported that its 2014 Revenue Requirement (allowing for measured growth from 2013 levels), after true-up for 2012, was $171.2 million. Of that total, the ISO's administrative costs (i.e., the 2014 Core Operating Budget) comprise $140.9 million; depreciation and amortization of regulatory assets, $28.4 million; and 2012 true-up, $1.9 million. The ISO further reported that the 2014 Capital Budget was $28 million, comprised of the following (with 2014 projected costs and target completion dates, if available, in parentheses):

Intra-day Offers (Q4 2014)	($6 million)	FCM Terminations and Retirements (Sep 2014)	($570,100)
CTS (Nov 2015)	($3.8 million)	Cyber Security (TBD)	($550,000)
Gen. Control Application (GCA) Production Part 1 (Mar 2015)	($2.4 million)	Business Continuity Plan Infrastructure Enhancements Phase III (Q2 2015)	($500,000)
Non-Project Capital Expenditures	($3.7 million)	Capitalized Interest	($500,000)
Other Emerging Work Including Strategic Planning Initiatives	($1.57 million)	Quarterly Release Projects 2014 (Quarterly)	($500,000)
2014 Issues Resolution Project (Q4 2014)	($1.5 million)	Wind Integration Phase II (Q4 2015)	($300,000)
Divisional Accounting (Nov 2015)	($1.23 million)	Simultaneous Feasibility Test and Market Sys. Upgrade (Apr 2014)	($280,000)
FCM Performance Incentives (FCA 9) (Q1 2015)	($1 million)	FCA8 (Feb 2014)	($200,000)
Alt. Technologies and Regulation Market (ATRM) (June 2014)	($1 million)	Web Enhancements Phase II (May 2014)	($150,000)
Business Intelligence Phase IV (Q4 2014)	($750,000)	Wind Integration Phase I (Jan 2014)	($105,000)
BCC Data Center Transition (Mar 2014)	($611,000)	Prerequisite Unit Dispatch and Scheduling Changes for GCA (March 2014)	($100,000)
Third-Party FTR Administration (Q4 2015)	($600,000)	Control Room Visualization Project (May 2014)	($80,800)

In accepting the 2014 ISO Budgets, the FERC found that the ISO had adequately supported the projected costs and associated Tariff Revisions.[16] The FERC rejected the limited protest by the CT PURA and CT OCC (the "Connecticut State Agencies") that asserted that the ISO's proposed increase in and funding for additional full-time employees ("FTEs") did not comply with the 2013 Budgets Settlement Agreement and suggested postponement of the ISO's increase and funding for additional FTEs, finding "ISO-NE has adequately supported and justified these additional positions, and … hiring of these additional personnel, who will perform important and time-sensitive work involving reliability and market efficiency matters, should not be delayed."[17] On November 18, the ISO answered the Connecticut State Agencies protest, challenging the assertion that the 2014 ISO Budgets do not comply with the 2013 Settlement Agreement and asserting that the funding for additional FTEs cannot wait. This matter is pending before the FERC. If there are any questions on this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

[15] *ISO New England Inc.*, 145 FERC ¶ 61,227 (2013) ("*ISO 2014 Budgets Order*").

[16] *Id.* at P 21.

[17] *Id.* at P 24.

- **2013/2014 Winter Reliability Program Bid Results Filing (ER13-2266)**

On October 7, the FERC conditionally accepted the list of the Market Participants selected to provide demand response ("DR") and oil inventory services in the 2013/2014 Winter Reliability Program and the prices they will be paid.[18] As previously reported, the procurement "is intended to balance fuel security for the region against the costs to consumers."[19] In accepting the filing, The FERC was not persuaded by protests pointing to the disparity between the estimated costs and actual costs in challenging the entire Program, which it viewed as a novel approach to addressing reliability concerns manifested last winter and which does not lend itself to precise cost predictions. The FERC indicated the arguments concerning the need for the Winter Reliability Program were more appropriately raised in a request for rehearing of the *2013/2014 Winter Reliability Program Order* (*see* ER13-1851 in Section III below). An ISO compliance filing directed by the *Bid Results Order*, further detailing its evaluation process in selecting winning bids,[20] as well as to reflect corrections identified by Essential Power and Exelon,[21] was accepted by the FERC on November 13.

TransCanada challenged the *Bid Results Order*[22] on November 6, 2013. On December 2, the FERC issued a tolling order affording it additional time to consider the TransCanada rehearing request, which remains pending before the FERC. If you have any questions concerning these matters, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **FCA1 Results Remand Proceeding (ER08-633)**

As previously reported, the DC Circuit issued on December 23, 2011, a *per curiam* order[23] that PSEG's May 2010 petition for review be granted, remanding the FERC's orders in this proceeding[24] for further consideration, which remains to be acted on. In particular, the FERC must (i) determine whether PSEG's position (that it should receive the full (unprorated) floor price for all its resources that it could not prorate) would be an appropriate way to interpret the then-existing Market Rules and, if not, (ii) respond to PSEG's objections that any contrary result would result in "undue discrimination" and would be "inconsistent with the fundamental policy goals" of FCM. On October 15, 2012, PSEG filed a motion requesting that the FERC issue an order on remand directing the ISO to pay PSEG the full FCA floor price without further delay (for PSEG, the difference totaling $2.8 million plus interest). The ISO filed on October 31, 2012 an answer to PSEG's October 15 motion. On November 1, 2012, Connecticut Generators[25] submitted comments

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[18] *ISO New England Inc.*, 145 FERC ¶ 61,023 (Oct. 7, 2013) ("*Bid Results Order*")

[19] The ISO received bids that nearly met its targeted procurement at a total price of $114.3 million. In approximate numbers, the ISO proposed to accept 83% of the targeted MWh at a price of $79 million.

[20] *Bid Results Order* at PP 23, 26-30.

[21] *Id.* at P 31. Essential Power identified an overstatement of its total MWh by 50% (the tank capacity for a shared fuel tank was not pro-rated when reflected in the units' awards); Exelon inadvertently miscalculated the usable portion of its oil storage tanks.

[22] TransCanada asserts that the FERC erred in: (1) failing to determine whether the costs and resulting bid prices are just and reasonable; (2) accepting the bidding results because the ISO failed to comply with its Tariff criteria; and (3) rejecting arguments re: the "excessive disparity" between the Analysis Group's estimated cost range and the actual price of the program.

[23] *PSEG Energy Res. & Trade LLC and PSEG Power Conn. LLC v. FERC*, No. 10-1103, 2011 U.S. App. LEXIS 25659, (D.C. Cir. Dec. 23, 2011).

[24] *ISO New England Inc.*, 123 FERC ¶ 61,290 (2008); *reh'g denied*, 130 FERC ¶ 61,235 (2010), *remanded*, *PSEG Energy Res. & Trade LLC and PSEG Power Conn. LLC v. FERC*, No. 10-1103, 2011 U.S. App. LEXIS 25659, (D.C. Cir. Dec. 23, 2011).

[25] "Connecticut Generators" are CP Energy Marketing (US) Inc. and Bridgeport Energy LLC (collectively, "Capital Power"); Dominion Resources Services ("Dominion"); Milford Power Co. and EquiPower Resources Management (collectively, "EquiPower"); NRG Power Marketing, Conn. Jet Power, Devon Power, Middletown Power, Montville Power, Norwalk Power, and Somerset Power (collectively, "NRG"); and PPL EnergyPlus.

supporting PSEG's request and a few of the Connecticut Generators moved to intervene out-of-time. As noted, this matter remains pending before the FERC.

III. Market Rule and Information Policy Changes, Interpretations and Waiver Requests

- **Demand Response Baseline Changes (ER14-727)**

On December 20, the ISO and NEPOOL jointly submitted revisions to Market Rule 1 and Appendix E1 (the "Demand Response Baseline Changes") to improve baseline accuracy by accounting for scheduled and forced curtailments of Real-Time Demand Response Assets and Real-Time Emergency Generation Assets (typically industrial or commercial facilities). Specifically, the Changes address the potential distortion of baselines due to scheduled or forced curtailments by requiring demand response ("DR") providers to submit meter data values during a curtailment that are equal to the last unadjusted baseline computed prior to the curtailment instead of actual meter readings. The Changes also provide that a DR provider may not submit a Demand Reduction Offer during a scheduled or forced curtailment since the affected assets are not actually available to be dispatched in order to balance Real-Time supply and demand. A June 1, 2014 effective date was requested, with DR Providers expected to provide notice in May 2014 for any curtailments scheduled to begin on or after June 1, 2014. The Demand Response Baseline Changes were supported by the Participants Committee by way of the December 6 Consent Agenda. Comments on this filing are due on or before January 10, 2014. Thus far, doc-less interventions were filed by Exelon, NRG and NU. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **eTariff Corrections: Section III.13.5 (ER14-713)**

On December 19, as corrected on January 7, the ISO submitted corrections to Sections III.13.5 of its eTariff that consolidate, effective December 17, 2013, changes accepted in ER13-585 (CSO Bilateral Transaction and Reconfiguration Auction Enhancements) and ER13-1742 (PRD Full Integration Changes & FCM Net Supply Revisions).[26] A December 17, 2013 effective date (the date changes accepted in ER13-585 became effective) was requested. A doc-less intervention was filed by NEPOOL on December 27. Comments on the December 19 filing are due on or before January 9, 2013; comments on the ISO's January 7 correction, January 17. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Dual-Fuel Switching Provisions Move to Market Rule 1 (ER14-707)**

On December 19, the ISO and NEPOOL jointly filed changes that move existing Tariff provisions that address Market Participant procedures for switching from a primary to a secondary fuel from Appendix K to Section III.1.11.3 of Market Rule 1 ("Dual-Fuel Switching Revisions"). The Dual-Fuel Switching Revisions will ensure that existing dual-fuel switching provisions remain in effect after the expiration of the Attachment K Winter 2013-14 Reliability Program on February 28, 2014. A March 1, 2014 effective date was requested. The changes were supported by the Participants Committee by way of the December 6, 2013 Consent Agenda. Doc-less interventions have been filed by Exelon and NRG. Comments on this filing are due on or before January 9, 2014. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **FCM Offer Review Trigger Price Revisions (ER14-616)**

On December 13, the ISO filed changes that establish new Offer Review Trigger Prices ("ORTP") for the ninth Forward Capacity Auction ("FCA9"), a revised methodology for calculating an ORTP for Demand Resources other than energy efficiency Demand Resources, and a mechanism for adjusting (by an index or combination of indices) the ORTPs for years when full recalculation of the ORTPs is not performed

[26] *ISO New England Inc. and New England Power Pool*, 144 FERC ¶ 61,140 (2013).

(collectively, the "ORTP Changes"). A February 11, 2014 effective date was requested. The ORTP Changes were considered but not supported by the Participants Committee at its December 6, 2013 meeting.

Interventions were filed by Brookfield, Deepwater Wind, Dominion, PSEG, NRG, NU, and UI. Comments were filed by NEPOOL (identifying the concerns and alternatives to the proposed ORTP Changes presented and reviewed in the course of the stakeholder process); First Wind (supporting the ORTP Changes), and NESCOE (supporting the ISO's revised ORTP values resulting from the recalculation process, requesting that, for FCA9 and beyond, the FERC direct the ISO to consider the best available resource capability and cost information in setting the ORTP for offshore wind, and supporting the EnerNOC amendment to enhance the new resource qualification provisions for demand response resources with distributed generation). Protests were submitted by EMCOS, EnerNOC, Exelon, National Grid, NEPGA/EPSA, NextEra, Protesting Parties,[27] and the NH PUC. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **LSCPR Cost Allocation Changes (ER14-584)**

On December 9, the ISO and NEPOOL jointly filed changes that revise the allocation of reliability costs associated with Local Second Contingency Protection Resources ("LSCPR Cost Allocation Changes"). Specifically, the changes revise the allocation of NCPC costs associated with the commitment of resources to provide local second contingency protection so that those costs are allocated based on Real-Time Load Obligation regardless of whether those resources are committed through the Day-Ahead or Real-Time Market. The ISO requested that the LSCPR Cost Allocation Changes become effective immediately upon the issuance of a FERC order in this proceeding and no later than February 7, 2014, 60 days from the date of the filing. The changes were supported by the Participants Committee by way of the December 6, 2013 Consent Agenda. Doc-less interventions were filed by Exelon, NRG and NU. No comments on this filing were submitted on or before the December 30, 2013 comment date, and this matter is pending before the FERC. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Demand Resource Commercial Operation Auditing Revisions (ER14-581)**

Also on December 9, the ISO and NEPOOL jointly filed changes that modify the existing Demand Resource auditing requirements to permit additional audits to be performed throughout the Capacity Commitment Period as new assets are added to the Demand Resource to facilitate the return of additional Financial Assurance, as the demand response provider performs additional audits to demonstrate that additional MW of the resource are commercially operational. The DR Commercial Operation Audit Revisions also make a number of other ancillary and conforming changes to the audit rules for Demand Resources and to rules that address how the audit values are utilized. The Filing Parties requested that the Demand Resource Commercial Operation Auditing Revisions become effective June 1, 2014. The changes were supported by the Participants Committee by way of the November 8, 2013 Consent Agenda. Doc-less interventions were filed by CMEEC, Exelon and NU. No comments on this filing were submitted on or before the December 30, 2013 comment date, and this matter is pending before the FERC. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Exigent Circumstances Filing – FCM Admin. Pricing Rules (ER14-463)**

On November 25, the ISO filed revisions to the FCM administrative pricing rules that (i) address what the ISO identified as a "gap" in the Insufficient Competition rules; (ii) sets an administrative rate of $7.025/kW-month to be applied if there is Insufficient Competition (as the ISO proposed to redefine it) or Inadequate Supply in FCA8; and (iii) make additional clarifying changes to the FCM administrative pricing rules (collectively, the "FCM Pricing Rule Changes"). The ISO proposed that the FCM Pricing Rule Changes

[27] "Protesting Parties" in this proceeding are: The American Wind Energy Association ("AWEA"), CLF, Energy Management, Inc. ("EMI"), The Offshore Wind Development Coalition, and Renewable Energy New England ("RENEW").

become effective on January 24, 2014. The ISO stated that the FCM Pricing Rule Changes were being submitted as an "Exigent Circumstances" filing.[28]

Comments on this filing were due on or before December 16, 2013. Interventions were filed by APPA, Brookfield, Calpine, ConEd, Dominion, Dynegy, EnerNOC, EPSA, Exelon, Footprint, HQUS, Maine OPA, MPUC, NRG, TransCanada, and Verso. Comments were submitted by NEPOOL, EPSA, the NEPOOL Industrial Customer Coalition, and Public Systems.[29] Protests were filed by Connecticut,[30] ENE and Participating Municipals, GDF Suez, MA AG, MA DPU, NECPUC, NESCOE, NextEra, NU and UI, and PSEG. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com), Harold Blinderman (860-275-0357; hblinderman@daypitney.com) or Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Waiver Request - Capacity Qualification Deadlines: Brookfield (ER14-442)**

On December 27, the FERC granted Brookfield's request for a limited waiver of the FCA8 Capacity Qualification Deadlines that would allow the ISO to reevaluate the Erie Boulevard Hydro facility capacity qualification and potentially permit Erie Boulevard to qualify an additional 35 MW of summer capacity and 18 MW of winter capacity.[31] The ISO submitted comments on December 12, 2013, indicating it did not oppose the waiver request and requesting an order on or before January 17, 2014, should the FERC grant the waiver, to allow any revised values to be reflected in the FCA8 software. Unless the December order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Waiver Request - Capacity Qualification Deadlines: Blue Sky West (ER14-364)**

On December 27, the FERC granted the limited, one-time waiver of the FCA8 Capacity Qualification Deadlines requested by Blue Sky West LLC ("Blue Sky West") to enable the IMM to consider the additional data submitted by Blue Sky West after the relevant deadlines which will correct an error that resulted in an overstated New Resource Offer for Blue Sky West's 186 MW on-shore wind facility in Maine.[32] As previously reported, the ISO submitted comments on November 25, 2013, indicating it did not oppose the waiver request and requesting an order on or before January 17, 2014, should the FERC grant the waiver, to allow the revised values to be reflected in the FCA8 software. Unless the December order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Waiver Request - Capacity Qualification Deadlines: CSG (ER14-356)**

On December 27, the FERC granted the limited, one-time waiver of the FCA8 Capacity Qualification Deadlines requested by Conservation Services Group ("CSG") to enable the IMM to consider the additional data submitted by CSG after the relevant deadlines to support its position that three of its Combined Heat &

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[28] Pursuant to Section 11.2 of the Participants Agreement, the ISO may file Market Rule changes in "Exigent Circumstances" before full consultation with NEPOOL through the FERC-approved Participant Processes. "Exigent Circumstances" are defined as circumstances where "ISO determines in good faith that (i) failure to immediately implement a new Market Rule, Operating Procedure, Reliability Standard, provision of the Information Policy, Non-TO OATT Provision or Manual would substantially and adversely affect (A) System reliability or security, or (B) the competitiveness or efficiency of the New England Markets, and (ii) invoking the procedures set forth in Section 11.1, 11.3 or 11.4 would not allow for timely redress of ISO's concerns."

