VIA ELECTRONIC MAIL

TO: MEMBERS AND ALTERNATES OF THE NEPOOL PARTICIPANTS COMMITTEE

RE: Supplemental Notice of August 2, 2013 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, August 2, 2013 at 10:00 a.m. at the Radisson Hotel, 700 Elm Street, Manchester, NH. The Participants Committee meeting will be held in the Salon A Ballroom for the purposes set forth on the attached agenda and posted with the meeting materials at http://www.nepool.com/NPC2013.php. For your information, this meeting is recorded, as are all the NEPOOL Participants Committee meetings. For those of you staying over or arriving early, breakfast will be served in the Curriers Room directly across from the Ballroom beginning at 7:30 a.m.

Rooms at the Radisson Hotel for the August 2 meeting are available at the rate of $129.00 per night, on a first-come, first-served basis UNTIL Monday, July 29, 2013. To take advantage of these arrangements, please contact the hotel directly (603-206-4109) and reference the “NEPOOL Participants Committee” block of rooms. Directions to the Radisson Hotel may be obtained by visiting the Hotel’s website (http://www.radisson.com/manchester-hotel-nh-03101/nhmanch) and clicking on the “Map & Directions” link.

Looking ahead, we would encourage you to mark your calendars for the 2013 Regional System Plan public meeting which will be held on Thursday, September 12, the day before the Participants Committee September 13 meeting. Both meetings will be held at The Colonnade Hotel in Boston. Details for the September 12 RSP meeting are available at: http://www.iso-ne.com/calendar/detail.action?eventId=121314&link=yes&filter=off. Rooms at The Colonnade Hotel for the September 13 meeting are available at the rate of $279.00 per night, on a first-come, first-served basis UNTIL September 9, 2013. To take advantage of these arrangements, please contact the hotel directly (617-424-7000) and reference the “NEPOOL Participants Committee” block of rooms.

Respectfully yours,

/s/
David T. Doot, Secretary
FINIAL AGENDA

1. To approve the preliminary minutes of the June 25-27, 2013 Participants Committee Summer Meeting. [Deferred]

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

2A To consider and take action, as appropriate, on proposed revisions to Schedule 22 of the ISO OATT in response to FERC Orders 764 and 764-A. Background materials and a draft resolution are posted with this supplemental notice.

3. To receive an ISO Chief Executive Officer Report.

4. To receive an ISO Chief Operating Officer Report.

5. To receive an ISO Internal Market Monitor Q2 2013 Quarterly Report.

6. To consider and take action, as appropriate, on proposed revisions to Market Rule 1 to allow regulation providers to incorporate inter-temporal opportunity costs into their bids in response to FERC Order 755. Background materials and a draft resolution are posted with this supplemental notice.

7. To consider and take action, as appropriate, on proposed revisions to Manual M-20 to provide additional detail for Import Capacity Resource qualification. Background materials and a draft resolution are posted with this supplemental notice.

8. To consider and take action, as appropriate, on proposed revisions to Market Rule 1 to modify the FCM Shortage Event Triggers. Background materials and a draft resolution are posted with this supplemental notice.

9. To consider and take action, as appropriate, on revisions to Appendix A to Market Rule 1 to allow Market Participants to submit a Section 205 Filing for cost recovery when a resource is dispatched under specific circumstances for reliability reasons, as proposed by the IMM in response to the FERC’s June 14 order in Docket No. EL13-72 et al. Background materials and a draft resolution are posted with this supplemental notice.

10. 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.

11. To receive reports from committees and subcommittees.

12. To transact such other business as may properly come before the meeting.
CONSENT AGENDA

From the notice of actions of the June 18, 2013 *Reliability Committee* meeting, dated June 19, 2013, which has been previously circulated:

1. **Retirement of Appendix B to OP 18**

   Support the retirement of Appendix B (PTF/Interconnection Energy Billing Metering Accuracy Levels) from ISO Operating Procedure (OP) No. 18 (Metering and Telemetering Criteria) (OP 18) and related conforming changes and administrative changes to OP 18, as recommended by the Reliability Committee at its June 18, 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 approved unanimously.

2. **Revisions to OP 23 and Additions of New Appendices B – F to OP 23**

   Support revisions to OP 23 (Generator Resource Auditing) and the additions of Appendices B-F to OP 23, as recommended by the Reliability Committee at its June 18, 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 approved unanimously.

3. **Revisions to Market Rule 1, Sections III.1.5.1 and 1.7.11 (Net-Metered, Non-Intermittent Generator Audit Revisions)**

   Support revisions to Market Rule 1 Sections III.1.5.1 and 1.7.11, which include (i) modifications to the Seasonal Claimed Capability for non-intermittent net-metered generators and special qualifying facilities that elect to audit (allowing the option of ratings based on median availability rather than median output), and (ii) various clean-up changes, as recommended by the Reliability Committee at its June 18, 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 approved unanimously.

4. **Revisions to PP 10 (Order for Review of De-List Bids Submitted at Same Price)**

   Support revisions to Planning Procedure No. 10 (Planning Procedure to Support the Forward Capacity Market)((PP 10), which clarify and provide guidance regarding the review order of de-list bids that are submitted at the same price, as recommended by the Reliability Committee at its June 18, 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 approved unanimously.

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1  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](http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/relblty/actions/index.html)
From the notice of actions of the July 10-11, 2013 Markets Committee meeting, dated July 11, 2013, which has been previously circulated:

5. **Revisions to Information Policy (Release of Minimum Power Data)**

   Support revisions to the Information Policy to allow the public release of minimum power values derived from Economic Minimum Limit offer data and used in the ISO’s planning studies, as recommended by the Markets Committee at its July 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 unanimously.

6. **Revisions to Market Rule 1, Appendix F to Market Rule 1, and ISO Manuals M-11 and M-28 (Tie-Line Name Cleanup)**

   Support revisions to Market Rule 1, Appendix F to Market Rule 1, and ISO Manuals M-11 and M-28 to correct obsolete tie-line names, as recommended by the Markets Committee at its July 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 unanimously.


   Support revisions to Manuals M-35 (Definitions and Abbreviations) and M-RPA (Registration and Performance Auditing) to conform to Market Rule 1 changes related to generation capacity auditing, as recommended by the Markets Committee at its July 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 unanimously.

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MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Eric Runge, NEPOOL Counsel

DATE: July 26, 2013

RE: Revisions to Schedule 22 of Section II of the ISO New England Inc. Transmission, Markets and Services Tariff (“ISO-NE OATT”)

At the August 2, 2013 Participants Committee meeting you will be asked to vote on proposed revisions to Schedule 22 of the ISO-NE OATT (the large generator interconnection procedures). The minor changes to Schedule 22 are in compliance with FERC Orders 764 and 764-A and relate to the integration of Variable Energy Resources (“VERs”). Specifically, the revisions include a definition of VER and an obligation on the part of VERs to provide certain meteorological and forced outage data to the ISO. An ISO presentation to the Transmission Committee on the revisions as well as a marked version of Schedule 22 have been included with this memo.

The Transmission Committee, at its July 22, 2013 meeting, unanimously recommended Participants Committee support for these revisions, and that recommendation would have been on the Consent Agenda but for the timing of the Transmission Committee vote.

The following resolution could be used for Participants Committee action on the Schedule 22 revisions:

RESOLVED, that the Participants Committee supports the proposed revisions to Schedule 22 of the ISO-NE OATT, as recommended by the Transmission Committee at its July 22, 2013 meeting, together with [such other changes as were agreed to at the meeting, and] such further non-substantive changes as may be approved by the Chair and Vice-Chair of the Transmission Committee.
FERC Orders 764 & 764-A
Integration of
Variable Energy Resources

ISO-NE Compliance

Marc Lyons
LEAD ANALYST – RELIABILITY & OPERATIONS SERVICES
Overview

• Summary of FERC Order 764 & 764-A
• ISO-NE’s proposed compliance with the Orders
• Schedule for Stakeholder Review
Summary of FERC Orders 764 & 764-A

• Order No. 764 sets out proposed reforms to the pro forma open access transmission tariffs (OATT) related to the integration of Variable Energy Resources (VER).

• Order 764 requires each public utility transmission provider to revise their OATT to:
  o Offer intra-hourly transmission scheduling at 15-minute intervals;
  and
  o Incorporate provisions into the pro forma Large Generator Interconnection Agreement (LGIA) requiring interconnection customers whose generating facilities are VERs to provide meteorological and forced outage data to the public utility transmission provider for the purpose of power production forecasting.
    ▪ Add definition of VER.
    ▪ Add new Article 8.4.

• Order No. 764-A affirms these requirements.
ISO-NE’s Proposed Compliance – Intra-hourly Scheduling

• The ISO does not propose to revise the ISO-NE OATT to incorporate intra-hourly transmission scheduling at 15-minute intervals.
  o The ISO-NE OATT does not offer pro forma transmission service over the Pool Transmission Facilities; it does not employ the system of physical rights or advanced reservations contemplated in the FERC pro forma OATT.
  o The ISO-NE OATT’s regional transmission service works in conjunction with the New England market design, which uses a security-constrained economic commitment and dispatch system that sends dispatch signals to generating resources on five-minute intervals.

• The driver for offering transmission customers an option to schedule transmission on a 15-minute interval basis is primarily to reduce VER exposure to imbalance charges under the pro forma OATT.
  o ISO-NE OATT does not impose imbalance charges.
  o Internal resources are subject to risks associated with deviations between Day-Ahead Energy Market and Real-Time Energy Market, but Intermittent Resources are not subject to Real-Time NCPC charges.
  o External transactions are unbundled from the source resource under the New England market rules, which eliminates any exposure to deviations.
ISO-NE’s Proposed Compliance –
Incorporate Provisions in the pro forma LGIA

• The ISO proposes to revise the pro forma LGIA to:
  o Add new Article 8.4 setting forth the *reporting requirement* regarding meteorological and forced outage data, but:
    ▪ Instead of cross-referencing Appendix C, Interconnection Details of the LGIA, Article 8.4 will cross-reference existing ISO-NE Operating Documents on meteorological and forced outage data requirements;
    ▪ Use the term of Intermittent Power Resources (IPR) that already exists in the ISO-NE Tariff instead of incorporating the term of VER; and
    ▪ Replace the term “Transmission Provider” with “System Operator”, which is the term used in the LGIA for ISO-NE.
Provisions in the pro forma LGIA (cont’d)

- Existing ISO-NE Operating Documents are consistent with Order 764 data collection requirements. For example:
  - Operating Procedure 14, Appendix F - ISO-NE currently collects certain the meteorological data - temperature, wind speed, wind direction, atmospheric pressure, and additional data as needed.
  - ISO-NE currently collects forced outage data by MW and number of turbines.
  - Collection is in real time (5 minute increments) and forecasted (hourly intra-day and daily for week ahead) for units represented in the ISO Energy Management System.
Provisions in the pro forma LGIA (cont’d)

• VER vs. IPR:
  o Order No. 764 defines VER as a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.”
  o ISO-NE Tariff defines IPR as wind, solar, run of river hydro and other renewable resources that do not have control over their net power output. Wind and solar resources shall be qualified as Intermittent Power Resources or Intermittent Settlement Only Resources (See Section III 13.1.2.2.2)

• ISO-NE proposes to use the term IPR in place of the VER term in pro forma LGIA, Section 8.4, because:
  o IPR is the existing term used in the ISO-NE.
  o Adding VER would introduce unnecessary confusion.
Schedule for Stakeholder Review

- June 20, 2013 TC Meeting - ISO-NE’s initial presentation of revisions to Schedule 22 LGIA to comply with FERC Order 764
- July 22/23, 2013 Joint MC/RC Summer Meeting - TC Action
- July 24, 2013 - PTOAC Discussion
- FERC Filing no later than November 12, 2013
Questions
SCHEDULE 22

LARGE GENERATOR INTERCONNECTION PROCEDURES
attention and/or correction by the other Party(ies). The Party owning such equipment shall correct such error or malfunction as soon as reasonably feasible.

8.3 **No Annexation.** Any and all equipment placed on the premises of a Party shall be and remain the property of the Party providing such equipment regardless of the mode and manner of annexation or attachment to real property, unless otherwise mutually agreed by the Parties.

8.4 **Provision of Data from an Variable Energy Resource Intermittent Power Resource**

The Interconnection Customer whose Generating Facility is an Intermittent Power Variable Energy Resource shall provide meteorological and forced outage data to the Transmission ProviderSystem Operator to the extent necessary for the Transmission ProviderSystem Operator’s development and deployment of power production forecasts for that class of Intermittent Power Variable Energy Resources. The Interconnection Customer with an Intermittent Power Variable Energy Resource having wind as the energy source, at a minimum, will be required to provide the Transmission ProviderSystem Operator with site-specific meteorological data including: temperature, wind speed, wind direction, and atmospheric pressure. The Interconnection Customer with an Intermittent Power Variable Energy Resource having solar as the energy source, at a minimum, will be required to provide the Transmission ProviderSystem Operator with site-specific meteorological data including: temperature, atmospheric pressure, and irradiance. The Transmission ProviderSystem Operator and Interconnection Customer whose Generating Facility is an Intermittent Power Variable Energy Resource shall mutually agree to any additional meteorological data that are required for the development and deployment of a power production forecast. The Interconnection Customer whose Generating Facility is an Intermittent Power Variable Energy Resource also shall submit data to the Transmission ProviderSystem Operator regarding all forced outages to the extent necessary for the System Operator’s development and deployment of power production forecasts for that class of Variable Energy Intermittent Power Resources. The exact specifications of the
meteorological and forced outage data to be provided by the Interconnection Customer to the Transmission Provider/System Operator, including the frequency and timing of data submittals, shall be made taking into account the size and configuration of the Variable Energy Intermittent Power Resource, its characteristics, location, and its importance in maintaining generation resource adequacy and transmission system reliability in its area. All requirements for meteorological and forced outage data must be commensurate with the power production forecasting employed by the Transmission Provider/System Operator. Such requirements for meteorological and forced outage data are specified in the ISO New England Operating Documents, et forth in Appendix C, Interconnection Details, of this LGIA, as they may change from time to time.

ARTICLE 9. OPERATIONS

9.1 General. Each Party shall comply with applicable provisions of ISO New England Operating Documents, Reliability Standards, or successor documents, regarding operations. Each Party shall provide to the other Party(ies) all information that may reasonably be required by the other Party(ies) to comply with Applicable Laws and Regulations and Applicable Reliability Standards.

9.2 Control Area Notification. Before Initial Synchronization Date, the Interconnection Customer shall notify the System Operator and Interconnecting Transmission Owner in writing in accordance with ISO New England Operating Documents, Reliability Standards, or successor documents. If the Interconnection Customer elects to have the Large Generating Facility dispatched and operated from a remote Control Area other than the Control Area in which the Large Generating Facility is physically located, and if permitted to do so by the relevant transmission tariffs and ISO New England Operating Documents, Reliability Standards, or successor documents, all necessary arrangements, including but not limited to those set forth in Article 7 and Article 8 of this LGIA, and remote Control Area generator interchange agreements, if applicable, and the appropriate measures under such agreements, shall be executed and implemented prior to the placement of the Large Generating Facility in the other Control Area for dispatch and operations.
To:        NEPOOL Participants Committee
From:     Erin Wasik-Gutierrez, Secretary
           NEPOOL Transmission Committee
Date:      July 24, 2013
Subject:   ACTIONS OF THE TRANSMISSION COMMITTEE

This memo is notification to the Participants Committee (PC) of the actions taken by the NEPOOL Transmission Committee on July 22, 2013. The following actions were taken, with oppositions and abstentions noted:

**Agenda Item No. 2: Transmission Committee Meeting Minutes**

It was moved and seconded to approve (as modified at this meeting) the minutes of the May 17, June 14 and June 20, 2013 Transmission Committee meetings.

*The motion to approve the minutes passed unanimously, based on a show of hands.*

**Agenda Item No. 3: FERC Order 764 & 764A – Integration of Variable Energy Resources**

The following main motion was moved and seconded:

*RESOLVED, the Transmission Committee recommends that the Participants Committee support for the proposed revisions to Schedule 22 Standard Large Generator Interconnection Procedures, Section II - Open Access Transmission Tariff (“OATT”) of the ISO New England Transmission, Markets and Services Tariff, as proposed by ISO New England Inc. to be filed with the Federal Energy Regulatory Commission in compliance with Order Nos. 764 & 764A – Integration of Variable Energy Resources, as circulated for the June 22, 2013 Transmission Committee meeting and as modified at that meeting with such further non-substantive changes as the Chair and Vice-Chair of the Transmission Committee may subsequently approve.*

*The motion to recommend Participants Committee support passed unanimously, based on a show of hands.*

cc:       Transmission Committee
Summary of ISO New England Board and Committee Meetings

August 2, 2013 Participants Committee Meeting

Since the last update, the Markets Committee met on July 18 by teleconference.

The Markets Committee reviewed reports on market monitoring, mitigation and reliability costs. The Committee discussed mitigation events during June. The Committee noted the increase in reserve market costs during June, and the fact that higher forward reserve market clearing prices in effect for the summer period and recent changes to the real-time reserve market rules contributed to the increased costs. The Committee also discussed the accuracy of load forecasts, and reviewed the methods that are used to subsequently validate load forecast algorithms based on actual weather conditions and the impact of relatively recent investments in energy efficiency efforts. The Committee was informed of a reduction in the average amount of virtual offers submitted in June and recent actions of the FERC that have heightened concerns for financial traders that conduct large amounts of virtual bidding and participate in the financial transmission rights market. Next, the Committee considered management’s response to the recommendations of the market monitors in their recent annual reports. It was noted that management substantially agrees with the recommendations of the market monitors and described in the response the status of efforts to address the recommendations. There was a general discussion concerning efforts to address generator performance issues. The Committee also discussed the importance of pending market changes. The Committee received a report on status of efforts to address the allocation of Net Commitment Period Compensation costs associated with virtual bidding, and an update on stakeholder review of the NCPC changes that are being drafted as part of the energy market offer flexibility project. The Committee received an update on Forward Capacity Market issues, including stakeholder views on a demand curve, the FCM performance incentives proposal and revisions to the Minimum Offer Price Rule. The Committee held a general discussion concerning the ISO’s FCM performance incentives proposal and a report by Robert Stoddard prepared on behalf of NextEra Energy, Inc. The Committee also received a summary of stakeholder reaction to the presentation of the FCM performance incentives impact analysis, and the key factors driving the results of the impact analysis.
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  - Forward Capacity Market
  - Reliability Costs - Net Commitment Period Compensation (NCPC) Operating Costs
  - Regional System Plan (RSP) & Interregional Planning
  - Operable Capacity Analysis – Summer 2013
  - Operable Capacity Analysis – Fall 2013
  - Operable Capacity Analysis – Appendix
Highlights

• Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  – July natural gas prices over the period were 7.6% higher while oil prices were 1.7% lower than June 2013 average values
  – Average RT Hub Locational Marginal Prices (LMPs) over the period were 66% higher than June 2013 averages
• Average July 2013 natural gas prices and RT Hub LMPs, respectively, were up 25% and 57%, respectively, from July 2012 averages.

*All data through July 24 unless noted.*
Highlights, cont.

• Daily Net Commitment Period Compensation (NCPC)
  – July payments over the period totaled $20.7M, up $10.9M from June
  – First Contingency payments totaled $11.1M, up $6.2M from June
    • $11.1M paid to internal resources, up $6.3M from June
      – $1.2M charged to DALO, $9.9M to RT Deviations
    • $25K paid to resources at external locations, down $43K from June
      – $15K charged to DALO at external locations, $10K to RT Deviations
  – Second Contingency payments totaled $1.2M, down $2.1M from the June total of $3.3M
    – Protection for Eastern load zones on seven days resulted in payments of $1.2M, most of which resulted on July 16-18 during the heat wave
  – Voltage payments totaled $6.9M, up $5.6M from June
  – Distribution payments totaled $1.5M, up $1.2M from June
  – NCPC payments over the period as percent of Energy Market value were 2.9%
Highlights, cont.

• The lowest 50/50 and 90/10 Summer Operable Capacity Margin is being calculated for the week beginning September 7th.

• The lowest 50/50 and 90/10 Fall Operable Capacity Margin is being calculated for the week beginning September 21st.
Highlights, cont.

• Manual 20 changes regarding external capacity transactions did not gain approval by the MC at their July meeting. The ISO will be seeking a vote at the August NPC
• ISO made a FERC compliance filing on July 30 indicating a schedule to target FCA #9 for changes related to the development of capacity zones
• RSP13 draft has been distributed to stakeholders for comment and will be reviewed at the August 13 PAC meeting
JULY 3, 2013 DCS EVENT
Highlights

• Forest fires in James Bay area of Quebec in vicinity of 735 kV transmission right-of-way

• Multiple transmission line trips coupled with losses of generation, load and exports
  – Four transmission lines tripped
  – Approximately 2,900 MW of Quebec generation rejected Special Protection Scheme
  – Approximately 3,500 MW of Quebec load tripped
  – Approximately 3,370 MW of exports to NYISO, ISO-NE, NBSO, and IESO tripped

• New England lost ~1,750 MW of imports from HQ

• New England recovered from the source loss in under 11 minutes

• No SOL or IROL violations in New England
Highlights, cont.

• Eastern Interconnection was able to sustain the loss of HQ Imports
  – System load was decreasing
  – Imports from HQ tripped over the course of several minutes
  – Length of disturbance allowed governor response and some level of AGC to mitigate the impact on Eastern Interconnection
  – Frequency decreased to a minimum value of 59.91

• TransÉnergie is working with NERC/NPCC to perform an event analysis
Preparations for the Week

• All transmission work and generation outages and reductions that could be postponed or cancelled were completed prior to the heat wave

• ISO New England Operations Staff had preparatory meetings with the following entities prior to and during the heat wave:
  – NYISO, HQ, NBSO, IESO, PJM and MISO Reliability Coordinators
  – Master Local Control Centers
  – Gas Pipeline Operators

• Implemented M/LCC #2 at 1045 on Monday, 7/15/13

• Forecasted tight operating reserves throughout the week
Preparations for the Week, cont.

- Weather deviations from forecast impacted load forecast accuracy. This was particularly the case on Thursday when the temperatures dropped significantly along the coast due to an afternoon sea breeze.
  - Actual average temperatures were lower than forecast by an average of 1.1°F during peak hours throughout the week.
  - Boston temperatures on Thursday during peak hours were lower than forecast by an average of 3.4°F with a dew point below forecast by an average of 1.4°F.
  - Friday saw the closest correlation between the weather and load forecast with very high temperatures and dew points throughout New England.
Capacity Deficiency Event Summary

- Operating Procedure #4 “Action During a Capacity Deficiency” (OP-4) implemented on July 19 due to generator reductions and transmission constraints.

<table>
<thead>
<tr>
<th>Action(s)</th>
<th>Implemented</th>
<th>Cancelled</th>
</tr>
</thead>
<tbody>
<tr>
<td>M/LCC #2</td>
<td>7/15 (10:45)</td>
<td>7/20 (21:00)</td>
</tr>
<tr>
<td>OP#4 Action 1</td>
<td>12:00</td>
<td>20:30</td>
</tr>
<tr>
<td>OP#4 Action 2*</td>
<td>13:00</td>
<td>20:30</td>
</tr>
<tr>
<td>OP#4 Action 3*</td>
<td>14:20</td>
<td>18:00</td>
</tr>
<tr>
<td>OP#4 Action 5*</td>
<td>15:00</td>
<td>18:00</td>
</tr>
</tbody>
</table>

(*) = Actions of OP#4 that were not implemented in Maine due to transmission constraints
Capacity Deficiency Event Summary, cont.

- On Friday forecasted an operating reserve deficiency of 449 MW based on the load forecast of 27,850
- Peak hour generator reductions and outages totaled 4,611 MW
- Peak hour (Hour Ending 17) imports were as follows:

<table>
<thead>
<tr>
<th>Interface</th>
<th>Actual</th>
<th>Interface</th>
<th>Actual</th>
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</thead>
<tbody>
<tr>
<td>NYN</td>
<td>629 Import</td>
<td>NB</td>
<td>800 Import</td>
</tr>
<tr>
<td>NNC</td>
<td>38 Export</td>
<td>Phase 2</td>
<td>1400 Import</td>
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<tr>
<td>CSC</td>
<td>330 Export</td>
<td>HG</td>
<td>218 Import</td>
</tr>
</tbody>
</table>
Capacity Deficiency Event Summary, cont.

- Forecasted temperature in Hartford and Boston was 99°F.
  - Sixth consecutive day with temperatures climbing above 90 degrees in New England
- Actual temperatures in Boston were as forecasted. Temperature in Hartford was slightly lower.
- Expected schedule of net deliveries for the peak hour were 1,718 MW. The actual scheduled net deliveries were 2,677 MW
Capacity Deficiency Event Summary, cont.

• Just prior to noon, operating reserves became deficient
  – OP#4 Action 1 was declared at 12:00 allowing for the depletion of 30 minute reserves and notification to all resources to be prepared to provide capacity up to Capacity Supply Obligation
  – At 13:00, Action 2 was declared (excluding Maine) dispatched all Real Time Demand Resources (193 MW)
  – At 14:20, Action 3 of OP#4 was declared requesting Market Participants to conserve energy
  – At 15:00, Action 5 of OP#4 was declared in order to maintain ten minute operating reserves. 200 MW of Participant Emergency Energy Transactions were purchased in Hour Ending 16.
System Load vs. Forecast on July 19

System Load vs. Forecast - Friday, July 19, 2013

Load Served vs. Forecast

MW

Hour Ending
System Load – Week of July 15 through July 19

System Load - Week of July 15 through July 19

MW

Hour Ending

1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Daily Peak Load – Week of July 14

ISO-NE July 14-20, 2013 Daily Peaks (MW)

<table>
<thead>
<tr>
<th>Demand Resources</th>
<th>07/14/2013 (Sun)</th>
<th>07/15/2013 (Mon)</th>
<th>07/16/2013 (Tue)</th>
<th>07/17/2013 (Wed)</th>
<th>07/18/2013 (Thu)</th>
<th>07/19/2013 (Fri)</th>
<th>07/20/2013 (Sat)</th>
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</thead>
<tbody>
<tr>
<td>Actual</td>
<td>22374</td>
<td>26089</td>
<td>26225</td>
<td>26623</td>
<td>26867</td>
<td>27359</td>
<td>24648</td>
</tr>
</tbody>
</table>

4th highest New England peak load

Highest New England Weekend Load
Total Energy Consumed in July since 2001

Energy: July 1-28, 2001-2013 (MWh)
Highest Energy for First Four Weeks of July
Summary of Demand Response Dispatch

- 193 MW Dispatched at 13:05 (performance measurement starts at 13:35)
- Demand Response dispatch cancelled at 20:35

<table>
<thead>
<tr>
<th>Duration of the July 19th, 2013 Real Time Event (Local Time)</th>
<th>MW Dispatched (NET CSO)</th>
<th>Performance during 100% Dispatch Period (MW)</th>
<th>Percent Avg. Performance vs. Net CSO</th>
</tr>
</thead>
<tbody>
<tr>
<td>Start Time</td>
<td>End Time</td>
<td>193</td>
<td>184</td>
</tr>
<tr>
<td>13:35</td>
<td>20:35</td>
<td>193</td>
<td>184</td>
</tr>
</tbody>
</table>
## Demand Response Performance

<table>
<thead>
<tr>
<th>Load Zone</th>
<th>Net CSO (MW)</th>
<th>Performance (MW)</th>
<th>Percent of Initial Performance to Net CSO</th>
</tr>
</thead>
<tbody>
<tr>
<td>CT</td>
<td>87.1</td>
<td>81.2</td>
<td>93.2%</td>
</tr>
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<td>NEMA</td>
<td>25.4</td>
<td>26.0</td>
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<td>NH</td>
<td>3.6</td>
<td>9.8</td>
<td>276.9%</td>
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<tr>
<td>RI</td>
<td>19.4</td>
<td>8.2</td>
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<tr>
<td>SEMA</td>
<td>10.1</td>
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<tr>
<td>VT</td>
<td>23.0</td>
<td>29.3</td>
<td>127.1%</td>
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<tr>
<td>WCMA</td>
<td>24.7</td>
<td>19.7</td>
<td>79.7%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>193.3</strong></td>
<td><strong>183.8</strong></td>
<td><strong>95.1%</strong></td>
</tr>
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</table>
Generation by fuel type at peak

- Natural Gas: 47%
- Nuclear: 18%
- Oil: 11%
- Coal: 9%
- Hydro: 5%
- Wind: 2%
- Pumped Storage: 5%
- Other Renewables: 3%
Peak Energy Rent (PER) Impacts on July 19

July 19, 2013 Preliminary Results

• Peak Energy Rent conditions occurred during 5 hours on July 19, 2013 (hours ending 13:00 through 17:00) in the Rest-Of-Pool Capacity Zone only
• The strike price for the day (for comparison to Hub LMPs) was $558.37/MWh (Actual Real-Time Hub LMPs ranged from $585-$869/MWh)
• The PER hours during July are estimated to produce a ~$1.9M reduction to CSO payments during the August 2013 delivery month (billed in September)
Observations

• Transmission Constraints from North to South locked in Northern Generation from getting to load centers
  – In past years, transfers from New Brunswick to New England have been low due to Point Lepreau outage and this is no longer the case

• 6\textsuperscript{th} hot day in a row (>90° F)
  – Generator reductions due to ambient air temperature and environmental issues

• No transmission system facilities failures

• Adequate reactive resources to maintain transmission system voltages

• System Operators at the ISO, LCCs, External Areas, Generating Designated Entities and Demand Designated Entities performed well and in a collaborative and coordinated fashion to maintain reliability of the system
SYSTEM OPERATIONS
## System Operations

<table>
<thead>
<tr>
<th>Weather Patterns</th>
<th>Boston</th>
<th>Hartford</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Temperature – Above Average (+2.0)</td>
<td>Temperature – Average (+3.0)</td>
</tr>
<tr>
<td></td>
<td>Max 99, Min 60</td>
<td>Max 97, Min 58</td>
</tr>
<tr>
<td></td>
<td>Precipitation 3.39” (Liquid) – Average Normal 2.86”</td>
<td>Precipitation 4.18” (Liquid) – Average Normal = 3.43</td>
</tr>
</tbody>
</table>

### Peak Load:

| Peak Load | 27, 377 MW * | July 19, 2013 | 17:00 |

### M/LCC2:
- **07/03/2013, 17:00 – 20:00**: Due to a New England capacity deficiency - H.Q. Major Transmission event
- **07/04/2013, 12:55 – 20:00**: Due to a New England capacity deficiency - Loss of 1 pole of Phase 2
- **07/10/2013, 14:30 – 20:00**: Due to A New England capacity deficiency with congestion in Maine
- **07/15/2013, 10:45 through 7/20/2013 21:00**: Due to extended hot weather and forecasted New England capacity deficiencies

### OP4:
- **Action 1**: 07/19/2013 12:00 - 20:30 Implemented Power Caution
- **Action 2**: 07/19/2013 13:15 – 20:30 Demand response activated all of New England except Maine -194 MW
- **Action 3**: 07/19/2013 14:20 - 18:00 Request Voluntary Load Curtailment of Market Participants in NE
- **Action 5**: 07/19/2013 15:00 - 18:00 Called for EET’s

* Does not include preliminary estimate 194 MW of RTDR dispatch.
# System Operations

<table>
<thead>
<tr>
<th><strong>NPCC Simultaneous Activation of Reserve Events:</strong></th>
<th></th>
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<tbody>
<tr>
<td>07/03/2013</td>
<td>NYISO</td>
</tr>
<tr>
<td>07/03/2013</td>
<td>ISO-NE</td>
</tr>
<tr>
<td>07/04/2013</td>
<td>ISO-NE</td>
</tr>
<tr>
<td>07/14/2013</td>
<td>IESO</td>
</tr>
<tr>
<td>07/15/2013</td>
<td>PJM</td>
</tr>
<tr>
<td>07/16/2013</td>
<td>IESO</td>
</tr>
<tr>
<td>07/17/2013</td>
<td>NYISO</td>
</tr>
<tr>
<td>07/18/2013</td>
<td>ISONE</td>
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<td>07/19/2013</td>
<td>IESO</td>
</tr>
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<td>07/22/2103</td>
<td>IESO</td>
</tr>
<tr>
<td>Minimum Generation Warning</td>
<td>07/01/13</td>
</tr>
<tr>
<td>---------------------------</td>
<td>----------</td>
</tr>
<tr>
<td>Minimum Generation Warning</td>
<td>07/02/13</td>
</tr>
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<td>Minimum Generation Warning</td>
<td>07/02/13 – 07/03/13</td>
</tr>
<tr>
<td>Minimum Generation Event</td>
<td>07/03/13</td>
</tr>
<tr>
<td>Minimum Generation Warning</td>
<td>07/10/13</td>
</tr>
<tr>
<td>Minimum Generation Warning</td>
<td>07/12/13</td>
</tr>
<tr>
<td>Minimum Generation Warning</td>
<td>07/13/13</td>
</tr>
<tr>
<td>Minimum Generation Event</td>
<td>07/13/13</td>
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<td>Minimum Generation Warning</td>
<td>07/14/13</td>
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<td>System Operations</td>
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<table>
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<tr>
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<th>Time Period</th>
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<td>Start-05:00 Expired-07:00 Interchange Cuts Only</td>
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<td>Minimum Generation Warning</td>
<td>07/25/13</td>
<td>Start-02:00, Expired 06:00 Interchange Cuts Only</td>
</tr>
<tr>
<td>Minimum Generation Warning</td>
<td>07/25/13</td>
<td>Start-12:30, Expired 22:59 Interchange Cuts &amp; SS Denied</td>
</tr>
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<td>Minimum Generation Warning</td>
<td>07/25/13</td>
<td>Start-00:01, Expired 07:00 Interchange Cuts Only</td>
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<td>Minimum Generation Warning</td>
<td>07/26/13</td>
<td>Start-23:00, Expired 23:59 Interchange Cuts Only</td>
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<td>07/27/13</td>
<td>Start-00:01, Expired 09:00 Interchange Cuts &amp; SS Denied</td>
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<td>Minimum Generation Event</td>
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<td>Start-05:00, Expired 08:00 Interchange Cuts &amp; SS Denied</td>
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<td>Minimum Generation Warning</td>
<td>07/28/13</td>
<td>Start-08:00, Expired 10:00 Interchange Cuts &amp; SS Denied</td>
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2013 System Operations – Load Forecast Accuracy

All Hours
Monthly Average, Daily Maximum and Minimum, Based on forecast published by 1000 on day before Operating Day

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<tr>
<th></th>
<th>J</th>
<th>F</th>
<th>M</th>
<th>A</th>
<th>M</th>
<th>J</th>
<th>J</th>
<th>A</th>
<th>S</th>
<th>O</th>
<th>N</th>
<th>D</th>
<th>Avg</th>
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<tbody>
<tr>
<td>Mo Avg</td>
<td>1.45</td>
<td>1.64</td>
<td>1.17</td>
<td>1.22</td>
<td>1.56</td>
<td>2.26</td>
<td>2.51</td>
<td>1.68</td>
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<td>Day Max</td>
<td>4.51</td>
<td>9.45</td>
<td>2.45</td>
<td>3.32</td>
<td>6.07</td>
<td>8.02</td>
<td>7.13</td>
<td>5.78</td>
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<td>Day Min</td>
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<td>0.52</td>
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<td>0.50</td>
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<td>0.53</td>
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<td>1.50</td>
<td>1.50</td>
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<td>1.50</td>
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</tr>
<tr>
<td>Rest of Year Goal</td>
<td>1.50</td>
<td>1.50</td>
<td>1.50</td>
<td>1.50</td>
<td>1.50</td>
<td>1.50</td>
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<td>1.50</td>
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<tr>
<td>Rest of year Actual</td>
<td>1.43</td>
<td>1.76</td>
<td>1.17</td>
<td>1.21</td>
<td>1.56</td>
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<tr>
<td>Summer Actual</td>
<td>1.43</td>
<td>1.76</td>
<td>1.17</td>
<td>1.21</td>
<td>1.56</td>
<td>1.50</td>
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<td>1.50</td>
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</tr>
</tbody>
</table>

Sponsor - John Norden
Contact – William Callan
Summer Goal - 2.6%, Rest of Year Goal - 1.5%
Summer consists of June, July & August
### 2013 System Operations - Load Forecast Accuracy cont.

**Peak Hours**

**Monthly Average, Daily Maximum and Minimum**

Based on forecast published by 1000 on day before Operating Day

<table>
<thead>
<tr>
<th>Month</th>
<th>Mo. Avg</th>
<th>Day Max</th>
<th>Day Min</th>
<th>Summer Goal</th>
<th>Rest of Year Goal</th>
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<tr>
<td>J</td>
<td>1.30</td>
<td>4.82</td>
<td>0.02</td>
<td>2.6%</td>
<td>&lt; 2.6%</td>
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<td>F</td>
<td>1.15</td>
<td>5.67</td>
<td>0.06</td>
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<td>A</td>
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<td>3.52</td>
<td>0.01</td>
<td>1.50</td>
<td>&lt; 1.5%</td>
</tr>
<tr>
<td>M</td>
<td>1.92</td>
<td>8.27</td>
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<td>&lt; 1.5%</td>
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<tr>
<td>J</td>
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<td>J</td>
<td>3.19</td>
<td>8.27</td>
<td>0.02</td>
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<td>&lt; 1.5%</td>
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<tr>
<td>A</td>
<td>0.01</td>
<td>0.09</td>
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<td>1.50</td>
<td>&lt; 1.5%</td>
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<tr>
<td>S</td>
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<td>0.02</td>
<td>0.03</td>
<td>1.50</td>
<td>&lt; 1.5%</td>
</tr>
<tr>
<td>O</td>
<td>0.01</td>
<td>0.02</td>
<td>0.03</td>
<td>1.50</td>
<td>&lt; 1.5%</td>
</tr>
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<td>N</td>
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<td>0.02</td>
<td>0.03</td>
<td>1.50</td>
<td>&lt; 1.5%</td>
</tr>
<tr>
<td>D</td>
<td>0.01</td>
<td>0.02</td>
<td>0.03</td>
<td>1.50</td>
<td>&lt; 1.5%</td>
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<tr>
<td>Avg</td>
<td>1.81</td>
<td>6.36</td>
<td>0.03</td>
<td>1.50</td>
<td>&lt; 1.5%</td>
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</table>

<table>
<thead>
<tr>
<th>Mo Avg</th>
</tr>
</thead>
<tbody>
<tr>
<td>F</td>
</tr>
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<td>M</td>
</tr>
<tr>
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<td>O</td>
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<tr>
<td>N</td>
</tr>
<tr>
<td>D</td>
</tr>
<tr>
<td>Avg</td>
</tr>
</tbody>
</table>

**Rest of Year Goal**

- **Actual**: 1.26
- **Goal**: 1.50

**Summer Actual**

- **Actual**: 2.9
- **Goal**: 2.6

**Contact**

- **William Callan**

**Summer**

- Consists of June, July & August

**Sponsor**

- **John Norden**

**Summary**

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

---

<table>
<thead>
<tr>
<th>Dashboard Indicator</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rest of Year Goal &lt; 1.5%</td>
</tr>
<tr>
<td>Summer Goal &lt; 2.6%</td>
</tr>
</tbody>
</table>
2013 System Operations - Load Forecast Accuracy

Percent of Hours Actual Load Above vs. Below Forecast
Based on LF published by 1000, day before Operating Day

Target = 50% Plus/Minus 5%

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<thead>
<tr>
<th></th>
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<tbody>
<tr>
<td>J</td>
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<td>55.0</td>
<td>45.0</td>
<td>36.0</td>
<td>45.0</td>
<td>53.0</td>
<td>43.0</td>
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<td>47.0</td>
</tr>
<tr>
<td>F</td>
<td>47.0</td>
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<td>55.0</td>
<td>64.0</td>
<td>55.0</td>
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<tr>
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<td>169.0</td>
<td>107.0</td>
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<td>134.0</td>
<td>222</td>
<td>202</td>
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<td>-42.7</td>
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</table>

% Error

- Above
- Below

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

Sponsor – John Norden
Contact – William Callan
2013 System Operations - Load Forecast Accuracy

Deviation of Actual Load from Forecasted Load Year to Date 2013

- Average Above
- Average Below
- Max Above
- Max Below

Month: Jan, Feb, Mar, Apr, May, Jun, Jul, Aug, Sep, Oct, Nov, Dec, AVG

Mega Watts: -3500 to 3500
Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL

**Net Energy for Load (NEL)**

- **Partial**

**Weather Normalized NEL**

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: July 1-24, 2013

Average price difference over this period (DA-RT): $-8.75
Average price difference over this period ABS(DA-RT): $16.98
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 26%
Gas price is average of Massachusetts delivery points; No6 Oil is New York Spot Price from DOE's Energy Information Administration

Underlying natural gas data furnished by:

Global markets in clear view
DA LMPs Average by Zone & Hub, July 2013

![Chart showing LMPs, Congestion, and Marginal Losses for different zones and hubs in July 2013.](chart-image)

- 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, July 2013

$/MWh

<table>
<thead>
<tr>
<th>Hub</th>
<th>ME</th>
<th>NH</th>
<th>VT</th>
<th>CT</th>
<th>RI</th>
<th>SEMA</th>
<th>WCMA</th>
<th>NEMA</th>
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<tbody>
<tr>
<td>$200</td>
<td>(15.0%)</td>
<td>(7.0%)</td>
<td>(3.6%)</td>
<td>0.8%</td>
<td>(0.5%)</td>
<td>0.6%</td>
<td>0.2%</td>
<td>1.2%</td>
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Legend:
- **LMP**
- **Congestion**
- **Marginal Losses**
Components of Cleared DA Supply and Demand – Last Three Months

Supply

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

Demand

- 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

Supply

Demand

Avg Hourly MW

MAY2013  JUN2013  JUL2013

Gen
Imports

Load
Exports
DA Fct Load
Hourly DA LMPs, July 1-24, 2013

Hourly Day-Ahead LMPs

Heat wave, high loads (24,000-25,500+ MW)
Hourly RT LMPs, July 1-24, 2013

Tight capacity with binding reserve constraints over the peak due to large reduction in net imports (Phase II and Highgate), complicated by smaller generator trips. Generation was postured.

Tight capacity with binding reserve constraints over the peak due to high loads (25,000 MW) and continued outage of Phase II. Generation was postured.

Tight capacity with binding reserve constraints due to high loads (26,000+ MW) that ran over the forecast.

System: Tight capacity with binding reserve constraints and reserve deficiency due to high loads (27,300+ MW) and unit reductions. OP-4 Actions 1-3, and 5.
System Unit Availability

Data as of 7/26/13
LOAD RESPONSE
Capacity Supply Obligation (CSO) MW by Demand Resource Type for August 2013

<table>
<thead>
<tr>
<th>Load Zone</th>
<th>RTDR*</th>
<th>RTEG**</th>
<th>On Peak</th>
<th>Seasonal Peak</th>
<th>Total</th>
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<td>ME</td>
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<td>87.09</td>
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<td>NH</td>
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<td>77.04</td>
<td>76.91</td>
<td>299.33</td>
<td>558.13</td>
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<tr>
<td>RI</td>
<td>23.32</td>
<td>9.39</td>
<td>77.77</td>
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<td>SEMA</td>
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<td>10.74</td>
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<td>WCMA</td>
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<td>22.56</td>
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<td>21.33</td>
<td>206.10</td>
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<tr>
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<td>352.08</td>
<td>163.43</td>
<td>814.89</td>
<td>328.02</td>
<td>1,658.43</td>
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</table>

* 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 7/24/13 Interim Queue Update

• One new project, with a capacity of 99 MW, has applied for interconnection study since the last update
  • The new project is a wind facility, with an expected in-service date of 2016
• One project withdrew from the Queue, resulting in a net increase in new generation projects of 81 MW
• In total, 58 generation projects are currently being tracked by the ISO, totaling 5,500 MW
Actual and Projected Annual Capacity Additions
By Supply Fuel Type and Demand Resource Type

- 2013 values include the 46 MW of generation that has gone 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

<table>
<thead>
<tr>
<th></th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>Total MW</th>
<th>% of Total*</th>
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</thead>
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<td>Demand Response - Passive</td>
<td>225</td>
<td>188</td>
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<td>888</td>
<td>693</td>
<td>391</td>
<td>2,799</td>
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<td>14</td>
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<td>Natural Gas/Oil</td>
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<td>8</td>
<td>332</td>
<td>1,461</td>
<td>416</td>
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<td>Natural Gas</td>
<td>40</td>
<td>20</td>
<td>0</td>
<td>0</td>
<td>482</td>
<td>542</td>
<td>9.9</td>
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<tr>
<td>Totals</td>
<td>640</td>
<td>867</td>
<td>1,380</td>
<td>1,274</td>
<td>1,303</td>
<td>5,464</td>
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* Sum may not equal 100% due to rounding
Actual and Projected Annual Generator Capacity Additions
By State

<table>
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<tr>
<th></th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>Total MW</th>
<th>% of Total*</th>
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<td>0</td>
<td>29</td>
<td>0</td>
<td>57</td>
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<tr>
<td>New Hampshire</td>
<td>97</td>
<td>59</td>
<td>171</td>
<td>0</td>
<td>0</td>
<td>327</td>
<td>5.9</td>
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<td>33</td>
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<td>152</td>
<td>544</td>
<td>391</td>
<td>1,614</td>
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<td>803</td>
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<td>745</td>
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<td><strong>660</strong></td>
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<td><strong>1303</strong></td>
<td><strong>5,583</strong></td>
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</table>

* Sum may not equal 100% due to rounding

- 2013 values include the 46 MW of generation that has gone commercial in 2013
# New Generation Projection

*By Fuel Type*

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<thead>
<tr>
<th>Fuel Type</th>
<th>Total</th>
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<th>Yellow</th>
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<tr>
<td></td>
<td>No. of Projects</td>
<td>Capacity (MW)</td>
<td>No. of Projects</td>
</tr>
<tr>
<td>Biomass/Wood Waste</td>
<td>5</td>
<td>214</td>
<td>2</td>
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<td>Hydro</td>
<td>5</td>
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<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>5</td>
<td>532</td>
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</tr>
<tr>
<td>Natural Gas/Oil</td>
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<tr>
<td>Oil</td>
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<tr>
<td>Solar</td>
<td>3</td>
<td>16</td>
<td>2</td>
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<tr>
<td>Wind</td>
<td>32</td>
<td>2,465</td>
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<tr>
<td><strong>Total</strong></td>
<td>58</td>
<td>5,537</td>
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</table>

- 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

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<td>Capacity (MW)</td>
<td>No. of Projects</td>
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<tr>
<td>Peaker</td>
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<tr>
<td>Wind Turbine</td>
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<td>2,465</td>
<td>3</td>
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<tr>
<td><strong>Total</strong></td>
<td>58</td>
<td>5,537</td>
<td>8</td>
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</table>

- 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*

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<tr>
<th>Fuel Type</th>
<th>No. of Projects</th>
<th>Capacity (MW)</th>
<th>No. of Projects</th>
<th>Capacity (MW)</th>
<th>No. of Projects</th>
<th>Capacity (MW)</th>
<th>No. of Projects</th>
<th>Capacity (MW)</th>
<th>No. of Projects</th>
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<th>No. of Projects</th>
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<th>Baseload</th>
<th>Intermediate</th>
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<th>Wind Turbine</th>
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<tr>
<td>Biomass/Wood Waste</td>
<td>5</td>
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<tr>
<td>Natural Gas</td>
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<td>Wind</td>
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<td>7</td>
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<td><strong>Total</strong></td>
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<td><strong>11</strong></td>
<td><strong>2,327</strong></td>
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<td><strong>7</strong></td>
<td><strong>11</strong></td>
<td><strong>8</strong></td>
<td><strong>32</strong></td>
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</table>
FORWARD CAPACITY MARKET
Forward Capacity Market Update

• CCP #8 (2017-2018)
  – Capacity Zones
    • Next stakeholder meeting scheduled for 8/19
    • ISO made a FERC compliance filing on July 30 indicating a schedule to target FCA #9 for changes related to the development of capacity zones
  – New import qualification continues
    • The ISO will be meeting with NYISO again in August
    • Two question sets have been sent to Participants thus far. A second teleconference with Participants is scheduled for late July
  – Non-price retirement (NPR) window opened 6/3 and closes 10/6
  – New Resource Qualification continues to be on target with QDN’s to be released on 9/27
# Capacity Supply Obligation FCA 4

<table>
<thead>
<tr>
<th>Resource Type</th>
<th>Resource Type</th>
<th>FCA 4</th>
<th>Proration</th>
<th>Annual Bilateral for ARA 2</th>
<th>ARA 2</th>
<th>Annual Bilateral for ARA 2</th>
<th>ARA 3</th>
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<td>CSO</td>
<td>*Change</td>
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* 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

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<th>Resource Type</th>
<th>Resource Type</th>
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<td>-2,644.443</td>
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<td>-1,137.189</td>
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</table>

* 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

<table>
<thead>
<tr>
<th>Resource Type</th>
<th>Resource Type</th>
<th>FCA</th>
<th>Proration</th>
<th>Annual Bilateral Period 1 for ARA 1</th>
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<th>Annual Bilateral Period 1 for ARA 2</th>
<th>ARA 2</th>
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<tr>
<td>Demand</td>
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<td></td>
<td></td>
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</table>

* 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

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<thead>
<tr>
<th>Resource Type</th>
<th>FCA</th>
<th>Proration</th>
<th>Annual Bilateral Period 1 for ARA 1</th>
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<th>Annual Bilateral Period 2 for ARA 2</th>
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<td>33,210.868</td>
<td>-3,008.656</td>
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</table>

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

** Change columns contain 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

<table>
<thead>
<tr>
<th>Component Name</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1&lt;sup&gt;st&lt;/sup&gt; Contingency NCPC Payments</td>
<td>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.</td>
</tr>
<tr>
<td>2&lt;sup&gt;nd&lt;/sup&gt; Contingency NCPC Payments</td>
<td>Reliability costs paid to resources providing capacity in constrained areas to respond to a local second contingency. They are committed based on 2&lt;sup&gt;nd&lt;/sup&gt; Contingency (2ndC) protocols, and are also known as Local Second Contingency Protection Resources (LSCPR).</td>
</tr>
<tr>
<td>Voltage NCPC Payments</td>
<td>Reliability costs paid to resources operated by ISO-NE to provide voltage support or control in specific locations.</td>
</tr>
<tr>
<td>Distribution NCPC Payments</td>
<td>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.</td>
</tr>
<tr>
<td>Delisted Units</td>
<td>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.</td>
</tr>
<tr>
<td>OATT</td>
<td>Open Access Transmission Tariff.</td>
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## Charge Allocation Key

<table>
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<tr>
<th>Allocation Category</th>
<th>Market / OATT</th>
<th>Allocation</th>
</tr>
</thead>
<tbody>
<tr>
<td>System 1\textsuperscript{st} Contingency</td>
<td>Market</td>
<td>DA 1\textsuperscript{st} C (excluding at external nodes) is allocated to system DALO. RT 1\textsuperscript{st} 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)</td>
</tr>
<tr>
<td>External DA 1\textsuperscript{st} Contingency</td>
<td>Market</td>
<td>DA 1\textsuperscript{st} C at external nodes (from imports, exports, Incs and Decs) are allocated to activity at the specific external node or interface involved</td>
</tr>
<tr>
<td>Zonal 2\textsuperscript{nd} Contingency</td>
<td>Market</td>
<td>DA and RT 2\textsuperscript{nd} C NCPC are allocated to load obligation the Reliability Region (zone) served</td>
</tr>
<tr>
<td>System Low Voltage</td>
<td>OATT</td>
<td>(Low) Voltage Support NCPC is allocated to system Regional Network Load and Open Access Same-Time Information Service (OASIS) reservations</td>
</tr>
<tr>
<td>Zonal High Voltage</td>
<td>OATT</td>
<td>High Voltage Control NCPC is allocated to zonal Regional Network Load</td>
</tr>
<tr>
<td>Distribution - PTO</td>
<td>OATT</td>
<td>Distribution NCPC is allocated to the specific Participant Transmission Owner (PTO) requesting the service</td>
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</table>
Year-Over-Year Total NCPC Dollars and Energy

Dollars

<table>
<thead>
<tr>
<th>Jan</th>
<th>Feb</th>
<th>Mar</th>
<th>Apr</th>
<th>May</th>
<th>Jun</th>
<th>Jul</th>
<th>Aug</th>
<th>Sep</th>
<th>Oct</th>
<th>Nov</th>
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Energy

<table>
<thead>
<tr>
<th>Jan</th>
<th>Feb</th>
<th>Mar</th>
<th>Apr</th>
<th>May</th>
<th>Jun</th>
<th>Jul</th>
<th>Aug</th>
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</tbody>
</table>

Note:

- Overall Reliability Cost MWh includes out of merit DA and RT 1st Contingency, 2nd Contingency, Voltage, and RT Distribution components.
- Energy includes daily totals of cleared DA energy and RT energy from resources receiving NCPC payments.
DA and RT NCPC Charges

JUL-13 Total = $20.66 M

Day-Ahead: 42%
Real-Time: 58%

Last 13 Months

<table>
<thead>
<tr>
<th>Month</th>
<th>DA</th>
<th>RT</th>
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<tr>
<td>JUL2012</td>
<td>$10</td>
<td>$30</td>
</tr>
<tr>
<td>AUG2012</td>
<td>$10</td>
<td>$30</td>
</tr>
<tr>
<td>SEP2012</td>
<td>$10</td>
<td>$30</td>
</tr>
<tr>
<td>OCT2012</td>
<td>$10</td>
<td>$30</td>
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<tr>
<td>NOV2012</td>
<td>$10</td>
<td>$30</td>
</tr>
<tr>
<td>DEC2012</td>
<td>$10</td>
<td>$30</td>
</tr>
<tr>
<td>JAN2013</td>
<td>$10</td>
<td>$30</td>
</tr>
<tr>
<td>FEB2013</td>
<td>$10</td>
<td>$30</td>
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<tr>
<td>MAR2013</td>
<td>$10</td>
<td>$30</td>
</tr>
<tr>
<td>APR2013</td>
<td>$10</td>
<td>$30</td>
</tr>
<tr>
<td>MAY2013</td>
<td>$10</td>
<td>$30</td>
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<tr>
<td>JUN2013</td>
<td>$10</td>
<td>$30</td>
</tr>
<tr>
<td>JUL2013</td>
<td>$10</td>
<td>$30</td>
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NCPC Charges by Type

JUL-13 Total = $20.66 M

1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage
Daily NCPC Charges by Type

![Daily NCPC Charges by Type Graph]

- **1st C**
- **2nd C**
- **Voltage**
- **Distribution**
NCPC Charges by Allocation

JUL-13 Total = $20.66 M

System 1stC  Ext DA 1stC  Zonal 2ndC  System Low V  Zonal High V  Dist - PTO

54%  0.1%  5.6%  33%

Last 13 Months

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<th>AUG12</th>
<th>SEP12</th>
<th>OCT12</th>
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<th>DEC12</th>
<th>JAN13</th>
<th>FEB13</th>
<th>MAR13</th>
<th>APR13</th>
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<th>JUN13</th>
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<tbody>
<tr>
<td>Millions</td>
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</table>
RT First Contingency Charges by Deviation Type

JUL-13 Total = $9.92 M

- 65.1% Gen
- 15.3% Import
- 14.8% Inc
- 4.8% Load

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

Last 13 Months

- Millions
- JUL-12
- AUG-12
- SEP-12
- OCT-12
- NOV-12
- DEC-12
- JAN-13
- FEB-13
- MAR-13
- APR-13
- MAY-13
- JUN-13
- JUL-13
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 as Percent of Energy Market

NCPC By Type as Percent of Energy Market

<table>
<thead>
<tr>
<th>Percent</th>
<th>1st C</th>
<th>2nd C</th>
<th>Distr</th>
<th>Voltg</th>
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<tr>
<td>4.0%</td>
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Date:
- JAN2013
- FEB2013
- MAR2013
- APR2013
- MAY2013
- JUN2013
- JUL2013
- AUG2013
- SEP2013
- OCT2013
- NOV2013
- DEC2013

Values:
- 1.1%
- 1.7%
- 2.3%
- 2.0%
- 3.5%
- 1.2%
- 1.6%
- 1.2%
- 2.2%
- 2.9%
First Contingency NCPC Charges

Value of Charges

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% of Energy Market Value

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<th>2013</th>
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<td>0.8%</td>
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<td>1.6%</td>
<td>1.6%</td>
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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

Value of Charges

% of Energy Market Value

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

<table>
<thead>
<tr>
<th>Year</th>
<th>NEMA</th>
<th>CT</th>
<th>ME</th>
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### July-12

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### July-13

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<td>$57.7%</td>
<td>$52.1%</td>
<td>$56.6%</td>
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</table>
Monthly Average Fuel Price and RT Hub LMP Indexes

Underlying natural gas data furnished by:...
Monthly Average Fuel Price and RT Hub LMP

Underlying natural gas data furnished by:
Reserve Market Results – July 2013

• Maximum potential Forward Reserve Market payments of $4.8M were reduced by credit reductions of $275K, failure-to-reserve penalties of $412K and failure-to-activate penalties of $34K, resulting in a net payout of $4.1M or 85% of maximum
  – Rest of System: $2.2M/$2.6M (85%)
  – Southwest Connecticut: $173K/$456K (38%)
  – Connecticut: $1.7M/$1.8M (97%)
  – NEMA: N/A

• $16.5M total Real-Time credits were reduced by $5.2M in Forward Reserve Energy Obligation Charges for a net of $11.3M in Real-Time Reserve payments
  – Rest of System: 199 hours, $5.9M
  – Southwest Connecticut: 199 hours, $2.7M
  – Connecticut: 199 hours, $2.0M
  – NEMA: 199 hours, $661K

* “Failure to reserve” results in both reductions in credits and penalties in the Locational Forward Reserve Market.
LFRM Charges to Load by Load Zone ($)

LFRM Charges by Zone, Last 13 Months

- **CT**, **ME**, **NEMA**, **NH**, **RI**, **SEMA**, **VT**, **WCMA**

Millions

- $0.0
- $1.0
- $2.0
- $3.0
- $4.0
- $5.0
- $6.0
- $7.0


- **$780K Max. Potential Charge**
- **$530K Max. Potential Charge**
- **$6.2M Max. Potential Charge**
DA vs. RT Load Obligation: July, This Year vs. Last Year

Monthly, Last 13 Months

Daily, This Year vs. Last Year

DA % of RT
93.0%
94.0%
95.0%
96.0%
97.0%
98.0%
99.0%
100%
101%
102%
103%
104%
105%
106%
107%
108%

JUL2012
AUG2012
SEP2012
OCT2012
NOV2012
DEC2012
JAN2013
FEB2013
MAR2013
APR2013
MAY2013
JUN2013
JUL2013

Monthly, Last 13 Months

DA % of RT
93%
92%
91%
90%
89%
88%
87%
86%
85%
84%
83%
82%
81%
80%
79%
78%
77%
76%
75%
74%
73%
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19%
18%
17%
16%
15%
14%
13%
12%
11%
10%
9%
8%
7%
6%
5%
4%
3%
2%
1%
0%

Daily, This Year vs. Last Year

Last_Year
This_Year

DA vs. RT Load Obligation:

July, This Year vs. Last Year

Monthly, Last 13 Months

Daily, This Year vs. Last Year
Zonal Increment Offers and Cleared Amounts

July Monthly Totals by Zone

MWh


Hub ME NH VT CT RI SEMA WCMA NEMA

Cleared Offered
Zonal Decrement Bids and Cleared Amounts

July Monthly Totals by Zone

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MWh

- Cleared
- Bid
Total Increment Offers and Decrement Bids

Zonal Level, Last 13 Months

Data excludes nodal offers and bids
Dispatchable vs. Non-Dispatchable Generation

Total Monthly Energy; Dispatchable % Shown
DA vs. RT Net Interchange
July 2013 vs. July 2012

Hourly Average by Day, Last Year
Hourly Average by Day, This Year

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

- RSP13 draft has been distributed to stakeholders for comment and will be reviewed at the August 13 PAC meeting

- August 13 Tentative Agenda:
  - Regional System Plan Page Turn
  - NESCOE Presentation on Use of Probabilistic Analysis in System Planning Base Case Development
  - Follow-up Discussion on EIPC non-Grant Work
## RSP Project Stage Descriptions

<table>
<thead>
<tr>
<th>Stage</th>
<th>Description</th>
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<tr>
<td>1</td>
<td>Planning and Preparation of Project Configuration</td>
</tr>
<tr>
<td>2</td>
<td>Pre-construction (e.g., material ordering, project scheduling)</td>
</tr>
<tr>
<td>3</td>
<td>Construction in Progress</td>
</tr>
<tr>
<td>4</td>
<td>In Service</td>
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North Shore Upgrades – Merrimack Valley

Status as of 7/25/13

Project Benefit: Maintains system reliability for the North Shore area

<table>
<thead>
<tr>
<th>Upgrade</th>
<th>Expected In-service</th>
<th>Present Stage</th>
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<tbody>
<tr>
<td>Wakefield Junction/Merrimack Valley</td>
<td></td>
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<tr>
<td>115 kV Overhead Reconductor (G133E)</td>
<td>Feb-08</td>
<td>4</td>
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<tr>
<td>Reconductor Wakefield Junction - Golden Hills Tap 115 kV</td>
<td>Sep-08</td>
<td>4</td>
</tr>
<tr>
<td>30 MVAR 115 kV Capacitor at Revere</td>
<td>Oct-08</td>
<td>4</td>
</tr>
<tr>
<td>Wakefield Junction Substation</td>
<td>Nov-09</td>
<td>4</td>
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<tr>
<td>Loop 345 kV and 115 kV Lines into Wakefield Substation</td>
<td>Nov-09</td>
<td>4</td>
</tr>
<tr>
<td>Retirement of Golden Hills Substation</td>
<td>Apr-10</td>
<td>4</td>
</tr>
<tr>
<td>Add Parallel 115 kV Cable in Mystic-Everett Line</td>
<td>Dec-12</td>
<td>4</td>
</tr>
<tr>
<td>Add King Street - W. Amesbury 115 kV Line</td>
<td>Apr-11</td>
<td>4</td>
</tr>
<tr>
<td>Reconductor Overhead Portion of Mystic-Everett 115 kV Line</td>
<td>May-13</td>
<td>4</td>
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</table>
## North Shore Upgrades – Salem Harbor Non-Price Retirement

*Status as of 7/25/13*

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

<table>
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<th>Upgrade</th>
<th>Expected In-service</th>
<th>Present Stage</th>
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<tbody>
<tr>
<td>Reconductor Y-151 Tewksbury Jct. - West Methuen 115 kV</td>
<td>Dec-13</td>
<td>2</td>
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<tr>
<td>Reconductor B-154N King St. - South Danvers 115 kV</td>
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<td>Reconductor C-155N King St. - South Danvers 115 kV</td>
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<tr>
<td>Reconductor S-145 Tewksbury - North Reading 115 kV</td>
<td>Aug-13</td>
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<tr>
<td>Reconductor T-146 Tewksbury - North Reading 115 kV</td>
<td>Aug-13</td>
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Lower Southeastern Massachusetts (SEMA) Proposed Long-term Upgrades

Status as of 7/25/13

Project Benefit: Improves system reliability for the Lower SEMA area

<table>
<thead>
<tr>
<th>Upgrade</th>
<th>Expected In-service</th>
<th>Present Stage</th>
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<tbody>
<tr>
<td>Expand the Carver Substation</td>
<td>Jun-13</td>
<td>4</td>
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<tr>
<td>Build New 345 kV Line from Carver to Vicinity of Bourne Substation and connect to Line 120. Expand Bourne with one breaker position.</td>
<td>Jun-13</td>
<td>4*</td>
</tr>
<tr>
<td>Construct New 115 kV Substation with 345-115 kV Autotransformer and Loop Line 115 into the new substation</td>
<td>Dec-13</td>
<td>3</td>
</tr>
<tr>
<td>Upgrade the 115 kV Bell Rock to High Hill D21 Line</td>
<td>May-13</td>
<td>4</td>
</tr>
<tr>
<td>Separate the 345 kV (342 / 322) Double Circuit Tower Lines</td>
<td>Jun-13</td>
<td>4</td>
</tr>
</tbody>
</table>

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 by December 2013.
NEEWS: Greater Springfield Reliability Project
Status as of 7/25/13

Plan Benefit: Improves reliability by eliminating greater Springfield and north-central Connecticut area criteria violations

<table>
<thead>
<tr>
<th>Upgrade</th>
<th>Expected In-service</th>
<th>Present Stage</th>
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<tbody>
<tr>
<td>Construct New 345 kV Ludlow - Agawam Line</td>
<td>Dec-13</td>
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<tr>
<td>Construct New 345 kV Agawam - North Bloomfield Line</td>
<td>Dec-13</td>
<td>4</td>
</tr>
<tr>
<td>Expand Existing 115 kV Agawam Station &amp; Construct New 345 kV Yard</td>
<td>Dec-13</td>
<td>4</td>
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<tr>
<td>Expand 345 kV North Bloomfield Station</td>
<td>Dec-13</td>
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</tr>
<tr>
<td>Expand &amp; Reconfigure 345 kV Ludlow Station</td>
<td>Dec-13</td>
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<tr>
<td>Rebuild 115 kV Agawam - Piper Line</td>
<td>Dec-13</td>
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<tr>
<td>Rebuild 115 kV Agawam - Chicopee Line</td>
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<tr>
<td>Construct New 115 kV Cadwell Switching Station</td>
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<tr>
<td>Reconductor 115 kV Ludlow - Orchard Line</td>
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<tr>
<td>Rebuild 115 kV Orchard - Cadwell Line</td>
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<tr>
<td>Rebuild 115 kV Ludlow - Cadwell Line</td>
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### NEEWS: Greater Springfield Reliability Project, cont.