[29] "Public Systems" are MMWEC, CMEEC, NHEC and VPPSA.

[30] In this proceeding, "Connecticut" is the Connecticut Public Utilities Regulatory Authority ("Connecticut PURA"), the Connecticut Office of Consumer Counsel ("CT OCC"), the Connecticut Attorney General ("CT AG"), and the Connecticut Department of Energy and Environmental Protection.

[31] *Brookfield Energy Marketing LP*, 145 FERC ¶ 61,286 (2013).

[32] *Blue Sky West, LLC*, 145 FERC ¶ 61,285 (2013).

Power ("CHP") projects in Massachusetts that were included in its aggregated FCM resources should be qualified for a New Resource Offer Floor Price below the FCA8 $15.819/kW-month Offer Review Trigger Price.[33] Unless the December order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Waiver Request - Capacity Qualification Deadlines: National Grid (ER14-311)**

On December 27, the FERC granted National Grid requested the limited waiver of the Capacity Qualification Deadlines for FCA8 it requested to enable the IMM to consider the additional data it had submitted after the relevant deadlines supporting qualification of two Combined Heat & Power ("CHP") projects, one in Rhode Island and one in Massachusetts, for a New Resource Offer Floor Price below the FCA8 $15.819/kW-month Offer Review Trigger Price.[34] Unless the December order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **CSO Terminations: Pawtucket (ER14-270)**

On December 23, 2013, the FERC accepted the termination of the CSO for Resource No. 326 held by Project Sponsor Pawtucket Power Holding Company LLC ("Pawtucket"). As indicated, the ISO will draw down the amount of financial assurance provided by Pawtucket with respect to the CSO. Unless the December 23 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **CSO Terminations: Entergy (ER14-266)**

On December 12, the FERC accepted the termination of a portion of the CSO for Resource No. 1630 held by Project Sponsor Entergy Nuclear Power Marketing LLC ("Entergy"). As indicated, the ISO will draw down the amount of financial assurance provided by Entergy with respect to the portion of the CSO terminated. Unless the December 12 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **eTariff Corrections: Sections I.2, III.1, and III.F (ER14-172)**

On December 23, the FERC accepted various corrections to the ISO's eTariff filed by the ISO on October 24, as amended on November 19 and supplemented November 27. The corrections revised Section I.2 (to restore terms accepted in ER13-1742), the Section III Table of Contents, Section III.1 (fixing a typographical error), and Section III Appendix F (to restore auditing revisions from ER13-323). Unless the December 23 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Energy Market Offer Flexibility Changes (ER13-1877)**

As previously reported, the FERC conditionally accepted, on October 3, 2013, energy market enhancements[35] designed to provide Market Participants greater flexibility in structuring and modifying their

[33] *Conservation Srvs. Group Inc.*, 145 FERC ¶ 61,284 (2013).

[34] *Nat'l Grid USA, Mas. Elec. Co. and The Narragansett Elec. Co.*, 145 FERC ¶ 61,284 (2013).

[35] Specifically, the changes (1) will permit the cost-related parameters of a Supply Offer or a Demand Bid for a Dispatchable Asset Related Demand ("DARD") to be modified after the initial Reserve Adequacy Analysis ("RAA") process is completed; (2) will permit submission of cost-related parameters of a Supply Offer or a Demand Bid for a DARD that vary by hour; (3) modify self-schedule implementation to reflect the ability to submit hourly Supply Offers and change Supply Offers in Real-Time; (4) permit submission of negative offers as low as negative $150/MWh for External Transactions and the energy Blocks for a Supply Offer, Demand Bid, Increment Offer and Decrement Bid; (5) reflect conforming changes to Appendix A mitigation rules consistent with these changes; and (6) reflect clarification and clean-up changes.

Supply Offers in the Day-Ahead and Real-Time Energy Markets (the "Offer Flexibility Changes").[36] The Offer Flexibility Changes were accepted effective as of December 1, 2014, as requested. In accepting the Offer Flexibility Changes, the FERC noted a few potential inconsistencies between the ISO's intended application of the proposed revisions, including the lock-out provisions, and the actual proposed Tariff language. Accordingly, the FERC conditioned its acceptance upon the submission of a compliance filing that reconciles the proposed Tariff language with the ISO's statements concerning application. Although the compliance filing would have been due December 2, NEPOOL and the ISO requested an extension of time, to and including January 17, 2014, to allow for the Markets Committee to review and make its recommendations concerning the compliance changes at its November and December meetings, and the Participants Committee to consider and vote on such recommendations at its January 10, 2014 meeting. That request was granted on October 30. The compliance changes are currently scheduled for consideration at the January 10 Participants Committee meeting under agenda item #7. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Winter 2013/2014 Reliability Program (ER13-1851)**

As previously reported, the FERC *conditionally* accepted the Winter Reliability Program on September 16, to be effective September 6, 2013 through February 28, 2014.[37] The FERC conditioned its acceptance of the Program on the allocation of Program costs to RTLO rather than Regional Network Load, and on the removal of the specific dates added to Section III.K.2 in the Emergency Amendments Filing (related to the timing for public comments, and issuance of a FERC order, on the Bid Results filing).[38] In directing the change in cost allocation, the FERC found that that costs of the Program should be allocated to RTLO "[b]ecause real-time load is the primary beneficiary, and the primary cost-driver, of the Winter Reliability Program."[39] The FERC found unpersuasive the arguments that it would be more appropriate to allocate Program costs to Regional Network Load.[40] As for the second condition, while the FERC recognized the urgency of the winter reliability concerns that led to the proposed specific dates, the FERC did not find that the record supported provisions binding it to issue an order by a specific date (or include a comment deadline for a proceeding that is already underway and pending before the FERC (*see* 2013/2014 Winter Reliability Program Bid Results Filing (ER13-2266) in Section II above). The allocation and other Tariff changes were reflected in an October 15 compliance filing that was accepted November 13, 2013. Rehearing of the 2013/2014 *Winter Reliability Program Order* was requested by EPSA and TransCanada. On November 12, 2013, the FERC issued a tolling order affording it additional time to consider the rehearing

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[36] *ISO New England Inc. and New England Power Pool*, 145 FERC ¶ 61,014 (Oct. 3, 2013) ("*Offer Flexibility Changes Order*"). The *Offer Flexibility Changes Order* was not challenged and is final and unappealable.

[37] *ISO New England et al.*, 144 FERC ¶ 61,204 (Sep. 16, 2013) ("*2013/2014 Winter Reliability Program Order*").

[38] The FERC also noted its expectation that the ISO would, as it committed to do in the proceeding, make a separate filing at the end of the Winter Reliability Program to relocate the market monitoring changes contained in Appendix K to elsewhere within Market Rule 1. Those changes to satisfy that commitment are under consideration at the Markets Committee.

[39] *Id.* at P 70.

[40] *Id.* at P 71. The filing parties asserted that Program cost allocation to Regional Network Load was more appropriate because (i) the Program is a discrete, out-of-market solution similar to a Gap RFP, and (2) the timing of the Program is such that it would have been difficult for LSEs to anticipate the costs and include them in their contracts. The FERC disagreed that the Program, which specifically addresses generation related concerns (resource performance coupled with the region's increased dependence on natural gas), is akin to a Gap RFP, which addressed transmission-related concerns. Further, the FERC also found unpersuasive the arguments that the timing of the Program warranted allocation to Regional Network Load (either because an RTLO allocation would impose unavoidable costs on LSEs on short notice or increase risk premiums). Citing the Winter 2005/2006 order, the FERC stated that "LSEs "voluntarily assume Real-Time Load Obligation when entering into bilateral contracts with end-use customers[;]" those "contracts contain inherent risk associated with unforeseeable future costs, and we would expect that risk to be captured in bilateral contracts between LSEs and end-use customers." (*Id.* at P 76).

requests, which remain pending before the FERC. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **FCM Conforming Changes Reflecting PRD Full Integration (ER12-1627)**

The ISO's March 15, 2013 compliance filing in this proceeding remains pending before the FERC. As previously reported, the FERC, on January 14, 2013, accepted in part, and rejected in part, the ISO's proposed changes, filed April 26, 2012, to make the FCM Market Rules consistent with the PRD full integration rules (currently scheduled to become effective on June 1, 2017).[41] The FERC also accepted the proposed revisions to Appendix E of Market Rule 1 to become effective June 1, 2017, as requested, and granted the ISO's request to delay implementation of the Fully Integrated rules to June 1, 2017. The FERC found just and reasonable the "must-offer requirement for demand response resources with a capacity supply obligation in ISO-NE's FCM,"[42] agreed that "the proposal will assist in correcting inefficiencies inherent in the current capacity market design, and will provide substantial benefits to many parties,"[43] and found the "proposal will be beneficial to both demand response providers and wholesale electricity customers".[44] However, the FERC rejected the ISO's proposal regarding net supply (contained in sections III.E.7.3 and III.13.7.1.5.2), without prejudice to a future filing revising Tariff language to clarify its rules regarding DR resources that provide capacity through both demand reductions and behind-the-meter generation.[45] Noting its concerns with other aspects of the filing, the FERC conditioned its acceptance of certain changes subject to explanations to be included in the 60-day compliance filing.

60-Day Compliance Filing. The ISO submitted, on March 15, 2013, a compliance filing providing the directed explanations and addressing the changes rejected in the *January 14 Order*. Protests on that compliance filing were submitted on April 5 by DR Supporters[46] and Verso Paper. DR Supporters protested the absence of any provision in the ISO Tariff or Manuals that provide details about the factors that the ISO and the IMM will consider in evaluating energy offers from DR Resources, though they "emphasize that they do not contest the reasonableness or level of specificity provided in aggregate by ISO-NE in its written assertions regarding how it will go about evaluating offers or the various factors it anticipates may be considered in 'legitimate offer strategies'". For its part, Verso Paper stated that "ISO-NE's proposed 'know it when they see it' process for monitoring and evaluating demand response offers will not work in practice for all demand response providers, and ISO-NE's explanation for retaining a 10 day refreshment period fails to recognize that, with a must-offer requirement, 10 days is too short a time to refresh the baseline." On April 19, the ISO answered the DR Supporters and Verso Paper protests. On April 30, Verso Paper answered the ISO's April 19 answer. The ISO's compliance filing and protests and answers related thereto remain pending before the FERC.

If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **FCM Redesign Compliance Filing: FCA8 Revisions (ER12-953 et al.)**

As previously reported, the FERC, on February 12, 2013, conditionally accepted in part and rejected in part the revisions to the FCM and FCM-related rules in the Tariff ("FCA8 Revisions") filed by the ISO and the PTO AC.[47] The *FCA8 Revisions Order* accepted the following aspects of the FCA8 Revisions as compliant with

[41] *ISO New England Inc.*, 142 FERC ¶61,027 (2012) ("*January 14 Order*").

[42] *Id.* at P 27.

[43] *Id.* at P 28.

[44] *Id.* at P 29.

[45] *Id.* at PP 44-46.

[46] "DR Supporters" are Comverge, EnerNOC, NICC, Wal-Mart, and the IECG.

[47] *ISO New England Inc.*, 142 FERC ¶ 61,107 (2013) ("*FCA8 Revisions Order*").

its prior FCM Orders: the ISO's offer review trigger prices;[48] unit specific offer review;[49] the ISO's proposal to subject a resource to offer floor mitigation until that resource clears in one FCA; imports' treatment under MOPR;[50] no exemptions to MOPR for new Self-Supplied Resources;[51] the application of mitigation to *all* new resources offering into the FCM, including renewables that are procured pursuant to state policy initiatives;[52] $1.00/kW-month Threshold to trigger IMM review of Dynamic De-List Bids;[53] and a number of other additional revisions.[54] The *FCA8 Revisions Order* rejected: the ISO's proposed methodology for reducing the offer floor of an uncleared resource that has already achieved commercial operation at the time of an FCA (directing the ISO to submit a revised proposal that subjects a resource to an offer floor until it has demonstrated that it is needed by the market)[55]; the ISO's request to model only 4 capacity zones for FCA8. Two requests for rehearing of the *FCA8 Revisions Order* were filed on March 15, 2013, one by MMWEC, NHEC, APPA, NEPPA, and NRECA; the other, by EMCOS and Danvers. On April 11, NEPGA filed an answer to the MMWEC *et al.* request. On April 15, the FERC issued a tolling order affording it additional time to consider the rehearing requests, which remain pending before the FERC.

If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com), Harold Blinderman (860-275-0357; hblinderman@daypitney.com) or Dave Doot (860-275-0102; dtdoot@daypitney.com).

- **Tie Benefits Calculation and Allocation (ER08-41)**

The ISO's January 14, 2010 update in this proceeding remains pending. As previously reported, the ISO filed, on January 14, 2010, an update to the joint ISO/NEPOOL November 26, 2008 report[56] regarding the plan to study and develop proposals to resolve issues related to the modeling of internal transmission constraints and tie benefits associated with individual lines. In the January 14, 2010 Update, the ISO proposed to comprehensively review and attempt to resolve during 2010 all outstanding and identified tie benefits issues (including the so-called "Reserved Issues", issues raised during 2009 stakeholder meetings, and tie benefits-related issues raised in Docket No. ER10-438) through a NEPOOL stakeholder process and to make a filing with the FERC on or before a date that will allow any related Market Rule or Tariff changes to be effective in time for FCA5 (covering the 2014/2015 Capacity Commitment Period). At its February 5, 2010 meeting, the Participants Committee considered and voted on the ISO's January 14 proposal. The ISO's Proposal received 43.25% support from the Participants Committee. On February 8, 2010, NEPOOL filed comments reflecting the results of that consideration and vote. NESCOE submitted a motion to intervene out-of-time and comments on February 12, 2010. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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[48] *FCA8 Revisions Order* at PP 37-38.

[49] *Id.* at P 53.

[50] *Id.* at P 70.

[51] *Id.* at P 80.

[52] *Id.* at P 97.

[53] *Id.* at P 126.

[54] *Id.* at P 127.

[55] *Id.* at PP 63-64.

[56] The 2008 Tie Benefits Report indicated that the stakeholder process would begin early during the second quarter of 2009 and would be completed in time for any proposed Market Rule 1 or other Tariff changes to be filed with the FERC before February 1, 2010. *See ISO New England Inc. and New England Power Pool*, 126 FERC ¶ 61,180 (2009).

IV. OATT Amendments / TOAs / Coordination Agreements

- ***Order 784* Compliance Filing (ER14-877)**

On December 27, the ISO submitted a compliance filing in response to *Order 784*. In its December 27 filing, the ISO explained how the Tariff's deviations from the FERC's *pro forma* Open Access Transmission Tariff ("OATT"), including the Regulation Market Rules, already meet the requirements and policy goals of *Order 784* and therefore meet the FERC's requirements for a showing of provisions that are "consistent with or superior to" the *pro forma* OATT. In addition, the ISO asked for a waiver of the new requirement to post on its OASIS historical one-minute and ten-minute certain Area Control Error ("ACE") data for the most recent calendar year, and to update this posting once per year. Comments on this filing are due on or before January 17, 2014. NEPOOL intervened on December 31. If you have any comments or concerns, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Order 764* Compliance Changes (ER14-375)**

On November 12, the ISO, NEPOOL, the PTO AC, CSC, and the Schedule 20A service providers ("SSPs") jointly filed revisions to Section II of the ISO Tariff to comply with the requirements of *Orders 764* and *764-A* (the "*Order 764* Compliance Changes"). Specifically, the Order 764 Compliance Changes revise Schedule 22 (LGIA) of the OATT. This transmittal letter also explains how FERC-approved deviations from the *pro forma* OATT already meet the requirements and policy goals of *Order 764* and are "consistent with or superior to" those provisions. The Participants Committee supported the *Order 764* Compliance Changes at its August 2, 2013 meeting. Comments on this filing were due on or before December 3, 2013. None were filed. Interventions were filed by Exelon and the NYISO. This matter remains pending before the FERC. If you have any comments or concerns, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Order 1000* Interregional Compliance Filing (ER13-1960; ER13-1957)**

On July 10, the ISO, NEPOOL and the PTO AC jointly filed revisions to Sections I and II of the ISO Tariff to comply with the interregional coordination and cost allocation requirements of *Orders 1000* and *1000-A* (the "*Order 1000* Interregional Compliance Changes") (ER13-1960). In addition, the ISO, on behalf of itself, NYISO and PJM, filed an Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol ("Amended Protocol") as part of its compliance changes (ER13-1957). The *Order 1000 Interregional Compliance Changes* include (i) revisions to Attachment K to add provisions describing the interregional coordination provisions included in the Amended Protocol, as well as adding other provisions facilitating the consideration of interregional solutions to regional needs; (ii) a new Schedule 15 reflecting the methodology for allocation among ISO-NE and NYISO of the costs of approved interregional transmission projects; (iii) revisions to Schedule 12 describing the regional cost allocation within New England of the costs of approved interregional transmission projects; and (iv) conforming changes to Tariff Section I. The *Order 1000* Interregional Compliance Changes and the Amended Protocol were supported by the Participants Committee at its June 27 Summer Meeting. On August 7, the FERC extended the comment deadline on these filings to and including September 9, 2013. Doc-less motions to intervene were filed by a number of New England parties in both proceedings, including Dominion, Exelon, PPL, PSEG, and NEPOOL (in the Protocol proceeding (in which it was not a filing party)). On August 26, NEPOOL filed comments supporting the Protocol. NEPOOL added that "From a stakeholder perspective, stakeholder input into revisions to the Protocol as it evolves over time would be easier and more likely to be taken into account if it were made part of the individual regional tariffs of each of the Northeast ISOs rather than existing solely as a stand-alone three-party agreement". On September 9, NESCOE submitted comments generally supporting the filings, but reserving the right to further comment on these filings should the substance of the changes be modified as a result of further FERC (*see* ER13-193 and ER13-196 below) or federal court proceedings. Public Interest Organizations[57] raised concerns that the Protocol and related amendments "do not meet certain of the transparency and cost allocation aspects of [*Order 1000*]'s minimum

[57] "Public Interest Organizations" are Conservation Law Foundation, Environment Northeast, Natural Resources Defense Council, Pace Energy and Climate Center, and the Sustainable FERC Project.

requirements." On September 24, the ISO answered Public Interest Organizations' and NEPOOL's comments. These matters remain pending before the FERC. If you have any comments or concerns, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Order 1000* Compliance Filing (ER13-193; ER13-196)**

Rehearing of the FERC's May 17, 2013 order on the region's *Order 1000* compliance filing[58] (described in previous Reports) remains pending. As previously reported, the *Order 1000 Compliance Order* accepted the ISO-NE/PTO compliance filing as partially complying with *Order 1000*, but required changes to the compliance proposal. The primary change was the elimination of the Right of First Refusal ("ROFR") and the establishment of competitive transmission development for all regional transmission projects (with an exception to the elimination of the ROFR for transmission needed for reliability within three years of the needs assessment determination and subject to certain other limiting criteria). Additionally, the *Order 1000 Compliance Order* required that the public policy transmission proposal be revised to: (i) make the ISO, rather than the New England states, the entity that evaluates and selects which transmission projects will be built to meet transmission needs driven by public policy; and (ii) include an *ex ante* default cost allocation method, transparent to all stakeholders, developed in advance of particular transmission facilities being proposed, rather than leaving it to the states to decide cost allocation on a project-specific basis after particular projects are proposed. While requiring these fundamental changes to the public policy transmission part of the filing, the *Order 1000 Compliance Order* also allowed for the NESCOE-driven proposal for both selection of projects and cost allocation to remain in the tariff as a complementary process for voluntary transmission projects alongside the *Order 1000*-compliant process. A more detailed summary of the *Order 1000 Compliance Order* was circulated to the Participants Committee on May 20, 2013. On June 17, the ISO, LS Power, PTO AC and NESCOE each filed requests for clarification and/or rehearing of the *Order 1000 Compliance Order*. On June 28, the ISO answered LSP Power's request concerning the effective date for the *Order 1000* compliance changes. On July 16, the FERC issued a tolling order affording it additional time to consider the requests for clarification and/or rehearing, which remain pending before the FERC.

November 15 Order 1000 Compliance Order Changes. On November 15, the ISO and the PTO AC jointly submitted proposed revisions to Sections I and II of the ISO Tariff and to the Transmission Operating Agreement ("TOA") (the "Compliance Revisions") to comply with the FERC's May 17, 2013 *Order 1000 Compliance Order*. The revisions included planning revisions (addressing competitive processes for developing new regional transmission projects), cost allocation revisions (regarding the allocation of costs for Public Policy Transmission Projects), and TOA revisions. The Planning Revisions and the Cost Allocation Revisions filed by the ISO and PTO AC were considered but not supported by the Participants Committee at its November 8 meeting.

Comments on the November 15 filing were filed by ***NEPOOL*** (seeking two sets of changes to the Planning Revisions filed by the ISO and PTO AC (i) limiting the scope of transmission projects that are grandfathered under the old, non-competitive processes, so that Proposed Projects are not grandfathered but instead are open to competition; and (ii) ensuring that all Qualified Transmission Project Sponsors ("QTPS") are on an equal footing regarding consulting with the ISO in assessing regional transmission needs and solutions (together, the "NEPOOL Alternative"); but taking no position on the Cost Allocation revisions); ***CLF and The Sustainable FERC Project*** (supporting the November 15 filing and its public policy planning and regional cost allocation provisions.); EMCOS/Participating Municipals (request the ISO and TOs be required to revise Section 3.3 of Attachment K to eliminate the grandfathering for proposed Transmission Projects, and to revise Schedule 12 to ensure that public power systems not subject to state Public Policy requirements are exempted from any obligation to pay for Public Policy projects); ***Environmental Groups***[59] (each supporting the Cost Allocation Revisions, but noting continuing concern that the region's planning

[58] *ISO New England Inc.*, 143 FERC ¶ 61,150 (2013) ("*Order 1000 Compliance Order*").

[59] "Environmental Groups" are Environment Northeast, Connecticut Fund for the Environment, Environment Council of Rhode Island, Health Care Without Harm, The Natural Resources Council of Maine, and The Sustainable FERC Project.

process fails to produce more cost-effective and efficient planning outcomes); ***LSP Transmission*** (supporting NEPOOL's Alternative, requesting a January 1, 2014 effective date for the compliance filing, and protesting the hold harmless provision contained in Attachment O, Section 9.01, the ISO's evaluation process and the proposed study deposit), ***MA DPU*** (supporting the Cost Allocation Revisions); ***NESCOE*** (without expressing a position on the Cost Allocation Revisions, affirming its support for NESCOE it having a central role in determining how public policy planning need relates to cost allocation); ***New Hampshire Transmission*** ("NHT") (protesting the November 15 filing and suggesting specific amendments to the proposal to be submitted a short time after an order on the second compliance filing is issued); ***Public Systems***[60] (requesting that the FERC adopt MMWEC's cost allocation proposal and direct the Filing Parties to include an express right of consumer-owned utilities to opt out of the non-regional allocated costs of projects satisfying policy requirements that do not apply to them); and ***VT/RI Parties***[61] (protesting the Cost Allocation Revisions). On December 18, the ISO and PTO AC requested a 15-day extension (to January 15, 2014) to respond to the Protests and Comments filed in this proceeding.

This matter is pending before the FERC. If you have any comments or concerns, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Capability Resource Ratings (ER11-2216)**

Action on MMWEC's request for rehearing of the FERC's January 28, 2011 *Capability Clarifications Order*[62] continues to be deferred. As previously reported, the revisions to Tariff accepted by the FERC were described as clarifying the controlling order/hierarchy of documents relied upon by the ISO to establish the energy and capacity output levels for certain Existing Generating Capacity Resources ("Capability Clarifications"). The filing parties (the ISO and the PTO AC) asserted that the Capability Clarifications addressed what the FERC found ambiguous in a July 2010 order in EL10-58,[63] namely, the controlling order of approval documents and data used by the ISO to establish the CNR Capability of an existing generating resource. The Capability Clarifications were considered by the Participants Committee at its October 18, 2010 meeting, but ultimately not supported. In accepting the Capability Clarifications, the FERC addressed protests filed by Dominion, MMWEC, and PSEG. The FERC found that the changes were consistent with, and not a collateral attack on, the FERC's July 2010 order, and provide equal treatment to resources seeking to change capacity limits. In addition, the FERC was also persuaded that interconnection agreements are a more reliable means of determining the CNR Capability ratings, and declined to direct the use of the MW ratings in the CELT Report. MMWEC requested rehearing of the *Capability Clarifications Order* on February 24, 2011, but requested the FERC defer action on the merits of the rehearing request until completion of the process under which the CNR rating for Stony Brook is currently under review. MMWEC stated that if it was able to secure adequate relief, it would so inform the FERC and withdraw the rehearing request; if not, it would ask the FERC to address the merits of its rehearing request. The FERC issued on March 24, 2011 a tolling order affording it additional time to consider the MMWEC rehearing request, which remains pending before the FERC. If you have any questions concerning this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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[60] In this proceeding, "Public Systems" are MMWEC and NHEC.

[61] "VT/RI Parties" are the State of New Hampshire Public Utilities Commission ("NHPUC"), the Rhode Island Public Utilities Commission ("RIPUC"), the Vermont Public Service Board ("VT PSB"), the Vermont Public Service Department ("VPSD"), Vermont Electric Power Company ("VELCO"), and Vermont Transco ("VT Transco").

[62] *ISO New England Inc. and the Participating Trans. Owners Admin. Comm.*, 134 FERC ¶ 61,057 (2011) ("*Capability Clarifications Order*"), *reh'g requested*.

[63] *See PSEG Power Conn. LLC v. ISO New England Inc.*, 132 FERC ¶ 61,022 at P 6 (2010).

V. Financial Assurance/Billing Policy Amendments

- **FCM Non-Commercial Capacity Changes to Financial Assurance Policy (ER14-525; ER14-487)**

The ISO and NEPOOL jointly re-submitted on December 4, 2013 changes related to financial assurance ("FA") for Non-Commercial Capacity in the FCM. The changes: (i) required Designated FCM Participants to provide additional FA prior to offering Non-Commercial Capacity in an FCA; (ii) strengthened the incentives to bring Non-Commercial Capacity to commercial status; (iii) employed a market price based-value, rather than a fixed value, to calculate FA for Non-Commercial Capacity; and (iv) eliminated the requirement that Non-Commercial Capacity that has not cleared in an FCA provide FA when acquiring CSOs through reconfiguration auctions or bilateral transactions. Although the changes were first filed on November 27 (ER14-487), they were subsequently withdrawn on December 3 to allow the new filing to accurately reflect the separate effective dates associated with implementation of the changes which, other than for those described in (iv) (which are to take effect March 28, 2014), are to take effect for resources that clear in FCA9 or later. Interventions were filed by NRG and NU. No comments on the re-filed changes were submitted. On January 7, the ISO amended the December 4 filing to correct errors in the eTariff viewer caused by errors in its eTariff software. Comments, if any, on the corrected eTariff data will be due on or before January 17. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com) or Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VI. Schedule 20/21/22/23 Changes

- **Schedule 21-UI: LCSAs (Bridgeport Energy) (ER14-691; ER14-690)**

On December 18, UI submitted a new Localized Cost Sharing Agreements ("LCSA") and a notice of termination of LCSA-14 under Schedule 21-UI. UI stated that the new LCSA with Emera Energy Services Subsidiary No. 5 ("EESS5") on behalf of Bridgeport Energy (LCSA-17) and the notice of termination of LCSA-14 (Capital Power) were filed so that UI could recover the Category B Load Ratio Share of the revenue requirement for UI's Localized Facilities from EESS5 under Schedule 21-UI. UI requested that the EESS5 LCSA and termination of the Capital Power LCSA become effective December 1, 2013. No comments on this filing were submitted on or before the January 8, 2014 comment date and this matter is pending before the FERC.. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-UI: LCSA (Wallingford) (ER14-650)**

On December 17, UI filed a LCSA with the Town of Wallingford Department of Public Utilities, Electric Division ("Wallingford") so that it could recover Wallingford's Category B Load Ratio Share of the revenue requirement for UI's Localized Facilities under Schedule 21-UI. A January 1, 2014 effective date was requested. No comments were submitted on or before the January 7, 2014 comment date and this matter is pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-NU: LCRAs (Emera, Capital Power) (ER14-465 et al.)**[64]

On November 26, the NU Companies submitted (1) a Notice of Cancellation of NU's Localized Costs Responsibility Agreement ("LCRA") with CP Energy Marketing (US) LLC ("Capital Power"); and (2) a new LCRA by and between the NU Companies and Emera Energy Services Subsidiary No. 5 LLC ("Emera"). The Agreements were filed to reflect the fact Emera acquired the Bridgeport Energy facility from Capital Power. A December 1, 2013 effective date was requested for each of the Agreements. No comments on these filings were submitted on or before the December 17 comment date and these filings are pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

[64] Because 3 NU Companies' eTariffs are involved, the LCRAs related to the Bridgeport Energy generated 3 dockets: ER14-465 (CL&P); ER14-466 (PSNH); and ER14-467 (WMECO).

- **Schedule 21-NU: LCRAs (CTMEEC, Wallingford) (ER14-324 et al.)**[65]

On December 20, 2014, the FERC accepted the following filing submitted by the NU Companies: 1) a Notice of Cancellation of NUSCO's LCRA with Connecticut Municipal Electric Energy Cooperative ("CMEEC"); (2) a LCRA by and between the NU Companies and Connecticut Transmission Municipal Electric Energy Cooperative ("CTMEEC"); and (3) a new LCRA by and between the NU Companies and the Town of Wallingford Department of Public Utilities, Electric Division ("Wallingford"). In addition, the Northeast Utilities Service Company ("NUSCO"), as agent for CL&P, submitted an agreement with Wallingford under which CL&P will provide scheduling and dispatch services to Wallingford through the Connecticut Valley Exchange ("CONVEX") dispatch center and amendments to the existing CMEEC and CTMEEC CONVEX Agreements. As previously reported, the Agreements were filed to reflect the fact that Wallingford will be procuring transmission service directly from the ISO, and to the extent necessary, from other New England TOs, rather than through CMEEC. The filings were accepted, effective January 1, 2014, as requested, subject to a further compliance filing to correct a Tariff section reference in each of the CTMEEC LCRAs. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-NU: Elimination of Unreserved Use Penalties (ER14-258)**

On December 17, the FERC accepted amendments to Schedule 21-NU to eliminate unreserved use penalties and the associated penalty distribution methodology filed by NUSCO and the ISO, effective January 1, 2014, as requested. Unless the December 17 order is challenged, this proceeding will be concluded. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **LGIA – BHE/Oakfield Wind Farm (ER14-63)**

On December 5, the FERC accepted a revised, non-conforming LGIA (LGIA-ISONE/BHE-12-02) under Schedule 22 of the ISO Tariff to govern the interconnection of Evergreen Wind II's 147.6 MW wind farm in Oakfield, Maine (the "Oakfield Project"), effective October 11, 2013, as requested, subject to Bangor Hydro submitting a compliance filing within 14 days of the Maine Commission's determination, describing the outcome of the proceeding and, as necessary, including an executed agreement.[66] That compliance filing was submitted on December 20, 2013 and is pending before the FERC. BHE reported that the LGIA did not conform to the *pro forma* LGIA because the revised LGIA is a four-party agreement (reflecting the separate ownership of certain interconnection facilities by Maine Gen Lead). If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-GMP: Merger Revisions; Cancellation of Schedule 21-CVPS (ER12-2304)**

As previously reported, the FERC accepted on September 24, 2012, the revised schedules and notices of cancellation filed by Green Mountain Power ("GMP") in this proceeding, but suspended the provisions, subject to refund, and established hearing and settlement judge procedures.[67] In its September 24 order, the FERC stated that its "preliminary analysis indicates that Applicants' proposed Schedules 21-GMP and 20A-GMP and notices of cancellation have not been shown to be just and reasonable, and … raise issues of material fact that cannot be resolved based on the record before us and are more appropriately addressed in the hearing and settlement judge procedures we order."[68] Requests for clarification and/or rehearing of the *GMP Merger Order* requested by VEC

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[65] Because 3 NU Companies' eTariffs are involved, the cancellation of the CMMEC LCRA generated 3 dockets: ER14-312 (CL&P); ER14-313 (PSNH); and ER14-315 (WMECO); the CTMEEC LCRA: ER14-318 (CL&P); ER14-319 (PSNH); and ER14-320 (WMECO); and the Wallingford LCRA: ER14-321 (CL&P); ER14-322 (PSNH); and ER14-324 (WMECO). The Convex Agreements were filed in ER14-326 (Wallingford); ER14-327 (CMEEC); and ER14-330 (CTMEEC).