**Status as of 7/25/13**

**Plan Benefit:** Improves reliability by eliminating greater Springfield and north-central Connecticut area criteria violations

<table>
<thead>
<tr>
<th>Upgrade</th>
<th>Expected In-service</th>
<th>Present Stage</th>
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</thead>
<tbody>
<tr>
<td>Build New 115 kV Fairmont Switching Station</td>
<td>Dec-13</td>
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</tr>
<tr>
<td>Rebuild 115 kV Fairmont - Piper Line</td>
<td>Dec-13</td>
<td>3</td>
</tr>
<tr>
<td>Rebuild 115 kV Fairmont - Chicopee Line</td>
<td>Dec-13</td>
<td>3</td>
</tr>
<tr>
<td>Rebuild 115 kV Fairmont - Cadwell Line</td>
<td>Dec-13</td>
<td>3</td>
</tr>
<tr>
<td>Rebuild 115 kV Fairmont - Shawinigan Line</td>
<td>Dec-13</td>
<td>3</td>
</tr>
<tr>
<td>Rebuild 115 kV Ludlow - Shawinigan Line</td>
<td>Dec-13</td>
<td>4</td>
</tr>
<tr>
<td>Reconfigure 115 kV South Agawam Switching Station</td>
<td>Dec-13</td>
<td>4</td>
</tr>
<tr>
<td>Reconfigure 115 kV Southwick - South Agawam Line</td>
<td>Dec-13</td>
<td>4</td>
</tr>
<tr>
<td>Rebuild Two 115 kV South Agawam - Agawam Lines</td>
<td>Dec-13</td>
<td>4</td>
</tr>
<tr>
<td>Terminate Two 115 kV East Springfield - Cadwell Lines</td>
<td>Dec-13</td>
<td>3</td>
</tr>
</tbody>
</table>
### NEEWS: Manchester – Meekville Project

**Status as of 7/25/13**

**Plan Benefit:** Improves reliability by eliminating greater Springfield and north-central Connecticut area criteria violations

<table>
<thead>
<tr>
<th>Upgrade</th>
<th>Expected In-service</th>
<th>Present Stage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Build New 345 kV Manchester to Meekville Junction Line</td>
<td>Dec-12</td>
<td>4</td>
</tr>
<tr>
<td>Separate 3-Terminal 345 kV 395 Line at Meekville Junction</td>
<td>Dec-12</td>
<td>4</td>
</tr>
<tr>
<td>Reretermine 345 kV North Bloomfield Line to Manchester Substation</td>
<td>Dec-13</td>
<td>4</td>
</tr>
</tbody>
</table>
## NEEWS: Rhode Island

### Status as of 7/25/13

Plan Benefit: Improves reliability by eliminating Rhode Island criteria violations

<table>
<thead>
<tr>
<th>Upgrade</th>
<th>Expected In-service</th>
<th>Present Stage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Construct New West Farnum - Kent County 345 kV Line</td>
<td>May-13</td>
<td>4</td>
</tr>
<tr>
<td>Install 3rd Kent County 345-115 kV Autotransformer</td>
<td>Sep-11</td>
<td>4</td>
</tr>
<tr>
<td>Kent County Substation Upgrades</td>
<td>May-12</td>
<td>4</td>
</tr>
<tr>
<td>Reconductor Kent County - Drumrock 115 kV Line</td>
<td>Jul-11</td>
<td>4</td>
</tr>
<tr>
<td>Reconductor Short Segments of West Farnum - Hartford Avenue - Drumrock 115 kV Lines</td>
<td>Mar-13</td>
<td>4</td>
</tr>
</tbody>
</table>
**NEEWS: Interstate & Central Connecticut**

*Status as of 7/25/13*

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

<table>
<thead>
<tr>
<th>Upgrade</th>
<th>Expected In-service</th>
<th>Present Stage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Interstate Reliability Project (Interstate)</td>
<td>Dec-15</td>
<td>1</td>
</tr>
<tr>
<td>Central Connecticut Reliability Project (CCRP)*</td>
<td>Jun-17</td>
<td>1</td>
</tr>
</tbody>
</table>

* Combined with Greater Hartford Central Connecticut Study
Maine Power Reliability Program (MPRP)
Status as of 7/25/13

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

<table>
<thead>
<tr>
<th>New 345 kV Lines</th>
<th>Expected In-Service</th>
<th>Present Stage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Construct New Section 3023 Orrington to Albion Road</td>
<td>May-13</td>
<td>4</td>
</tr>
<tr>
<td>Construct New Section 3024 Albion Road to Coopers Mills</td>
<td>Jan-15</td>
<td>2</td>
</tr>
<tr>
<td>Construct New Section 3025 Coopers Mills to Larrabee Road</td>
<td>Mar-15</td>
<td>3</td>
</tr>
<tr>
<td>Construct New Section 3026 Larrabee Road to Surowiec</td>
<td>Dec-12</td>
<td>4</td>
</tr>
<tr>
<td>Construct New Section 3020 Surowiec to Raven Farm</td>
<td>Nov-13</td>
<td>3</td>
</tr>
<tr>
<td>Construct New Section 3021 South Gorham to Maguire Road</td>
<td>Jun-14</td>
<td>3</td>
</tr>
<tr>
<td>Construct New Section 3022 Maguire Road to Eliot</td>
<td>Jun-14</td>
<td>2</td>
</tr>
</tbody>
</table>

• The above listing focuses on major transmission line construction and rebuilding.
Maine Power Reliability Program, cont.

Status as of 7/25/13

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

<table>
<thead>
<tr>
<th>New 115 kV Lines</th>
<th>Expected In-Service</th>
<th>Present Stage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Construct New Section 254 Orrington to Coopers Mills</td>
<td>Feb-15</td>
<td>3</td>
</tr>
<tr>
<td>Construct New Section 243A Livermore Falls to Junction Section 243</td>
<td>May-14</td>
<td>3</td>
</tr>
<tr>
<td>Construct New Section 251 Livermore Falls to Larrabee Road</td>
<td>Apr-14</td>
<td>3</td>
</tr>
<tr>
<td>Construct New Section 255 Larrabee Road to Middle Street</td>
<td>Apr-15</td>
<td>2</td>
</tr>
<tr>
<td>Construct New Section 86A Tap to Belfast</td>
<td>July-14</td>
<td>2</td>
</tr>
<tr>
<td>Construct New Section 256 Middle Street to Lewiston Lower</td>
<td>April-15</td>
<td>1</td>
</tr>
</tbody>
</table>

• The above listing focuses on major transmission line construction and rebuilding.
Maine Power Reliability Program, cont.
Status as of 7/25/13

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

<table>
<thead>
<tr>
<th>115 kV Lines Rebuilds</th>
<th>Expected In-Service</th>
<th>Present Stage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rebuild Section 66 Detroit to Wyman Hydro</td>
<td>May-11</td>
<td>4</td>
</tr>
<tr>
<td>Rebuild Section 67 Detroit to Albion Road</td>
<td>May-13</td>
<td>4</td>
</tr>
<tr>
<td>Rebuild Section 203 Detroit to Bucksport</td>
<td>Apr-12</td>
<td>4</td>
</tr>
<tr>
<td>Rebuild Section 257 (formerly 67) Coopers Mills to Albion Road</td>
<td>May-13</td>
<td>4</td>
</tr>
<tr>
<td>Rebuild Section 258 (formerly 84) Coopers Mills to Albion Road</td>
<td>Aug-13</td>
<td>3</td>
</tr>
<tr>
<td>Rebuild Section 166 Surowiec to Spring Street</td>
<td>Nov-11</td>
<td>4</td>
</tr>
<tr>
<td>Rebuild Section 167 Surowiec to Moshers</td>
<td>Nov-11</td>
<td>4</td>
</tr>
</tbody>
</table>

- The above listing focuses on major transmission line construction and rebuilding.
Maine Power Reliability Program, cont.
Status as of 7/25/13

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

<table>
<thead>
<tr>
<th>115 kV Lines Rebuilds (continued)</th>
<th>Expected In-Service</th>
<th>Present Stage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rebuild Section 60 Coopers Mills to Bowman Street</td>
<td>Feb-15</td>
<td>3</td>
</tr>
<tr>
<td>Rebuild Section 88 Coopers Mills to Augusta East Side</td>
<td>Feb-15</td>
<td>3</td>
</tr>
<tr>
<td>Rebuild Section 89 Livermore Falls to Riley</td>
<td>Mar-14</td>
<td>2</td>
</tr>
<tr>
<td>Rebuild Section 229 Riley to Rumford IP</td>
<td>May-13</td>
<td>4</td>
</tr>
<tr>
<td>Rebuild Section 212 Monmouth to Larrabee Road</td>
<td>Feb-13</td>
<td>4</td>
</tr>
<tr>
<td>Rebuild Section 269 Bowman Street to Monmouth</td>
<td>May-12</td>
<td>4</td>
</tr>
<tr>
<td>Rebuild Section 238 Louden to Maguire Road</td>
<td>Feb-12</td>
<td>4</td>
</tr>
<tr>
<td>Rebuild Section 250 Maguire Road to Three Rivers</td>
<td>Dec-13</td>
<td>2</td>
</tr>
</tbody>
</table>

• The above listing focuses on major transmission line construction and rebuilding.
Maine Power Reliability Program, cont.  
Status as of 7/25/13

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

<table>
<thead>
<tr>
<th>345/115 kV Autotransformers</th>
<th>Expected In-Service</th>
<th>Present Stage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Install One 345/115 kV Autotransformer at Albion Road</td>
<td>Apr-13</td>
<td>4</td>
</tr>
<tr>
<td>Install One 345/115 kV Autotransformer at Coopers Mills</td>
<td>Jan-15</td>
<td>2</td>
</tr>
<tr>
<td>Install One 345/115 kV Autotransformer at Larrabee Road</td>
<td>Dec-12</td>
<td>4</td>
</tr>
<tr>
<td>Install One 345/115 kV Autotransformer at Maguire Road</td>
<td>Jun-14</td>
<td>3</td>
</tr>
<tr>
<td>Install One 345/115 kV Autotransformer at South Gorham</td>
<td>Nov-09</td>
<td>4</td>
</tr>
</tbody>
</table>

The above listing focuses on major transmission line construction and rebuilding.
Transmission Siting Update

- **NEEWS**
  - Rhode Island Reliability Project
    - Received siting approval from Rhode Island authorities
  - Greater Springfield Reliability Project
    - Received siting approval from both Connecticut and Massachusetts authorities
  - 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 PUC made a recommendation to the RI EFSB on 4/8/13 to approve the project. Siting hearings in MA are scheduled to begin in August

- **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 - awaiting written order on Lewiston Loop
  - TCAs are being revised to reflect the new version of the project
Status of Tariff Studies

![Bar Chart Diagram]

**Project Status**

- Distribution
- Executed IA
- Negotiating IA
- Facility Study
- Sys. Impact Study
- Optional Study
- Feasibility Study
- Scoping

**Number of Projects**

- Jul-12: 5,935 MW
- Aug-12: 5,666 MW
- Sep-12: 5,640 MW
- Oct-12: 5,721 MW
- Nov-12: 5,063 MW
- Dec-12: 4,976 MW
- Jan-13: 4,997 MW
- Feb-13: 5,347 MW
- Mar-13: 5,291 MW
- Apr-13: 5,619 MW
- May-13: 5,453 MW
- Jun-13: 5,453 MW
- Jul-13: 5,534 MW

**5,935 MW**

- Distribution: 71
- Executed IA: 10
- Negotiating IA: 13
- Facility Study: 4
- Sys. Impact Study: 2
- Optional Study: 0
- Feasibility Study: 1
- Scoping: 0

**5,666 MW**

- Distribution: 70
- Executed IA: 30
- Negotiating IA: 0
- Facility Study: 10
- Sys. Impact Study: 0
- Optional Study: 1
- Feasibility Study: 1
- Scoping: 0

**5,640 MW**

- Distribution: 69
- Executed IA: 29
- Negotiating IA: 5
- Facility Study: 15
- Sys. Impact Study: 2
- Optional Study: 1
- Feasibility Study: 0
- Scoping: 0

**5,721 MW**

- Distribution: 70
- Executed IA: 29
- Negotiating IA: 0
- Facility Study: 13
- Sys. Impact Study: 1
- Optional Study: 1
- Feasibility Study: 0
- Scoping: 0

**5,063 MW**

- Distribution: 61
- Executed IA: 23
- Negotiating IA: 1
- Facility Study: 7
- Sys. Impact Study: 2
- Optional Study: 0
- Feasibility Study: 0
- Scoping: 0

**4,976 MW**

- Distribution: 59
- Executed IA: 20
- Negotiating IA: 1
- Facility Study: 1
- Sys. Impact Study: 0
- Optional Study: 0
- Feasibility Study: 0
- Scoping: 0

**4,997 MW**

- Distribution: 62
- Executed IA: 19
- Negotiating IA: 1
- Facility Study: 0
- Sys. Impact Study: 0
- Optional Study: 0
- Feasibility Study: 0
- Scoping: 0

**5,347 MW**

- Distribution: 58
- Executed IA: 16
- Negotiating IA: 1
- Facility Study: 0
- Sys. Impact Study: 0
- Optional Study: 0
- Feasibility Study: 0
- Scoping: 0

**5,291 MW**

- Distribution: 61
- Executed IA: 18
- Negotiating IA: 0
- Facility Study: 0
- Sys. Impact Study: 0
- Optional Study: 0
- Feasibility Study: 0
- Scoping: 0

**5,619 MW**

- Distribution: 62
- Executed IA: 18
- Negotiating IA: 1
- Facility Study: 0
- Sys. Impact Study: 0
- Optional Study: 0
- Feasibility Study: 0
- Scoping: 0

**5,453 MW**

- Distribution: 62
- Executed IA: 18
- Negotiating IA: 1
- Facility Study: 0
- Sys. Impact Study: 0
- Optional Study: 0
- Feasibility Study: 0
- Scoping: 0

**5,534 MW**

- Distribution: 62
- Executed IA: 18
- Negotiating IA: 1
- Facility Study: 0
- Sys. Impact Study: 0
- Optional Study: 0
- Feasibility Study: 0
- Scoping: 0
OPERABLE CAPACITY ANALYSIS

Summer 2013
### Summer 2013 Operable Capacity Analysis

<table>
<thead>
<tr>
<th>50/50 Load Forecast (Reference)</th>
<th>September-2013</th>
<th>September-2013</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>CSO</td>
<td>SCC</td>
</tr>
<tr>
<td>Generator Operable Capacity MW (^1)</td>
<td>29,458</td>
<td>31,192</td>
</tr>
<tr>
<td>OP CAP From OP-4 RTDR (+)</td>
<td>429</td>
<td>429</td>
</tr>
<tr>
<td>OP CAP From OP-4 RTEG (+)</td>
<td>234</td>
<td>234</td>
</tr>
<tr>
<td>Operable Capacity Generator with OP-4 DR and RTEG</td>
<td>30,121</td>
<td>31,855</td>
</tr>
<tr>
<td>External Node Available Capacity – CSO Only (+)</td>
<td>1,183</td>
<td>1,183</td>
</tr>
<tr>
<td>Non Commercial Capacity (+)</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Non Gas-fired Planned Outage MW (-)</td>
<td>1,393</td>
<td>1,466</td>
</tr>
<tr>
<td>Allowance for Unplanned Outages (-)</td>
<td>2,100</td>
<td>2,100</td>
</tr>
<tr>
<td>Gas Generator Outages MW (-)</td>
<td>232</td>
<td>244</td>
</tr>
<tr>
<td>Generation at Risk Due to Gas Supply (-) (^4)</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Net Capacity (NET OPCAP SUPPLY MW) (^3)</td>
<td>27,579</td>
<td>29,228</td>
</tr>
<tr>
<td>Peak Load Forecast  MW(adjusted for Other Demand Resources) (^2)</td>
<td>26,690</td>
<td>26,690</td>
</tr>
<tr>
<td>Operating Reserve Requirement MW</td>
<td>2,375</td>
<td>2,375</td>
</tr>
<tr>
<td>Operable Capacity Required (NET LOAD OBLIGATION MW)</td>
<td>29,065</td>
<td>29,065</td>
</tr>
<tr>
<td>Operable Capacity Margin (^3)</td>
<td>(1,486)</td>
<td>163</td>
</tr>
</tbody>
</table>

\(^1\) Generator Operable Capacity is based on data as of July 23\(^{rd}\), 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, weeks beginning September 7\(^{th}\) 2013

\(^3\) Includes OP4 actions associated with RTEG and RTDR

\(^4\) Total of (Gas at Risk MW) – (Gas Gen Outages MW)
### Summer 2013 Operable Capacity Analysis

<table>
<thead>
<tr>
<th>90/10 Load Forecast (Extreme)</th>
<th>September-2013</th>
<th>September-2013</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>CSO</td>
<td>SCC</td>
</tr>
<tr>
<td>Generator Operable Capacity MW</td>
<td>29,458</td>
<td>31,192</td>
</tr>
<tr>
<td>OP CAP From OP-4 RTDR (+)</td>
<td>429</td>
<td>429</td>
</tr>
<tr>
<td>OP CAP From OP-4 RTEG (+)</td>
<td>234</td>
<td>234</td>
</tr>
<tr>
<td>Operable Capacity Generator with OP-4 DR and RTEG</td>
<td>30,121</td>
<td>31,855</td>
</tr>
<tr>
<td>External Node Available Capacity – CSO Only (+)</td>
<td>1,183</td>
<td>1,183</td>
</tr>
<tr>
<td>Non Commercial Capacity (+)</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Non Gas-fired Planned Outage MW (-)</td>
<td>1,393</td>
<td>1,466</td>
</tr>
<tr>
<td>Allowance for Unplanned Outages (-)</td>
<td>2,100</td>
<td>2,100</td>
</tr>
<tr>
<td>Gas Generator Outages MW (-)</td>
<td>232</td>
<td>244</td>
</tr>
<tr>
<td>Generation at Risk Due to Gas Supply (-)</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Net Capacity (NET OPCAP SUPPLY MW)</td>
<td>27,579</td>
<td>29,228</td>
</tr>
<tr>
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</tr>
<tr>
<td>Operating Reserve Requirement MW</td>
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<td>2,375</td>
</tr>
<tr>
<td>Operable Capacity Required (NET LOAD OBLIGATION MW)</td>
<td>31,360</td>
<td>31,360</td>
</tr>
<tr>
<td>Operable Capacity Margin</td>
<td>(3,781)</td>
<td>(2,132)</td>
</tr>
</tbody>
</table>

1 Generator Operable Capacity is based on data as of July 23rd, 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 September 7th, 2013

3 Includes OP4 actions associated with RTEG and RTDR

4 Total of (Gas at Risk MW) – (Gas Gen Outages MW)
Summer 2013 Operable Capacity Analysis (MW)
50/50 Forecast (Reference)

Operable Capacity Margin (MW)
August 3, 2013 - September 14, 2013, W/B Saturday
New England Operable Capacity Margins - CSO - with RTDR & RTEG
50/50 FORECAST
Summer 2013 Operable Capacity Analysis (MW) 
90/10 Forecast (Extreme)
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.

### ISO-NE 2013-2014 OPERABLE CAPACITY ANALYSIS

**July 29, 2013 - 50/50- FORECAST - CSO**

| STUDY WEEK (Week Beginning, Saturday) | AVAILABLE OPCAP MW | EXTERNAL NODE AVAILABLE 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 MW | OPCAP FROM OP4 actions through OP4 Step 2 MW | OPCAP MARGIN MW | OPCAP FROM OP4 REAL-TIME EMER. GEN MW | OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW |
|--------------------------------------|--------------------|-----------------------------------|-----------------------------|--------------------------------|-----------------------------------|------------------------------|----------------|-------------------|--------------------|-----------------------------|------------------|----------------|---------------------------------|----------------|---------------------------------|----------------|---------------------------------|----------------|--------------------------------|----------------|
| 08/03/2013                           | 29,748             | 1,039                             | 0                           | 1,286                          | 2,100                            | 0                            | 0              | 27,401            | 26,690                       | 2,375                       | 29,065           | (1,664)          | 352                            | (1,312)         | 163                             | (1,149)         |
| 08/10/2013                           | 29,748             | 1,039                             | 0                           | 1,026                          | 2,100                            | 0                            | 0              | 27,661            | 26,690                       | 2,375                       | 29,065           | (1,404)          | 352                            | (1,052)         | 163                             | (889)           |
| 08/17/2013                           | 29,748             | 1,039                             | 0                           | 1,070                          | 2,100                            | 0                            | 0              | 27,617            | 26,690                       | 2,375                       | 29,065           | (1,448)          | 352                            | (1,096)         | 163                             | (933)           |
| 08/24/2013                           | 29,748             | 1,039                             | 0                           | 1,076                          | 2,100                            | 0                            | 0              | 27,611            | 26,690                       | 2,375                       | 29,065           | (1,454)          | 352                            | (1,102)         | 163                             | (939)           |
| 08/31/2013                           | 29,458             | 1,183                             | 0                           | 1,361                          | 2,100                            | 232                           | 0              | 28,348            | 26,690                       | 2,375                       | 29,065           | (2,117)          | 429                            | (1,688)         | 234                             | (1,454)         |
| 09/07/2013                           | 29,458             | 1,183                             | 0                           | 1,393                          | 2,100                            | 232                           | 0              | 26,916            | 26,690                       | 2,375                       | 29,065           | (2,149)          | 429                            | (1,720)         | 234                             | (1,486)         |
| 09/14/2013                           | 29,458             | 803                               | 0                           | 2,284                          | 2,100                            | 896                           | 0              | 24,981            | 22,701                       | 2,375                       | 25,076           | (95)               | 429                            | 334             | 234                             | 568             |

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 external Capacity Supply Obligations, CSO.
3. New resources that have acquired a CSO but have not become commercial.
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9. Peak Load Forecast per data included in the 2013 CELT Report adjusted for Other Demand Resources.
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13. OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
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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).
# Summer 2013 Operable Capacity Analysis (MW)
## 90/10 Forecast (Extreme)

### ISO-NE 2013-2014 OPERABLE CAPACITY ANALYSIS

**July 29, 2013 - 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.

<table>
<thead>
<tr>
<th>STUDY WEEK (Week Beginning, Saturday)</th>
<th>AVAILABLE OPCAP MW</th>
<th>EXTERNAL NODE AVAIL CAPACITY MW</th>
<th>NON COMMERCIAL CAPACITY MW</th>
<th>NON-GAS PLANNED OUTAGES CSO MW</th>
<th>ALLOWANCE FOR UNPLANNED OUTAGES MW</th>
<th>GAS GENERATOR OUTAGES CSO MW</th>
<th>GAS AT RISK MW</th>
<th>NET OPCAP SUPPLY MW</th>
<th>PEAK LOAD FORECAST MW</th>
<th>OPER RESERVE REQUIREMENT MW</th>
<th>NET LOAD OBLIGATION MW</th>
<th>OPCAP MARGIN MW</th>
<th>OPCAP FROM OP4 ACTIVE REAL-TIME DR MW</th>
<th>OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW</th>
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</table>

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 external Capacity Supply Obligations, CSO.
3. New resources that have acquired a CSO but have not become commercial.
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8. Net OpCap Supply MW Available \((1 + 2 + 3 - 4 - 5 - 6 - 7 = 8)\)
9. Peak Load Forecast per data included in the 2013 CELT Report adjusted for Other Demand Resources.
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11. Total Net Load Obligation per the formula \((9 + 10 = 11)\)
13. OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
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OPERABLE CAPACITY ANALYSIS

Fall 2013
### Fall 2013 Operable Capacity Analysis

<table>
<thead>
<tr>
<th>50/50 Load Forecast (Reference)</th>
<th>September-2013 ² CSO</th>
<th>September-2013 ² SCC</th>
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<tbody>
<tr>
<td>Generator Operable Capacity MW ¹</td>
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<tr>
<td>OP CAP From OP-4 RTDR (+)</td>
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<td>429</td>
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<tr>
<td>OP CAP From OP-4 RTEG (+)</td>
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<td>234</td>
</tr>
<tr>
<td>Operable Capacity Generator with OP-4 DR and RTEG</td>
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<td>31,855</td>
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<tr>
<td>External Node Available Capacity – CSO Only (+)</td>
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<td>1,183</td>
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<tr>
<td>Non Commercial Capacity (+)</td>
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<td>0</td>
</tr>
<tr>
<td>Non Gas-fired Planned Outage MW (-)</td>
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<td>3,516</td>
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<tr>
<td>Allowance for Unplanned Outages (-)</td>
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<tr>
<td>Gas Generator Outages MW (-)</td>
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<tr>
<td>Generation at Risk Due to Gas Supply (-) ⁴</td>
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<td>Net Capacity (NET OPCAP SUPPLY MW) ³</td>
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<td>Peak Load Forecast  MW(adjusted for Other Demand Resources) ²</td>
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¹ Generator Operable Capacity is based on data as of July 23, 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, weeks beginning September 21\(^{th}\) 2013

³ Includes OP4 actions associated with RTEG and RTDR

⁴ Total of (Gas at Risk MW) – (Gas Gen Outages MW)
## Fall 2013 Operable Capacity Analysis

### 90/10 Load Forecast (Extreme)

<table>
<thead>
<tr>
<th></th>
<th>September-2013&lt;sup&gt;2&lt;/sup&gt; CSO</th>
<th>September-2013&lt;sup&gt;2&lt;/sup&gt; SCC</th>
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</thead>
<tbody>
<tr>
<td>Generator Operable Capacity MW&lt;sup&gt;1&lt;/sup&gt;</td>
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<td>31,192</td>
</tr>
<tr>
<td>OP CAP From OP-4 RTDR (+)</td>
<td>429</td>
<td>429</td>
</tr>
<tr>
<td>OP CAP From OP-4 RTEG (+)</td>
<td>234</td>
<td>234</td>
</tr>
<tr>
<td>Operable Capacity Generator with OP-4 DR and RTEG</td>
<td>30,121</td>
<td>31,855</td>
</tr>
<tr>
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<td>1,183</td>
<td>1,183</td>
</tr>
<tr>
<td>Non Commercial Capacity (+)</td>
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<td>0</td>
</tr>
<tr>
<td>Non Gas-fired Planned Outage MW (-)</td>
<td>3,340</td>
<td>3,516</td>
</tr>
<tr>
<td>Allowance for Unplanned Outages (-)</td>
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<td>2,100</td>
</tr>
<tr>
<td>Gas Generator Outages MW (-)</td>
<td>751</td>
<td>791</td>
</tr>
<tr>
<td>Generation at Risk Due to Gas Supply (-)&lt;sup&gt;4&lt;/sup&gt;</td>
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<td>0</td>
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<td>Net Capacity (NET OPCAP SUPPLY MW)&lt;sup&gt;3&lt;/sup&gt;</td>
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<tr>
<td>Peak Load Forecast MW(adjusted for Other Demand Resources)&lt;sup&gt;2&lt;/sup&gt;</td>
<td>24,567</td>
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<tr>
<td>Operating Reserve Requirement MW</td>
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<tr>
<td>Operable Capacity Required (NET LOAD OBLIGATION MW)</td>
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<tr>
<td>Operable Capacity Margin&lt;sup&gt;3&lt;/sup&gt;</td>
<td>(1,829)</td>
<td>(311)</td>
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</tbody>
</table>

<sup>1</sup> Generator Operable Capacity is based on data as of July 23<sup>rd</sup>, 2013 and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity.