[66] *ISO New England Inc. and Bangor Hydro Elec. Co.*, 145 FERC ¶ 61,197 (2013).

[67] *ISO New England, Inc., Central Vt. Pub. Srvc. Corp. and Green Mountain Power Corp.*, 140 FERC ¶ 61,239 (2012) ("*GMP Merger Order*"), *reh'g denied*, 142 FERC ¶ 61,146 (2013).

[68] *Id.* at PP 21-22.

and WEC ("Cooperatives")[69] were denied on February 25, 2013.[70] Also on February 25, the FERC accepted GMP's October 31, 2012 compliance filing, rejecting Cooperatives' arguments protesting the compliance filing as beyond the scope of the compliance filing proceeding.[71]

Judge Karen V. Johnson was designated as the settlement judge, and convened two settlement conferences. After a lengthy period of reported negotiation, Green Mountain Power Corporation ("GMP") submitted on November 13 a Settlement Agreement and Offer of Settlement ("Settlement") that reportedly resolves all disputes in these proceedings. Pursuant to a December 2 notice issued by Judge Johnson, the deadline for filing initial comments was December 13, 2013; the deadline for filing reply comments, December 23, 2013. FERC Staff filed comments on December 13 indicating that it did not oppose certification or approval of the settlement. On December 18, Judge Johnson issued a status report indicating that she would consider certification following expiration of the December 23 reply comments deadline This matter is pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

- **New England Simultaneous Import Limits (AD10-2)**

As previously reported, the ISO filed with the FERC, on November 20, 2013, the 2012 simultaneous import limits ("SIL") for the New England-wide geographic market and the Connecticut Import Interface ("CT Import Interface") and the Southwest Connecticut Import Interface ("SWCT Import Interface") geographic submarkets to assist New England sellers in preparing their updated market power indicative screens and Delivered Price Test ("DPT") analyses to be submitted pursuant to Order 697.

- **Quarterly Reports Regarding Non-Generating Resource Regulation Market Participation (ER08-54)**

The ISO filed its twenty-first report on December 19, 2013. As previously reported, the ISO committed in the August 5, 2008 Regulation Filing to provide the FERC with quarterly reports on its progress in implementing and carrying out market rule revisions to allow non-generating resources to provide Regulation, including the Alternative Technologies Pilot Program.[72] In the 21st report, the ISO reported that the Market Rule changes that would have been implemented upon conclusion of the Pilot Program pursuant to the August 8, 2008 filing instead have been incorporated in, and will become effective on October 1, 2014 as part of, the ISO's Order 755 compliance changes. In addition, the ISO reported that interim regulation market

[69] Cooperatives asserted that the FERC failed to appropriately address the Mobile Sierra claim contained in VEC's Protest and further explained in WEC's Answer. WEC separately requested that the FERC correct three statements in the *GMP Merger Order* concerning positions taken by WEC.

[70] *ISO New England, Inc., Central Vt. Pub. Srvc. Corp. and Green Mountain Power Corp.*, 142 FERC ¶ 61,146 (2013).

[71] *Green Mountain Power Corp.*, 142 FERC ¶ 61,147 (2013). The FERC noted that Cooperatives' raised the same issues in their joint request for rehearing of the *GMP Merger Order*, submitted in Docket No. ER12-2304-001, and their arguments will be addressed in that proceeding. *Id.* at n. 7.

[72] *See* Market Rule 1 revisions regarding the provision of Regulation by non-generating resources, *ISO New England Inc. and New England Power Pool*, Docket Nos. ER08-54-000 and -001 (filed Aug. 5, 2008) (the "Regulation Filing").

design changes, to include energy opportunity costs in the clearing price, became effective July 1, 2013. These reports are not noticed for public comment.

IX. Membership Filings

- **January 2014 Membership Filing (ER14-930)**

On December 31, NEPOOL requested that the FERC accept, effective January 1, 2014: (i) the membership of Eligo Energy, LLC (Supplier Sector); Emera Energy Services Subsidiary Nos. 6, 7, and 8 (Related Persons to Emera Maine (f/k/a Bangor Hydro), Transmission Sector); Genbright, LLC (Provisional Member, AR Sector, LR Sub-Sector); Mid-Maine Waste Action Corporation (AR Sector, RG Sub-Sector, Small RG Group Member); Oasis Energy (Supplier Sector); and Yes Energy, LLC (Data Only Participant); and (ii) the termination of the Participant status of Exelon New England Holdings (Supplier Sector). Comments on this filing are due on or before January 21, 2014.

- **December 2013 Membership Filing (ER14-497)**

On December 23, FERC accepted (i) the membership of BTG Pactual Commodities (Data Only Participant); and (ii) the termination of the Participant status of AEP Energy (Supplier Sector) (Nov 1, 2013).

X. Misc. - ERO Rules, Filings; Reliability Standards

Questions concerning any of the ERO Reliability Standards or related rule-making proceedings or filings can be directed to Pat Gerity (860-275-0533; *pmgerity@daypitney.com*).

- **FFT Report: December 2013 (NP14-14)**

NERC submitted on December 30, 2013, its Find, Fix, Track and Report ("FFT") informational filing for the month of December 2013. The December FFT resolves 69 possible violations of 12 Reliability Standards that posed a risk minimal risk to bulk power system ("BPS") reliability, but which have since been remediated.[73] The 18 Registered Entities involved each submitted a mitigation activities statement of completion. These filings are for information only and will not be noticed for public comment by the FERC.

- **Revised Definition of Bulk Electric System (RD14-2)**

On December 13, NERC filed for FERC approval proposed revisions to the definition of the term "Bulk Electric System" ("BES Definition") in the *NERC Glossary of Terms Used in Reliability Standards*. NERC stated that the proposed revisions add clarity and granularity that will allow for greater transparency and consistency in the identification of Elements and facilities that make up the Bulk Electric System ("BES") and is responsive to the technical and policy concerns discussed in *Orders 773* and *773-A*. Comments on this filing are due on or before January 17, 2014.

- **Revised Reliability Standards: PRC-023-003 and -025-001 (RM14-2; RM13-19)**

On December 17, 2013, NERC filed for approval changes to PRC-023 (Transmission Relay Loadability) in Docket No. RM14-2. NERC requested that the FERC concurrently on these changes together with changes to PRC-025 (Generator Relay Loadability) pending in Docket no. RM13-19. Proposed PRC-025-1 was proposed in response to FERC directives in Order 733[74] to address generator protective relay loadability. PRC-023-003 was

[73] Only possible violations that pose a minimal risk to Bulk-Power System reliability are eligible for FFT treatment. *See N. Am. Elec. Reliability Corp.*, 138 FERC ¶ 61,193 (2012) at PP 46-56.

[74] *Transmission Relay Loadability Standard*, Order No. 733, 130 FERC ¶ 61,221, at P 104-08 (2010), *order on reh'g and clarification*, Order No. 733-A, 134 FERC ¶ 61,127, *order on reh'g and clarification*, Order No. 733-B, 136 FERC ¶ 61,185 (2011).

developed to establish a bright-line between the applicability of load-responsive protective relays in the transmission and generator relay loadability Reliability Standards. NERC requested that the revised PRC Standards become effective in accordance with the implementation plans filed with the revised Standards, or the first day of the first calendar quarter following FERC approval of the revised Standards. As of the date of this report, a comment date has not been set for either filing.

- **New Reliability Standard: EOP-010-1 (Geomagnetic Disturbance Operations) (RM14-1)**

On November 14, 2013, NERC filed for approval a new Reliability Standard that requires Bulk-Power System owners and operators to develop and implement operational procedures to mitigate the effects of Geomagnetic Disturbances consistent with the reliable operation of the BPS. As of the date of this report, a comment date has not been set. The lack of a comment date or NOPR notwithstanding, interventions have to this point been filed by APPA, EEI, Exelon, and NRECA.

- **NOPR: Revised Reliability Standards: MOD-025-2, MOD-026-0, MOD-027-0, PRC-019-1 and PRC-024-1 (RM13-16)**

On September 19, 2013, the FERC issued a NOPR proposing to approve changes to MOD-025-2 (Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability) and the following 4 new Reliability Standards:[75]

  - MOD-026-1 (Verification of Models and Data for Generator Excitation Control System or Plant Volt/VAR Control Functions);
  - MOD-027-1 (Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions);
  - PRC-019-1 (Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection); and
  - PRC-024-1 (Generator Frequency and Voltage Protective Relay Settings).

FERC also proposed to approve, with modifications, the associated implementation plans, Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs"). Finally, the FERC proposed to approve, as requested, the retirement of MOD-024-1 (Verification of Generator Gross and Net Real Power Capability) and MOD-025-1 (Verification of Generator Gross and Net Reactive Power Capability) prior to the effective date of MOD-025-2. FERD stated that the revised and new Standards will help ensure that verified data is available for power system planning and operational studies by requiring the verification of generator equipment needed to support Bulk-Power System reliability and enhance coordination of important protection system settings. Comments on the NOPR were due on or before November 25, 2013[76] and were filed by eight parties, including ISO-NE, EEI, and NERC. In its comments, ISO-NE asked the FERC to modify Reliability Standards MOD-026-1 and MOD-027-1 to include generators rated below 100 MVA. ISO-NE asserted that the 100 MVA threshold was too high, would exclude too many new England generating units, and should be lowered to match the "bulk electric system" registration requirement of 20 MVA. This NOPR is pending before the FERC.

- **NOPR: Revised TOP and IRO Reliability Standards (RM13-15, RM13-14, RM13-12)**

On November 21, 2013, the FERC issued a NOPR[77] proposing (i) to approve NERC's proposed revisions to Reliability Standard TOP-006-3 (Monitoring System Conditions) filed in RM13-12, but (ii) to remand changes

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[75] *Generator Verification Reliability Standards*, 144 FERC ¶ 61,205 (2013).

[76] The *Generator Verification Reliability Standards* NOPR was published in the *Fed. Reg.* on Sep. 24, 2013 (Vol. 78, No. 185) pp. 58,492-58,500.

[77] *Monitoring System Conditions - Transmission Operations Reliability Standard, Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards*, 145 FERC ¶ 61,158 (Nov. 21, 2013) ("*Nov 21 NOPR*").

to the following Interconnection Reliability Operations and Coordination ("IRO") and Transmission Operating ("TOP") Reliability Standards filed in RM13-14 and RM13-15:

- IRO-001-3 (Reliability Coordination — Responsibilities and Authorities);
- IRO-002-3 (Reliability Coordination – Analysis Tools);
- IRO-005-4 (Reliability Coordination – Current Day Operations);
- IRO-0014-2 (Coordination Among Reliability Coordinators);
- TOP-001-2 (Transmission Operations);
- TOP-002-3 (Operations Planning);
- TOP-003-2 (Operational Reliability Data); and
- PRC-001-2 (System Protection Coordination).[78]

As previously reported, the changes to TOP-006-3 filed April 5, 2013 are targeted to address the respective monitoring role and notification obligation of Reliability Coordinators ("RCs"), Balancing Authorities ("BAs") and Transmission Operators ("TOPs") by clarifying that TOPs are responsible for monitoring and reporting available transmission resources and that BAs are responsible for monitoring and reporting available generation resources. In addition, the changes confirm that RCs, TOPs, and BAs are required to supply their operating personnel with appropriate technical information concerning protective relays located within their respective areas.

The changes to the IRO Standards were to achieve two important overall reliability benefits: (1) delineate a clean division of responsibilities between the Reliability Coordinator and Transmission Operators; and (2) improve system performance by raising the bar on monitoring of Interconnection Reliability Operating Limits ("IROLs") and System Operating Limits ("SOLs") in order to focus monitoring on IROLs and SOLs that are important to reliability.

The changes to the remaining TOP Standards were to upgrade the overall quality of the Standards, eliminate gaps in the requirements, eliminate ambiguity, eliminate redundancies, and address Order 693 directives. NERC indicated in its April filing that the proposed TOP Standards are also more efficient than the currently-enforceable TOP Reliability Standards because they incorporate the necessary requirements from the eight currently-effective TOP Reliability Standards (TOP-001-1a, TOP-002-2.1b, TOP-003-1, TOP-004-2, TOP-005-2a, TOP-006-2, TOP-007-0, TOP-008-1) and the PER-001-0.2 Reliability Standard into three cohesive, comprehensive Reliability Standards that are focused on achieving a specific result.

Because the proposed TOP and IRO Reliability Standards were interrelated, and because the proposed revisions to Reliability Standard TOP-006-3 involved similar issues raised in the TOP and IRO proposals concerning monitoring of the interconnected transmission network and notification of and by registered entities, the FERC addressed all three proposals together in the one NOPR. Although the FERC acknowledged that the proposed TOP and IRO Reliability Standards contain some improvements over the current Standards, concerns that the changes would create reliability gaps in the Standards that are critical to reliable operation of the BPS resulted in the proposed remand of the proposed TOP Standards.[79] The FERC went on to explain that

> given the interrelationship between the TOP and IRO Reliability Standards and that NERC requests that both sets of standards be addressed together, we believe a remand of the proposed IRO standards in addition to those of the TOP will enable NERC to more comprehensively consider modifications to the standards that would address the reliability concerns identified in this NOPR. This

[78] The changes in proposed PRC-001-2 were administrative in nature and were limited to removal of three requirements in currently-effective PRC-001-1 that were to be addressed in proposed TOP-003-2.

[79] *Id.* at P 4.

> approach, in turn, should allow NERC more flexibility in developing appropriate modifications that address our concerns since changes to the TOP standards might require, in some instances, commensurate changes to the IRO standards.[80]

Comments are the *Nov 21 NOPR* are due on or before February 3, 2014.[81]

On December 20, NERC requested that the FERC defer action in this proceeding to January 31, 2015 to allow NERC time to consider the reliability concerns raised by the FERC in the *Nov 21 NOPR* and by an independent review commissioned by NERC that identified proposed TOP-001-2, PRC-001-2, IRO-001-3, and IRO-005-4 as high risk standards requiring improvement. On January 6, 2014, the ISO/RTO Council and NRECA filed comments supporting NERC's requested deferral.

- **NOPR: Revised Reliability Standard: BAL-003-1 (RM13-11)**

On July 18, the FERC issued a NOPR proposing to approve changes to BAL-003 (Frequency Response and Frequency Bias Setting), as well as the associated definitions, implementation plan, VRFs, and VSLs, submitted by NERC on March 19, 2013.[82] NERC stated that the changes respond to FERC directives in Order 693[83] to develop modifications to BAL-003-0 that: (1) include Levels of Non-Compliance; (2) determine the appropriate periodicity of frequency response surveys necessary to ensure that Requirement R2 and other requirements of the Reliability Standard are being met, and to modify Measure M1 based on that determination and (3) define the necessary amount of Frequency Response needed for Reliable Operation for each balancing authority with methods of obtaining and measuring that the frequency response is achieved. Specifically, the Revised Standard is designed to ensure that each of the Interconnections have sufficient Frequency Response to guard against underfrequency load shedding ("UFLS") due to an event in that Interconnection. NERC requested an effective date that is the first day of the first calendar quarter that is 12 months following the effective date of a Final Rule in this docket. Comments on this NOPR were due September 27, 2013,[84] and were filed by NERC, BPA, Electricity Consumers Resource Council, jointly by EEI, APPA, NRECA, and EPSA, MISO, ISO/RTO Council, and Arizona Public Service. NERC filed reply comments on October 15, 2013. This NOPR is pending before the FERC.

- ***Order 786*: TPL-001-4 (footnote 'b') (RM13-9; RM12-1)**

On October 17, the FERC approved TPL-001-4.[85] As previously reported, NERC had a long standing compliance obligation to address FERC concerns with footnote 'b'.[86] NERC's February 28 filing addressed those concerns (by changing the requirements and processes for planned load shed in the event of a single Contingency (identified in a revised footnote 10 included in TPL-001-4)). *Order 786* also approved the consolidation of all of the currently effective TPL Standards (including superseding proposed TPL-001-2, which NERC had proposed in a previous NOPR to remand) into one Standard. Finally, the FERC directed NERC to modify Reliability Standard TPL-001-4 to address the concern that the Standard could exclude planned maintenance outages of

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[80] *Id.*

[81] The *Nov 21 NOPR* was published in the *Fed. Reg.* on Dec. 5, 2013 (Vol. 78, No. 234) pp. 73,112-73,128.

[82] *Frequency Response and Frequency Bias Setting Rel. Std.*, 144 FERC ¶ 61,057 (July 18, 2013)

[83] *Order 693* at P 375.

[84] The NOPR was published in the *Fed. Reg.* on July 29, 2013 (Vol. 78, No. 145) pp. 45,479-45,490.

[85] *Trans. Planning Rel. Standards*, 145 FERC ¶ 61,051 (2013) ("*Order 786*").

[86] *See Trans. Planning Rel. Standards*, 139 FERC ¶ 61,059 (2012) ("*TPL-001-2 NOPR*"). The FERC found TPL-001-2 vague and unenforceable because the Standard did not adequately define the circumstance in which an entity can plan for non-consequential load loss following a single contingency.

significant facilities from future planning assessments and directed NERC to change the TPL-001-4, Requirement R1 Violation Risk Factor from medium to high.[87] *Order 786* will became effective December 23, 2013.[88]

- ***Order 788*: Retirement of Reliability Standard Requirements: P 81 Project (RM13-8)**

As previously reported, the FERC approved, on November 21, 2013, the retirement of 34 requirements in 19 Standards that NERC indicated were redundant and/or otherwise could be removed with little or no effect on reliability.[89] In addition, the FERC withdrew 41 directives that remained outstanding that required NERC to develop modifications to Reliability Standards because the identified outstanding directives had either been addressed in some other manner, were redundant with another directive or provided general guidance as opposed to a specific directive.[90] *Order 788* will become effective January 21, 2014.[91]

- ***Order 793*: Revised Reliability Standard: PRC-005-2 (RM13-7)**

On December 19, the FERC approved changes to PRC-005 (Protection System Maintenance) filed by NERC on February 26, 2013 that: (1) include maximum allowable intervals in PRC-005 for time-based, condition-based, and performance-based maintenance programs; (2) combine PRC-005, PRC-008, PRC-011, and PRC-017 into one Standard; and (3) clarify that it is the equipment owner that will be responsible for completing required maintenance.[92] *Order 793* will become effective [60 days after publication in the *Federal Register*].[93]

- **NOPR: Remand of Interpretation of BAL-002-1a (RM13-6)**

This May 16 NOPR, which proposes to remand NERC's proposed interpretation of BAL-002 (Disturbance Control Performance Reliability Standard) filed February 12, 2013 (which would prevent Registered Entities from shedding load to avoid possible violations of BAL-002), remains pending.[94] NERC asserted that the proposed interpretation clarifies that BAL-002-1 is intended to be read as an integrated whole and relies in part on information in the Compliance section of the Reliability Standard. Specifically, the proposed interpretation would clarify that: (1) a Disturbance that exceeds the most severe single Contingency, regardless if it is a simultaneous Contingency or non-simultaneous multiple Contingency, would be a reportable event, but would be excluded from compliance evaluation; (2) a pre-acknowledged Reserve Sharing Group would be treated in the same manner as an individual Balancing Authority; however, in a dynamically allocated Reserve Sharing Group, exclusions are only provided on a Balancing Authority member by member basis; and (3) an excludable Disturbance was an event with a magnitude greater than the magnitude of the most severe single Contingency. The FERC, however, proposes to remand the proposed interpretation because it believes the interpretation changes the requirements of the Reliability Standard, thereby exceeding the permissible scope for interpretations. Comments on the *BAL-002-1a Interpretation Remand NOPR* were due on or before July 8, 2013,[95] and were filed by NERC, EEI, ISO/RTO Council, MISO, NC Balancing Area, Northwest Power Pool Balancing Authorities, NRECA, and WECC. This NOPR is pending before the FERC.

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[87] *Order 786* at P 3.

[88] *Order 786* was published in the *Fed. Reg.* on Oct. 23, 2013 (Vol. 78, No. 205) pp. 63,036-63,052.

[89] *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, Order No. 788, 145 FERC ¶ 61,147 (Nov. 21, 2013) ("*Order 788*").

[90] *Id.* at P 2.

[91] *Order 788* was published in the *Fed. Reg.* on Dec. 6, 2013 (Vol. 78, No. 235) pp. 73,424-73,434.

[92] *Protection System Maintenance Reliability Standard*, Order No. 793, 145 FERC ¶ 61,253 (Dec. 19, 2013) ("*Order 793*").

[93] *Order 793* has not yet been published in the *Fed. Reg.*

[94] *Electric Reliability Organization Interpretation of Specific Requirements of the Disturbance Control Performance Standard*, 143 FERC ¶ 61,138 (2013) ("*BAL-002-1a Interpretation Remand NOPR*").

[95] The *BAL-002-1a Interpretation Remand NOPR* was published in the *Fed. Reg.* on May 23, 2013 (Vol. 78, No. 99) pp. 30,245-30,810.

- ***Order 791*: Version 5 CIP Reliability Standards (-002 through -011) (RM13-5)**

On November 22, 2013, the FERC approved the Version 5 Critical Infrastructure Protection ("CIP") Reliability Standards submitted by NERC, which adopt new cyber security controls and extend the scope of the systems that are protected by the CIP Standards.[96] The FERC also approved 19 new or revised definitions associated with the CIP version 5 Standards for inclusion in NERC's Glossary of Terms. In addition, as it proposed in the prior NOPR, the Commission directed NERC to develop modifications to the CIP version 5 Standards to address concerns that limited aspects of the CIP Version 5 Standards are potentially ambiguous and may raise questions regarding the enforceability of the standards. The FERC also directed NERC to submit informational filings regarding certain issues during and following implementation of the CIP version 5 Standards. *Order 791* will become effective February 3, 2014.[97] Rehearing and/or clarification of Order 791 was requested on December 20, 2013 by APPA/NRECA, EEI/EPSA, and Brian Evans-Mongeon. The requests for clarification and/or rehearing are pending before the FERC, with FERC action required on or before January 20, 2014, or the requests will be deemed denied.

- ***Order 773-A*: Revised "Bulk Electric System" Definition and Procedures (RM12-7; RM12-6)**

Other than a pending request for re-hearing of the FERC's June 13, 2013 order in this proceeding,[98] which deferred the effective date for the revised BES definition as approved in *Order Nos. 773*[99] *and 773-A*[100] to July 1, 2014 (rather than July 1, 2013), this proceeding has largely been concluded. The Pacific Northwest Generating Cooperative ("PNGC") requested rehearing of the *June 13 Order*, asserting that, in granting the request, the FERC incorrectly stated that utilities must apply the BES definition prior to seeking a local distribution determination from the FERC and, consequently, inappropriately postponed filing of local distribution filings until the BES definition becomes effective. The FERC issued a tolling order on August 7, 2013 affording it additional time to consider the PNGC rehearing request, which remains pending before the FERC.

- **2014 NERC/NPCC Business Plans and Budgets (RR13-9)**

On November 1, the FERC largely accepted NERC's proposed 2014 Business Plan and Budget, as well as the 2014 Business Plans and Budgets for the Regional Entities, including NPCC.[101] As previously reported, NERC's proposed 2014 Funding requirement is approximately $52.3 million, representing an overall increase of approximately $2.1 million (3.9%) over NERC's 2013 Funding requirement. The NPCC U.S. allocation of NERC's net funding requirement is $3,440,461. NPCC has requested $14.1 million in statutory funding (a U.S. assessment per kWh (2011 NEL) of $0.0000409) and $1.065 million for non-statutory functions. Based on the information contained in the NERC Application, the FERC rejected NERC's proposal to allocate $3.8 million to "restricted working capital" to offset future liabilities under NERC's lease agreements. Instead, the FERC directed NERC to submit a compliance filing within 30 days of the November 1 order indicating how NERC will

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[96] *Version 5 Critical Infrastructure Protection Reliability Standards*, Order No. 791, 145 FERC ¶ 61,160 (Nov. 22, 2013) ("*Order 791*").

[97] *Order 791* was published in the *Fed. Reg.* on Dec. 3, 2013 (Vol. 78, No. 232) pp. 72,756-72, 787. As previously reported, and as requested, the FERC granted an extension of the compliance deadline for the Version 4 CIP Reliability Standards from Apr. 1, 2014 to Oct. 1, 2014. *See Version 4 Critical Infrastructure Protection Reliability Standards and Version 5 Critical Infrastructure Protection Reliability Standards*, 144 FERC ¶ 61,123 (2013).

[98] *Revisions to ERO Definition of Bulk Electric System and Rules of Procedure*, 143 FERC ¶ 61,231 (2013) ("*June 13 Order*"), *reh'g requested.*

[99] *Revisions to ERO Definition of Bulk Electric System and Rules of Procedure*, Order No. 773, 141 FERC ¶ 61,236 (2012) ("*Order 773*"), *order on reh'g and clarification*, 143 FERC ¶ 61,053 (2013), *order denying reh'g*, 144 FERC ¶ 61,174 (2013).

[100] *Revisions to ERO Definition of Bulk Electric System and Rules of Procedure*, Order No. 773-A, 143 FERC ¶ 61,053 (2013) ("*Order 773-A*"), *order denying reh'g*, 144 FERC ¶ 61,174 (2013).

[101] *N. Am. Elec. Reliability Corp.*, 145 FERC ¶ 61,097 (2013).

allocate the $3.8 million consistent with NERC's Working Capital and Operating Reserve Policy. NERC submitted that compliance filing on November 22, and that compliance filing was accepted on January 3, 2014.

- **Market Implications of Frequency Response and Frequency Bias Setting Requirements (AD13-8)**

On July 18, 2013, the FERC solicited comment on the potential market and commercial impacts of certain of the requirements of the proposed Reliability Standard BAL-003-1 (Frequency Response and Frequency Bias Setting) (*see* RM13-11 above).[102] The FERC did not propose changes to proposed Reliability Standard BAL-003-1. Rather, the FERC indicated the comments would inform its consideration and coordination of the requirements of the proposed Standard with tariffs and markets rules subject to its jurisdiction.[103] Comments were due on October 18, 2013. Comments were submitted by NERC, Arizona Public Service, BPA, EEI, EPSA, the Electricity Consumers Resource Council, the Electricity Storage Association ("ESA"), MISO and PJM, and PG&E. This matter is pending before the FERC.

XI. Misc. - of Regional Interest

- **CFTC Exemption**

As previously reported, the Commodity Futures Trading Commission ("CFTC") issued on March 28, 2013, a 142-page final order in response to a February 7, 2012 petition by the RTO/ISOs, including ISO-NE,[104] that exempts from certain provisions of the Commodity Exchange Act ("CEA") the purchase or sale of specifically defined "financial transmission rights," "energy transactions," "forward capacity transactions," and "reserve or regulation transactions" that are offered or sold in a market administered by one of the petitioning RTOs or ISOs pursuant to a tariff or protocol that has been approved or permitted to take effect by FERC or PUCT, as applicable. To be eligible for the exemption, the specifically defined transactions are required to be entered to by persons who are: (1) "appropriate persons," as defined in section 4(c)(3)(A) through (J) of the CEA; (2) "eligible contract participants," as defined in section 1a(18) of the CEA and CFTC regulation 1.3(m); or (3) in the business of (i) generating, transmitting, or distributing electric energy, or (ii) providing electric energy services that are necessary to support the reliable operation of the transmission system. The exemption is subject to the continued effectiveness of acceptable information sharing arrangements between the CFTC and the FERC. The exemption also requires the RTOs and ISOs to keep CFTC requests for information confidential. In addition, the CFTC's anti-fraud and anti-manipulation authority, and scienter-based prohibitions will continue to apply, and the exemption is subject to certain additional conditions stated within the final order. Changes to the FAP and Information Policy required to comport with the CFTC Order were filed and have been accepted.

The April 30, 2012 ISO-NE request for supplemental order clarifying that the contracts, agreements, and transactions entered into under the ISO's Tariff (including internal bilaterals) are exempt from the Act and CFTC regulations to the same degree and extent as the already relief granted in the March 28 order remains pending.[105] If there are questions on this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **203 Application: NRG Kendall / Veolia ENH (EC14-33)**

On January 7, 2014, the FERC authorized the sale of 100% of the common equity interests in NRG Kendall by NRG to a joint venture between ISQ Thermal Kendall LLC and Veolia Energy North America Holdings, Inc. ("Veolia ENH").[106] Unless the January 7 order is challenged, this proceeding will be concluded. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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[102] *Market Implications of Frequency Response and Frequency Bias Setting Reqs.*, 144 FERC ¶ 61,058 (2013).

[103] *Id.* at P 2.

[104] A copy of the "Consolidated Request" is available at http://www.iso-ne.com/regulatory/ferc/fed/index.html.

[105] A copy of the supplemental request was circulated to the Committee on Apr. 30, 2012 and is also available at http://www.iso-ne.com/regulatory/ferc/fed/2012/index.html.

[106] *NRG North America LLC and NRG Kendall LLC*, 146 FERC ¶ 62,006 (Jan. 7, 2014).

- **203 Application: Edison Mission / NRG (EC14-14)**

As previously reported, NRG Energy Holdings Inc. ("NRG") and Edison Mission Energy ("EME") and its public utility subsidiaries requested, on October 25, 2013, approval of a transaction whereby NRG will acquire substantially all of EME's assets, including EME's direct and indirect interests in EME's public utility subsidiaries and other generation-owning entities, in exchange for cash and stock. Applicants asked for a FERC order by January 31, 2014. O December 5, the FERC requested that NRG submit additional information, and that information was provided on December 11, 2013. Interventions were filed by various creditors of EME, Bank of New York, PJM Customer Coalition, and PSEG affiliates that are the owners-lessors of certain affected facilities. PJM's IMM submitted comments on December 9 indicating that the proposed transaction will have a "limited, but not inconsequential impact on the potential competitiveness of PJM markets" and recommending that the FERC consider mitigation to address the issues it identified in its comments. NRG answered the December 9 PJM IMM comments on December 23. The PJM IMM submitted additional comments on January 2, 2014. NRG also answered those comments on January 7. This matter is pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **203 Application: Maine Public Service / Bangor Hydro (EC13-81)**

Pending notice that this merger has been consummated, this proceeding has been completed. As previously reported, the FERC authorized the merger of Maine Public Service ("MPS") into Bangor Hydro ("Applicants") on July 18, 2013.[107] The merger will result in a single electric utility with operations in both central and northern Maine, but without resulting in the direct interconnection of the facilities currently owned by Bangor Hydro and MPS (which are currently only indirectly interconnected via transmission lines in Canada owned by unrelated entities). Bangor Hydro's current transmission system will remain under the functional control of the ISO, while that currently owned by MPS will not. In a companion order (ER13-1125),[108] the FERC waived its regulations to permit Bangor Hydro to maintain two OATTs following consummation of the transaction – one for the central Maine transmission lines currently owned by Bangor Hydro, and one for the northern Maine lines currently owned by MPS. Applicants committed to hold harmless transmission and wholesale customers from transaction-related costs for five years. Among other conditions, the *BHE/MPS Merger Order* required Applicants to notify the FERC within 10 days of the consummation of the merger, which was expected to occur on January 1, 2014. As of the date of this Report, that notice has not been posted on the FERC's eLibrary. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **203 Application: Boston Gen / Constellation Mystic Power (EC10-85)**

Rehearing remains pending of FERC's December 22, 2010 order authorizing Fore River Development, LLC, Mystic I, LLC, Mystic Development, LLC, and Boston Generating, LLC (together, "Boston Gen") and Constellation Mystic Power, LLC ("Mystic Power") to sell five of Boston Gen's generating facilities (Fore River, Mystic 7, 8, and 9, and Mystic Jet) and certain other assets to Constellation Holdings, Inc. or its designee (in this case, its wholly-owned affiliate Mystic Power).[109] As previously reported, the Bankruptcy Court authorized on November 24, 2010 the sale of the generating facilities and other assets to Constellation ("Sale Order"). Mystic Power notified the FERC that the transaction was consummated on January 3, 2011. On January 21, 2011, NSTAR filed a request for rehearing of FERC's order authorizing the transaction to correct the common mode failure reliability condition of Mystic 8 and 9. On February 22, 2011, the FERC issued a tolling order affording it additional time to consider NSTAR's request. On June 3, NSTAR submitted to the FERC additional information to accompany its January 21 request for rehearing. Mystic Power requested on June 20 that the FERC disregard NSTAR's June 3 filing, and affirm its December 22, 2010 order. NSTAR's request for rehearing remains pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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[107] *Bangor Hydro Elec. Co. and Me. Pub. Serv. Co.*, 144 FERC ¶ 61,030 (2013) ("*BHE/MPS Merger Order*").