<sup>2</sup> Based on week with lowest Operable Capacity Margin, week beginning September 21<sup>st</sup>, 2013

<sup>3</sup> Includes OP4 actions associated with RTEG and RTDR

<sup>4</sup> Total of (Gas at Risk MW) – (Gas Gen Outages MW)
Fall 2013 Operable Capacity Analysis (MW)
50/50 Forecast (Reference)

New England Operable Capacity Margins - CSO - with RTDR & RTEG
50/50 FORECAST

Operable Capacity Margin (MW)
September 21 - October 26, 2013, W/B Saturday

September 21 - October 26, 2013, W/B Saturday
Fall 2013 Operable Capacity Analysis (MW)  
90/10 Forecast (Extreme)

New England Operable Capacity Margins - CSO - with RTDR & RTEG  
90/10 FORECAST

Operable Capacity Margin (MW)

September 21 - October 26, 2013, W/B Saturday
### ISO-NE 2013-2014 OPERABLE CAPACITY ANALYSIS

**July 29, 2013 - 50/50- FORECAST - CSO**

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<th>NON-GAS PLANNED OUTAGES CSO MW</th>
<th>ALLOWANCE FOR UNPLANNED OUTAGES MW</th>
<th>GAS GENERATOR OUTAGES CSO MW</th>
<th>GAS AT RISK MW</th>
<th>NET OPCAP SUPPLY MW</th>
<th>PEAK LOAD FORECAST MW</th>
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<th>OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW</th>
</tr>
</thead>
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<td>29,458</td>
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<td>24,984</td>
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<td>(105)</td>
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# Fall 2013 Operable Capacity Analysis (MW) 90/10 Forecast (Extreme)

## ISO-NE 2013-2014 OPERABLE CAPACITY ANALYSIS

July 29, 2013 - 90/10- FORECAST - CSO

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<th>OPCAP FROM OP4 ACTIVE REAL-TIME DR MW</th>
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<th>OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW</th>
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<td>2,142</td>
<td>0</td>
<td>23,212</td>
<td>18,373</td>
<td>2,375</td>
<td>20,748</td>
<td>2,464</td>
<td>467</td>
<td>2,931</td>
<td>234</td>
<td>3,105</td>
</tr>
<tr>
<td>10/26/2013</td>
<td>29,560</td>
<td>989</td>
<td>114</td>
<td>2,732</td>
<td>3,600</td>
<td>2,375</td>
<td>0</td>
<td>21,956</td>
<td>18,588</td>
<td>2,375</td>
<td>20,963</td>
<td>993</td>
<td>467</td>
<td>1,460</td>
<td>234</td>
<td>1,694</td>
</tr>
</tbody>
</table>

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 external Capacity Supply Obligations, CSO.
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 per data included in the 2013 CELT Report adjusted for Other 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)
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

<table>
<thead>
<tr>
<th>OP 4 Action Number</th>
<th>Page 1 of 2 Action Description</th>
<th>Amount Assumed Obtainable Under OP 4 (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>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.</td>
<td>600</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Dispatch real time Demand Resources.</td>
<td>600</td>
</tr>
<tr>
<td>3</td>
<td>Voluntary Load Curtailment of Market Participants’ facilities.</td>
<td>40</td>
</tr>
<tr>
<td>4</td>
<td>Implement Power Watch</td>
<td>0</td>
</tr>
<tr>
<td>5</td>
<td>Schedule Emergency Energy Transactions and arrange to purchase Control Area-to-Control Area Emergency</td>
<td>1,000</td>
</tr>
<tr>
<td>6</td>
<td>Voltage Reduction requiring &gt; 10 minutes Dispatch real time Emergency Generation</td>
<td>130</td>
</tr>
<tr>
<td></td>
<td></td>
<td>400</td>
</tr>
<tr>
<td>7</td>
<td>Request generating resources not subject to a Capacity Supply Obligation to voluntary provide energy for reliability purposes</td>
<td>0</td>
</tr>
<tr>
<td>8</td>
<td>Voltage Reduction requiring 10 minutes or less</td>
<td>260</td>
</tr>
<tr>
<td>9</td>
<td>Transmission Customer Generation Not Contractually Available to Market Participants during a Capacity Deficiency. Voluntary Load Curtailment by Large Industrial and Commercial Customers.</td>
<td>5</td>
</tr>
</tbody>
</table>

1. \[\text{MW}\]
2. \[\text{MW}\]
3. \[\text{MW}\]
4. \[\text{MW}\]
Possible Relief Under OP4 based on OP4 Appendix A

<table>
<thead>
<tr>
<th>OP 4 Action Number</th>
<th>Page 2 of 2 Action Description</th>
<th>Amount Assumed Obtainable Under OP 4 (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>10</td>
<td>Radio and TV Appeals for Voluntary Load Curtailment Implement Power Warning</td>
<td>200 (^2)</td>
</tr>
<tr>
<td>11</td>
<td>Request State Governors to Reinforce Power Warning Appeals.</td>
<td>100 (^2)</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td>3,535</td>
</tr>
</tbody>
</table>

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 MW values are reviewed on a quarterly basis; actual available MW amounts can be viewed using the demand response dispatch software.
4. The MW values are based on a 26,462 MW system load and the most recent voltage reduction test % achieved.
2013 Second Quarter Quarterly Markets Report

DRAFT
Overview of Quarterly Markets Report

• The Quarterly Markets Report reviews energy market competitiveness and contains summary information regarding overall market performance and outcomes

• The IMM studies specific market events, changes in market conditions and possible trends and reports on them each quarter

• Issues for further study and recommendations are presented

• The Quarterly Markets Reports are posted at:
  
# Highlights

<table>
<thead>
<tr>
<th></th>
<th>2nd Quarter 2013</th>
<th>1st Quarter 2013</th>
<th>2nd Quarter 2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>Real-Time Load (GWh)</td>
<td>30,174</td>
<td>32,308</td>
<td>30,039</td>
</tr>
<tr>
<td>Weather Normalized Real-Time Load (GWh)</td>
<td>29,805</td>
<td>32,474</td>
<td>30,086</td>
</tr>
<tr>
<td>Peak Real-Time Load (MW)</td>
<td>25,112</td>
<td>20,887</td>
<td>25,677</td>
</tr>
<tr>
<td>Average Day-Ahead Hub LMP ($/MWh)</td>
<td>$40.09</td>
<td>$86.16</td>
<td>$28.80</td>
</tr>
<tr>
<td>Average Real-Time Hub LMP ($/MWh)</td>
<td>$40.19</td>
<td>$81.28</td>
<td>$29.06</td>
</tr>
<tr>
<td>Average Natural Gas Price ($/MMBtu)</td>
<td>$4.64</td>
<td>$11.57</td>
<td>$2.81</td>
</tr>
<tr>
<td>Average #6 Oil Price 1% sulfur ($/MMBtu)</td>
<td>$15.30</td>
<td>$16.40</td>
<td>$17.03</td>
</tr>
</tbody>
</table>
IMM Analysis of Changes in Available Capacity from the Day-Ahead Market to Real-Time

- The IMM measured changes in the amount of available capacity between the day-ahead and real-time energy markets
  - Total available capacity was calculated based on offered EcoMax values and redeclarations made during the operating day
    - Redeclarations made to EcoMax during the operating day include Participant and ISO imposed redeclarations
  - Changes that occur from Day-ahead to Re-offer to Real-time can result in an increase or decrease from the previous time period
Summary of Results

• The available capacity reductions are highest in the early morning hours of the day

• The amount of reduction is highest among gas-fired resources, and these reductions influence the intra-day trends in capacity reductions

• More available capacity reductions occur between the Day-Ahead to Re-offer interval than the Re-offer to Real-Time interval
Percent Reduction In Capacity From Day-ahead To Real-time By Fuel Type and by Hour

![Graph showing percent reduction in capacity by hour and fuel type over 24 hours. The graph includes two lines, one for Natural Gas and another for Other, indicating the reduction in capacity over the course of a day.](image-url)
Average Hourly Reduction in Capacity from Day-Ahead to Re-offer by Year

Year

MWs

2010

2011

2012

2013

Day-ahead to Reoffer (other)

Day-ahead to Reoffer (gas)
Market Performance Metrics

• The IMM has included an article to discuss the two metrics that assess market efficiency and competitiveness:

  – **Gross Margin:**
    • Measures the impact of resources’ offers on the suppliers of energy
    • Reveals the extent that participants can sustain profits above competitive levels

  – **Competitiveness Measure:**
    • Measures the impact of resources’ offers on consumers
    • Reveals the extent to which generators are able to increase prices above competitive levels
Competition of the Energy Market

• The price outcomes of the ISO administered energy market are consistent with those expected of a competitive market
• The energy market is generally unconcentrated and structurally competitive
• Energy prices by and large reflect supplier short-run marginal costs
• When needed, mitigation rules provide adequate behavioral remedies
## Virtual Transactions

<table>
<thead>
<tr>
<th></th>
<th>2nd Quarter 2013</th>
<th>1st Quarter 2013</th>
<th>2nd Quarter 2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Submitted Virtual Transactions (GWh)</td>
<td>5,632</td>
<td>5,889</td>
<td>6,228</td>
</tr>
<tr>
<td>Total Cleared Virtual Transactions (GWh)</td>
<td>979</td>
<td>675</td>
<td>1,144</td>
</tr>
</tbody>
</table>
## NCPC Payments

<table>
<thead>
<tr>
<th>NCPC Category</th>
<th>Q2 2013</th>
<th>Q1 2013</th>
<th>Q2 2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>Economic and First Contingency Payments</td>
<td>$10,745,109</td>
<td>$49,290,161</td>
<td>$15,980,379</td>
</tr>
<tr>
<td>Second Contingency Payments</td>
<td>$8,942,671</td>
<td>$21,796,697</td>
<td>$3,236,214</td>
</tr>
<tr>
<td>Voltage Payments</td>
<td>$1,654,472</td>
<td>$3,156,351</td>
<td>$1,624,677</td>
</tr>
<tr>
<td>Distribution Payments</td>
<td>$408,534</td>
<td>$450,073</td>
<td>$384,600</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$21,750,786</strong></td>
<td><strong>$74,693,282</strong></td>
<td><strong>$21,917,287</strong></td>
</tr>
</tbody>
</table>
Supplemental Commitments

<table>
<thead>
<tr>
<th></th>
<th>Minimum</th>
<th>25th Percentile</th>
<th>50th Percentile</th>
<th>75th Percentile</th>
<th>Maximum</th>
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<tbody>
<tr>
<td>Jan</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>268</td>
<td>1847</td>
</tr>
<tr>
<td>Feb</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>548</td>
<td>2982</td>
</tr>
<tr>
<td>Mar</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>45</td>
<td>1475</td>
</tr>
<tr>
<td>Apr</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>250</td>
<td>610</td>
</tr>
<tr>
<td>May</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>26</td>
<td>795</td>
</tr>
<tr>
<td>Jun</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>157</td>
<td>900</td>
</tr>
</tbody>
</table>

For this analysis, *supplemental commitments* are defined as the capacity of non-fast-start generators the ISO committed outside the day-ahead market for the peak hour, dispatched at their economic minimum.
Other Market Outcomes

• In Q2 2013, total real-time reserve payments were $4.8 million; a 15% reduction relative to Q1 2013

• The clearing price in the Forward Reserve Market (FRM) auction for summer 2013 was $5,946/MW-month, compared to $3,450/MW-month in the summer 2012 auction and $3,301/MW/month in the winter 2013 auction
  – The increase in the price was the result of an increase in the TMNSR requirement

• Total Regulation market payments in Q2 2013 were $3.0 million, compared to $6.2 million in Q1 2013
  – The decrease in regulation payments is attributable to lower natural gas prices and regulation requirements during the Reporting Period
Questions
MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Sebastian M. Lombardi, NEPOOL Counsel

DATE: July 26, 2013

RE: ISO-NE Order 755 Compliance Item (Frequency Regulation Compensation)

At its August 2, 2013 meeting, the Participants Committee will be asked to support Markets Committee recommended changes to Market Rule 1 to allow regulation providers to incorporate inter-temporal opportunity costs into their bids, as proposed by the ISO in response to the FERC’s June 20, 2013 order in Docket No. ER12-1643 (the “June 20 Order”).

The June 20 Order conditionally approved revised Regulation Market design changes that were jointly filed by the ISO and NEPOOL to comply with Order 755, subject to the ISO submitting a further compliance filing by August 5, 2013. In that compliance filing, the ISO is required to make an additional Tariff modification to explicitly allow a resource’s Regulation Capacity Offer to include inter-temporal opportunity costs, subject to the requirement that the inter-temporal opportunity costs must be verifiable.

The Markets Committee met on July 25 and voted unanimously to recommend Participants Committee support for Tariff revisions proposed by the ISO to comply with the FERC’s June 20 Order. Included with this memorandum is a copy of those Markets Committee recommended changes, along with background materials from the ISO that were previously circulated to the Markets Committee. But for the timing of the Markets Committee consideration, this matter would have been on the Consent Agenda.

The following form of resolution may be used for Participants Committee action on this matter:

RESOLVED, that the Participants Committee supports the revisions to Market Rule 1 to allow regulation providers to incorporate inter-temporal opportunity costs into their bids as recommended by the Markets Committee at its July 25, 2013 meeting 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.


To: Markets Committee  
From: Jonathan Lowell – ISO New England  
Date: July 25, 2013  
Subject: FERC Order 755 – Compliance Requirement

On June 20, 2013 the Commission issued an order approving the ISO’s Order 755 regulation market design filed on February 6, 2013 with one additional compliance requirement, which is to modify the tariff language to explicitly state that a resource’s Regulation Capacity Offer may include intertemporal opportunity costs, subject to the requirement that the intertemporal opportunity costs must be verifiable.

The ability to include verifiable intertemporal opportunity costs is a requirement of Order 755, and the ISO’s February 6th filing did not include specific language to address the requirement. The following underlined sentence will be added to Market Rule 1 tariff language at III.14.3(a)(v) to meet the requirement:

“The Regulation Capacity Offer price must be greater than or equal to $0/MW and may not exceed $100/MW. A Market Participant may include estimated intertemporal opportunity costs in its Regulation Capacity Offer price.”

To allow the estimated intertemporal opportunity costs to be verifiable, eMarket will allow participants to submit regulation capacity offers in two parts – 1) intertemporal opportunity costs, and 2) everything else. The two parts will be summed to determine a resource’s Regulation Capacity Offer price. The capacity offer is then used, in accordance with the February 6th design, to determine resource selection, the Regulation Capacity Clearing Price, and to calculate a resource’s regulation make-whole payment. There is no change to the regulation market design.

Should the Internal Market Monitor identify a need to verify the intertemporal opportunity costs included in a Participant’s Regulation Capacity Offer price, existing provisions in Market Rule 1 Appendix A provide sufficient authority to request supporting information from the Participant to justify the intertemporal opportunity cost estimates.

The ISO notes that the February 6th design includes a Regulation Capacity Offer price cap of $100/MW, but otherwise does not limit what a Participant may choose to include in its offer. The regulation market has been, and is expected to remain, very competitive, and a resource with a high capacity offer price would simply not be selected to provide regulation for the next interval. This is presumably the precise outcome a Participant with expected high intertemporal opportunity costs would desire. The ISO further notes the market design allows regulation offers to be updated continuously, and changing estimates of intertemporal opportunity costs can be readily reflected.

The ISO seeks a vote from the NEPOOL Markets Committee to recommend support for the proposed tariff language addition to meet the June 20th FERC compliance requirement.
Reference Material

The previously provided ISO material on this subject can be accessed with the following links.

<table>
<thead>
<tr>
<th>Markets Committee Materials</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial Presentation</td>
</tr>
<tr>
<td>July 10, 2013 – Agenda Item 3</td>
</tr>
<tr>
<td>Proposed Tariff Language</td>
</tr>
<tr>
<td>July 10, 2013 – Agenda Item 3</td>
</tr>
</tbody>
</table>

The ISO previously outlined its plans for this FERC compliance requirement at the July 10, 2013 Market Committee meeting.
Regulation Market (Order 755) Compliance

Tariff Clarification to Comply with June 20, 2013 FERC Order

Jonathan Lowell

Principal Analyst | Market Development
III.14    Regulation Market.

III.14.1    Regulation Market System Requirements.

The Regulation Capacity Requirement and Regulation Service Requirement are determined based on historical control performance and compliance with NERC and NPCC control standards. The Regulation Capacity Requirement and Regulation Service Requirement will be published on the ISO’s website.

During abnormal system conditions, the ISO may deviate from the Regulation Capacity Requirement or Regulation Service Requirement to maintain system reliability.

III.14.2    Regulation Market Eligibility.

To be eligible to provide Regulation, a Resource must satisfy the following conditions:

(a)    Physical Parameters.

   (i)    Automatic Response Rate.

       (1)    The minimum Automatic Response Rate is 1 MW/minute.

   (ii)   Regulation Capacity.

       (1)    The minimum Regulation Capacity of a generating unit will be determined based on unit size and operating characteristics and must be greater than or equal to: (a) 10 megawatts, and; (b) two times the generating unit’s AGC SetPoint Deadband plus one.

       (2)    The minimum Regulation Capacity of a Resource that is not a generating unit is no less than one megawatt after aggregation.

(b)    Regulation Technical Requirements.

A Resource providing Regulation must:

   (i)    be located within the New England Control Area.

   (ii)   meet the technical requirements specified in ISO New England Operating Procedure No. 14, Technical Requirements for Generators, Demand Resources and Asset Related Demands and ISO New England Operating Procedure No. 18, Metering and Telemetering Criteria.

   (iii)  be capable of receiving and following AGC SetPoints sent electronically at four-second intervals.

   (iv)   have a demonstrated capability to reliably follow Dispatch Instructions, consistent with normal operating characteristics and physical offer parameters, including Regulation Capacity
and Automatic Response Rate. Resources without an operational history of providing Regulation must establish and demonstrate this capability as follows:

(1) Demand Response Regulation Resources, Dispatchable Asset Related Demand, Alternative Technology Regulation Resources and any Resource with less than one-hour sustainability must participate in the Regulation test environment specified in Section III.14.9.

(2) All Resources must satisfy a minimum responsiveness test that demonstrates that a Resource can follow AGC SetPoints.

(c) Aggregation.
Non-generation sub-resources less than one megawatt in size may be aggregated into a single Resource to meet the Regulation Market eligibility requirements specified in Section III.14.2.

A single AGC SetPoint will be sent every AGC cycle to the aggregated Resource. A Market Participant with an aggregated Resource is responsible for management and control of the individual, aggregated sub-resources to ensure an accurate aggregate response to the AGC SetPoint. The sub-resources may be geographically dispersed, provided:

(i) all of the sub-resources are located within the New England Control Area

(ii) the sub-resources are metered and recorded in a manner that allows real-time performance to be measured against Dispatch Instructions and provides for the retention of the recorded information for purposes of verification, accounting for any performance offsets from other loads, generation or devices under the direct or indirect control of the aggregator as specified in ISO New England Operating Procedure No. 18, Metering and Telemetering Criteria.

(iii) communications and metering are installed and tested for each sub-resource in accordance with ISO New England Operating Procedure No. 18, Metering and Telemetering Criteria and ISO New England Operating Procedure No. 14, Technical Requirements for Generators, Demand Resources and Asset Related Demands.

III.14.3 Regulation Market Offers.
(a) A Market Participant providing Regulation must submit a Supply Offer. The Supply Offer shall remain effective until cancelled or replaced by the Market Participant. The Supply Offer must specify the following offer parameters:
(i) Regulation unit status (available/unavailable)
Regulation unit status for each hour in an Operating Day must be submitted daily prior to the
close of the Re-Offer Period. After initial submission, unit status may be modified at any time.

(ii) Regulation High Limit
For generating units, the Regulation High Limit must be less than or equal to a generating unit’s
Economic Maximum Limit. For Dispatchable Asset Related Demand, the Regulation High Limit
must be greater than or equal to a Dispatchable Asset Related Demand’s Minimum Consumption
Limit.

(iii) Regulation Low Limit
For generating units, the Regulation Low Limit must be greater than or equal to a generating
unit’s Economic Minimum Limit. For Dispatchable Asset Related Demand, the Regulation Low
Limit must be less than or equal to a Dispatchable Asset Related Demand’s Maximum
Consumption Limit.

(iv) Automatic Response Rate (MW/minute)

(v) Regulation Capacity Offer ($/MW)
The Regulation Capacity Offer price must be greater than or equal to $0/MW and may not
exceed $100/MW. A Market Participant may include estimated intertemporal opportunity costs
in its Regulation Capacity Offer price.

(vi) Regulation Service Offer ($/MW of instructed movement)
The Regulation Service Offer price must be greater than or equal to $0/MW of instructed
movement and may not exceed $10/MW of instructed movement.

(b) Additional Constraints on Offer Parameters.
(i) Regulation offer parameters that exceed recent historical performance for Regulation
Capacity or Automatic Response Rate will be constrained to reflect values consistent with the
demonstrated performance of the Resource. The Resource of a Market Participant that submits
offer parameters inconsistent with demonstrated performance will be disqualified from selection
to provide Regulation until the submitted parameters are modified to be consistent with
demonstrated performance.
(ii) A Resource that is dispatchable in the Real-Time Energy Market and providing Regulation shall have its energy dispatch range reduced by twice the amount of the Regulation provided as follows: the upper limit of the Resource’s energy dispatch range will be reduced by the amount of Regulation Capacity, and the lower limit of the Resource’s energy dispatch range will be increased by the amount of Regulation Capacity.

(c) Sustainability.
Regulation Capacity offers for Resources with less than one-hour sustainability will be evaluated in the selection process using a capacity value adjusted to reflect historical performance when dispatched at the non-adjusted value. The adjusted value will account for the Resource’s demonstrated ability to follow the AGC dispatch signal over an hour at the offered Regulation Capacity level. The percentage adjustment will be reevaluated periodically to account for changes in the performance of the Resource. Resources with no historical performance record will be evaluated pursuant to the regulation resource test environment specified in Section III.14.9.

Adjusted Regulation Capacity will be used for the purpose of selecting Resources to meet the Regulation Capacity Requirement and for determining Regulation Capacity compensation.

Resources will be dispatched for Regulation in accordance with the unadjusted Regulation Capacity offer parameters.

For a storage-based resource, sustainability is measured based on full rate of charge/discharge starting from a half-full status.

III.14.4 Regulation Market Administration.
A Market Participant may modify Regulation offer parameters at any time. The offered parameters will remain in effect until modified by the Market Participant. The most recent offer parameters will be used each time new Resources are selected and until a new selection process is completed.

III.14.5 Regulation Market Resource Selection.
Resources are selected to provide Regulation from eligible and available Resources to meet the Regulation Capacity Requirement and Regulation Service Requirement at the least-cost based on Regulation Capacity Offers, Regulation Service Offers, estimated energy opportunity costs, impacts on
system production costs, and operational requirements related to reliability, including a minimum aggregated response rate and minimizing short-term changes in the assignment of Resources to provide Regulation. For the purposes of least-cost Resource selection, the following penalty factors are used for any violation of the Regulation requirements constraint: (1) $100/MW plus the Energy Component of the Real-Time Locational Marginal Price at the reference point for each megawatt of Regulation Capacity shortfall, and: (2) $10/MW for each megawatt of Regulation Service shortfall. In addition, selection will consider opportunity cost sensitivities associated with large changes in the estimated opportunity cost of a Resource due to the shape of the Resource’s Supply Offer price curve. An eligible Resource may be omitted from providing Regulation due to operational restrictions, including, but not limited to, binding transmission constraints, planned shutdown prior to the end of the settlement interval, or known or anticipated system operating conditions.

The ISO may deviate from the market-based Resource selections to maintain system reliability.

If one or more Resources providing Regulation become unavailable, a new selection process may be conducted to obtain the Resources needed to fulfill the Regulation Capacity Requirement and the Regulation Service Requirement and new clearing prices determined pursuant to Section III.14.8(a).

In the event one or more Resources have equivalent least-cost characteristics in the selection process, the Resource with the larger Regulation Capacity value will be selected or, if the Regulation Capacity value is also equal, the Resource with the earliest Supply Offer submission time will be selected.

III.14.6 Delivery of Regulation Market Products.

Resources selected for Regulation are dispatched to reduce the New England Control Area’s area control error as needed to ensure reliability and compliance with NERC and NPCC control standards.

Resources that are generating units are dispatched based on relative response rates using multi-valued AGC SetPoints with AGC SetPoint Deadbands. Resources that are not generating units are dispatched using a trinary dispatch that calculates AGC SetPoints equal to one of the following three values: Regulation High Limit, Regulation Low Limit, and a midpoint between the Regulation High Limit and the Regulation Low Limit. Dispatch will be coordinated with the objective of achieving consistent and non-discriminatory treatment of Resources providing similar offer parameters.
AGC SetPoints will be established to cost-effectively meet reliability criteria based on the current area control error, the Automatic Response Rate and offer parameters of the selected Resources, as well as the current and predicted state of the system.

**III.14.7 Performance Monitoring.**

The performance of a Resource providing Regulation will be monitored in Real-Time. For each settlement interval, a Resource is considered to be non-performing if, after a grace period, the Resource is not responding to AGC SetPoints at a rate at least equal to a percentage of its Automatic Response Rate or outside a tolerance band around the AGC SetPoint that is equal to a percentage of the Regulation Capacity of the Resource. The grace period will be between two and four minutes. The percentage of the Automatic Response Rate will be between 80 and 95 percent. The percentage of the Regulation Capacity of the Resource will be between 5 and 15 percent. The specific values will be published on the ISO’s website.

A Resource that changes its direction of movement in a manner inconsistent with the AGC SetPoint is considered non-performing for the remainder of the settlement interval.

Compensation adjustments for non-performing Resources are addressed in Section III.14.8(b)(iv).

**III.14.8 Regulation Market Settlement and Compensation.**

(a) Calculation of Regulation Clearing Prices.

(i) Regulation Service clearing prices.

The Regulation Service clearing price is set equal to the highest Regulation Service Offer of the Resources selected to provide Regulation pursuant to Section III.14.5.

(ii) Regulation Capacity clearing prices.

The Regulation Capacity clearing price is set such that total compensation from the Regulation Service clearing price and the Regulation Capacity clearing price will, based on a uniform clearing price applied to all selected Resources, ensure recovery of as-bid costs for Regulation Capacity, estimated Regulation Service, estimated energy opportunity costs, and the Resource-specific incremental cost savings payment determined for each Resource for the planned duration of the settlement interval.
The incremental cost savings provided by each Resource is assessed by determining the least-cost selection of Resources as specified in Section III.14.5 both with and without the particular Resource. The incremental cost savings for the settlement interval is the estimated total cost of Regulation without the Resource minus the estimated total cost of Regulation with the Resource, including the application of penalty factors to any violation of the Regulation requirements constraint.

(b) Compensation to Regulation Providers.

(i) A Market Participant with a Resource that is selected to provide Regulation and that complies with the dispatch and performance requirements in Section III.14 shall receive:

(1) A capacity payment equal to the amount of Regulation Capacity selected times the Regulation Capacity clearing price.

(2) A service payment equal to the amount of service provided, while the Resource is considered to be performing as specified in Section III.14.7, as measured by the absolute value of the Resource’s scheduled movement at the claimed rate of response without delay, in megawatts, toward the AGC SetPoint in response to AGC dispatch signals times the Regulation Service clearing price.


A Resource-specific Regulation energy opportunity cost payment for those Resources dispatchable in the Real-Time Energy Market is determined for each settlement interval that the Resource is selected to provide Regulation. The Regulation energy opportunity cost payment shall be equal to the product of (i) the absolute value of the deviation of the Resource’s dispatch level necessary to follow the ISO’s Regulation signals from the Resource’s expected dispatch level if it had been dispatched in economic merit order and (ii) the absolute value of the difference between the Real-Time Price at the Node associated with the Resource and the megawatt weighted average Supply Offer or Demand Bid price for the energy associated with the deviation of the Resource’s expected dispatch level if it had been dispatched in economic merit order. Regulation energy opportunity costs are only incurred when a Resource is providing Regulation.
(iii) Make-Whole Payment
If revenues from the Regulation Capacity clearing price and the Regulation Service clearing price are insufficient to cover a Market Participant’s as-bid costs for the actual Regulation Capacity and the amount of Regulation Service provided during a settlement interval plus actual energy opportunity costs as calculated in Section III.14.8(b)(ii), a make-whole payment will be provided for the period that the Resource is considered to be performing as specified in Section III.14.7.

(iv) Performance Adjustments.
A selected Resource’s capacity payment will be reduced in proportion to the percentage of four-second AGC cycles during which the Resource was not performing.

(v) Compensation for Replacement Resources
If system conditions require the ISO to designate additional Resources in order to satisfy Regulation requirements for the remainder of a settlement interval without completing the selection process described in Section III.14.5, compensation for replacement Resources will be made according to the Resource’s actual performance using the Regulation Capacity clearing price, the Regulation Service clearing price, and any make-whole payments as specified in Section III.14.8(b)(iii).

(c) Regulation Charges.
Each Market Participant shall have a Regulation charge equal to its pro rata share of the Regulation Capacity Requirement and Regulation Service Requirement for the settlement period based on the Market Participant’s total Real-Time Load Obligation. The total cost of providing Regulation for each settlement period is charged to Market Participants based on their pro rata share of Real-Time Load Obligation during the period. For the purposes of allocating Regulation charges, the Real-Time Load Obligation of a Dispatchable Asset Related Demand providing Regulation shall be limited to the Minimum Consumption Limit of the Resource.

(d) Net Energy Settlement for Alternative Technology Regulation Resources.
During the asset registration process, a Market Participant with an Alternative Technology Regulation Resource must determine, in conjunction with any interconnecting Transmission Owner, if the interconnection and metering arrangements for the resource will result in the resource’s net energy requirements (energy consumption for the energy settlement interval less energy injections for the energy settlement interval) being separately reported to the ISO as Real-Time Load Obligation or will be
included in the Real-Time Load Obligation of a separate LSE. If the Alternative Technology Regulation Resource has separately metered and reported Real-Time Load Obligation, the Market Participant with the resource will pay for the net energy consumed at the Real-Time Price at the resource’s Node.