[108] *Bangor Hydro Elec. Co.*, 144 FERC ¶ 61,031 (2013) ("*BHE OATT Waiver Order*").

[109] *Fore River Dev., LLC*, 133 FERC ¶ 61,248 (2010).

- **SGIA – CMP/MMWAC (ER14-451)**

On December 23, the FERC accepted the non-conforming SGIA (IA-CMP-14-01) filed by CMP to govern the interconnection of the 2.1 MW waste-to-energy facility of Mid-Maine Waste Action Corporation ("MMWAC") in Auburn, Maine to replace the agreement with CMP that expired at the end of 2013. CMP reported that the SGIA did not conform to the *pro forma* SGIA because of modifications to recognize (i) that the ISO is not a party to the LGIA and (ii) the MMWAC facility has been connected to the grid for many years and therefore there has been no new interconnection request or change/break in service with CMP. A January 1, 2014 effective date was granted, as requested. Unless the December 23 order is challenged, this proceeding will be concluded. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **NSTAR/HQUS Use Rights Transfer Agreement (ER14-244)**

On December 12, the FERC accepted an Agreement between NSTAR and H.Q. Energy Services (U.S.), Inc. ("HQUS") that transfers, for an additional year, NSTAR's transmission capacity Use Rights on the HQ Interconnection.[110] Once transferred, HQUS may use or market and sell those Use Rights at its sole discretion, consistent with the Restated Use Agreement and/or in compliance with the ISO-NE OATT and OASIS posting requirements. NSTAR retains all of its IRH management committee voting rights, financial obligations and all other rights and responsibilities provided for in its Support Agreements and the Restated Use Agreement that are not directly related to the Use Rights and their exercise by HQUS. The Agreement was accepted effective as of January 1, 2014, as requested. Unless the December 12 order is challenged, this proceeding will be concluded. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Bangor Hydro (Emera Maine) Notice of Succession to MPS OATT (ER14-218)**

On December 23, the FERC accepted the filing by Emera Maine (f/k/a Bangor Hydro) that provides for the succession by Emera Maine to the Maine Public OATT and (ii) changes the name on the OATT to reflect that succession. As previously reported, the FERC approved the merger of MPS and BHE and waiver of its regulations to permit the successor entity to maintain two OATTs on file with the FERC – one for the former MPS transmission system and one for the former BHE transmission system (*see* EC13-81 above).[111] The revised OATT was accepted effective as of January 1, 2014, as requested. Unless the December 23 order is challenged, this proceeding will be concluded. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **FERC Enforcement Action: Staff Notices of Alleged Violations (IN__-___)**

Constellation. On October 4, 2013, the FERC issued a notice that Staff has preliminarily determined that Constellation Energy Commodities Group, Inc. violated 18 CFR § 35.41(b) and the parallel provision of the California ISO ("CAISO") tariff, § 37.5.1, by not providing accurate information to CAISO.

Louis Dreyfus. On January 6, 2014, the FERC issued a notice that Staff has preliminarily determined that Louis Dreyfus Energy Services, L.P. ("Louis Dreyfus") violated 18 C.F.R. § 1c.2 (2013) by placing virtual trades in MISO at a node in North Dakota to affect the value of its nearby Financial Transmission Rights ("FTRs") during the November 2009 to February 2010 period.

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[110] Pursuant to the "Third Amendment And Restated Use Agreement With Respect To Use Of Quebec Interconnection," ("Restated Use Agreement"), NSTAR has rights to use a portion of the transfer capability on the Phase I and Phase II high-voltage, direct-current transmission facilities ("HQ Interconnection"), which are known as "Use Rights". The Agreement continues, with modifications summarized in the filing, the First Transfer Agreement accepted in a series of orders in Docket No. ER09-207. *See NSTAR Elec. Co.*, 125 FERC ¶ 61,371 (2008).

[111] *Bangor Hydro Elec. Co.*, 144 FERC ¶ 61,030 (2013); *Bangor Hydro Elec. Co.*, 144 FERC ¶ 61,031 (2013).

Recall that Notices of Alleged Violations ("NoVs") are issued only after the subject of an enforcement investigation has either responded, or had the opportunity to respond, to a preliminary findings letter detailing Staff's conclusions regarding the subject's conduct.[112] NoVs are designed to increase the transparency of Staff's nonpublic investigations conducted under Part 1b of its regulations. A NoV does not confer a right on third parties to intervene in the investigation or any other right with respect to the investigation.

- **MISO Methodology to Involuntarily Allocate Costs to Entities Outside Its Control Area (ER11-1844)**

On December 18, 2012, Judge Sterner issued his 374-page initial decision which, following hearings described in previous reports, found at its core that "it is unjust, unreasonable, and unduly discriminatory to allocate costs of Phase Angle Regulating Transformers ("PARs") of the International Transmission Company ("ITC") to NYISO and PJM",[113] which the Midwest ISO ("MISO") and ITC proposed unilaterally to do (without the support of either PJM or NYISO) in its October 20, 2010 filing initiating this proceeding. For a summary of specific findings, please refer to any of the January to June 2013 Reports.

On January 17, 2013, ITC and MISO challenged the Initial Decision through their Brief on Exceptions. Briefs opposing exceptions were filed by the FERC Trial Staff, MISO TOs, NYISO, NY TOs, PJM, and the PJM TOs. On February 25, Joint Applicants moved to strike a portion of the PJM Brief Opposing Exceptions. On March 12, PJM answered Joint Applicants February 25 motion. Since the last report, MISO (now called "Midcontinent Independent System Operator, Inc.") moved to lodge a portion of OE's 2012 State of the Markets Report, presented to the FERC on May 16, 2013, which addressed "Phase Angle Regulators Between Michigan & Ontario Enter Service." Oppositions to that motion to lodge were filed by FERC Staff, NYISO, NY TOs, PJM, PJM TOs. This matter remains pending before the FERC. If there are any questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Waiver of Transmission Standards of Conduct: Emera Maine (f/k/a Bangor Hydro) Request (TS11-5)**

Emera Maine's October 31, 2011 amended waiver request remains pending before the FERC. As previously reported, the FERC denied, without prejudice, Bangor Hydro's initial request for waiver of the FERC's Standards of Conduct requirements.[114] Bangor Hydro requested a limited waiver from the FERC's Standards of Conduct requirements,[115] to the extent necessary, to permit its transmission function personnel to undertake the actions necessary to re-sell into the New England Market energy from the Rollins Project which the MPUC has mandated it purchase but cannot otherwise sell at retail. The FERC stated that it would revisit its determination if Bangor Hydro brought forward information demonstrating that it met the criteria for waiver set forth in section 358.1(c) and summarized in the order (i.e. a demonstration that Bangor Hydro has no access to information concerning the operation of the transmission facilities by the ISO and that it obtains information about such matters only by viewing the ISO's OASIS). In response to the *BHE Standards of Conduct Order*, Bangor Hydro amended its waiver request in 2 respects: First, Bangor Hydro revised its request to apply only to the energy required to be purchased from the Rollins Project and the Exeter Agri-Energy Project. Second, Bangor Hydro committed, as a condition of the waiver (if granted), not to engage in any purchases or sales of wholesale electric capacity or energy except for those required under Maine laws and/or regulations or orders of the MPUC. The MPUC filed comments supporting Bangor Hydro's amended waiver request on November 15, 2011. This matter remains pending before the FERC.

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[112] *See Enforcement of Statutes, Regulations, and Orders*, 129 FERC ¶ 61,247 (2009), *order on requests for reh'g and clarification*, 134 FERC ¶ 61,054 (Jan. 24, 2011).

[113] *Midwest Indep. Trans. Sys.Op., Inc.*, 141 FERC ¶ 63,021 (2012) ("*MISO Initial Decision*") at P 923.

[114] *Bangor Hydro-Elec. Co.*, 136 FERC ¶ 61,182 (2011) ("*BHE Standards of Conduct Order*").

[115] *See* 18 C.F.R. § 358 (2013) *et seq*.

- **Termination of Fitchburg Mandatory PURPA QF Purchase Obligation from Pinetree QF (QM14-1)**

On December 17, 2013, Fitchburg Gas and Electric Light Company ("Fitchburg") filed to terminate its mandatory purchase obligation with respect to the output of the 16 MW Qualifying Facility ("QF") owned and operated by Pinetree Power Fitchburg, Inc. in Westminster, MA ("Pinetree QF"). In its petition, Fitchburg asserts that the Pinetree QF has nondiscriminatory access to the New England Markets (through its parent GDF Suez) and requests that Fitchburg be relieved of its mandatory PURPA purchase requirement with respect to the Pinetree QF. Comments on Fitchburg's petition are due on or before January 14, 2014. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

XII. Misc. - Administrative & Rulemaking Proceedings

- **Zero Rate Reactive Power Rate Schedules (AD14-1)**

On December 11, FERC staff led a workshop that explored the mechanics of filing reactive power rate schedules for which there is no compensation. The workshop was held pursuant to a FERC directive in *Chehalis.*[116] Interested persons were invited to file written comments, on or before January 24, 2014, focused on the mechanics of filing reactive power rate schedules for which there is no compensation.

- **RTO/ISO Centralized Capacity Markets (AD13-7)**

On September 25, 2013, the FERC held a technical conference on centralized capacity markets. The purpose of the technical conference was to consider how current capacity market rules and structures are supporting the procurement and retention of resources necessary to meet future reliability and operational needs. The technical conference provided an opportunity to review the market rules and structures at a high level and examine how they are accomplishing their intended goals and objectives. The technical conference focused on the goals and objectives of existing centralized capacity markets (e.g., resource adequacy, long-term price signals, fixed-cost recovery, etc.) and examined how specific design elements are accomplishing existing and emerging goals and objectives. Comments and presentations have been posted in eLibrary under Docket No. ER13-7. On October 25, the FERC issued a notice inviting post-tech conference comments on any or all of questions attached to the Notice regarding capacity markets in the three Northeast Control Areas. Comments were due on or before January 8, 2014 and were filed by over 50 parties, including the following New England parties: Brookfield, CMEEC, CPV, EMCOS, Entergy, Exelon, GDF SUEZ, Green Mountain Power, LIPA, MMWEC, NEPGA, Potomac Economics, PSEG, UCS, Viridity, Vitol, VT DPS.

- **NOI: Open Access and Priority Rights on Interconnection Facilities (AD12-14; AD11-11)**

As previously reported, the FERC issued a notice of inquiry ("NOI"), on April 19, 2012, seeking comments on whether, and, if so, how, the FERC should revise its current policy concerning priority rights and open access with regard to certain interconnection facilities. The FERC reported that it had, on a case-by-case basis, permitted an owner of interconnection facilities to have priority to capacity over its facilities for its existing use at the time of a third-party request for service. Specifically, in the instance where an owner of interconnection facilities has specific, pre-existing generator expansion plans with milestones for construction of generation facilities and can demonstrate that it has made material progress toward meeting those milestones, the FERC has granted priority rights for the capacity on the interconnection facilities to those future generation projects or expansions as well. Further, an affiliate of the current interconnection facility owner that is developing its own generator projects also may obtain priority rights to the capacity on the interconnection facilities by meeting the "specific plans and milestones "standard with respect to future use, provided that the plans include a future transfer of ownership of the interconnection facilities to such an affiliate. More than 25 parties filed comments on options for addressing priority rights on interconnection facilities, and this matter remains pending before the FERC.

[116] *See Chehalis Power Generating, L.P.*, 145 FERC ¶ 61,052 (Oct. 17, 2013) ("*Chehalis*").

- **WIRES Request for Policy Statement on ROE for Electric Transmission (RM13-18)**

On June 26, WIRES[117] petitioned the FERC to institute an expedited generic proceeding and to provide such policy and clarifications as necessary to provide "greater stability and predictability regarding regulated rates of return on equity for existing and future investments in high voltage electric transmission infrastructure." Specifically, WIRES recommended a new policy that (1) standardizes selection of proxy groups; (2) denies complainants a hearing on rates of return for existing facilities unless it is shown that existing returns are at the extremes of the zone of reasonableness; (3) allows consideration of competing infrastructure investments of other industries; (4) permits use of other rate of return methodologies; and (5) supports use of more forward-looking data and modeling. In addition, WIRES urged the FERC to support consideration of a project's actual and anticipated benefits when a complaint is filed against the ROE for an existing project. Although the WIRES petition has not been noticed for public comments, more than 16 sets of comments have been filed. Since the last report, WIRES submitted on October 3 a summary of the comments and analysis filed to that point in the proceeding. On October 16, the Organization of PJM States noted its position that the WIRES petition did not present a compelling reason for the FERC to initiate a generic rulemaking proceeding or abandon its Discounted Cash Flow methodology. On November 5, a letter from US Senator Angus King, urging the FERC to establish a more certain regulatory environment that provide investors the level of confidence necessary to support and encourage needed infrastructure investments, was posted in eLibrary. This matter is pending before the FERC.

- ***Order 792*: Revisions to *Pro Forma* SGIA and SGIP (RM13-2)**

On November 22, 2013, the FERC amended its *pro forma* Small Generator Interconnection Procedures ("SGIP") and *pro forma* Small Generator Interconnection Agreement ("SGIA"), originally set forth in Order 2006, to: (1) incorporate provisions that would provide an Interconnection Customer with the option of requesting from the Transmission Provider a pre-application report providing existing information about system conditions at a possible Point of Interconnection; (2) revise the 2 MW threshold for participation in the Fast Track Process included in section 2 of the pro forma SGIP; (3) revise the customer options meeting and the supplemental review following failure of the Fast Track screens so that the supplemental review is performed at the discretion of the Interconnection Customer and includes minimum load and other screens to determine if a Small Generating Facility may be interconnected safely and reliably; (4) revise the *pro forma* SGIP Facilities Study Agreement to allow the Interconnection Customer the opportunity to provide written comments to the Transmission Provider on the upgrades required for interconnection; (5) revise the *pro forma* SGIP and the *pro forma* SGIA to specifically include energy storage devices; and (6) clarify certain sections of the *pro forma* SGIP and the *pro forma* SGIA.[118] *Order 792* will become effective February 3, 2014.[119]

Each public utility Transmission Provider must submit a compliance filing within six months of the February 3 effective date revising its SGIP and SGIA or other document(s) subject to the FERC's jurisdiction as necessary to demonstrate that it meets the requirements set forth herein.[120] The FERC will consider requests for variations submitted on compliance on the same bases as the variations permitted for compliance with Order 2006.[121] RTOs will be afforded greater flexibility to propose "independent entity variations" from any revisions to the *pro forma* SGIP and SGIA.[122] Requests for regional reliability variations or independent entity variations

[117] WIRES, the **W**orking group for **I**nvestment in **R**eliable and **E**conomic electric **S**ystems, describes itself as a national non-profit association of investor-, member-, and publicly-owned entities dedicated to promoting investment in a strong, well-planned, and environmentally beneficial high voltage electric transmission grid. Information about its principles and members is available on its website www.wiresgroup.com.

[118] *Small Generator Interconnection Agreements and Procedures*, Order No. 792, 145 FERC ¶ 61,159 (Nov. 22, 2013) ("*Order 792*").

[119] *Order 792* was published in the *Fed. Reg.* on December 5, 2013 (Vol. 78, No. 234) pp. 73,240-73,354.

[120] *Order 792* at P 269.

[121] *Id.* at P 270.