The ISO administers a regulation resource test environment that allows Market Participants to evaluate or demonstrate the performance of Resources without an operational history of providing Regulation prior to participation in the Regulation Market.

Resources providing Regulation under the regulation resource test environment will be compensated for the Regulation Capacity and Regulation Service provided in response to AGC SetPoints at the lowest of the Regulation Capacity Offer prices and Regulation Service Offer prices offered for any Resource selected during each settlement interval. Resources that are also dispatchable in the Real-Time Energy Market will be compensated for Regulation energy opportunity costs incurred while operating under the regulation resource test environment.

Resources performing a minimal responsiveness test will not be compensated for Regulation.

A Resource may only provide Regulation under the regulation test environment until sufficient operational information has been collected to verify reasonable operating parameters for the Resource or to determine that the Resource does not meet the eligibility requirements necessary to participate in the Regulation Market.
MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Sebastian M. Lombardi, NEPOOL Counsel

DATE: July 26, 2013

RE: FCA Qualification Process for Import Capacity Resources

At its August 2, 2013 meeting, the Participants Committee will be asked to support revisions to Manual M-20 proposed by the ISO to provide additional detail on the Forward Capacity Auction qualification process for Import Capacity Resources (the “Import Capacity Qualification Changes”). A copy of the proposed changes, as well as materials from the ISO describing these changes that were circulated to the Markets Committee, have been included with this memorandum.

By way of background, during the qualification process for the seventh Forward Capacity Auction (“FCA7”), the ISO submitted additional questions to Market Participants that were seeking to qualify Import Capacity Resources. That additional information the ISO indicated was designed to satisfy the ISO that external resources would be deliverable to the New England Control Area. Referring to the answers it received to those questions, the ISO for FCA7 did not initially qualify certain Import Capacity Resources, asserting that the resources did not demonstrate how they would be deliverable through New York to the New England Control Area for the 2016-2017 Capacity Commitment Period. Two affected Market Participants, HQUS and Brookfield, filed responses to the ISO’s FCA7 Informational Filing and initiated separate Section 206 complaint proceedings in order to reverse the ISO’s denial of qualification. On December 6, 2012, in its answer, the ISO acknowledged that it could have been clearer in its communications and that, “[i]n order to prevent future misunderstandings, the ISO will work with stakeholders to provide more detailed and specific information regarding the qualification of New Import Capacity Resources for future auctions in PP-10 and/or M-20.” The FERC ultimately granted waiver of the qualification deadline and waived applicable timing requirements in order to permit Import Capacity Resources of HQUS and Brookfield to qualify for FCA7.

In its proposal to the Markets Committee, the ISO explained that it had posted the Import Capacity Resource qualification questionnaire on its website and has clarified that the ISO is collecting the information to determine under the Tariff whether to qualify Import Capacity Resources. The ISO also proposed to update Manual 20 to include a link to the qualification questionnaire and to include a reference to the provisions that permit the ISO and the bidder of new Resources to consult, which are contained in Market Rule 1, Section III.13.1.1.2.7.
At its July 10-11, 2013 meeting, the Markets Committee considered a resolution to recommend Participants Committee support for the ISO’s proposed Import Capacity Qualification Changes. That motion failed with a 54.8% Vote in favor.¹

We understand that the ISO is discussing potential modifications to its proposed Import Capacity Qualification Changes and will update you, as appropriate, with any further developments in advance of the August 2 meeting.

The following form of resolution may be used for Participants Committee action on this matter:

RESOLVED, that the Participants Committee supports the revisions to Manual M-20 to provide additional detail for Import Capacity Resource qualification as proposed by the 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.

¹ The individual Sector votes were Generation (0% in favor, 17.1% opposed, 9 abstentions), Transmission (17.1% in favor, 0% opposed, 3 abstention), Supplier (3.42% in favor, 13.68% opposed, 11 abstentions), Alternative Resources (0.08% in favor, 14.42% opposed, 5 abstentions), Publicly Owned Entity (17.1% in favor, 0% opposed, 1 abstention), and End User (17.1% in favor, 0% opposed, 2 abstentions).
To:       NEPOOL Participants Committee

From:    Mark Karl

Date:   August 1, 2013

Subject:   Import Capacity Resource Qualification Documentation

Based on stakeholder feedback following the July 11 Markets Committee meeting, the ISO has made non-substantive revisions to the Manual-20 changes. As you may recall, at the July 11 Markets Committee meeting the ISO presented changes to Manual-20 that included a link to Forward Capacity Market (“FCM”) questions posted on the ISO’s website. Based on stakeholder feedback, the ISO has removed the proposed link to the questions. In place of the link, the ISO has included the questions as an attachment to Manual 20. A redline of the new changes is below:


To effectuate this change, the ISO has included a new Attachment L to Manual-20, which will include the questions that were previously provided in the link. The new Attachment L is listed in the table of contents for Manual-20 as “Attachment L: New Import Capacity Resource Qualification Information Form.” With respect to the questions, the only changes were to take out specific references to the eighth Forward Capacity Auction (“FCA”). The questions now reference the FCA generically instead of FCA 8. There are no other changes to the questions. The ISO has provided the redlined revisions in the attachments to this memo.
ISO New England Manual for the

**Forward Capacity Market (FCM)**

Manual M-20

Revision: 9
Effective Date: August 31, 2012

Prepared by
ISO New England Inc.
# ISO New England Manual for the Forward Capacity Market (FCM)

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Attachment L: New Import Capacity Resource Qualification Information Form

Revision History

Approval...................................................................................................................... REV-1

Revision History...................................................................................................... REV-1
Welcome to the ISO New England Manual for the Forward Capacity Market. In this introduction, you will find the following information:

What you can expect from this ISO New England Manual (see “About This Manual”).

How to use this Manual (see “Using This Manual”).

About This Manual

The ISO New England Manual for the Forward Capacity Market is one of a series of manuals within the ISO New England set of manuals. This manual focuses on the procedures for the Forward Capacity Market administered by the ISO pursuant to Section 13 of Market Rule 1.

This manual is designed as a reference guide to provide a Market Participant participating in the Forward Capacity Market with additional information or details regarding steps or actions they must take as defined in Section 13 of the Market Rule that pertain to the Forward Capacity Market. A copy of the Market Rule and ISO Tariff may be obtained from the ISO website at www.iso-ne.com.

This manual was written assuming that the reader has read the Market Rule before or in conjunction with using this manual. Terms that are capitalized in this manual shall have the meaning ascribed to them in the Market Rule or ISO Tariff.

The reader is referred first to the Market Rule for an explanation and information regarding that aspect of the operation of the FCM or requirements for complying with the FCM. This manual provides additional implementation or other detail for those provisions of the Market Rule which require the Market Participant to take an action. Manual provisions are developed and refined through the NEPOOL stakeholder processes. Manuals are not filed with or approved by the Federal Energy Regulatory Commission. In the event of any conflict between a Market Rule provision and this manual, the text of the Market Rule provision governs.

This manual is organized as a set of matrices. The Market Participant Action Matrices identify for each provision of the Market Rule the Resource Type(s) to which the provision applies and, where the provision requires an action by the FCM participant, a statement of the action and information regarding the ISO process or system to be used by the Market Participant to complete that action. There is a separate Participant Action Matrix for each major section/subsection of the Market Rule.

The format of the Participant Action Matrix and a key explaining the matrix are provided below.
## Market Participant Action Matrix – Sample and Key

The Market Participant Action Matrix in the following format.

<table>
<thead>
<tr>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
<th>E</th>
<th>F</th>
</tr>
</thead>
<tbody>
<tr>
<td>Resource Type</td>
<td>Master Schedule Identifier</td>
<td>Market Rule I § III Section Number</td>
<td>Participant Action</td>
<td>Description of Participant Deliverables/ Additional Information</td>
<td>System and/or Process</td>
</tr>
<tr>
<td>D R</td>
<td>G C I I P</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
The following table provides further detail and explanation regarding the manual matrix.

<table>
<thead>
<tr>
<th>Column</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>A</strong> Resource Type. These columns identify the Resource Type to which each Market Rule provision applies (reflected by an “X”). The Resource Types are identified below.</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Matrix Abbreviation</th>
<th>Resource Type as defined in the Market Rule</th>
</tr>
</thead>
<tbody>
<tr>
<td>DR</td>
<td>Real-Time Demand Response Resource</td>
</tr>
<tr>
<td>DR</td>
<td>Real-Time Emergency Generation Resource</td>
</tr>
<tr>
<td>DR</td>
<td>On-Peak Demand Resource</td>
</tr>
<tr>
<td>DR</td>
<td>Seasonal Peak Resource</td>
</tr>
<tr>
<td>GC</td>
<td>Generating Capacity Resource</td>
</tr>
<tr>
<td>IC</td>
<td>Import Capacity Resource</td>
</tr>
<tr>
<td>IP</td>
<td>Intermittent Power Resource(^1)</td>
</tr>
<tr>
<td>IP</td>
<td>Intermittent Settlement Only Resource</td>
</tr>
</tbody>
</table>

\(^1\) All Intermittent Power Resources are Generating Capacity Resources, however not all Generating Capacity Resources are Intermittent Power Resources. Therefore any reference to an Intermittent Power Resource will also include a reference to Generating Capacity Resource.
## Market Participant Action Matrix Key

<table>
<thead>
<tr>
<th>Column</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>B</td>
<td><strong>Master Schedule Identifier.</strong> This column permits the reader to cross-reference that provision of the Market Rule to the applicable timetable or process schedule defined in the Market Rule and/or developed by the ISO for implementation of that particular aspect of the Market Rule. The schedules are included as Attachment 2 to this manual. A listing of these schedules is provided below</td>
</tr>
<tr>
<td>C</td>
<td><strong>Market Rule 1 Section Number.</strong> This column identifies by provision number and title the Market Rule provision at issue and serves as an indexing function for the reader.</td>
</tr>
<tr>
<td>D</td>
<td><strong>Participant Action.</strong> This column defines the action this provision of the Market Rules requires a Market Participant to take. Entries are provided for those provisions requiring or permitting a Market Participant action. The user must refer to the Market Rule provision as stated in the Tariff for a complete statement of the required or permitted action and the eligibility of the Market Participant to take that action, as well as any precursor steps that may be required. If no entry appears in this column for a provision, the ISO has determined that the provision does not describe a required or permitted Market Participant action.</td>
</tr>
<tr>
<td>E</td>
<td><strong>Description of Participant Deliverables/Additional Information.</strong> This column provides additional implementation detail regarding the deliverable the Market Rule provision requires or permits the Market Participant to do. If no entry is made in this column for a provision, the Market Rule provides sufficient detail to enable the Market Participant to determine the form and format of the Market Participant deliverable(s) and action(s).</td>
</tr>
<tr>
<td>F</td>
<td><strong>ISO System and/or Process.</strong> This column identifies the ISO system or process (as applicable) the Market Participant must use to complete the required or permitted actions or submit the required deliverables.</td>
</tr>
</tbody>
</table>

Participants are encouraged to take advantage of the numerous training opportunities available to advance their understanding of the Market Rule and the actions undertaken to participate in the New England Markets, including the Forward Capacity Market. A variety of classroom courses and Web conferences are offered on a regular schedule, and all recent training presentations are posted to the ISO Website. In addition, participants may view at their convenience numerous recorded Web conferences and Web-based Training tutorials that are posted on the ISO Website as well.
For a complete list of the current offerings, please consult the Market Training page on the ISO Website.
### Section 1: Master Forward Capacity Market Schedule

<table>
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<tr>
<th></th>
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<th></th>
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</tr>
</thead>
<tbody>
<tr>
<td>13.1.8</td>
<td>A17</td>
<td>ISO Posts Existing Capacity Static De-List Bid, Permanent De-List Bid and Export Bid Information</td>
<td>2/6/2009</td>
<td>12/4/2009</td>
<td>10/6/2010</td>
<td>8/4/2011</td>
<td>15 days after the FCA is conducted</td>
<td>15 days after the FCA is conducted</td>
</tr>
<tr>
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<tr>
<td>13.1.4.2.2</td>
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<td></td>
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<td></td>
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<tr>
<td>13.1.3.5.3.1</td>
<td></td>
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</tr>
</tbody>
</table>
## Section 2: Market Participant Action Matrices

### 2.1 Resource Qualification

<table>
<thead>
<tr>
<th>#</th>
<th>Resource Type</th>
<th>Master Schedule Identifier</th>
<th>Market Rule 1 § III Section Number (13.1.3)</th>
<th>Participant Action</th>
<th>Description of Participant Deliverables / Additional Information</th>
<th>ISO System and/or Process</th>
</tr>
</thead>
<tbody>
<tr>
<td>4</td>
<td></td>
<td>A19</td>
<td>13.1.3.5.2</td>
<td>Submit a description of how the Capacity Supply Obligation will be met.</td>
<td><strong>Market Participants seeking to qualify New Import Capacity Resources shall submit responses to the FCA questions located on the ISO’s website, <a href="http://www.iso-ne.com/markets/othrmkts_data/fc/a/from/index.html">http://www.iso-ne.com/markets/othrmkts_data/fc/a/from/index.html</a> in Attachment L to this Manual.</strong>&lt;br&gt;&lt;br&gt;The ISO may seek additional information under the Section III.13.1.1.2.7 consultation provisions.&lt;br&gt;&lt;br&gt;Include the name of the specific External Resources that will back the New Import Capacity Resource; and a demonstration that the External Resource has sufficient capacity that is not committed outside the New England Control Area to meet the Capacity Supply Obligation.</td>
<td>This information is submitted using the Forward Capacity Tracking System (FCTS) user interface.</td>
</tr>
<tr>
<td>#</td>
<td>Resource Type</td>
<td>Master Schedule Identifier</td>
<td>Market Rule 1 § III Section Number (13.1.3)</td>
<td>Participant Action</td>
<td>Description of Participant Deliverables / Additional Information</td>
<td>ISO System and/or Process</td>
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</tbody>
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ISO New England Inc.
Revision 9, Effective Date: August 31, 2012
ISO New England (ISO-NE) Forward Capacity Market
New Import Capacity Resource Qualification
Information Form

ISO New England Inc.
Resource Adequacy
Posted: April 24, 2013 Revised: July 31, 2013
ISO New England (ISO-NE) Forward Capacity Market
New Import Capacity Resource Qualification Information Form

One form must be completed for each generator supporting the New Import Capacity Resource being proposed for to qualify to participate in the eighth Forward Capacity Auction (FCA #8) Qualification.

In accordance with Section III.13.1.1.2.7, which grants the ISO the authority to gather all necessary information, failure to provide adequate information sufficient to establish the ability of the generator to deliver capacity to New England will result in Resource Disqualification for the relevant Capacity Commitment Period 2017-18.

1. Generator Name: __________________________________________________

2. Provide the Station Name that the generator is associated with if the generator is a part of a multi-unit generating station:

________________________________________________________________

3. Provide the control area in which the generator is interconnected:

________________________________________________________________

4. (If applicable) Provide the unique identifier for the generator utilized by the control area in which the generator is interconnected:

________________________________________________________________

---

1 Example: If a power station consists of four generators that connect at four separate interconnection points then provide four separate forms, but in the event that the four generators connect to a single interconnection point, provide a single form.

2 Balancing Authority Area - For compliance with NERC reliability standards, an area comprising a collection of generation, transmission, and loads within metered boundaries for which a responsible entity (defined by NERC to be a Balancing Authority) integrates resource plans for that area ahead of time, maintains the area's load-resource balance, and supports the area's interconnection frequency in real time. This term is used interchangeably with control area.
5. Is there a capacity market in the control area in which this generator is interconnected?

- ☐ Yes
- ☐ No

If yes, provide the following:

a. Provide documentation for the generator’s approved maximum interconnection limit amount in the native control area.

b. Provide documentation for the last five years identifying the MW amount that the generator was/would have been approved to provide as capacity by the control area in which it is interconnected.

c. Is the generator, or will the generator be, obligated to provide capacity to the control area in which it is interconnected or to a control area other than ISO-NE from June 1, 2017 through May 31, 2018 for the relevant Capacity Commitment Period? If so, which control area and how many MWs are required to be provided?

6. Provide the ISO New England FCM Resource Name and Resource ID that this generator part of: ____________________________________________________________________________________________
7. Generator Type(s):
   - Hydraulic Turbine - Conv Daily ROR
   - Hydraulic Turbine - Conv Daily Pondage
   - Combined Cycle Total Unit
   - Compressed Air Energy Storage
   - Fuel Cell - Electrochemical
   - Combustion (Gas) Turbine
   - Hydraulic Turbine - Pipeline
   - Internal Combustion Engine
   - Integrated Coal Gasification Comb Cycle
   - Pressurized Fluidized Bed Combustion
   - Hydraulic Turbine - Reversible
   - Photovoltaic (solar)
   - Steam Turbine
   - Wind Turbine
   - Hydraulic Turbine - Conv Weekly Pondage
   - Run of River Hydro<sup>3</sup>
   - Unknown at this Time
   - Other

---

<sup>3</sup> For the purpose of completing this document, “Run of River Hydro” is defined by System Planning as a hydro resource that has 4 hours or less pondage when operating at full load: Hours in Full Pond - hours of generation available from a full pond without use of natural flow when generating at Max. Capacity. Hours in Full Pond represents the usable water between maximum (full) pond and minimum pond elevation requirements. \( \text{Hours in Full Pond} = \frac{\text{kWh in Full Pond}}{\text{Max. Capacity}} \)
8. Energy Source(s):

- Anthracite Coal and Bituminous Coal
- Agricultural Crop Byproducts/Straw/Energy Crops
- Blast Furnace Gas
- Black Liquor
- Distillate Fuel Oil. Including Diesel, No. 1
- Distillate Fuel Oil. Including Diesel, No. 2
- Distillate Fuel Oil. Including Diesel, No. 4
- Jet Fuel
- Kerosene
- Landfill Gas
- Lignite Coal
- Municipal Solid Waste
- Natural Gas
- Nuclear Uranium, Plutonium, Thorium
- Other Biomass Gas. Includes digester gas, methane, and other biomass gasses.
- Other Biomass Liquids.
- Other Biomass Solids
- Petroleum Coke
- Gaseous Propane
- Purchased Steam
- Residual Fuel Oil Bunker C
- Residual Fuel Oil No. 6 020
- Coal Synfuel.
- Sludge Waste
- Subbituminous Coal
- Solar
- Tire-derived Fuels
- Water at a Conventional Hydroelectric Turbine
- Waste/Other Coal.
- Wood Waste Liquids excluding Black Liquor.
- Wind
- Waste/Other Oil.
- Distillate Fuel Oil. Including Diesel, No. 3
- Distillate Fuel Oil No. 5
- Liquefied Propane, No. 3
- Multifuel
- Gasoline, Conventional
- Gasoline, Reformed
- Gasoline, Ethanol
- Gasoline, Oxygenated
- Gasoline
- Other (explain in detail the characteristics)

______________________
______________________
______________________
9. Describe the generation classification in the control area in which it is interconnected. For example, a run of river hydro electrical generator that does not have control over its water would be considered “intermittent” in the New England control area in accordance with Section III.13.1.2.2.2 of the ISO-NE Tariff. Cite supporting documentation to verify classification.

a. Is the generator able to respond to its control area dispatch instructions output over full operating range?

☐ Yes
☐ No

i. If no, describe any limitations to respond to these control area dispatch instructions?

________________________________________________________________________
________________________________________________________________________
________________________________________________________________________

b. Does the generator meet the ISO-NE definition of a Limited Energy Generator?

(ISO-NE defines a Limited Energy Generator as a “generator that, due to design considerations, environmental restriction on operations, cyclical requirements, such as the need to recharge or refill or manage water flow, or fuel limitations, is unable to operate continuously at full output on a daily basis”).

☐ Yes
☐ No

c. Is the generator a solar, wind, run of river hydro or does the net power output of the generator have variability that is beyond the control of the facility owner or operator during any of the following periods:

- June-September: during hours ending 1400-1800; and
- October-May: during hours ending 1800-1900

☐ Yes
☐ No
10. For any generator answering yes to questions 9b or 9c, provide the actual median MW value of the proposed generator’s output for each of the last five years, during the hours described in question 9c.

<table>
<thead>
<tr>
<th>Year</th>
<th>June-September Actual Median MWs during hours ending 1400-1800</th>
<th>October-May Actual Median MWs during hours ending 1800-1900</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2011</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2010</td>
<td></td>
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11. For generators with a capacity market in the control area in which they are interconnected, provide the capacity rating for the past five years. For generators interconnected to a control area without a capacity market provide the audit (demonstrated maximum) MW rating for the generator for the last 5 years during the summer period (June-September) and the winter period (October-May).

<table>
<thead>
<tr>
<th>Year</th>
<th>Summer Audit Value MWs (June-September)</th>
<th>Winter Audit Value MWs October-May</th>
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12. Explain in detail the process, and commercial arrangement, by which the capacity and associated energy from the proposed generator will be deliverable to the New England control area border, on the peak design day of the control area to which the generator is interconnected and any intervening control areas through which the proposed capacity may be wheeled. Provide detail how the capacity and associated energy will be recognized by the control area to which the generator is interconnected with the same priority as native load.
13. Per the ICAP Memorandum Of Understanding (MOU)\(^4\) Curtailment Principal 1.a, the control area to which the generator is interconnected and any intervening control areas through which the capacity may be wheeled is not required to deliver the energy associated with capacity if there is a transmission constraint that is located between the capacity generator and the external interface that is at or approaching a violation, and the flow from that generator to the external interface has a direct impact on that constraint.

As such, for generators interconnected to control areas that are signatory to the aforementioned ICAP MOU describe any internal transmission constraints that could prevent the capacity and/or energy [as appropriate] from this generator from being delivered to the ISO-NE control area with a priority equal to native load in the control area in which the generator is interconnected. Cite both on peak and off peak periods that relevant transmission constraints would impact the ability of the capacity and/or the energy to reach the New England Border. For each constraint cited, provide documentation shared with NERC Reliability Coordinator as well as documentation (e.g., manuals, tariff language, and operating documents) that support capacity-backed energy transaction during periods when relevant constraints are binding.

14. In addition to ISO-NE and the originating control area, will the proposed generator be wheeled thru any other control area?

☐ Yes  ☐ No

a. If yes, and for each control area through which the proposed capacity transaction is wheeled, provide documentation that the wheeled through control area(s) allows [recognizes] a capacity transaction to be wheeled through its area.

b. If yes, describe the process(es) used in the [wheeled through] control area to match the import of capacity to the export of capacity during daily operation to ensure the [capacity and associated] energy that is received at one border is delivered and credited to the receiving control area with a priority equal to that of native load.

c. For any import and export interface [in the wheeled through control area ]associated with a wheel through of capacity and associated energy provide the MW interface (long-term emergency) limit, and provide any MW portion of the limit preferentially allocated for delivery to native load in the control area.

Note: For the purposes of completing Questions 14a, b, and c, it is not sufficient to identify procedures that permit the wheeling of non-firm energy during daily operation. In answering this question, a capacity wheel would be defined as a capacity transaction that treats the import side of the wheel the same as it would treat an operating physical generator interconnected at the import point.

d. For proposed generators that must be wheeled-through an adjacent control area before reaching the New England border, describe any and all transmission constraints that may prevent the capacity and/or energy [as appropriate] from being delivered to the ISO-NE control area.
To: NEPOOL Markets Committee
From: Janine Dombrowski
Date: May 29, 2013
Subject: Import Capacity Resource Qualification Documentation

During the annual qualification process for the seventh Forward Capacity Auction, the ISO did not initially qualify certain Import Capacity Resources because the resources did not demonstrate how they would be deliverable to the New England Control Area for the 2016-2017 Capacity Commitment Period. Specifically, the ISO was seeking information demonstrating the deliverability\(^1\) of these resources through the Central-East Interface, a known transmission constraint in New York. On November 6, 2012, the ISO submitted the Informational Filing for qualification in the Forward Capacity Market (“Informational Filing”) with the Commission. Certain import resources filed responses to the Informational Filing with additional qualification details that, with approval from the Commission, allowed the ISO to qualify the Import Capacity Resources.

On December 6, 2012,\(^2\) in its answer to the protests and comments in response to the Informational Filing, the ISO acknowledged that it could have been clearer in its communications and that, “In order to prevent future misunderstandings, the ISO will work with stakeholders to provide more detailed and specific information regarding the qualification of New Import Capacity Resources for future auctions in PP-10 and/or M-20.”

The ISO has reviewed its procedures and manuals. During the FCM qualification periods, beginning with the qualification for the sixth FCA, the ISO has provided additional questions to Market Participants seeking to qualify Import Capacity Resources. These questions include a requirement that the Market Participant demonstrate how the resource will be deliverable to the New England Control Area for the relevant Capacity Commitment Period and provide an opportunity for the ISO to communicate with the Market Participant to understand the basis for qualification.

The ISO has enhanced its training materials to include additional guidelines for Import Capacity Resource qualification. In addition, the ISO has posted the Import Capacity Resource qualification questionnaire on its website and clarified that the ISO is collecting the information for qualification

\(^1\) To ensure that the ISO meets its resource adequacy needs, a New Capacity Import Resource must demonstrate how it will be deliverable to the New England Control Area for the relevant Capacity Commitment Period. For new import resources located west of the Central-East Interface, the ISO requires information that explains the deliverability of these resources given the constraints at the Central-East Interface.

purposes under the tariff. The ISO is also proposing to update Manual 20 to include a link to the qualification questionnaire.

The manual changes are contained in Section 2: Market Participant Action Matrices, Row 4. The ISO proposes to strike the existing description, which merely parrots the tariff language in III.13.1.3.5.2 and proposes to insert a link to the location of the FCM questions on the ISO’s website. The ISO also has included a reference to the consultation provisions, which are contained in III.13.1.1.2.7. The revisions are shown below.
### Section 2: Market Participant Action Matrices

#### 2.1 Resource Qualification

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<th>P</th>
<th>Master Schedule Identifier</th>
<th>Market Rule 1 § III Section Number (13.1.3)</th>
<th>Participant Action</th>
<th>Description of Participant Deliverables / Additional Information</th>
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<td>4</td>
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<td>13.1.3.5.2</td>
<td>Submit a description of how the Capacity Supply Obligation will be met.</td>
<td>Market Participants seeking to qualify New Import Capacity Resources shall submit responses to the FCA questions located on the ISO’s website, <a href="http://www.iso-ne.com/markets/othrmkts_data/fcm/qual/forms/index.html">http://www.iso-ne.com/markets/othrmkts_data/fcm/qual/forms/index.html</a>. The ISO may seek additional information under the Section III.13.1.2.7 consultation provisions. Include the name of the specific External Resources that will back the New Import Capacity Resource; and a demonstration that the External Resource has sufficient capacity that is not committed outside the New England Control Area to meet the Capacity Supply Obligation.</td>
<td>This information is submitted using the Forward Capacity Tracking System (FCTS) user interface.</td>
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ISO New England Inc.
One Sullivan Road, Holyoke, MA 01040-2841
www.iso-ne.com  T 413 5XX XXXX  F 413 5XX XXXX
At its August 2, 2013 meeting, the Participants Committee will be asked to consider supporting changes to Market Rule 1 to modify the definition of a Shortage Event (the “Shortage Event Trigger Proposal”). This memorandum provides further detail on the Shortage Event Trigger Proposal and also discusses potential amendments to this proposal of which we have been advised. A copy of the Markets Committee recommended Tariff revisions are included with this memorandum as Attachment A.

The Shortage Event Trigger Proposal specifies the following:

- For system-wide conditions, a Shortage Event shall be: (1) in all Capacity Zones, any period of thirty or more contiguous minutes of Reserve Constraint Penalty Factor (RCPF) activation for Ten-Minute Non-Spinning Reserves (TMNSR); or (2) in any Capacity Zone, any period of thirty or more contiguous minutes of RCPF activation for system-wide Thirty-Minute Operating Reserves (TMOR) while Action 2 of Operating Procedure No. 4 (the dispatch of Real Time Demand Resources) has also been implemented in the Capacity Zone.1

- In an import-constrained Capacity Zone, a Shortage Event shall be any Action 2 under Operating Procedure No. 4, or an Operating Procedure No. 7 event (load shedding) that is declared for the entire zone for thirty or more contiguous minutes, and that is not also declared for the entire Rest-of-Pool Capacity Zone.

- Beginning June 1, 2017, once Real-Time Demand Resources will be dispatched according to their energy offer and are no longer dispatched under Action 2 of Operating Procedure No. 4 (“OP4”), the TMOR Shortage Event trigger will cease to require any activation of OP4. Similarly, the Shortage Event Trigger Proposal also specifies that, as of June 1, 2017, the definition of a Shortage Event for an import-constrained zone will be thirty or more contiguous minutes of RCPF activation for local Thirty-Minute Operating Reserves.

At its July 10-11, 2013 meeting, the Markets Committee considered and approved a resolution to recommend Participants Committee support for the ISO’s unamended main motion (i.e., the Shortage Event Trigger Proposal) with a 60.01% Vote in favor.2 A copy of the July 12, 2013

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1 Under this second trigger, the Shortage Event Trigger Proposal states that if the qualifying conditions exist in Rest-of-Pool, but not in an export-constrained zone, there will only be a Shortage Event in Rest-of-Pool.

2 The individual Sector votes were Generation (0% in favor, 17.1% opposed, 3 abstentions), Transmission (17.1% in favor, 0% opposed), Supplier (0% in favor, 17.1% opposed, 8.3 abstentions), Alternative Resources (8.71% in favor, 5.79% opposed, 2 abstentions), Publicly Owned Entity (17.1% in favor, 0% opposed, 30 abstentions), and End User (17.1% in favor, 0% opposed, 3 abstentions).
As indicated, prior to the Markets Committee’s vote on the ISO’s Shortage Event Trigger Proposal, the following two motions to amend the main motion were considered and have been identified to us as proposals for consideration by the Participants Committee at its August 2 meeting: (Further details on these amendments are included with this memorandum).

A.  _NextEra Amendment_

This amendment, which is sponsored by NextEra, would effectively maintain the current definition of a FCM Shortage Event until June 1, 2017. The Markets Committee failed to recommend support for this motion to amend with a 59.94% Vote in favor. (“Vote 1” in the Notice of Actions). We have included as Attachment C materials from NextEra pertaining to its proposed amendment.

B.  _PSEG Amendment_

The PSEG amendment would make implementation of the modified Shortage Event triggers that would go into effect beginning June 1, 2017 contingent upon the eligibility of Demand Resources to provide Operating Reserves. The Markets Committee supported the PSEG amendment with a 72.25% Vote in favor. (“Vote 2” in the Notice of Actions). However, the Markets Committee failed to recommend Participants Committee support for the amended main motion with a 28.5% Vote in favor, and the ISO decided not to include PSEG’s proposed modifications in the Markets Committee vote on its proposal. (“Vote 3” in the Notice of Actions). We have included as Attachment D materials from PSEG concerning its proposed amendment. Note that these materials provide slightly modified language than what was considered at the Markets Committee.

If any Participant wishes to offer an additional amendment to the Shortage Event Trigger Proposal that is not already included with this memorandum, please let NEPOOL Counsel know as soon as possible and provide a copy of the proposed amendment so it can be reviewed and considered by your colleagues and the ISO ahead of the meeting. You can e-mail any such proposals to NEPOOL Counsel (slombardi@daypitney.com).

The following form of resolution may be used for Participants Committee action on the Shortage Event Trigger Proposal:

RESOLVED, that the Participants Committee supports support the revisions to Market Rule 1 to modify the FCM Shortage Event triggers as recommended by the Markets Committee at its July 10-11, 2013 meeting 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.
To: Markets Committee  
From: Andrew Gillespie – ISO New England  
Date: July 11, 2013  
Subject: FCM Shortage Event Trigger Revision.

The ISO is presenting and requesting a vote on a proposal to modify Market Rule 1 specific to the definition of a Shortage Event. Below is a summary of this proposal which was discussed at the listed Markets Committee meetings.

System Wide Conditions

First, the modifications specify that the current trigger for Shortage Events remains in place. This means that in all Capacity Zones any period of thirty or more contiguous minutes of Reserve Constraint Penalty Factor (RCPF) activation for Ten-Minute Non-Spinning Reserves (TMNSR) shall be a Shortage Event.

Second, the modifications add a condition that a Shortage Event in any Capacity Zone shall also be any period of thirty or more contiguous minutes of RCPF activation for system-wide Thirty-Minute Operating Reserves while Action 2 of Operating Procedure No. 4 (the dispatch of Real Time Demand Resources) has also been implemented in the Capacity Zone.1

Therefore, if there is either a 30-minute activation of TMNSR, or 30 minutes of TMOR in conjunction with Action 2 of OP4, a Shortage Event will have occurred. However, once Real Time Demand Resources are no longer dispatched under Action 2 of Operating Procedure No. 4 (June 1, 2017), the TMOR Shortage Event trigger will cease to require any activation of Operating Procedure No. 4.

Import-Constrained Zone Conditions

The modifications specify that for an import-constrained Capacity Zone, a Shortage Event shall be Action 2 under Operating Procedure No. 4, or an Operating Procedure No. 7 event (load shedding) that is declared for the entire zone for thirty or more contiguous minutes, and that is not also declared for the

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1 Under the second modification, the proposed language makes clear that if the qualifying conditions exist in ROP, but not an export-constrained zone, there will only be a Shortage Event in ROP.
entire Rest-of-Pool Capacity Zone. Similarly, after Real Time Demand Resources will be dispatched according to their energy offer and not under Action 2 of OP4 (June 1, 2017), the proposed modifications also specify that, as of that date, the definition of a Shortage Event for the import-constrained zone will be thirty or more contiguous minutes of RCPF activation for local Thirty-Minute Operating Reserves.

Meeting Materials

- 1st Meeting: November 7-8, 2012 (agenda item #11: A11 ISO Presentation 11-08-12)
- 2nd Meeting: December 11-12, 2012 (agenda item #14: A14 ISO Presentation 12-12-12)
- 3rd Meeting: April 9-10, 2013 (agenda item #9: A9 ISO Presentation 04-09-13)
- 5th Meeting: June 4-5, 2013 (agenda item #4: A04 ISO Presentation 06-04-13)
III.13.7.1.1.1. Definition of Shortage Events.

(a) A Shortage Event is, in all Capacity Zones, any period of thirty or more contiguous minutes of system-wide Reserve Constraint Penalty Factor activation, defined as being short of operating reserves. Reserve Constraint Penalty Factor activation for Ten-Minute Non-Spinning Reserves shall be a Shortage Event.

(b) Prior to June 1, 2017, in any Capacity Zone, any period of thirty or more contiguous minutes of Reserve Constraint Penalty Factor activation at the $500/MWh level for system-wide Thirty-Minute Operating Reserves when Action 2 under Operating Procedure No. 4, has also been implemented for the entire Capacity Zone shall also be a Shortage Event. Beginning on June 1, 2017, in any Capacity Zone, any period of thirty or more contiguous minutes of Reserve Constraint Penalty Factor activation at the $500/MWh level for system-wide Thirty-Minute Operating Reserves shall also be a Shortage Event.

(c) Prior to June 1, 2017, in an import-constrained Capacity Zone, as determined pursuant to Section III.13.2.3.4, a Shortage Event shall also be any Action 2 under Operating Procedure No. 4, or any Operating Procedure No. 7 OP4 Action 6, OP4 Action 12, OP4 Action 13, or OP7 event, or their successor operating procedures, that is declared for the entire import-constrained Capacity Zone for based on adequacy and not security, as defined in the ISO New England Manuals, with a duration of thirty or more contiguous minutes, and that is not also declared for the entire Rest-of-Pool outside of the Capacity Zone. Beginning on June 1, 2017, in an import-constrained Capacity Zone, as determined pursuant to Section III.13.2.3.4, a Shortage Event shall also be any period of thirty or more contiguous minutes of Reserve Constraint Penalty Factor activation at the $250/MWh level for local Thirty-Minute Operating Reserves.

(c) An export-constrained Capacity Zone, as determined pursuant to Section III.13.2.3.4, shall be exempt from a Shortage Event if an OP4 Action 6, OP4 Action 11, OP4 Action 12, OP4 Action 13, or OP7 event has been declared for the Rest-of-Pool Capacity Zone but not for that export-constrained Capacity Zone.

(d) In all cases, to be considered discrete Shortage Events, such events must be separated by at least 2.5 hours. Events that would satisfy the definition of Shortage Events except that they are separated by less than 2.5 hours shall be considered a single Shortage Event with a duration equal to the sum of the lengths of the underlying events. There shall be no more than two Shortage Events per Capacity Zone per
day. If there are more than two Shortage Events in a day, only the first two Shortage Events that occur will be recognized.

(e) For the purposes of Section III.13.7.1.1.1(d), Shortage Events that cross daily boundaries will be considered to occur on the day in which the Shortage Event was triggered. Availability during Shortage Events that cross monthly boundaries will be applied to the Obligation Month in which the Shortage Event was triggered.
To: Participants Committee

From: Alex Kuznecow, Secretary, Markets Committee

Date: July 12, 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 its July 10 and 11, 2013 meeting. All Sectors had a quorum.

1. (Agenda Item 1A) MAY 13, 2013 JOINT MC/RC MEETING and MAY 14 & 15, 2013 MC MEETING MINUTES
ACTION: APPROVED

It was moved, seconded and unanimously approved by the Markets Committee on a show of hands to accept the minutes of the May 13th Joint Markets Committee/Reliability Committee meeting and May 14th and 15th Markets Committee meeting.

2. (Agenda Item 2) INFORMATION POLICY – RELEASE OF MINIMUM POWER DATA
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 the ISO New England Information Policy to allow the public release of minimum power values derived from Economic Minimum Limit offer data and used in the ISO’s planning studies as proposed by ISO New England Inc. (the “ISO”) and as circulated for this meeting with those further changes recommended by this Committee and supported by the ISO and such further non-substantive changes as the Chair and Vice-Chair approve.

The motion was then voted. Based on a show of hands, the motion passed unanimously.

3. (Agenda Item 7) TIE-LINE NAME CLEAN-UP
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 Market Rule 1, Appendix F to Market Rule 1, and ISO New England Manuals M-11 and M-28 to correct obsolete tie-line names as proposed by ISO New England Inc. (the “ISO”) and as circulated for this meeting with those further changes recommended by this Committee and supported by the ISO and such further non-substantive changes as the Chair and Vice-Chair approve.

The motion was then voted. Based on a show of hands, the motion passed unanimously.
4. **(Agenda Item 8) GENERATION CAPACITY AUDITING – CONFORMING MANUAL CHANGES**

**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 conform ISO New England Manuals M-35 and M-RPA to Market Rule 1 implementing the generation capacity auditing subject as proposed by ISO New England Inc. (the “ISO”) and as circulated for this meeting with those further changes recommended by this Committee and supported by the ISO and such further non-substantive changes as the Chair and Vice-Chair approve.`

The motion was then voted. Based on a show of hands, the motion passed unanimously.

5. **(Agenda Item 9) IMPORT CAPACITY RESOURCE QUALIFICATION DOCUMENTATION**

**ACTION: MOTION FAILED**

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 ISO New England Manual M-20 to provide additional detail for Import Capacity Resource qualification as proposed by ISO New England Inc. (the “ISO”) and as circulated for this meeting with those further changes recommended by this Committee and supported by the ISO and such further non-substantive changes as the Chair and Vice-Chair approve.`

The motion was then voted. The motion failed with a vote of 54.8% in favor. The individual Sector votes were Generation (0% in favor, 17.1% opposed, 9 abstentions), Transmission (17.1% in favor, 0% opposed, 3 abstention), Supplier (3.42% in favor, 13.68% opposed, 11 abstentions), Alternative Resources (0.08% in favor, 14.42% opposed, 5 abstentions), Publicly Owned Entity (17.1% in favor, 0% opposed, 1 abstention), and End User (17.1% in favor, 0% opposed, 2 abstentions).

6. **(Agenda Item 10) FCM SHORTAGE EVENT TRIGGERS**

**ACTION: MOTION FAILED**

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 Market Rule 1 to modify the FCM Shortage Event triggers as proposed by ISO New England Inc. (the “ISO”) and as circulated for this meeting with those further changes recommended by this Committee and supported by the ISO and such further non-substantive changes as the Chair and Vice-Chair approve.`

**(Vote 1 – Failed (NextEra Amendment))** Before the main motion could be voted, it was moved and seconded by the Markets Committee to amend the main motion as follows:

(1) Revise the proposed Sections III.13.7.1.1.1 (b) and (c) of Market Rule 1 in accordance with the NextEra proposed changes (see NextEra Amendment).
The motion to amend was then voted. The motion to amend failed with a vote of 59.94% in favor. The individual Sector votes were Generation (17.1% in favor, 0% opposed, 2 abstentions), Transmission (2.85% in favor, 14.25% opposed), Supplier (17.1% in favor, 0% opposed, 3 abstentions), Alternative Resources (5.79% in favor, 8.71% opposed, 2 abstentions), Publicly Owned Entity (17.1% in favor, 0% opposed, 4 abstentions), and End User (0% in favor, 17.1% opposed, 1 abstention).

(Vote 2 – Passed (PSEG Amendment)) Before the main motion could be voted, it was moved and seconded by the Markets Committee to amend the main motion as follows:

1. Revise the proposed Sections III.13.7.1.1.1 (b) and (c) of Market Rule 1 in accordance with the PSEG proposed changes (see PSEG Amendment).

The motion to amend was then voted. The motion to amend passed with a vote of 72.25% in favor. The individual Sector votes were Generation (17.1% in favor, 0% opposed, 3 abstentions), Transmission (0% in favor, 17.1% opposed, 1 abstention), Supplier (17.1% in favor, 0% opposed, 9 abstentions), Alternative Resources (8.13% in favor, 6.37% opposed), Publicly Owned Entity (17.1% in favor, 0% opposed, 2 abstentions), and End User (12.83% in favor, 4.27% opposed, 2 abstentions).

(Vote 3 – Failed) The amended main motion was then voted. The amended main motion failed with a vote of 28.5% in favor. The individual Sector votes were Generation (0% in favor, 17.1% opposed, 4 abstentions), Transmission (0% in favor, 0% opposed, 6 abstentions), Supplier (0% in favor, 17.1% opposed, 10.3 abstentions), Alternative Resources (0% in favor, 14.5% opposed, 3 abstentions), Publicly Owned Entity (17.1% in favor, 0% opposed, 30 abstentions), and End User (11.4% in favor, 5.7% opposed, 2 abstentions).

7. (Agenda Item 10) FCM SHORTAGE EVENT TRIGGERS

ACTION: VOTE PASSED

The ISO proceeded to ask the Markets Committee to provide a vote on the ISO’s proposed revisions to Market Rule 1 to modify the FCM Shortage Event triggers.

The Markets Committee action on the ISO’s proposed revisions to Market Rule 1 to modify the FCM Shortage Event triggers resulted in a vote of 60.01% in favor. The individual Sector votes were Generation (0% in favor, 17.1% opposed, 3 abstentions), Transmission (17.1% in favor, 0% opposed), Supplier (0% in favor, 17.1% opposed, 8.3 abstentions), Alternative Resources (8.71% in favor, 5.79% opposed, 2 abstentions), Publicly Owned Entity (17.1% in favor, 0% opposed, 30 abstentions), and End User (17.1% in favor, 0% opposed, 3 abstentions).
III.13.7.1.1. Definition of Shortage Events.

(a) A Shortage Event in all Capacity Zones, any period of thirty or more contiguous minutes of system-wide Reserve Constraint Penalty Factor activation, defined as being short of operating reserves Reserve Constraint Penalty Factor activation for Ten-Minute Non-Spinning Reserves shall be a Shortage Event.

(b) Beginning on June 1, 2017, in any Capacity Zone, any period of thirty or more contiguous minutes of Reserve Constraint Penalty Factor activation at the $500/MWh level for system-wide Thirty-Minute Operating Reserves shall also be a Shortage Event.

(b) Prior to June 1, 2017, in an import-constrained Capacity Zone, as determined pursuant to Section III.13.2.3.4, a Shortage Event shall also be any OP4 Action 6, OP4 Action 12, OP4 Action 13, or OP7 event, or their successor operating procedures, that is declared based on adequacy and not security, as defined in the ISO New England Manuals, with a duration of thirty or more contiguous minutes, and that is not also declared outside of the Capacity Zone. Beginning on June 1, 2017, in an import-constrained Capacity Zone, as determined pursuant to Section III.13.2.3.4, a Shortage Event shall also be any period of thirty or more contiguous minutes of Reserve Constraint Penalty Factor activation at the $250/MWh level for local Thirty-Minute Operating Reserves.

(c) Prior to June 1, 2017, in an export-constrained Capacity Zone, as determined pursuant to Section III.13.2.3.4, shall be exempt from a Shortage Event if an OP4 Action 6, OP4 Action 11, OP4 Action 12, OP4 Action 13, or OP7 event has been declared for the Rest-of-Pool Capacity Zone but not for that export-constrained Capacity Zone.

(d) In all cases, to be considered discrete Shortage Events, such events must be separated by at least 2.5 hours. Events that would satisfy the definition of Shortage Events except that they are separated by less than 2.5 hours shall be considered a single Shortage Event with a duration equal to the sum of the lengths of the underlying events. There shall be no more than two Shortage Events per Capacity Zone per day. If there are more than two Shortage Events in a day, only the first two Shortage Events that occur will be recognized.

(e) For the purposes of Section III.13.7.1.1.1(d), Shortage Events that cross daily boundaries will be considered to occur on the day in which the Shortage Event was triggered. Availability during Shortage
Events that cross monthly boundaries will be applied to the Obligation Month in which the Shortage Event was triggered.
NEPOOL Participants Committee
August 2, 2013 Meeting
Agenda Item 8

PSEG Proposed Amendment to Shortage Event Trigger Proposal:

Beginning June 1, 2017 certain demand response resources will be required to participate in the Day-Ahead and Real-Time Energy Market through priced-based bidding and Demand Response activation will be removed from actions under OP4. However, offer prices by Demand Response resources will not be subject to the same offer mitigation rules that apply to generation resources and as such, offers from Demand Resources may be well above the $500/MWh Reserve Constraint Penalty Factor (RCPF) that would be the trigger for Shortage Events under the ISO proposal. The result would be that these price-based demand response resources would not be available to the ISO to ameliorate the emergency condition, while at the same time subjecting non-intermittent generation resources to potential penalties.

In fact, this same rationale is the reason why PRIOR to June 1, 2017 the Shortage Event Trigger Proposal requires the implementation of Action 2 under OP4 – the dispatch of demand response as a condition for the triggering condition.

PSEG’s proposed amendment attempts to mirror that very rationale. Specifically, in order to ensure that demand response resources can be counted upon during a shortage condition when the RCPF binds, ISO must have access to these capacity resources, at least as reserve resources. Therefore if dispatchable demand response resources are eligible to provide 30 minute operating reserves (and if ISO counts these resources as providing reserves), then when the RCPF binds, all dispatchable demand response will be contributing to addressing the reserve deficiencies and only then all capacity resources not available at that time would be subject to the Shortage Event Penalty.

Proposed Amendment in Yellow:

**III.13.7.1.1. Definition of Shortage Events.**

(a) **A Shortage Event is** In all Capacity Zones, any period of thirty or more contiguous minutes of Reserve Constraint Penalty Factor activation for Ten-Minute Non-Spinning Reserves shall be a Shortage Event system-wide Reserve Constraint Penalty Factor activation, defined as being short of operating reserves.

(b) **Prior to June 1, 2017** In any Capacity Zone, any period of thirty or more contiguous minutes of Reserve Constraint Penalty Factor activation at the $500/MWh level for system-wide Thirty-Minute Operating Reserves when Action 2 under Operating Procedure No. 4, has also been implemented for the
entire Capacity Zone shall also be a Shortage Event. Beginning on June 1, 2017, and contingent upon demand response resources that are obligated to participate in the Day Ahead and Real-Time Energy Markets being eligible to provide Operating Reserves, with any such reserves permitted to be designated by the ISO to meet the Real-Time Operating Reserve requirements, in any Capacity Zone, any period of thirty or more contiguous minutes of Reserve Constraint Penalty Factor activation at the $500/MWh level for system-wide Thirty-Minute Operating Reserves shall also be a Shortage Event.

(c) Prior to June 1, 2017, in an import-constrained Capacity Zone, as determined pursuant to Section III.13.2.3.4, a Shortage Event shall also be any Action 2 under Operating Procedure No. 4, or any Operating Procedure No. 7 OP4 Action 6, OP4 Action 12, OP4 Action 13, or OP7 event, or their successor operating procedures, that is declared for the entire import-constrained Capacity Zone for based on adequacy and not security, as defined in the ISO New England Manuals, with a duration of thirty or more contiguous minutes, and that is not also declared for the entire Rest-of-Pool Capacity Zone. Beginning on June 1, 2017, in an import-constrained Capacity Zone, as determined pursuant to Section III.13.2.3.4, and contingent upon demand response resources that are obligated to participate in the Day Ahead and Real-Time Energy Markets being eligible to provide Operating Reserves, with any such reserves permitted to be designated by the ISO to meet the Real-Time Operating Reserve requirements, a Shortage Event shall also be any period of thirty or more contiguous minutes of Reserve Constraint Penalty Factor activation at the $250/MWh level for local Thirty-Minute Operating Reserves.
MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Dave Doot and Sebastian Lombardi, NEPOOL Counsel

DATE: July 26, 2013

RE: Appendix A Cost Recovery Compliance Changes

At its August 2, 2013 meeting, the Participants Committee will be asked to consider supporting changes to Appendix A to Market Rule 1, as proposed by the IMM and recommended by the Markets Committee, in response to the FERC’s June 14, 2013 order in Docket No. EL13-72 (the “June 14 Order”).1 Included with this memorandum as Attachment A is a copy of those changes, along with background materials from the IMM that were circulated to the Markets Committee.

By way of background, on April 15, 2013, pursuant to Section III.A.15 of Appendix A to Market Rule 1, Dominion Energy Marketing, Inc. (“Dominion”) requested that the FERC authorize the recovery of additional fuel costs incurred with the dispatch of its Manchester Street Units on February 10, 2013,2 as well as reasonable, related regulatory costs to be identified in a compliance filing. In addition, Dominion asked the FERC to direct the ISO to implement certain Market Rule changes to minimize the risk that generators in the future would be unable to recover their full incremental costs for operating their units when requested by the ISO to provide a critical reliability service. On the latter point, NEPOOL opposed Dominion’s request for an order to change the Market Rules absent a request for such changes in the stakeholder process and a properly filed complaint proceeding if that process did not produce the desired result.

In the June 14 Order, the FERC granted Dominion’s fuel cost recovery request (and conditionally accepted Dominion’s request for regulatory cost recovery).3 Addressing Dominion’s additional request, the June 14 Order did not accept NEPOOL’s opposition and instead instituted a Section 206 proceeding (EL13-72) finding Section III.A.15 to Market Rule 1 “unjust, unreasonable, unduly discriminatory or preferential, because it does not provide resources an adequate opportunity to recover costs incurred to comply with ISO-NE directives to ensure reliability in instances when their supply offers were not mitigated.”4 Accordingly, the

1 Dominion Energy Marketing, Inc., 143 FERC ¶ 61,233 (2013) (“June 14 Order”). A copy of the June 14 Order is included with this memorandum as Attachment F.

2 Dominion Energy Marketing, Inc., Request for Additional Cost Recovery, Docket No. ER13-1291-000 (“On February 10, 2013, Manchester Street Units were committed for area reliability and their Supply Offers into the energy market were mitigated under the ISO-NE’s Constrained Area Mitigation and Reliability Commitment Mitigation processes.”).

3 June 14 Order at P 24.

4 Id. at P 25.
FERC directed the ISO to submit by July 29 Tariff revisions to Appendix A to allow Market Participants to submit a Section 205 filing for cost recovery when a resource is dispatched under certain circumstances for reliability reasons. In response to a joint request by NEPOOL and the ISO, without opposition by Dominion, the FERC extended the compliance filing date to August 13.\(^5\)

In response to the *June 14 Order*, the IMM proposed and the Markets Committee recommended for approval revisions to Appendix A (the “Cost Recovery Proposal”) that will permit a Section 205 filing when a resource is committed beyond its Day-Ahead Energy Market schedule in response to the ISO declaring an Abnormal Conditions Alert (M/LCC-2). In that proposal, if the ISO declares an action of either Operating Procedure No. 4 (action during a capacity deficiency) or Operating Procedure No. 7 (action in an emergency), those declarations would also constitute declaration of an abnormal conditions alert for purposes of the cost recovery provision.

At its July 25, 2013 meeting, the Markets Committee considered and approved a resolution to recommend Participants Committee support for the IMM’s Cost Recovery Proposal with a 87.18% Vote in favor.\(^6\) A copy of the July 26, 2013 Notice of Actions of the Markets Committee detailing this vote, including amendments proposed at, but not supported by, the Markets Committee, is also included with this memorandum as Attachment B.

**Potential Motions to Amend the Cost Recovery Proposal**

The following amendments have been identified to us as proposals that may be offered for consideration by the Participants Committee at its August 2 meeting: (Further details on these amendments are included with this memorandum).

A. **Calpine/Capital Power Proposal**

This amendment, which is jointly sponsored by Calpine and Capital Power, would provide an opportunity for gas-fired generators to submit a Section 205 cost recovery filing if there is a force majeure event on the pipeline system. The Markets Committee failed to recommend support for this motion to amend with a 36.83% Vote in favor. (“Vote 1” in the Notice of Actions). We have included as Attachment C materials pertaining to this proposed amendment.

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\(^5\) On July 14, 2013, the last day for challenging the June 14 Order, Dominion submitted a request for clarification and, in the alternative, rehearing of the *June 14 Order* because it disagreed with the IMM’s preliminary proposal, which it believes is contrary to what the Commission intended. Dominion continues to oppose IMM’s proposal.

\(^6\) The individual Sector votes were Generation (8.55% in favor, 8.55% opposed, 2 abstentions), Transmission (17.1% in favor, 0% opposed), Supplier (12.83% in favor, 4.27% opposed, 11 abstentions), Alternative Resources (14.5% in favor, 0% opposed, 4 abstentions), Publicly Owned Entity (17.1% in favor, 0% opposed), and End User (17.1% in favor, 0% opposed).
B. **Dominion Proposals**

Two separate Dominion amendments were offered at the Markets Committee to broaden the set of circumstances where a resource could seek additional cost recovery when dispatched for a reliability reason.

The first amendment, included with this memorandum as Attachment D, failed to obtain a Markets Committee recommendation with a 23.6% Vote in favor. ("Vote 2" in the Notice of Actions). In response to this proposed amendment, the IMM provided the Markets Committee with some information on the frequency and number of oil and gas-fired units dispatched without a Day Ahead Energy Market schedule. The IMM stated that in the month of June 2013 there were approximately 120 oil and gas-fired units that would have satisfied Dominion's proposed criteria, representing approximately 260 GWh of energy, and in the month of February 2013 there were approximately 130 oil and gas-fired units, representing approximately 400 GWh.

Similar to the first amendment, the Markets Committee also failed to recommend Participants Committee support for Dominion’s second amendment, which we have included as Attachment E, with a 24.7% Vote in favor. ("Vote 3" in the Notice of Actions).

If any Participant wishes to offer an additional amendment to the Markets Committee recommended Cost Recovery Proposal that is not already included with this memorandum, please let NEPOOL Counsel know as soon as possible and provide a copy of the proposed amendment so it can be reviewed and considered by your colleagues and the ISO ahead of the meeting. You can e-mail any such proposals to NEPOOL Counsel (slombardi@daypitney.com).

The following form of resolution may be used for Participants Committee action on the Markets Committee-recommended proposal:

RESOLVED, that the Participants Committee supports the revisions to Appendix A to Market Rule 1 to allow Market Participants to submit a Section 205 filing for cost recovery when a resource is dispatched under specific circumstances for reliability reasons as recommended by the Markets Committee at its July 25, 2013 meeting 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.
To: NEPOOL Markets Committee
From: Robert Laurita, Internal Market Monitor
Date: July 10, 2013, updated July 22, 2013
Subject: Appendix A Changes for Dominion Compliance Filing – Updated for July 25 Markets Committee Meeting

BACKGROUND:

On June 14, 2013 the Commission issued an order in response to Dominion Energy Marketing, Inc.’s (Dominion) request to seek recovery of fuel costs for its Manchester Street Station Units. Additionally, Dominion requested the Commission direct the ISO to implement tariff changes before winter 2013-2014, which would ensure that market participants that provide a critical reliability service\(^1\) at the ISO’s request have a reasonable opportunity to recover costs associated with providing that service.

The Commission found that the existing tariff, in particular Section III.A.15 of Appendix A, is unjust, unreasonable, unduly discriminatory or preferential, because it does not provide an adequate opportunity to recover costs incurred to comply with ISO directives.

The Commission ordered the ISO to submit a compliance filing revising section III.A.15 of Appendix A no later than 45 days from the date of the order. NEPOOL and the ISO have requested that this deadline be extended to August 13, 2013.

\(^1\) *Dominion Energy Marketing, Inc., et al.* Order Granting Cost Recovery, Instituting Section 206 Proceeding, and Establishing Refund Effective Date, FERC ¶ 61,233 (June 14, 2013) (the “Dominion Order”).
The Commission’s order requires that Appendix A be revised to allow Market Participants to submit a filing:

- to submit a section 205 filing for cost recovery, including fuel and variable operation and maintenance costs for the resource, in circumstances where for reliability reasons a resource is dispatched: (1) beyond its day-ahead schedule, where there is no opportunity to refresh the offer price to reflect current costs; or (2) after the results of the day-ahead market schedule are published, where the resource did not receive a day-ahead market schedule.

**PROJECT GOALS:**

The goal of this project is to make appropriate changes to Appendix A that define the conditions or “triggers” under which a Market Participant will be eligible to seek cost recovery. The Dominion Order provides guidance in this area. The following are excerpts from the order, with emphasis added in italic:

- The Commission finds that it is appropriate to require that resources providing *critical reliability services* have a reasonable opportunity to recover costs associated with providing that service.
- Allow for cost recovery in circumstances, for example, when a resource responds to a directive from ISO-NE to provide *essential support to part of the system* but has no reasonable opportunity to recover its costs
- Provide enough flexibility to allow for cost recovery by resources that respond under *extraordinary circumstances like those faced by the ISO-NE market on February 8 and 9.*

Further, the Commission acknowledged the ISO’s concerns that imposing a mechanism to allow generators with resources committed for reliability purposes to recover their actual fuel costs incurred in meeting the reliability need could undermine the accuracy of submitted offers or incentivize market participants to submit low offers in anticipation of a reliability event in order to increase their chance of

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2 Dominion Order at Page 26.
NEPOOL Markets Committee
July 10, 2013
Page 3 of 6

being selected or to submit high offers in order to be mitigated and eligible for cost recovery. Therefore, the triggers should limit eligibility for cost recovery to Resources that are called upon to “respond to critical reliability needs” and “respond under extraordinary circumstances.”

The conditions outlined in the Commission’s order are consistent with those currently defined in Master Local Control Center Procedure No. 2 (M/LCC-2) Abnormal Conditions Alert. The M/LCC-2 procedure is used to: (emphasis added)

[A]lert applicable power system operations, maintenance, construction and test personnel as well as each applicable Market Participant (MP) when an abnormal condition affecting the reliability of the power system exists or is anticipated. Once notified of an M/LCC-2 Abnormal Condition Alert, these entities are expected to take precautions so that routine maintenance, construction or test activities associated with any generating station, Dispatchable Asset Related Demand (DARD), Real-Time Demand Response, Real-Time Emergency Generation, transmission line, substation, dispatch computer, and communications equipment do not further jeopardize the reliability of the power system. If a maintenance, construction or test activity could jeopardize the reliability of the power system such activity shall be stopped and/or postponed during the M/LCC 2 Abnormal Condition Alert.

PROPOSAL:

The IMM proposes to modify Appendix A such that Market Participants are eligible to seek incremental cost recovery during periods when the ISO issues an Abnormal Conditions Alert under Master/LCC Procedure No. 2. The process would work as follows:

1. The ISO issues an Abnormal Conditions Alert (M/LCC-2) either system-wide or for a sub-region.
2. The ISO issues a dispatch instruction that exceeds the Resource’s Day-Ahead Energy Market schedule (i.e., DDP MW > DA Scheduled MW). If the Resource does not have a Day-Ahead Energy Market schedule (i.e., DA Scheduled MW = 0) then the entire dispatched amount (DDP) would be eligible for cost recovery.
3. The Market Participant can seek to recover incremental fuel and variable operating and maintenance costs, incurred as a direct result of the ISO’s dispatch in excess of the Resource’s Day-Ahead Energy Market schedule, that are not otherwise compensated through the energy market.
4. The IMM would verify that the period for which the Market Participant is seeking incremental cost recovery coincided with an Abnormal Conditions Alert. If the Abnormal Conditions Alert is for a sub-region, then the Resource must have been dispatched in excess of its Day-Ahead Energy Market schedule to help resolve or avoid a problem within the sub-region.

The table below illustrates a hypothetical Resource dispatched in excess of its Day-Ahead Energy Market schedule and the MW values that would be eligible for incremental cost recovery under the IMM’s proposal.