[122] *Id.* at P 274.

are due on February 3, 2014. Requests for variations that are "consistent with or superior to" the *pro forma* OATT may be submitted on or after the February 3 effective date.[123]

- ***Order 784*: 3rd-Party Provision of Ancillary Services; New Electric Storage Technology Accounting and Financial Reporting (RM11-24; AD10-13)**

As previously reported, the FERC issued Order 784[124] on July 18, 2013, revising certain aspects of the FERC's current market-based rate regulations, ancillary services requirements under the *pro forma* OATT, and accounting and reporting requirements in order to foster competition and transparency in ancillary services markets. Specifically, *Order 784* (i) reforms the FERC's policies governing the sale of ancillary services at market-based rates to public utility transmission providers; (ii) requires each public utility transmission provider to add to its OATT Schedule 3 a statement that it will take into account the speed and accuracy of regulation resources in its determination of reserve requirements for Regulation and Frequency Response service; (iii) requires each public utility transmission provider to post and update yearly certain Area Control Error ("ACE") data; and (iv) revises FERC accounting and reporting requirements to better account for and report transactions associated with the use of energy storage devices in public utility operations. The FERC found that the record in this proceeding was insufficient for it to relieve restrictions for Reactive Supply and Voltage Control service and Regulation and Frequency Response service in the same manner as Imbalance and Operating reserves, but indicated that it intends to gather further information regarding the provision of Reactive Supply and Voltage Control service and Regulation and Frequency Response service in a separate, new proceeding. *Order 784* will become effective November 27, 2013.[125] Compliance filings implementing the changes to OATT Schedule 3 must be submitted on or before December 27, 2013. Requests for clarification of *Order 784* were filed by EEI, Powerex, SoCal Edison, and WSPP. On September 16, 2013, the FERC issued a tolling order affording it additional time to consider the requests for clarification, which remain pending before the FERC.

- ***Order 771*: Availability of e-Tag Information to FERC Staff (RM11-12)**

Rehearing of portions of *Order 771* has been requested and remains pending. As previously reported, the FERC issued *Order 771 o*n December 20, 2012.[126] *Order 771* granted the FERC access, on a non-public and ongoing basis, to the complete electronic tags ("e-Tags") used to schedule the transmission of electric power interchange transactions in wholesale markets. *Order 771* requires e-Tag Authors (through their Agent Service) and Balancing Authorities (through their Authority Service) to take steps to ensure FERC access to the e-Tags covered by this Rule by designating the FERC as an addressee on the e-Tags. The FERC stated that the information made available under this Final Rule will bolster its market surveillance and analysis efforts by helping it detect and prevent market manipulation and anti-competitive behavior. In addition, *Order 771* requires e-Tag information be made available to RTO/ISOs and their Market Monitoring Units, upon request to e-Tag Authors and Authority Services, subject to appropriate confidentiality restrictions. *Order 771* became effective February 26, 2013.[127] In response to requests for clarification and/or rehearing of *Order 771* filed by EEI/NRECA, Open Access Technology International, Inc., NRECA (separately), and Southern Companies (collectively, the "Rehearing Requests"), the FERC issued, on March 8, 2013, *Order 771-A*.[128] *Order 771-A* addressed only those issues that needed to be answered on an expedited basis to allow affected entities to comply with the requirement to ensure FERC access in a timely manner to the e-Tags covered by *Order 771*.[129] The

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[123] *Id.* at P 276.

[124] *Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies*, Order No. 784, 144 FERC ¶ 61,056 (Jul. 18, 2013) ("*Order 784*").

[125] *Order 784* was published in the *Fed. Reg.* on July 30, 2013 (Vol. 78, No. 146) pp. 46,178-46,237.

[126] *Availability of E-Tag Info. to Comm'n Staff*, Order No. 771, 141 FERC ¶ 61,235 (2012) ("*Order 771*"), *order on reh'g and clarification*, 142 FERC ¶ 61,181 (2013).

[127] *Order 771* was published in the *Fed. Reg.* on Dec. 28, 2012 (Vol. 77, No. 249) pp. 76,367-76,380.

[128] *Availability of E-Tag Info. to Comm'n Staff*, Order No. 771-A, 142 FERC ¶ 61,181 (2013) ("*Order 771-A*").

[129] *Order 771-A* clarified that: (1) Balancing Authorities and their Authority Services will have until 60 days after publication of this order to implement the validation requirements of *Order 771*; (2) validation of e-Tags means that the Sink

FERC noted that it would issue an additional rehearing order, addressing the remaining issues raised on rehearing and clarification, which therefore remain pending before the FERC.

- ***Order 764-A*: Variable Energy Resources (RM10-11)**

Requests for rehearing and/or clarification of *Order 764-A* remain pending before the FERC. As previously reported, the FERC, in *Order 764-A*,[130] affirmed its basic *Order 764* determinations,[131] provided clarification, and granted EEI's request to extend the period for compliance filings. Specifically, *Order 764-A* clarified (i) that the intra-hour scheduling reform adopted in the *Order 764* applies to ***all*** transmission customers that schedule transmission service under an OATT;[132] (ii) in the absence of sub-hourly settlement and dispatch, a public utility transmission provider must account for intra-hour imbalances in order to ensure that they are properly factored into the calculation of hourly imbalance charges;[133] and (iii) that schedules for firm transmission service will continue to have curtailment priority over schedules for non-firm transmission service.[134] Remaining requests for clarification and/or rehearing were denied. Requests for clarification and/or rehearing of *Order 764-A* were submitted on January 22, 2013 by Powerex and Iberdrola. On February 19, 2013, the FERC issued a tolling order affording it additional time to consider the Powerex and Iberdrola requests, which remain pending before the FERC. The region's *Order 764/764-A* compliance revisions were considered and supported at the August 2, 2013 meeting. Since the last report, the ISO, NEPOOL, PTO AC, CSC and SSPs jointly filed, on November 12, 2013, New England's compliance changes (*see* Section IV, ER14-375 above). If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **NOPR: Incorporation of WEQ Version 003 Standards (RM05-5)**

On July 18, the FERC issued a NOPR[135] which proposes to amend FERC regulations by incorporating by reference ***Version 003*** of the Standards for Business Practices and Communication Protocols for Public Utilities adopted by the Wholesale Electric Quadrant ("WEQ") of the North American Energy Standards Board ("NAESB"). The Version 003 Standards update earlier versions of these standards previously incorporated by reference into FERC regulations at 18 CFR 38.2. The Version 003 standards include modifications to support Order Nos. 890, 890-A, 890-B and 890-C, including the standards to support Network Integration Transmission Service on an Open Access Same-Time Information System ("OASIS"), Service Across Multiple Transmission Systems ("SAMTS"), standards to support FERC policy regarding rollover rights for redirects on a firm basis, standards that incorporate the functionality for transmission providers to credit redirect requests with the capacity of the parent reservation and standards modifications to support consistency across the OASIS-related standards. The Version 003 Standards also include modifications to the OASIS-related standards that NAESB states support Order Nos. 676, 676-A, 676-E and 717 and add consistency. In addition, there are modifications to the Coordinate Interchange standards to compliment recent updates to e-Tag specifications, modifications to the Gas/Electric Coordination standards to provide consistency between the two markets, and re-organized and

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Balancing Authority, through its Authority Service, must reject any e-Tags that do not correctly include the FERC in the CC field; (3)the requirement for the FERC to be included in the CC field on the e-Tags applies only to e-Tags created on or after March 15, 2013; (4) the FERC will deem all e-Tag information made available to the FERC pursuant to *Order 771* as being submitted pursuant to a request for privileged and confidential treatment under 18 CFR 388.112; (5) the FERC is to be afforded access to the Intra-Balancing Authority e-Tags in the same manner as interchange e-Tags; and (6) the requirement on Balancing Authorities to ensure FERC access to e-Tags pertains to the Sink Balancing Authority and no other Balancing Authorities that may be listed on an e-Tag.

[130] *Integration of Variable Energy Res.*, 141 FERC ¶ 61,232 (2012) ("*Order 764-A*"), *reh'g requested.*

[131] *Integration of Variable Energy Res.*, 139 FERC ¶ 61,246 (2012) ("*Order 764*"), *order on reh'g*, 141 FERC ¶ 61,232 (2012), *reh'g requested.*

[132] *Id.* at P 15.

[133] *Id.* at P 19.

[134] *Id.* at P 23.

[135] *Standards for Bus. Practices and Communication Protocols for Pub. Utils.*, 144 FERC ¶ 61,026 (Jul. 18, 2013) ("*WEQ Version 003 Standards NOPR*").

revised definitions to create a standard set of terms, definitions and acronyms applicable to all NAESB WEQ standards. The Version 003 Standards include the Standards addressed in *Order 676-G* below and the recent Smart Grid Standards. Comments on the WEQ Version 003 Standards NOPR were due on or before September 24, 2013,[136] and were filed by 11 parties, including APPA, EEI, and the IRC. This matter is pending before the FERC.

- ***Order 676-G*: Incorporation of WEQ DR and EE M&V Standards (RM05-5)**

On February 21, 2013, the FERC issued *Order 676-G*,[137] which amends FERC regulations to incorporate by reference the business practice standards adopted by the NAESB Wholesale Electric Quadrant ("WEQ") to categorize various DR and energy efficiency ("EE") products and services and to support the measurement and verification ("M&V") of those products and services in RTO/ISOs (collectively, the "Phase II M&V Standards"). The standards provide common definitions and processes regarding DR and EE products in organized wholesale electric markets where such products are offered. The Phase II M&V Standards also require each RTO/ISO to address in its governing documents the performance evaluation methods to be used for DR products. The FERC stated that the Phase II M&V Standards facilitate the ability of DR and EE providers to participate in RTO/ISOs, "reducing transaction costs and providing an opportunity for more customers to participate in these programs, especially for customers that operate in more than one organized market"[138] and "represent an incremental improvement to the existing standards that we incorporated by reference in Order No. 676-F."[139] *Order 676-G* became effective May 6, 2013.[140] The PSEG Companies requested rehearing of *Order 676-G* on March 25, 2013. The FERC issued a tolling order on April 22, 2013 to allow it additional time to consider the PSEG Companies' request, which remains pending before the FERC. With respect to implementation, compliance was required beginning May 6, 2013, and inclusion in the OATT required, either in a stand-alone filing or as part of an unrelated tariff filing, no later than December 31, 2013.[141] New England's *Order 676-G* compliance changes were filed on August 7, 2013 and accepted September 4, 2013.

XIII. Natural Gas Proceedings

For further information on any of the natural gas proceedings, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Jennifer Galiette (860-275-0338; jgaliette@daypitney.com).

- ***Order 787*: Gas/Electric Operational Info Sharing (RM13-17)**

As previously reported, the FERC issued, on November 15, 2013, its final rule revising its regulations to provide explicit authority to interstate natural gas pipelines and public utilities that own, operate, or control facilities used for the transmission of electric energy in interstate commerce to share nonpublic, operational information with each other for the purpose of promoting reliable service or operational planning on either the public utility's or pipeline's system.[142] Recipients of the non-public, operational information will be subject to a

[136] The *WEQ Version 003 Standards NOPR* was published in the *Fed. Reg.* on July 26, 2013 (Vol. 78, No. 144) pp. 45,096-45,104.

[137] *Standards for Bus. Practices and Communication Protocols for Pub. Utils.*, Order No. 676-G, 142 FERC ¶ 61,131 (2013) ("*Order 676-G*").

[138] *Id.* at P 1.

[139] *Id.* at P 33.

[140] *Order 676-G* was published in the *Fed. Reg.* on Mar 7, 2012 (Vol. 78, No. 45) pp. 14,654-14,664.

[141] The FERC will allow an RTO/ISO to incorporate the WEQ standard by reference in its OATT using the following language: "Measurement and Verification of Wholesale Electricity Efficiency (WEQ-021 2010 Annual Plan Item 4(d), July 16, 2012; and Measurement and Verification of Wholesale Electricity Demand Response (WEQ-015, 2010 Annual Plan Items 4(a) and 4(b), Mar. 21, 2011)".

[142] *Communication of Operational Information Between Natural Gas Pipelines and Electric Transmission Operators*, Order No. 787, 145 FERC ¶ 61,134 (Nov. 15, 2013) ("*Order 787*").

No-Conduit Rule that prohibits subsequent disclosure of that information to an affiliate or third party. The approach to the sharing of non-public information proposed by the FERC is intentionally permissive, but the FERC noted that should this voluntary approach prove inadequate to promote reliable service or operational planning on natural gas pipelines and electric transmission systems, it may revisit the need to require certain communications or information sharing between transmission operators in the future. *Order 787* became effective December 23, 2013.[143]

On December 16, the Natural Gas Supply Association ("NGA"), Process Gas Consumers Group, and the Northwest Industrial Gas Users, as well as Enable Interstate Pipelines requested clarification and/or rehearing of *Order 787*. The requests for clarification and/or rehearing are pending before the FERC, with FERC action required on or before January 15, 2014, or the requests will be deemed denied. Regionally, the Participants Committee will be asked at the January 10 meeting to support changes to the Information Policy that would allow the ISO, consistent with *Order 787*, to share Confidential Information with interstate natural gas pipelines..

- **NOI: Enhanced Natural Gas Market Transparency (RM13-1)**

Comments on the FERC's November 15, 2012 NOI seeking input on what changes, if any, should be made to the regulations under the natural gas market transparency provisions of section 23 of the Natural Gas Act ("NGA") are pending before the FERC. As previously reported, the FERC is considering the extent to which quarterly reporting of every jurisdictional natural gas transaction that entails physical delivery for the next day (i.e., next day gas) or for the next month (i.e., next month gas) would provide useful information for improving natural gas market transparency. Comments were received from over 40 parties.

- **Natural Gas-Related Enforcement Actions**

The FERC continues to closely monitor and enforce compliance with regulations governing open access transportation on interstate natural gas pipelines. There was no activity since the last Report

XIV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XV. Federal Courts

The following are NEPOOL-related matters, including petitions for review of FERC decisions in NEPOOL-related proceedings, that are currently pending before the United States Court of Appeals for the District of Columbia Circuit (unless otherwise noted). An "**" following the Case No. indicates that NEPOOL has intervened or is a litigant in the appeal. The remaining matters are appeals as to which NEPOOL has no organizational interest but that may be of interest to Participants. For further information on any of these proceedings, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **New England's *Order 745* Compliance Filing (12-1306)**
  Underlying FERC Proceedings: ER11-4336[144]
  Appellants: EPSA and NEPGA

On July 16, 2012, EPSA and NEPGA filed a petition for review of FERC's orders on New England's *Order 745* (Demand Response Compensation) filings. On August 16, 2012, EPSA and NEPGA filed a statement of issues as well as an unopposed motion to hold case in abeyance pending the final resolution of

[143] *Order 787* was published in the *Fed. Reg.* on Nov. 22, 2013 (Vol. 78, No. 226) pp. 70,164-70,188.

[144] 138 FERC ¶ 61,042 (Jan. 19, 2012); 139 FERC ¶ 61,116 (May 17, 2012).

Case Nos. 11-1486, et al. (*EPSA et al. v. FERC*) (*see* Orders 745 and 745-A below). On August 23, 2012, the Court granted the motion to hold the case in abeyance. Motions to govern future proceedings will be due 30 days following the course issuance of mandate in the *Order 745* appeal.

- **Orders 1000 and 1000-A ((12-1232 consolidated with 12-1233, 12-1250, 12-1276, 12-1279, 12-1280, 12-1285, 12-1292, 12-1293, 12-1296, 12-1299, 12-1300, 12-1304, 12-1448, 12-1478, and 7th Cir. 12-2248)**
  Underlying FERC Proceedings: RM10-23[145]
  Appellants: SC PSA, Coalition for Fair Transmission, PSEG, and Sacramento Municipal Utility District

Petitions for review of FERC's Order 1000 and 1000-A, as identified in previous reports, remain pending before the DC Circuit in the consolidated proceedings identified above. Petitioners briefs were filed on May 28, 2013; Respondent's brief, September 25, 2013; Intervenors in Support of Respondent's Brief, October 16; and Reply Briefs, November 15. Final Briefs were filed on December 13, 2013. Also on December 13, 2013, an unopposed motion of Petitioners proposing format for oral argument was filed. In that motion, Petitioners proposed to waive oral argument on three of the eight issue-based briefs and contemplated oral argument solely on the issues in the remaining five briefs, divided into five sessions totaling 69 minutes per side. Respondent-Intervenors CLF et al. filed a response to Petitioners' motion and cross-motion for the allocation of three minutes of additional and separate time from that of the FERC to respond to Petitioners' and Supporting Intervenors' arguments on the issue of Transmission Planning and Public Policy. The date for oral arguments and the composition of the merits panel has not yet been ordered.