<table>
<thead>
<tr>
<th>Hour Ending</th>
<th>DA Cleared (MW)</th>
<th>DDP (MW)</th>
<th>M/LCC-2 Alert</th>
<th>Eligible for Additional Cost Recovery (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>8</td>
<td>100</td>
<td>85</td>
<td></td>
<td>0</td>
</tr>
<tr>
<td>9</td>
<td>100</td>
<td>95</td>
<td></td>
<td>0</td>
</tr>
<tr>
<td>10</td>
<td>120</td>
<td>115</td>
<td>Y</td>
<td>0</td>
</tr>
<tr>
<td>11</td>
<td>120</td>
<td>129</td>
<td>Y</td>
<td>9</td>
</tr>
<tr>
<td>12</td>
<td>150</td>
<td>162</td>
<td>Y</td>
<td>12</td>
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<td>13</td>
<td>150</td>
<td>175</td>
<td>Y</td>
<td>25</td>
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<td>14</td>
<td>150</td>
<td>200</td>
<td>Y</td>
<td>50</td>
</tr>
<tr>
<td>15</td>
<td>0</td>
<td>185</td>
<td>Y</td>
<td>185</td>
</tr>
<tr>
<td>16</td>
<td>0</td>
<td>115</td>
<td>Y</td>
<td>115</td>
</tr>
<tr>
<td>17</td>
<td>0</td>
<td>50</td>
<td>Y</td>
<td>50</td>
</tr>
</tbody>
</table>

In the Section 205 filing the Market Participant must explain why the actual incremental costs of operating the Resource in excess of the amount scheduled for the Resource in the Day-Ahead Energy Market, in a time period for which the ISO has implemented Master/LCC Procedure No. 2 Abnormal Conditions Alert for the Operating Days, exceeded the incremental costs as reflected in their Supply Offer.
There are several advantages of this approach:

- Using M/LCC-2 as the trigger would not require any changes in the ISO’s procedures, practices or software.
- The approach is simple and transparent. M/LCC-2 alerts are currently distributed to many Market Participants and published on the ISO’s website.
- Because the trigger is transparent, all Market Participants will know that if their Resource is dispatched in excess of its day-ahead schedule and they purchase fuel at a price that is greater than the price at which they based their Supply Offer to comply with the ISO’s dispatch instructions, they will be eligible to recover their fuel costs. This should make it more likely that Market Participants will purchase the required fuel and comply with the ISO’s dispatch instructions.
- This approach covers situations like that of February 8th and 9th referenced in the Commission’s order when system reliability was at risk but OP-4 was not implemented
- M/LCC2 is called infrequently and therefore will not provide a disincentive for Market Participants to be lax in fuel procurement. The table below is a summary of the days, for the period 2010 to date, with M/LCC2 Alerts and M/LCC-2 Alerts that coincided with the declaration of OP4:

<table>
<thead>
<tr>
<th>Year</th>
<th>M/LCC-2 Alerts</th>
<th>M/LCC-2 Alerts and OP4</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>22</td>
<td>6</td>
</tr>
<tr>
<td>2011</td>
<td>10</td>
<td>2</td>
</tr>
<tr>
<td>2012</td>
<td>18</td>
<td>0</td>
</tr>
<tr>
<td>2013 (To Date)</td>
<td>9</td>
<td>0</td>
</tr>
</tbody>
</table>

**UPDATED COST RECOVERY PROVISION FOR JULY 25 MC MEETING:**

The cost recovery provision has been modified to address comments received during the July 10-11 Markets Committee meeting. The provision continues to permit a Section 205 filing when a resource is committed beyond its Day-Ahead Energy Market schedule in response to the ISO declaring an abnormal conditions alert. However, the tariff language no longer includes a
reference to M/LCC-2 and instead has been expanded to directly include the triggers (based on M/LCC-2) that will result in the declaration of an abnormal conditions alert. In addition, a sentence has been added to provide that if the ISO declares an action of either Operating Procedure No. 4 (action during a capacity deficiency) or Operating Procedure No. 7 (action in an emergency), that also will constitute declaration of an abnormal conditions alert for purposes of the cost recovery provision. Further minor clarifications have been made to the rule language, in particular to clarify that cost recovery may only be requested for the costs incurred during operation above the Day-Ahead commitment, and not for costs incurred during the period of the Day-Ahead commitment.

The ISO does not believe it is appropriate to broaden the cost recovery filing triggers to apply every time a resource is dispatched beyond its Day-Ahead Energy Market commitment for “reliability.” Every dispatch in the Real-Time Energy Market could be considered as necessary for “reliability.” The ISO does not believe the Commission intended to implement a provision that would permit a Section 205 filing for cost recovery for every instance in which a capacity resource is dispatched in real time to a level that is different than its day-ahead schedule. The ISO believes that permitting cost recovery filings anytime a resource is dispatched above its day-ahead schedule would reduce the incentives for market participants to make arrangements in advance to ensure the real-time availability of their resources, which they are expected to do, and have been paid to do, as capacity suppliers. The failure to make such arrangements and to accurately price them both puts system reliability at risk and reduces the accuracy of price as an indicator of the cost of providing electricity.

The ISO believes that the proposal to permit cost recovery in the event of a fuel-related force majeure event is contrary to the provision the Commission is anticipating in the June 14 order. The Commission indicates in the June 14 order that the cost recovery provision should permit a Section 205 filing only for costs incurred beyond the day-ahead commitment, and only when those costs are incurred for operation during extraordinary reliability circumstances on the electrical system. A proposal to permit cost recovery for a force majeure event affecting a resource, but not necessarily the system, would apply to day-ahead commitments and would apply irrespective of conditions on the electrical system.

III.A.15.1. Filing Right.

If either:

(a) as a result of mitigation has been applied to a Resource under this Appendix A for all or part of one or more Operating Days, or

(b) in the absence of mitigation, a Market Participant has despite having submitted a Supply Offer at the energy offer cap specified in Section III.1.10.1.A(d) of Market Rule 1 for a Resource, or

(c) at the direction of the ISO a Market Participant has adjusted the output of a Resource to an amount that exceeds the amount scheduled for the Resource in the Day-Ahead Energy Market to address a critical reliability issue that has resulted in the ISO declaring an abnormal conditions alert for one of the reasons specified in Section III.A.15.1.1 below, a

and as a result of the actions in (a) or (c), or despite the action in (b), the Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource for those Operating Days, the Market Participant may, within sixty days of the receipt of the first Invoice issued containing credits or charges for the applicable Operating Day, submit a filing to the Commission seeking recovery of those costs pursuant to Section 205 of the Federal Power Act.

A request under this Section III.A.15 may seek recovery of additional costs incurred during the following periods: (a) if as a result of mitigation, costs incurred for the duration of the mitigation event, (b) if as a result of having submitted a Supply Offer at the energy offer cap, costs incurred for the duration of the period of time for which the Resource was operated at the energy offer cap, and (c) if as a result of being operated to address a critical reliability issue that has resulted in the ISO declaring an abnormal conditions alert, for the duration of the period of time when the Resource was required to operate to address the critical reliability issue, but only for the amount by which the actual incremental costs of operating the Resource in excess of the amount
scheduled in the Day-Ahead Energy Market exceeded the incremental costs as reflected in the Supply Offer.

**III.A.15.1. Basis for declaration of an abnormal conditions alert.**

(a) Forecasted or actual deficiency of operating reserves requiring implementation of ISO New England Operating Procedure No. 4, Action During a Capacity Deficiency, or ISO New England Operating Procedure No. 7, Action in an Emergency.
(b) The electric system in New England experiences low transmission voltages and/or low reactive reserves.
(c) A solar magnetic disturbance occurs.
(d) A cold weather event is declared.
(e) Inability to provide first contingency protection when an undesirable post-contingency condition might result, such as load shedding.
(f) A credible threat to power system reliability is made, such as sabotage or an approaching storm.
(g) Operational staffing shortage impacting normal power system operations within New England occurs.
(h) Any other condition that may cause a critical reliability issue as determined by the ISO’s operations shift supervisor or the Local Control Center system operator.

For purposes of this Section III.A.15, declaring an action of ISO New England Operating Procedure No.4 or ISO New England Operating Procedure No. 7 shall be treated as declaring an abnormal conditions alert.

**III.A.15.2. Contents of Filing.**

Any Section 205 filing made pursuant to this section shall include: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data and calculations for those costs; (ii) an explanation of (a) why the actual costs of operating the Resource for the Operating Days exceeded the Reference Level costs or, (b) in the absence of mitigation, why the actual costs of operating the Resource for the Operating Days exceeded the costs as reflected in the Supply Offer at the energy offer cap or, (c) why the actual incremental costs of operating the Resource in excess of the amount scheduled in the Day-Ahead Energy Market, during the time period for which the ISO has declared an abnormal conditions...
alert for the Operating Day, exceeded the incremental costs as reflected in the Supply Offer; (iii) the Internal Market Monitor’s written explanation provided pursuant to Section III.A.15.3; and (iv) all requested regulatory costs in connection with the filing.

III.A.15.3. Review by Internal Market Monitor Prior to Filing.

Within twenty days of the receipt of the first Invoice containing credits or charges for the applicable Operating Day, a Market Participant that intends to make a Section 205 filing pursuant to this Section III.A.15 shall submit to the Internal Market Monitor the information and explanation detailed in Section III.A.15.2 (i) and (ii) that is to be included in the Section 205 filing. Within twenty days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written explanation of the events that resulted in the Section III.A.15 request for additional cost recovery. The Market Participant shall include the Internal Market Monitor’s written explanation in the Section 205 filing made pursuant to this Section III A.15.


In the event that the Commission accepts a Market Participant’s filing for cost recovery under this section, the ISO shall allocate charges to Market Participants for payment of those costs in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource’s actual dispatch for the Operating Days in question.
III.A.15. Request for Additional Cost Recovery

III.A.15.1. Filing Right.

If either

(a) as a result of mitigation has been applied to a Resource under this Appendix A for all or part of one or more Operating Days, or

(b) in the absence of mitigation, a Market Participant has despite having submitted a Supply Offer at the energy offer cap specified in Section III.1.10.1.A(d) of Market Rule 1 for a Resource, or

(c) at the direction of the ISO a Market Participant has adjusted the output of a Resource to an amount that exceeds the amount scheduled for the Resource in the Day-Ahead Energy Market to address a critical reliability issue that has resulted in the ISO declaring an abnormal conditions alert for one of the reasons specified in Section III.A.15.1.1 below,

and as a result of the actions in (a) or (c), or despite the action in (b), a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource for the duration of the mitigation event, the Market Participant may, within sixty days of the receipt of the first Invoice issued containing credits or charges for the applicable Operating Day, submit a filing to the Commission seeking recovery of those costs pursuant to Section 205 of the Federal Power Act.

A request under this Section III.A.15 may seek recovery of additional costs incurred during the following periods: (a) if as a result of mitigation, costs incurred for the duration of the mitigation event, (b) if as a result of having submitted a Supply Offer at the energy offer cap, costs incurred for the duration of the period of time for which the Resource was operated at the energy offer cap, and (c) if as a result of being operated to address a critical reliability issue that has resulted in the ISO declaring an abnormal conditions alert, for the duration of the period of time when the Resource was required to operate to address the critical reliability issue, but only for the amount by which the actual incremental costs of operating the Resource in excess of the amount scheduled in the Day-Ahead Energy Market exceeded the incremental costs as reflected in the Supply Offer.
III.A.15.1.1. Basis for declaration of an abnormal conditions alert.

(a) Forecasted or actual deficiency of operating reserves requiring implementation of ISO New England Operating Procedure No. 4, Action During a Capacity Deficiency, or ISO New England Operating Procedure No. 7, Action in an Emergency.

(b) The electric system in New England experiences low transmission voltages and/or low reactive reserves.

(c) A solar magnetic disturbance occurs.

(d) A cold weather event is declared.

(e) Inability to provide first contingency protection when an undesirable post-contingency condition might result, such as load shedding.

(f) A credible threat to power system reliability is made, such as sabotage or an approaching storm.

(g) Operational staffing shortage impacting normal power system operations within New England occurs.

(h) Any other condition that may cause a critical reliability issue as determined by the ISO’s operations shift supervisor or the Local Control Center system operator.

For purposes of this Section III.A.15, declaring an action of ISO New England Operating Procedure No.4 or ISO New England Operating Procedure No. 7 shall be treated as declaring an abnormal conditions alert.

III.A.15.2. Contents of Filing.

Any Section 205 filing made pursuant to this section shall include: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data and calculations for those costs; (ii) an explanation of (a) why the actual costs of operating the Resource for the duration of the mitigation event exceeded the Reference Level costs or, (b) in the absence of mitigation, why the actual costs of operating the Resource for the duration of the mitigation event exceeded the costs as reflected in the Supply Offer at the energy offer cap or, (c) why the actual incremental costs of operating the Resource in excess of the amount scheduled in the Day-Ahead Energy Market, during the time period for which the ISO has declared an abnormal conditions alert for the Operating Day, exceeded the incremental costs as reflected in the Supply Offer; (iii) the Internal Market Monitor’s written explanation provided pursuant to Section III.A.15.3; and (iv) all requested regulatory costs in connection with the filing.
III.A.15.3. Review by Internal Market Monitor Prior to Filing.

Within twenty days of the receipt of the first Invoice containing credits or charges for the applicable Operating Day, a Market Participant that intends to make a Section 205 filing pursuant to this Section III.A.15 shall submit to the Internal Market Monitor the information and explanation detailed in Section III.A.15.2 (i) and (ii) that is to be included in the Section 205 filing. Within twenty days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written explanation of the events that resulted in the Section III.A.15 request for additional cost recovery. The Market Participant shall include the Internal Market Monitor’s written explanation in the Section 205 filing made pursuant to this Section III A.15.


In the event that the Commission accepts a Market Participant’s filing for cost recovery under this section, the ISO shall allocate charges to Market Participants for payment of those costs in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource’s actual dispatch for the Operating Days in question.
To: Participants Committee
From: Alex Kuznecow, Secretary, Markets Committee
Date: July 26, 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 its July 25, 2013 meeting. All Sectors had a quorum.

1. (Agenda Item 2) RELIABILITY COMMITMENT COST RECOVERY – FERC COMPLIANCE REQUIREMENT
   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 Appendix A to Market Rule 1 to allow Market Participants to submit a section 205 filing for cost recovery when a resource is dispatched under specific circumstances for reliability reasons as proposed by ISO New England Inc. (the “ISO”) and as circulated for this meeting with those further changes recommended by this Committee and supported by the ISO and such further non-substantive changes as the Chair and Vice-Chair approve.

(Vote 1 – Failed (Calpine/Capital Power Amendment)) Before the main motion could be voted, it was moved and seconded by the Markets Committee to amend the main motion as follows:

(1) Revise the proposed Sections III.A.15.1 and III.A.15.2 of Appendix A to Market Rule 1 in accordance with the Calpine/Capital Power proposed changes (see Calpine/Capital Power Amendment).

The motion to amend was then voted. The motion to amend failed with a vote of 36.83% in favor. The individual Sector votes were Generation (17.1% in favor, 0% opposed), Transmission (0% in favor, 17.1% opposed), Supplier (14.32% in favor, 2.78% opposed, 4.7 abstentions), Alternative Resources (5.41% in favor, 9.09% opposed, 5 abstentions), Publicly Owned Entity (0% in favor, 17.1% opposed), and End User (0% in favor, 17.1% opposed, 1 abstention).

(Vote 2 – Failed (Dominion 1st Amendment)) Before the main motion could be voted, it was moved and seconded by the Markets Committee to amend the main motion as follows:

(1) Revise the existing Section III.A.15.1 of Appendix A to Market Rule 1 in accordance with the Dominion proposed changes (see Dominion 1st Amendment).

The motion to amend was then voted. The motion to amend failed with a vote of 23.6% in favor. The individual Sector votes were Generation (10.26% in favor, 6.84% opposed, 3 abstentions), Transmission (6.84% in favor, 10.26% opposed, 1 abstention), Supplier (6.41% in favor, 10.69% opposed, 8 abstentions), Alternative Resources (0.08% in favor, 14.42% opposed, 4 abstentions), Publicly Owned Entity (0% in favor, 17.1% opposed), and End User (0% in favor, 17.1% opposed).
(Vote 3 – Failed (Dominion 2nd Amendment)) Before the main motion could be voted, it was moved and seconded by the Markets Committee to amend the main motion as follows:

1. Revise the proposed Section III.A.15.1 of Appendix A to Market Rule 1 in accordance with the Dominion proposed changes (see Dominion 2nd Amendment).

The motion to amend was then voted. The motion to amend failed with a vote of 24.7% in favor. The individual Sector votes were Generation (17.1% in favor, 0% opposed, 4 abstentions), Transmission (0% in favor, 17.1% opposed, 3 abstentions), Supplier (7.6% in favor, 9.5% opposed, 6 abstentions), Alternative Resources (0% in favor, 14.5% opposed, 3 abstentions), Publicly Owned Entity (0% in favor, 17.1% opposed), and End User (0% in favor, 17.1% opposed).

(Vote 4 – Passed) The main motion was then voted. The main motion passed with a vote of 87.18% in favor. The individual Sector votes were Generation (8.55% in favor, 8.55% opposed, 2 abstentions), Transmission (17.1% in favor, 0% opposed), Supplier (12.83% in favor, 4.27% opposed, 11 abstentions), Alternative Resources (14.5% in favor, 0% opposed, 4 abstentions), Publicly Owned Entity (17.1% in favor, 0% opposed), and End User (17.1% in favor, 0% opposed).

2. (Agenda Item 3) REGULATION MARKET (ORDER 755) – FERC COMPLIANCE REQUIREMENT
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 Market Rule 1 to allow regulation providers to incorporate inter-temporal opportunity costs into their bids as proposed by ISO New England Inc. (the “ISO”) and as circulated for this meeting with those further changes recommended by this Committee and supported by the ISO and such further non-substantive changes as the Chair and Vice-Chair approve.

The motion was then voted. Based on a show of hands, the motion passed unanimously.
Calpine and Capital Power Amendment

III.A.15. Request for Additional Cost Recovery

III.A.15.1. Filing Right.

If either

(a) as a result of mitigation has been applied to a Resource under this Appendix A for all or part of one or more Operating Days, or

(b) in the absence of mitigation, a Market Participant has despite having submitted a Supply Offer at the energy offer cap specified in Section III.1.10.1.A(d) of Market Rule 1 for a Resource, or

(c) at the direction of the ISO a Market Participant has adjusted the output of a Resource to an amount that exceeds the amount scheduled for the Resource in the Day-Ahead Energy Market to address a critical reliability issue that has resulted in the ISO declaring an abnormal conditions alert for one of the reasons specified in Section III.A.15.1.1 below,

(d) a force majeure has been declared on the gas pipeline system,

and as a result of the actions in (a) or (c) or (d), or despite the action in (b), a the Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource for those Operating Days, the Market Participant may, within sixty days of the receipt of the first Invoice issued containing credits or charges for the applicable Operating Day, submit a filing to the Commission seeking recovery of those costs pursuant to Section 205 of the Federal Power Act. A request under (d) above may only be made for incremental fuel costs above its Supply Offer for a natural gas-fired generating Resource that is unable to procure fuel at the price anticipated by the Resource in its Supply Offer due to the force majeure declaration by the pipeline or upstream pipeline via which the Resource’s anticipated fuel supply would have been delivered.

A request under this Section III.A.15 may seek recovery of additional costs incurred during the following periods: (a) if as a result of mitigation, costs incurred for the duration of the mitigation event, (b) if as a result of having submitted a Supply Offer at the energy offer cap, costs incurred for the duration of the period of time for which the Resource was operated at the energy offer cap, and (c) if as a result of being operated to address a critical reliability issue that has resulted
in the ISO declaring an abnormal conditions alert, for the duration of the period of time when the Resource was required to operate to address the critical reliability issue, but only for the amount by which the actual incremental costs of operating the Resource in excess of the amount scheduled in the Day-Ahead Energy Market exceeded the incremental costs as reflected in the Supply Offer, and (d) if as a result of a force majeure declaration on the gas pipeline system, incremental costs incurred for a natural gas-fired generating Resource for the duration of the declaration until such time as the Market Participant is able to submit a new Supply Offer for the Resource to reflect its incremental costs.

### III.A.15.1.1. Basis for declaration of an abnormal conditions alert.

(a) Forecasted or actual deficiency of operating reserves requiring implementation of ISO New England Operating Procedure No. 4, Action During a Capacity Deficiency, or ISO New England Operating Procedure No. 7, Action in an Emergency.

(b) The electric system in New England experiences low transmission voltages and/or low reactive reserves.

(c) A solar magnetic disturbance occurs.

(d) A cold weather event is declared.

(e) Inability to provide first contingency protection when an undesirable post-contingency condition might result, such as load shedding.

(f) A credible threat to power system reliability is made, such as sabotage or an approaching storm.

(g) Operational staffing shortage impacting normal power system operations within New England occurs.

(h) Any other condition that may cause a critical reliability issue as determined by the ISO’s operations shift supervisor or the Local Control Center system operator.

For purposes of this Section III.A.15, declaring an action of ISO New England Operating Procedure No.4 or ISO New England Operating Procedure No. 7 shall be treated as declaring an abnormal conditions alert.

### III.A.15.2. Contents of Filing.

Any Section 205 filing made pursuant to this section shall include: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data and calculations for those costs; (ii) an explanation of (a) why the actual costs of operating the Resource for the Operating Days exceeded the Reference Level costs or, (b) in the
absence of mitigation, why the actual costs of operating the Resource for the Operating Days exceeded the costs as reflected in the Supply Offer at the energy offer cap or, (c) why the actual incremental costs of operating the Resource in excess of the amount scheduled in the Day-Ahead Energy Market, during the time period for which the ISO has declared an abnormal conditions alert for the Operating Day, exceeded the incremental costs as reflected in the Supply Offer, or (d) if as a result of a force majeure declaration on the gas pipeline system, incremental costs incurred for a Resource until (i) the end of the force majeure declaration or (ii) the Market Participant is able to update the Supply Offer for the Resource to reflect its incremental costs, whichever occurs first; (iii) the Internal Market Monitor’s written explanation provided pursuant to Section III.A.15.3; and (iv) all requested regulatory costs in connection with the filing.

III.A.15.3. Review by Internal Market Monitor Prior to Filing.

Within twenty days of the receipt of the first Invoice containing credits or charges for the applicable Operating Day, a Market Participant that intends to make a Section 205 filing pursuant to this Section III.A.15 shall submit to the Internal Market Monitor the information and explanation detailed in Section III.A.15.2 (i) and (ii) that is to be included in the Section 205 filing. Within twenty days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written explanation of the events that resulted in the Section III.A.15 request for additional cost recovery. The Market Participant shall include the Internal Market Monitor’s written explanation in the Section 205 filing made pursuant to this Section III A.15.


In the event that the Commission accepts a Market Participant’s filing for cost recovery under this section, the ISO shall allocate charges to Market Participants for payment of those costs in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource’s actual dispatch for the Operating Days in question.
Dominion’s Proposal for Improved Cost Recovery

July 25, 2013
FERC-Directed Tariff Revisions to Appendix A Re: Fuel Cost Recovery (EL13-72)

- The June 14, 2013 Order issued by the FERC in response to Dominion’s fuel cost recovery filing found that:
  - Section III.A.15 to Market Rule 1 is “unjust, unreasonable, unduly discriminatory or preferential, because it does not provide resources an adequate opportunity to recover costs incurred to comply with ISO-NE directives to ensure reliability in instances when their supply offers were not mitigated.” (Order at P 25).

- As a result the Commission directed ISO-NE to submit certain Tariff revisions to Appendix A to allow resources to submit a Section 205 filing for cost recovery in circumstances where for reliability reasons a resource is dispatched:
  - “(1) beyond its day-ahead schedule, where there is no opportunity to refresh the offer price to reflect current costs; or (2) after the results of the day-ahead market schedule are published, where the resource did not receive a day-ahead market schedule.”
Modifying Appendix A Section III.A.15.1. as highlighted will directly implement the FERC Order

III.A.15.1. Filing Right.

If either (a) as a result of mitigation applied to a Resource under this Appendix A for all or part of one or more Operating Days, (b) in the absence of mitigation, despite having submitted a Supply Offer at the energy offer cap specified in Section III.1.10.1.A(d) of Market Rule 1, or (c) in the absence of mitigation, the ISO requests for reliability reasons that (i) a Resource extend its run time beyond that Resource’s day-ahead commitment, or (ii) an offline Resource that did not clear in the Day-Ahead Energy Market to operate in real time, a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource for those Operating Days, the Market Participant may, within sixty days of the receipt of the first Invoice issued containing credits or charges for the applicable Operating Day, submit a filing to the Commission seeking recovery of those costs pursuant to Section 205 of the Federal Power Act.
QUESTIONS?
III.A.15. Request for Additional Cost Recovery

III.A.15.1. Filing Right.

If either

(a) as a result of mitigation, costs incurred for the duration of the mitigation event,
(b) if as a result of having submitted a Supply Offer at the energy offer cap, costs incurred for the duration of the period of time for which the Resource was operated at the energy offer cap, and
(c) if as a result of being operated to address a critical reliability issue, costs incurred for the duration of the period of time when the

and as a result of the actions in (a) or (c), or despite the action in (b), the Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource for those Operating Days, the Market Participant may, within sixty days of the receipt of the first Invoice issued containing credits or charges for the applicable Operating Day, submit a filing to the Commission seeking recovery of those costs pursuant to Section 205 of the Federal Power Act.

A request under this Section III.A.15 may seek recovery of additional costs incurred during the following periods: (a) if as a result of mitigation, costs incurred for the duration of the mitigation event, (b) if as a result of having submitted a Supply Offer at the energy offer cap, costs incurred for the duration of the period of time for which the Resource was operated at the energy offer cap, and (c) if as a result of being operated to address a critical reliability issue that has resulted in the ISO declaring an abnormal conditions alert, for the duration of the period of time when the
Resource was required to operate to address the critical reliability issue, but only for the amount by which the actual incremental costs of operating the Resource in excess of the amount scheduled in the Day-Ahead Energy Market exceeded the incremental costs as reflected in the Supply Offer.

III.A.15.1. Basis for declaration of an abnormal conditions alert.

- Forecasted or actual deficiency of operating reserves requiring implementation of ISO New England Operating Procedure No. 4, Action During a Capacity Deficiency, or ISO New England Operating Procedure No. 7, Action in an Emergency.
- The electric system in New England experiences low transmission voltages and/or low reactive reserves.
- A solar magnetic disturbance occurs.
- A cold weather event is declared.
- Inability to provide first contingency protection when an undesirable post-contingency condition might result, such as load shedding.
- A credible threat to power system reliability is made, such as sabotage or an approaching storm.
- Operational staffing shortage impacting normal power system operations within New England occurs.
- Any other condition that may cause a critical reliability issue as determined by the ISO’s operations shift supervisor or the Local Control Center system operator.

For purposes of this Section III.A.15, declaring an action of ISO New England Operating Procedure No. 4 or ISO New England Operating Procedure No. 7 shall be treated as declaring an abnormal conditions alert.

III.A.15.2. Contents of Filing.

Any Section 205 filing made pursuant to this section shall include: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data and calculations for those costs; (ii) an explanation of (a) why the actual costs of operating the Resource for the Operating Days exceeded the Reference Level costs or, (b) in the absence of mitigation, why the actual costs of operating the Resource for the Operating Days exceeded the costs as reflected in the Supply Offer at the energy offer cap or, (c) why the actual incremental costs of operating the Resource in excess of the amount scheduled in the Day-Ahead Energy Market exceeded the incremental costs as reflected in the Supply Offer.
During the time period for which the ISO has declared abnormal conditions, the internal Market Monitor’s written explanation provided pursuant to Section III.A.15.3; and (iv) all requested regulatory costs in connection with the filing.

III.A.15.3. Review by Internal Market Monitor Prior to Filing.

Within twenty days of the receipt of the first Invoice containing credits or charges for the applicable Operating Day, a Market Participant that intends to make a Section 205 filing pursuant to this Section III.A.15 shall submit to the Internal Market Monitor the information and explanation detailed in Section III.A.15.2 (i) and (ii) that is to be included in the Section 205 filing. Within twenty days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written explanation of the events that resulted in the Section III.A.15 request for additional cost recovery. The Market Participant shall include the Internal Market Monitor’s written explanation in the Section 205 filing made pursuant to this Section III.A.15.


In the event that the Commission accepts a Market Participant’s filing for cost recovery under this section, the ISO shall allocate charges to Market Participants for payment of those costs in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource’s actual dispatch for the Operating Days in question.
III.A.15. Request for Additional Cost Recovery

III.A.15.1. Filing Right.

If either

(a) as a result of mitigation has been applied to a Resource under this Appendix A for all or part of one or more Operating Days, or

(b) in the absence of mitigation, a Market Participant has despite having submitted a Supply Offer at the energy offer cap specified in Section III.1.10.1.A(d) of Market Rule 1 for a Resource, or

(c) at the direction of the ISO a Market Participant has adjusted the output of a Resource to an amount that exceeds the amount scheduled for the Resource in the Day-Ahead Energy Market to address a critical reliability issue that has resulted in the ISO declaring an abnormal conditions alert for one of the reasons specified in Section III.A.15.1.1 below,

and as a result of the actions in (a) or (c), or despite the action in (b), a-the Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource for those Operating Days, the Market Participant may, within sixty days of the receipt of the first Invoice issued containing credits or charges for the applicable Operating Day, submit a filing to the Commission seeking recovery of those costs pursuant to Section 205 of the Federal Power Act. Absent a declaration of an abnormal conditions alert by the ISO in (c), the Market Participant may still follow the procedures under this section for a Section 205 cost recovery filing, however, the Market Participant must also bear the burden of showing that cost recovery is warranted because they were dispatched to address a critical reliability issue given a reliability directive by ISO-NE dispatchers.

A request under this Section III.A.15 may seek recovery of additional costs incurred during the following periods: (a) if as a result of mitigation, costs incurred for the duration of the mitigation event, (b) if as a result of having submitted a Supply Offer at the energy offer cap, costs incurred for the duration of the period of time for which the Resource was operated at the energy offer.
cap, and (c) if as a result of being operated to address a critical reliability issue that has resulted in the ISO declaring an abnormal conditions alert, for the duration of the period of time when the Resource was required to operate to address the critical reliability issue, but only for the amount by which the actual incremental costs of operating the Resource in excess of the amount scheduled in the Day-Ahead Energy Market exceeded the incremental costs as reflected in the Supply Offer.

III.A.15.1.1. Basis for declaration of an abnormal conditions alert.

(a) Forecasted or actual deficiency of operating reserves requiring implementation of ISO New England Operating Procedure No. 4, Action During a Capacity Deficiency, or ISO New England Operating Procedure No. 7, Action in an Emergency.

(b) The electric system in New England experiences low transmission voltages and/or low reactive reserves.

(c) A solar magnetic disturbance occurs.

(d) A cold weather event is declared.

(e) Inability to provide first contingency protection when an undesirable post-contingency condition might result, such as load shedding.

(f) A credible threat to power system reliability is made, such as sabotage or an approaching storm.

(g) Operational staffing shortage impacting normal power system operations within New England occurs.