- **FCM Re-Design (12-1060 consolidated with 12-1074, 12-1085, and 12-1149) ****
  Underlying FERC Proceedings: ER10-787; EL10-57; EL10-50[146]
  Appellants: NEPGA, NSTAR, MMWEC/NHEC, VT DPS/VT PSB, NRG

Petitions for review of FERC's orders in the FCM Re-Design proceeding were filed by NEPGA on January 27, 2012; by NSTAR on February 3, 2012; by MMWEC/NHEC on February 10, 2012; by VT DPS/VT PSB on March 1, 2012; and by NRG on March 16, 2012. By orders dated February 7, 2012, February 27, 2012, March 2, and March 22, 2012, the Court consolidated the first four cases, with Case No. 12-1060 remaining the lead Case No. On February 29, 2012, the FERC filed an unopposed motion to hold the NEPGA, NSTAR, MMWEC/NHEC petitions in temporary abeyance pending expiration of the statutory deadline for the filing of petitions for review of the challenged orders. On May 7, 2012, NEPOOL notified the Court of its intent to be aligned as an intervenor in support of NSTAR (12-1074) and MMWEC/NHEC (12-1085), reserving the right to join in an intervenors' brief in support of those petitioners. On October 9, briefs were filed by MMWEC/NHEC, NSTAR, and NEPGA. Supporting petitions were filed on October 23 by NECPUC and PSEG. NEPOOL indicated that it would not join in any intervenor's brief. On January 7, 2013, FERC filed its Respondent Brief. Intervenor for Respondent Briefs were filed on January 22, 2013 by NEPGA and jointly by the CT PURA, HQ US, NICC, NSTAR, and NECPUC. Reply Briefs for Generator Petitioners and Distribution Utility Petitioners were filed on February 5, 2013. Final Briefs were submitted on March 5, 2013. Oral arguments were held on November 19, 2013 before Judges Sentelle, Brown and Griffith. This matter is now pending a decision of that panel.

- **Orders 745 and 745-A (11-1486 consolidated with 11-1489, 12-1088, 12-1091 and 12-1093)**
  Underlying FERC Proceedings: RM10-17-000[147]
  Appellants: EPSA, CAISO, ODEC, EEI, CA PUC

As previously reported, petitions for review of FERC's Order 745 (Demand Response Compensation) were filed by EPSA on December 23, 2011; by CAISO on December 27, 2011; by Old Dominion Electric

[145] 136 FERC ¶ 61,051 (Jul. 21, 2011); 139 FERC ¶ 61,132 (May 17, 2012).

[146] 131 FERC ¶ 61,065 (Apr. 23, 2010); 132 FERC ¶ 61,122 (Aug. 12, 2010); 135 FERC ¶ 61,029 (Apr. 13, 2011); 138 FERC ¶ 61,027 (Jan. 19, 2012).

[147] 134 FERC ¶ 61,187 (Mar. 15, 2011); 137 FERC ¶ 61,215 (Dec. 15, 2011).

Cooperative ("ODEC"); and by EEI and the California Public Utilities Commission ("CA PUC") on February 13, 2012. The DC Circuit consolidated the EPSA and CAISO cases on December 28. By orders dated February 13, 2012 and February 15, 2012, the Court consolidated Case Nos. 12-1088, 12-1091 and 12-1093 with 11-1486. All briefing has been completed. Oral argument in this case was held on September 23, 2013 and this matter is pending before the DC Circuit.

- **PPL EnergyPlus, LLC v. Nazarian, (D. MD - MJG-12-1286)**

On September 30, the United States District Court for the District of Maryland found that a Maryland Public Service Commission ("MD PSC") order directing three Maryland distribution utilities to enter into a 'contract for differences' for capacity and energy in the PJM control area (the "CfD") with a gas-fired merchant generator selected by the MD PSC (the "MD PSC Order") violated the Supremacy Clause of the United States Constitution and cannot be enforced.[148]

The MD PSC Order,[149] after finding that the long-term demand for electricity in Maryland, and specifically in the transmission-congested area encompassing portions of Maryland and the District of Columbia ("SWMAAC Zone"), compelled it to order new generation in that Zone by 2015, directed the utilities to negotiate and enter into the CfD with CPV Maryland, LLC ("CPV"),[150] which had been selected by the MD PSC to provide that generation pursuant to a MD PSC-implemented competitive bid process ("RFP"). Under the CfD, CPV was guaranteed a fixed price for its capacity and energy sales in the PJM markets. The CfD required CPV be paid by the utilities for any revenue shortfall below the fixed contract price and that CPV pay the utilities any excess revenue above the fixed contract price. Any losses would be recouped from, and any gains passed onto, those utilities' standard offer service customers.[151] The MD PSC Order was challenged by a number of PPL companies, PSEG Power, and Essential Power ("Plaintiffs") on the grounds that the Order violated the U.S. Constitution's Supremacy Clause and "dormant" Commerce Clause,[152] and that the MD PSC had deprived Plaintiffs of their federal statutory rights ("Section 1983 Claim").

The District Court held that the MD PSC Order, through the CfD, set or established the ultimate price to be received by CPV for its wholesale energy and capacity sales.[153] However, by setting that price, the MD PSC encroached on the FERC's exclusive authority to set wholesale energy and capacity prices.[154] The FERC, the District Court stated, "has exclusive domain in that field and has fixed the price for wholesale energy and capacity sales in the PJM Markets as the market-based rate produced by the auction processes approved by FERC and utilized by PJM."

> While Maryland may retain traditional state authority to regulate the development, location, and type of power plants within its borders, the scope of Maryland's power is necessarily limited by FERC's exclusive authority to set wholesale energy and capacity prices under, *inter alia*, the Supremacy Clause and the field preemption doctrine.[155] Based on this principle, Maryland cannot

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[148] *PPL EnergyPlus, LLC v. Nazarian*, __ F.Supp.2d ___ (D. Md. Sep. 30, 2013); 2013 U.S. Dist. LEXIS 140210, 2013 WL 5432346 ("*District Court Order*").

[149] MD PSC Order No. 84815 (Apr. 12, 2012).

[150] *Id.* at pp 29-30.

[151] *See id.* at pp. 26-27.

[152] The "dormant commerce clause" is a doctrine developed by the U.S. Supreme Court that limits states' power to improperly discriminate against interstate commerce, even in the absence of affirmative federal law/regulation, or where federal law/regulation is "dormant"..

[153] *District Court Order* at *132.

[154] *Id.* at *133.

[155] "Field preemption" is a doctrine based on the Supremacy Clause of the U.S. Constitution that holds that any federal law, including regulations of a federal agency, takes precedence over any conflicting state law. Preemption can be

> secure the development of a new power plant by regulating in such a manner as to intrude into the federal field of wholesale electric energy and capacity price-setting.[156]

Accordingly, the MD PSC Order was found to have violated the Supremacy Clause by virtue of field preemption, and the PSC was enjoined from enforcing the Generation Order, which includes the requirement that the Maryland utilities enter into the CfD with CPV.[157]

With respect to Plaintiffs' remaining claims (the dormant Commerce Clause and Section 1983 Claims), the Court denied both. The Court denied the dormant Commerce Clause claim finding that (i) the MD PSC Order did not affect the ability of other market participants to sell energy and capacity in the PJM Markets and (ii) the addition of a state-sponsored market participant physically located within the SWMAAC Zone did not impose a burden on interstate commerce.[158] The Section 1983 Claim was not viable, the Court found, because "the Supremacy Clause is not a source of substantive individual rights that could support an action brought pursuant to Section 1983."

The September 30 decision has been appealed to the United States Court of Appeals for the Fourth Circuit (consolidated under 13-2424) and will be reported under that docket going forward.

- **PPL EnergyPlus, LLC v. Hanna (D. NJ 11-745)**

On October 11, the United States District Court for the District of New Jersey issued an analogous decision declaring unconstitutional (and therefore null and void) New Jersey's Long Term Capacity Agreement Pilot Program Act ("LCAPP").[159]

LCAPP authorized, pursuant to New Jersey Public Service Board ("NJ PSB") oversight, the construction of several gas-fired generators in or near New Jersey "[to] ensure[] sufficient generation is available to the region, and thus the users in [New Jersey] in a timely and orderly manner"[160] and to address a perceived lack of incentives under PJM's reliability pricing model ("RPM") to achieve that goal. Like the MD PSC Order, to accomplish those goals, LCAPP required New Jersey's four electric distribution companies to enter into NJ PSB-issued "standard offer capacity agreements" or "SOCAs" with NJ PSB-selected generators ("LCAPP generators"), obligating the LCAPP generators to construct their facilities and participate in the RPM. The utilities were obligated to pay for any RPM revenue shortfall below the LCAPP generator's NJ PSB-approved development costs, while the LCAPP generators were obligated to pay back any excess RPM Auction revenues received above the generator's NJ PSB-approved development costs.[161] Any losses would be recouped from, and any gains passed onto, those utilities' standard offer service customers. LCAPP and its implementation was challenged by PPL, Atlantic City, Calpine, Exelon, and PSEG companies.

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implied when federal law/regulation "occupies the field" in which the state is attempting to act/regulate. Field preemption occurs when there is "no room" left for state regulation. Accordingly, a state may not pass a law or take any action in a field, like the regulation of wholesale power sales, pervasively regulated by federal law/regulation.

[156] *Id.* at *102.

[157] The ability of the Maryland utilities and CPV to enter into the CfD absent state directive was not directly challenged by the Plaintiffs and was not addressed by the District Court Order.

[158] The Court also held that, even if the Generation Order could be viewed as placing or imposing some burden on interstate commerce, the burden would be *de minimis*, and thus, not clearly excessive in relation to the benefits to Maryland.

[159] *PPL EnergyPlus, LLC v. Hanna*, __ F.Supp.2d ___ (D. NJ. Oct. 11, 2013); 2013 U.S. Dist. LEXIS 147273, ("*NJ Order*").

[160] N.J.S.A. § 48:3-98(d)(2).

[161] *NJ Order* at *72-73.

The Court found LCAPP and its implementation unconstitutional under both the field and conflict preemption doctrines of the Supremacy Clause.[162] With respect to the field preemption doctrine, the Court stated "[a]lthough the State of New Jersey and the NJ PSB retained the responsibility for the siting and construction of power plants, they are required to exercise this responsibility without interfering with the [FERC]'s exclusive authority to regulate wholesale sales of electricity in interstate commerce."[163] By establishing the price that LCAPP generators would receive for their sales of capacity, LCAPP "supplants the Federal Power Act and intrudes upon the FERC's exclusive jurisdiction over interstate wholesale power rates."[164] The Court rejected arguments that the SOCAs were purely financial contracts, and thereby did not intrude upon the FERC's exclusive jurisdiction. "[T]he SOCAs are contingent upon the LCAPP generators' successful sale of capacity to PJM" and "expressly condition payment on physical performance."[165] Accordingly, LCAPP "invades the field occupied by Congress and is [field] preempted by the Federal Power Act."[166] The Court also found that LCAPP and the SOCAs were unconstitutional under the conflict preemption doctrine of the Supremacy Clause.[167] "From reviewing the entire scheme of the RPM process, it is clear that [LCAPP] [and the SOCA's imposition of a government-imposed price] poses as an obstacle to the [FERC]'s implementation of the RPM."[168]

The October 11 decision has been appealed to the United States Court of Appeals for the Third Circuit (13-4330) and will be reported under that docket going forward.

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[162] The Court denied Plaintiffs' dormant Commerce Clause claim that the "community benefit" points awarded to New Jersey generators unconstitutionally favored in-state enterprises over out-of-state enterprises (effectively prohibiting out-of-state generators from competing to be LCAPP-eligible generators), finding it reasonable that the NJ PSB would incentivize construction in areas where reliability concerns are in flux. *Id.* at *110.

[163] *Id.* at *104.

[164] *Id.* at *103.

[165] *Id.* at *102. Physical performance includes plant construction, provision of available capacity, bidding into and clearing in RPM and the PJM markets.

[166] *Id.* at 103.

[167] "Conflict preemption" occurs where there is a conflict between a state law and a federal law. ("[E]ven if Congress has not occupied the field, state law is naturally preempted to the extent of any conflict with a federal statute."). Such a conflict occurs when "the challenged state law stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress. The court must look to "'the entire scheme of the statute'" and determine "'[i]f the purpose of the [federal] act cannot otherwise be accomplished--if its operation with its chosen field [would] be frustrated and its provisions be refused their natural effect. Where a state law conflicts with a federal law, the Court does not balance the competing federal and state interests. Any state law, however clearly within a State's acknowledged power, which interferes with or is contrary to federal law, must yield." *Id.* at 105-106.

[168] *Id.* at 106.

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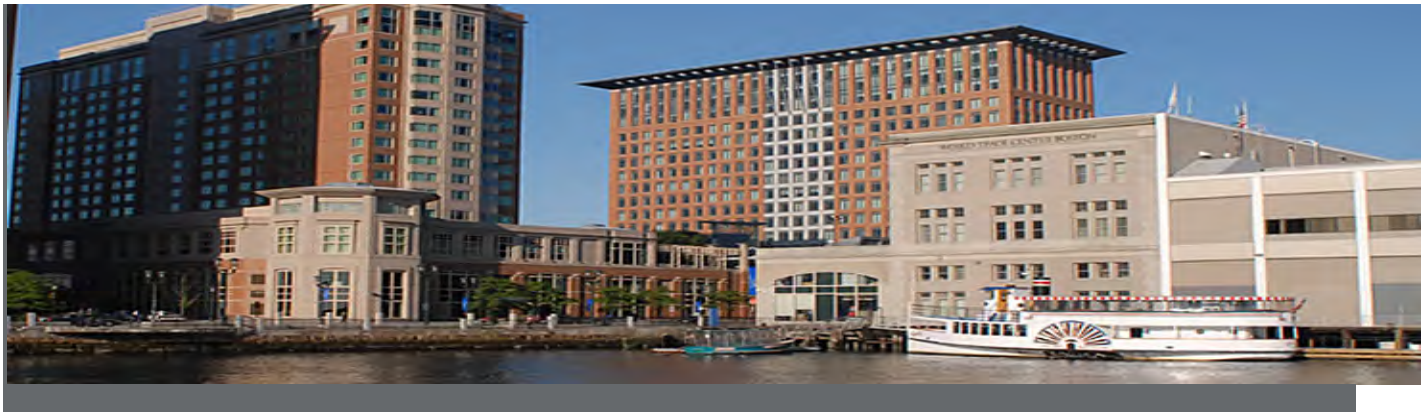

SEAPORT HOTEL

FROM Points West via I-90:

Follow the Massachusetts Turnpike/Interstate 90 East to Exit 25 – South Boston. At the top of the ramp, bear left towards Seaport Boulevard. At the first set of lights, proceed straight onto East Service Road. At the next set of lights, take a right onto Seaport Boulevard. The Seaport Boulevard entrance to the Seaport Garage is located ahead on the right.

FROM Points South via I-93:

Heading northbound on I-93 towards Boston, take Exit 20, which will be immediately after Exit 18. Follow the signs to “I-90 East.” Take the first tunnel exit to "South Boston.” At the first set of lights at the top of the ramp, proceed straight onto East Service Road. At the next set of lights, take a right onto Seaport Boulevard. The Seaport Boulevard entrance to the Seaport Garage will be ahead on the right.

FROM Points North via I-93:

Heading southbound on Interstate 93 Boston, take Exit 23, Purchase Street and move into the left lane. At the top of the ramp, take a left turn onto the Evelyn Moakley Bridge/Seaport Boulevard. Follow Seaport Boulevard for approximately .8 miles, the Seaport Boulevard entrance to the Seaport Garage will be on the right, after the Seaport Boulevard/B Street intersection.

FROM Logan International Airport and Route 1A South:

Follow the signs towards I-90 West - Ted Williams Tunnel. Take the Ted Williams Tunnel to Exit 25. At the top of the ramp proceed straight onto B Street. Follow B Street to the end and take a right onto Seaport Boulevard. The Seaport Boulevard entrance to the Seaport Garage will be on your right.

PUBLIC TRANSPORTATION

The MBTA Silver Line Waterfront (SL1) provides service from the WTC Station to Logan International Airport terminals every 10 minutes during the weekday and every 15 minutes during the weekend. The Silver Line station is located adjacent to the hotel.

Seaport Boston is about 3 miles from Logan Airport, one of several hotels near the Boston Convention Center and a quick ride away from all Boston attractions. Taxis are readily available from the lobby of our hotel.

This scenic way to travel is a great way to avoid traffic. Hop on the water taxi shuttle at your terminal and enjoy the ride. The stop for pick up and drop off is at the Seaport World Trade Center, directly across the street from the Seaport hotel.