(h) Any other condition that may cause a critical reliability issue as determined by the ISO’s operations shift supervisor or the Local Control Center system operator.

For purposes of this Section III.A.15, declaring an action of ISO New England Operating Procedure No.4 or ISO New England Operating Procedure No. 7 shall be treated as declaring an abnormal conditions alert.

III.A.15.2. Contents of Filing.

Any Section 205 filing made pursuant to this section shall include: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data and calculations for those costs; (ii) an explanation of (a) why the actual costs of operating the Resource for the Operating Days exceeded the Reference Level costs or, (b) in the absence of mitigation, why the actual costs of operating the Resource for the Operating Days exceeded the costs as reflected in the Supply Offer at the energy offer cap or, (c) why the actual
incremental costs of operating the Resource in excess of the amount scheduled in the Day-Ahead Energy Market, during the time period for which the ISO has declared an abnormal conditions alert for the Operating Day, exceeded the incremental costs as reflected in the Supply Offer; (iii) the Internal Market Monitor’s written explanation provided pursuant to Section III.A.15.3; and (iv) all requested regulatory costs in connection with the filing.

III.A.15.3. Review by Internal Market Monitor Prior to Filing.

Within twenty days of the receipt of the first Invoice containing credits or charges for the applicable Operating Day, a Market Participant that intends to make a Section 205 filing pursuant to this Section III.A.15 shall submit to the Internal Market Monitor the information and explanation detailed in Section III.A.15.2 (i) and (ii) that is to be included in the Section 205 filing. Within twenty days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written explanation of the events that resulted in the Section III.A.15 request for additional cost recovery. The Market Participant shall include the Internal Market Monitor’s written explanation in the Section 205 filing made pursuant to this Section III A.15.


In the event that the Commission accepts a Market Participant’s filing for cost recovery under this section, the ISO shall allocate charges to Market Participants for payment of those costs in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource’s actual dispatch for the Operating Days in question.
III.A.15. Request for Additional Cost Recovery

III.A.15.1. Filing Right.

If either

(a) as a result of mitigation has been applied to a Resource under this Appendix A for all or part of one or more Operating Days, or

(b) in the absence of mitigation, a Market Participant has despite having submitted a Supply Offer at the energy offer cap specified in Section III.10.1.A(d) of Market Rule 1 for a Resource, or

(c) at the direction of the ISO a Market Participant has adjusted the output of a Resource to an amount that exceeds the amount scheduled for the Resource in the Day-Ahead Energy Market to address a critical reliability issue that has resulted in the ISO declaring an abnormal conditions alert for one of the reasons specified in Section III.A.15.1.1 below,

and as a result of the actions in (a) or (c), or despite the action in (b), a the Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource for the duration of the mitigation event, the Market Participant may, within sixty days of the receipt of the first Invoice issued containing credits or charges for the applicable Operating Day, submit a filing to the Commission seeking recovery of those costs pursuant to Section 205 of the Federal Power Act. Absent a declaration of an abnormal conditions alert by the ISO in (c), the Market Participant may still follow the procedures under this section for a Section 205 cost recovery filing, however, the Market Participant must also bear the burden of showing that cost recovery is warranted because they were given a reliability directive by ISO-New England dispatchers.

A request under this Section III.A.15 may seek recovery of additional costs incurred during the following periods: (a) if as a result of mitigation, costs incurred for the duration of the mitigation event, (b) if as a result of having submitted a Supply Offer at the energy offer cap, costs incurred for the duration of the period of time for which the Resource was operated at the energy offer cap, and (c) if as a result of being operated to address a critical reliability issue that has resulted in the ISO declaring an abnormal conditions alert, for the duration of the period of time when the
Resource was required to operate to address the critical reliability issue, but only for the amount by which the actual incremental costs of operating the Resource in excess of the amount scheduled in the Day-Ahead Energy Market exceeded the incremental costs as reflected in the Supply Offer.

**III.A.15.1.1. Basis for declaration of an abnormal conditions alert.**

(a) Forecasted or actual deficiency of operating reserves requiring implementation of ISO New England Operating Procedure No. 4, Action During a Capacity Deficiency, or ISO New England Operating Procedure No. 7, Action in an Emergency.

(b) The electric system in New England experiences low transmission voltages and/or low reactive reserves.

(c) A solar magnetic disturbance occurs.

(d) A cold weather event is declared.

(e) Inability to provide first contingency protection when an undesirable post-contingency condition might result, such as load shedding.

(f) A credible threat to power system reliability is made, such as sabotage or an approaching storm.

(g) Operational staffing shortage impacting normal power system operations within New England occurs.

(h) Any other condition that may cause a critical reliability issue as determined by the ISO’s operations shift supervisor or the Local Control Center system operator.

For purposes of this Section III.A.15, declaring an action of ISO New England Operating Procedure No.4 or ISO New England Operating Procedure No. 7 shall be treated as declaring an abnormal conditions alert.

**III.A.15.2. Contents of Filing.**

Any Section 205 filing made pursuant to this section shall include: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data and calculations for those costs; (ii) an explanation of (a) why the actual costs of operating the Resource for the duration of the mitigation event exceeded the Reference Level costs or, (b) in the absence of mitigation, why the actual costs of operating the Resource for the duration of the mitigation event exceeded the costs as reflected in the Supply Offer at the energy offer cap or, (c) why the actual incremental costs of operating the Resource in excess of the amount scheduled in the Day-Ahead Energy Market, during the time period for which the ISO
has declared an abnormal conditions alert for the Operating Day, exceeded the incremental costs as reflected in the Supply Offer; (iii) the Internal Market Monitor’s written explanation provided pursuant to Section III.A.15.3; and (iv) all requested regulatory costs in connection with the filing.

III.A.15.3. Review by Internal Market Monitor Prior to Filing.

Within twenty days of the receipt of the first Invoice containing credits or charges for the applicable Operating Day, a Market Participant that intends to make a Section 205 filing pursuant to this Section III.A.15 shall submit to the Internal Market Monitor the information and explanation detailed in Section III.A.15.2 (i) and (ii) that is to be included in the Section 205 filing. Within twenty days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written explanation of the events that resulted in the Section III.A.15 request for additional cost recovery. The Market Participant shall include the Internal Market Monitor’s written explanation in the Section 205 filing made pursuant to this Section III.A.15.


In the event that the Commission accepts a Market Participant’s filing for cost recovery under this section, the ISO shall allocate charges to Market Participants for payment of those costs in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource’s actual dispatch for the Operating Days in question.
1. On April 15, 2013, pursuant to section 205 of the Federal Power Act (FPA)\(^1\) and section III.A.15 of Appendix A to Market Rule 1 of the ISO New England Inc. (ISO-NE) Transmission, Markets, and Services Tariff (tariff), Dominion Energy Marketing, Inc. (Dominion) submitted a request seeking recovery of $336,095 in fuel costs, plus reasonable regulatory costs, for its Manchester Street Station Units,\(^2\) which were mitigated under ISO-NE’s Constrained Area Mitigation\(^3\) and Reliability Commitment


\(^{2}\) Manchester Street Station (Manchester Street) is located in Providence, Rhode Island and consists of three combined-cycle generating units (Units 9, 10 and 11, referred to collectively as the Manchester Street Units), each having a current capacity supply obligation of approximately 140 MW. The Manchester Street Units are dual fuel capable and have oil storage tanks on site to provide a back-up fuel source.

\(^{3}\) Under section III.A.5.5.2 of Appendix A, mitigation is applied to any resource that violates the Conduct Test and Impact Test for Constrained Area Energy and is determined to be within a constrained area.
Mitigation processes. Additionally, Dominion requests the Commission direct ISO-NE to implement tariff changes before winter 2013-2014, which would ensure that resources that provide a critical reliability service at ISO-NE’s request have a reasonable opportunity to recover costs associated with providing that service. As discussed below, we grant Dominion’s fuel cost recovery request and grant subject to condition its request for regulatory costs. We will further institute a proceeding under section 206 of the FPA, in Docket No. EL13-72-000, and require ISO-NE to submit tariff revisions to allow resources to submit a section 205 filing for cost recovery in circumstances where for reliability reasons a resource is dispatched: (1) beyond its day-ahead schedule, where there is no opportunity to refresh the offer price to reflect current costs; or (2) after the results of the day-ahead market schedule are published, where the resource did not receive a day-ahead market schedule. We will also establish a refund effective date.

I. Background

2. On February 8-10, 2013, a significant snowfall resulted in the Manchester Street Units being one of the only generation resources capable of maintaining stability and voltage support in the Rhode Island (RI) and South East Massachusetts (SEMA) load zones, thus becoming critical to maintaining system reliability in that geographic region.

3. ISO-NE dispatched the Manchester Street Units beyond their day-ahead energy market schedule and into the following operating day to support reliability on each of those days, February 8, 9, and 10. On Friday, February 8, after the deadline to nominate natural gas deliveries over the weekend on the pipeline serving Manchester Street, Algonquin Gas Transmission (Algonquin), ISO-NE notified the Manchester Street Units to continue to run beyond their day-ahead schedule. Additionally, while Manchester Street has dual fuel capability, ISO-NE directed that the Manchester Street Units continue

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4 Under section III.A.5.5.5 mitigation is applied to any resource that violates the Conduct Test for Local Reliability Commitment Mitigation and is committed, or required to remain online, to provide one or more of the following: a) local first contingency protection or local second contingency protections; b) VAR or voltage support; or c) Special Constraint Resource Service.


6 The dates in question occurred over a weekend, beginning on Friday, February 8.

7 Transmittal at 2. Dominion states that ISO-NE discussed a series of operational issues at its March 2013 Participants committee meeting which further explain the reliability issues encountered during February 8-10. Id. at 3.
running on natural gas rather than come off-line to switch to fuel oil because doing so would carry additional reliability risks for the ISO-NE system.\textsuperscript{8}

4. Dominion further notes that Algonquin established Capacity Constraint Notices on February 8-10, 2013, which precluded customers from burning more natural gas than nominated (during the Thursday and Friday timely nomination cycles), which meant that while Algonquin agreed to provide the additional natural gas transmission service, Dominion would be exposed to tariff-defined imbalance penalties if Dominion was not able to procure “post cycle” natural gas.\textsuperscript{9} Dominion states that this subjected Manchester Street to extremely high spot market natural gas prices.

5. Dominion was unable to reflect these higher natural gas prices in its supply offer because, as Dominion explains, under the ISO-NE tariff, the only opportunity for market participants to update their supply offers is after the close of the day-ahead energy market, through the reoffer period, which at the time of the storm was between 4:00 pm and 6:00 pm. Market participants are able to change the supply offer’s financial parameters during this reoffer period to, for example, reflect the change in fuel price. Thus, the latest time that Manchester Street would have been able to change its supply offer and reference price was at 6:00 p.m. the day before the operating day – well before ISO-NE directed the Manchester Units to continue operating beyond their day-ahead schedules.\textsuperscript{10}

6. Dominion further states that, on the morning of February 8, 2013, while the natural gas markets were liquid, there was not a reasonable expectation that Manchester Street Units would run beyond their day-ahead schedules over the February 8-10, 2013 weekend. According to Dominion, the approaching storm significantly decreased load expectations and raised the likelihood that ISO-NE would call a Minimum Generation Emergency. Indeed, consistent with its expectations, the Manchester Street units were awarded a day-ahead schedule of only a few evening hours. Moreover, Dominion states that it expected that it would be permitted to run on fuel oil if the Manchester Street Units were dispatched beyond their day-ahead energy market award. However, as noted above, late on all three days, after the last opportunity to nominate natural gas deliveries on the

\textsuperscript{8} The Manchester Street Units must be brought off-line to switch fuel sources due to environmental restrictions and operational procedures.

\textsuperscript{9} “Post cycle” gas is the term Dominion uses to describe natural gas that is available after the last pipeline nomination cycle. While the pipeline has no obligation to do so, it sometimes permits generators to nominate post cycle natural gas.

\textsuperscript{10} Transmittal at 3-4.
Algonquin pipeline (6:00 p.m.), ISO-NE requested that the Manchester Street units run beyond their day-ahead energy market schedule and to continue burning natural gas, rather than switch to fuel oil. In order to run through the night on natural gas, Dominion states that it needed to procure additional natural gas during the weekend and within the operating day at a significant premium over the cost of procuring natural gas during the timely nomination window the day before the operating day. Dominon states that, as a result of being dispatched beyond the day-ahead awards and not being able to switch to fuel oil, i.e., by complying with ISO-NE’s reliability directives, Dominion under-recovered its fuel costs by approximately $2.4 million.

II. Cost Recovery Filing and Tariff Revision Proposal

7. Section III.A.15 of Appendix A to the ISO-NE tariff currently allows a market participant to seek additional cost recovery under section 205 of the FPA, if, as a result of mitigation applied under Appendix A, it will not recover the fuel and variable operating and maintenance costs of a resource for all or part of one or more operating days. Specifically, section III.A.15.1 provides that:

If either (a) as a result of mitigation applied to a Resource under this Appendix A for all or part of one or more Operating Days, or (b) in the absence of mitigation, despite having submitted a Supply Offer at the energy offer cap specified in Section III.1.10.1.A(d) of Market Rule 1, a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource for those Operating Days, the Market Participant may, within sixty days of the receipt of the first Invoice issued containing credits or charges for the applicable Operating Day, submit a filing to the Commission seeking recovery of those costs pursuant to Section 205 of the Federal Power Act. (Emphasis added).

Section III.A.15.2 provides that:

Any Section 205 filing made pursuant to this section shall include: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data and calculations for those costs; (ii) an explanation of (a) why the actual costs of operating the Resource for the Operating Days exceeded the Reference Level costs or, (b) in the absence of mitigation, why the actual costs of operating the Resource for the Operating Days exceeded the costs as reflected in the Supply Offer

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11 Dominion notes that natural gas markets lack liquidity on weekends, thus the spot market prices are higher. Transmittal at 4.
at the energy offer cap; (iii) the Internal Market Monitor’s [(IMM)] written explanation provided pursuant to Section III.A.15.3; and (iv) all requested regulatory costs in connection with the filing.

8. Dominion explains that the IMM mitigated Manchester Street’s February 10 supply offers below the units’ actual fuel costs but did not mitigate the Manchester Street Units’ offers on February 8 or 9 because the supply offers were below the mitigation reference price.\(^{12}\) Dominion states that its day-ahead supply offers for February 8 and 9 also were below the units’ actual incurred fuel costs when they were dispatched in real-time beyond their day-ahead schedule.

9. Consistent with section III.A.5, Dominion requests fuel cost recovery of $336,095, plus reasonable regulatory costs, for its unrecovered costs incurred relating to only the February 10 operating day. Dominion states that, pursuant to ISO-NE’s tariff, it previously submitted to the IMM its actual fuel costs and supporting material. The IMM issued a report supporting Dominion’s request for additional cost recovery for February 10. Dominion states that it has complied with the section III.A.15 requirements for a cost recovery filing for the February 10 costs and that the IMM agrees that Dominion properly complied. However, the IMM concluded that Dominion did not satisfy the requirements for additional cost recovery for February 8 or 9 because, under the tariff, mitigation of supply offers is a necessary pre-condition for market participants to seek additional cost recovery when the actual costs of operating the resource are under-recovered.

10. Dominion further states that while it is not seeking here to recover its roughly $2 million in additional fuel costs for February 8 and 9, it requests that the Commission direct ISO-NE to implement tariff changes before winter 2013-2014 that would: (1) provide a mechanism for generation resources committed for reliability to recover their fuel costs incurred in meeting the reliability need without first having its supply offer mitigated and without submitting a section 205 filing to the Commission; and (2) allow resources to update their supply offers in real-time to reflect changes to their operating costs.\(^{13}\)

11. Dominion challenges the tariff as forcing generators to incur the administrative burden and associated costs of making a section 205 filing every time they are unable to recover fuel costs, because, according to Dominion, the mitigation reference prices do not accurately reflect those costs. Dominion opines that under the tariff, ISO-NE cannot

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\(^{12}\) Id. at 4.

\(^{13}\) Id. at 7.
accommodate timely supply offers that reflect the true marginal costs of energy. Moreover, Dominion adds that the tariff provides a perverse incentive for generators to submit supply offers with the purpose of being mitigated, because mitigation is a prerequisite to recovering costs not reflected in supply offers. Absent mitigation, generators are in the position of incurring significant and unrecoverable fuel costs and potential pipeline penalties in order to meet ISO-NE’s system reliability needs.\(^\text{14}\)

12. Dominion states that ISO-NE acknowledged these shortcomings in a November 30, 2012 Energy Market Enhancements White Paper and currently is evaluating proposed market rule enhancements for implementation in late 2014, which will allow resources to modify their offers in real-time to reflect increases in fuel costs. Dominion asserts that ISO-NE must move forward with planned market rules changes now to ensure that resources that serve a critical reliability need have a reasonable opportunity to recover their fuel costs associated with meeting that need.

13. Dominion posits that its requested tariff revisions will help resolve a current disconnect between the New England electric and natural gas markets, and ensure that resources called upon to support system reliability are able to recover their costs and that the New England market design produces outcomes where the marginal price of electric energy accurately reflects the cost of the marginal resource.\(^\text{15}\)

III. Notice of Filing and Responsive Pleadings


IV. Discussion

A. Procedural Issues

15. Pursuant to Rule 214 of the Commission’s Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2012), the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

\(^{14}\) *Id.* at 10.

\(^{15}\) *Id.* at 10-11.
16. Rule 213(a)(2) of the Commission’s Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2012), prohibits an answer to a protest unless otherwise ordered by the decisional authority. We will accept Dominion’s answer because it has provided information that assisted us in our decision-making process.

B. Comments and Protest

17. ISO-NE generally supports Dominion’s request for additional cost recovery for February 10, in the amount of $336,095 plus Dominion’s regulatory costs. NEPOOL takes no position on the amount but acknowledges Dominion’s right under the tariff to submit a request for recovery of fuel costs and affirms that it is properly submitted under section 205 of the FPA.16

18. NEPOOL and ISO-NE oppose Dominion’s request for a Commission order directing that ISO-NE change its tariff, stating that the request is procedurally improper in a section 205 proceeding. NEPOOL states that ISO-NE is the entity authorized to file changes to its tariff and market rules under section 205, and ISO-NE has not sought any changes in this proceeding. NEPOOL further states that a market participant’s request to change market rules on file with the Commission is properly raised in a complaint under section 206 of the FPA. ISO-NE also contends that Dominion must meet the substantive burden of proof that would be required under a section 206 complaint, which Dominion has failed to do.

19. NEPOOL argues that Dominion’s proposed changes should be addressed first in the stakeholder process and not in a Commission proceeding without the benefit of stakeholder consideration. Indeed, NEPOOL and ISO-NE state that the stakeholders are already considering some of Dominion’s requested changes, including a proposal that allows for updating supply offers in real-time throughout the operating day.

20. ISO-NE further states that, even if the stakeholders and the Commission ultimately approve new hourly offer rules, substantial software changes would be necessary to implement them, so having those rules in place by winter 2013-2014, as Dominion requests, is impracticable. ISO-NE explains that the changes proposed in the stakeholder process will require, among other things, extensive modifications to database functions and information technology enhancements, as well as a number of revisions to other parts of the tariff, including Net Commitment Period Compensation (uplift). ISO-NE states that its implementation timetable for these changes is aggressive and reflects the high priority that ISO-NE and stakeholders have placed on the implementation of the hourly

16 NEPOOL Comments at 1-2.
offer flexibility rules. ISO-NE confirms that it currently anticipates implementing certain hourly rule changes during the fourth quarter of 2014.

21. Regarding Dominion’s request that the tariff be modified in the interim to provide a mechanism for generation resources committed for reliability to recover their actual fuel costs without having their supply offers mitigated, and without having to submit a section 205 filing with the Commission, ISO-NE argues that such a change is incompatible with competitive markets. Specifically, ISO-NE states that binding offers are fundamental to markets, and if offers are not binding, then the prices based on those offers are not reliable indicators of the cost of providing electricity. ISO-NE states that inaccurate prices would undermine both buyers’ and sellers’ confidence in the market.

22. ISO-NE also states that, to the extent Dominion seeks a tariff-based, out-of-market payment mechanism to recover fuel costs that are not reflected in generators’ supply offers, such a mechanism also would undermine the accuracy of submitted offers. ISO-NE asserts that it would provide market participants with an incentive to submit low, non-competitive offers in instances where they anticipate a reliability event in order to increase their chance of being selected, with the expectation of receiving an out-of-market payment to recover their actual costs. ISO-NE notes that such an incentive would be especially problematic during times of natural gas pipeline constraints, when the natural gas market is less liquid and more volatile. ISO-NE explains that, under such circumstances, it is particularly important that resource offers and resulting prices reflect the best information available to each resource about fuel prices and availability, and the possibility of essentially riskless participation in the fuel markets would provide the greatest advantage to a resource selected to run for reliability. ISO-NE adds that the out-of-market payment mechanism would significantly erode the potential of the market clearing price to reflect the competitive cost of supplying energy, confer an unfair advantage to certain resources, and would subject consumers to significant uncertainty regarding energy prices.

C. Answer

23. Dominion responds that the market rule changes it requests can be both directed by the Commission and accomplished through the ongoing stakeholder process. Dominion agrees that any market rule changes should be vetted in the existing stakeholder process, and Dominion deliberately elected not to file a section 206 complaint at this time to allow that process to move forward expeditiously. However, Dominion states that it strongly disagrees that the reforms outlined in its cost recovery filing should be delayed beyond winter 2013-2014, especially since, according to Dominion, ISO-NE identified the need to address generator offer flexibility almost 10
years ago. Acknowledging that ISO-NE may not be able to implement a long-term solution prior to winter 2013-2014, Dominion seeks an interim mechanism for generation resources committed for reliability to recover their fuel costs incurred in meeting a reliability need without the necessity of having its supply offer first mitigated and without having to submit a section 205 filing. Dominion explains that there would be no market manipulation concerns with its proposal, considering that a market participant cannot accurately predict a reliability event and submit a non-competitive offer in anticipation of an event.

D. Determination

1. Dominion’s Request for Cost Recovery

24. The Commission grants Dominion’s fuel cost recovery request of $336,095, plus reasonable regulatory costs incurred in connection with this filing, subject to Dominion submitting a compliance filing detailing the actual regulatory costs. Dominion followed the requirements of section III.A.15 of Appendix A to the tariff to obtain the cost recovery for additional costs incurred on February 10. According to the tariff, a resource’s supply offer must be mitigated in order for the IMM to approve a cost recovery request. Dominion’s supply offer for February 10 was mitigated and it submitted a cost recovery request to the IMM for the costs it incurred on February 8-10. As noted above, the IMM issued a report supporting Dominion’s request for cost recovery for February 10 but finding that because mitigation is a necessary pre-condition for market participants to receive cost recovery under the tariff, Dominion did not satisfy the requirements for additional cost recovery for February 8 or 9. Once the IMM provides a written explanation to the market participant on its cost recovery request, and, within 60 days of that explanation, the market participant can exercise its right to submit a cost recovery filing to the Commission under section 205. It is undisputed that Dominion properly exercised that right here.


Dominion states that its regulatory costs will be based solely on fees and costs for outside and in-house counsel and will not include any costs associated with work performed by other employees of Dominion or its affiliates. See Transmittal at 7.
2. **Dominion’s Request for Tariff Changes**

25. Pursuant to the Commission’s authority under section 206 of the FPA, we find that ISO-NE’s existing tariff, in particular section III.A.15 of Appendix A, is unjust, unreasonable, unduly discriminatory or preferential, because it does not provide resources an adequate opportunity to recover costs incurred to comply with ISO-NE directives to ensure reliability in instances when their supply offers were not mitigated. In situations such as the one Dominion experienced on February 8 and 9, despite complying with ISO-NE’s directives to maintain reliability, resources could suffer significant financial loss in unrecovered costs.\(^{19}\) The Commission finds that this outcome for resources called upon to respond to critical reliability needs is unjust and unreasonable.

26. Therefore, pursuant to our authority under section 206 of the FPA, we direct ISO-NE to submit tariff revisions which allow resources to submit a section 205 filing for cost recovery, including fuel and variable operation and maintenance costs for the resource, in circumstances where for reliability reasons a resource is dispatched: (1) beyond its day-ahead schedule, where there is no opportunity to refresh the offer price to reflect current costs; or (2) after the results of the day-ahead market schedule are published, where the resource did not receive a day-ahead market schedule. This provision will be in addition to the current provisions allowing cost recovery when a resource is mitigated or when a supply offer was submitted at the energy offer cap; therefore, a resource seeking cost recovery would follow the same cost recovery process for a bid that was mitigated or offered at the energy offer cap, i.e., submit the request to the IMM for analysis prior to submitting a section 205 filing to the Commission. We direct ISO-NE to submit these revisions in a compliance filing no later than 45 days from the date of this order.

27. The Commission acknowledges ISO-NE’s concerns that imposing a mechanism to allow generation resources committed for reliability purposes to recover their actual fuel costs incurred in meeting the reliability need could undermine the accuracy of submitted offers or incentivize market participants to submit low offers in anticipation of a reliability event in order to increase their chance of being selected or high offers in order to be mitigated and therefore eligible for cost recovery. However, the existing tariff already suffers from similar defects, encouraging resources to submit supply offers with the intent of being mitigated in order to assure cost recovery through the cost recovery mechanism. On balance, the Commission finds that it is appropriate to require that resources providing critical reliability services have a reasonable opportunity to recover costs associated with providing that service.

\(^{19}\) Some of Dominion’s supply offers were based on natural gas as the fuel source while others were based on oil.
28. To provide guidance to ISO-NE as it prepares its compliance filing, the Commission expects that the parameters of the tariff provision(s) directed here will be sufficiently restrictive to discourage anticompetitive offering behavior but still allow for cost recovery in circumstances, for example, when a resource responds to a directive from ISO-NE to provide essential support to part of the system but has no reasonable opportunity to recover its costs. In other words, the tariff provision should ensure that a resource would be permitted to seek cost recovery, where, for instance, a resource submits an offer based on one fuel type but is required to run on another or cannot burn natural gas based on an Operation Flow Order restriction. These examples are not intended to be exhaustive and should not unduly limit the criteria ISO-NE develops for cost recovery under extraordinary circumstances. Our intention is for ISO-NE’s tariff to provide enough flexibility to allow for cost recovery by resources that respond under extraordinary circumstances like those faced by the ISO-NE market on February 8 and 9.

29. The Commission also acknowledges that ISO-NE and its stakeholders are discussing comprehensive long-term changes to ISO-NE’s market rules, which may address our concerns regarding the existing tariff. However, as ISO-NE admits, those changes will not be in effect for winter 2013-14, necessitating our action here. The Commission does not intend to prejudge any alternative approaches that might result from the stakeholder process, but, at the same time, recognizes the need to address critical reliability concerns in the near-term. We understand that the cost-recovery mechanism required herein may be replaced by a long-term solution resulting from the on-going stakeholder process.

30. In cases where, as here, the Commission institutes a proceeding under section 206, section 206(b) of the FPA requires that the Commission establish a refund effective date that is no earlier than publication of notice of the Commission’s initiation of its proceeding in the Federal Register, and no later than five months subsequent to that date. We establish a refund date to be the earliest date possible in order to provide maximum protection to customers, i.e., the date that notice of initiation of the section 206 proceeding in Docket No. EL13-72-000 is published in the Federal Register.

The Commission orders:

(A) Dominion’s request for fuel cost recovery, plus reasonable regulatory costs incurred in connection with this filing, is hereby granted, subject to a compliance filing detailing the actual regulatory costs, as discussed in the body of this order.

(B) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Commission by section 402(a) of the Department of Energy Organization Act and by the FPA, particularly section 206 thereof, and pursuant to the
Commission’s Rules of Practice and Procedure and the regulations under the Federal Power Act (18 C.F.R., Chapter I), the Commission hereby institutes a proceeding in Docket No. EL13-72-000, as discussed in the body of this order.

(C) ISO-NE is hereby directed to submit a compliance filing revising section III.A.15 of Appendix A no later than 45 days from the date of this order, as discussed in the body of this order.

(D) The Secretary shall promptly publish in the Federal Register a notice of the Commission’s initiation of the proceeding ordered in Ordering Paragraph (B) above, under section 206 of the FPA.

(E) The refund effective date established pursuant to section 206(b) of the Federal Act will be the date of publication in the Federal Register of the notice discussed in Ordering Paragraph (D) above.

By the Commission.

( S E A L )

Nathaniel J. Davis, Sr.,
Deputy Secretary.
### EXECUTIVE SUMMARY

The following activity, as more fully described in the attached litigation report, has occurred since the report dated June 25, 2013 was circulated. New matters/proceedings since the last report are preceded by an asterisk */*. Page numbers precede the matter description.

#### I. Complaints

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<thead>
<tr>
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<tr>
<td>1</td>
<td>FERC-Directed Changes to Fuel Cost Recovery for Certain Reliability Responses (EL13-72)</td>
<td>Jul 5</td>
<td>FERC grants extension of compliance filing deadline to Aug 13, 2013. Dominion requests clarification and/or rehearing of the Jun 14 <em>Dominion Fuel Cost Recovery Order</em></td>
</tr>
<tr>
<td>3</td>
<td>Base ROE Complaint (2011) (EL11-66)</td>
<td>Jun 28</td>
<td>Complainants, EMCOS, TOs, Trial Staff submit Reply Briefs; all briefing completed; initial decision expected by Sep 13, 2013.</td>
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#### II. Rate, ICR, FCA, Cost Recovery Filings

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<tr>
<td>4</td>
<td>RCM Add'l Cost Recovery: Dominion (ER13-1291)</td>
<td>Jul 15</td>
<td>Dominion requests clarification and/or rehearing of the Jun 14 <em>Dominion Fuel Cost Recovery Order</em></td>
</tr>
<tr>
<td>5</td>
<td>2013 Capital Budget (ER13-192)</td>
<td>Jun 27</td>
<td>FERC approves Settlement Agreement resolving all issues in this proceeding.</td>
</tr>
<tr>
<td>5</td>
<td>2013 Administrative Costs Budget (ER13-185)</td>
<td>Jun 27</td>
<td>FERC approves Settlement Agreement resolving all issues in this proceeding.</td>
</tr>
<tr>
<td>6</td>
<td>ISO Issuance of Securities: $39 Million to Refinance Capital Expenditures Financings (ES13-34)</td>
<td>Jul 1</td>
<td>ISO requests authorization for $11 million in Senior Unsecured Notes in order to support a higher-than-projected level of capital expenditures; comment date Aug 7.</td>
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#### III. Market Rule Changes, Interpretations and Waiver Requests

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<td>6</td>
<td></td>
<td>Jul 9-22</td>
<td>ISO and NEPOOL jointly file changes.</td>
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<tr>
<td>7</td>
<td></td>
<td>Jul 2-23</td>
<td>ISO and NEPOOL jointly file changes.</td>
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<tr>
<td>7</td>
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<td>Jul 2-24</td>
<td>ISO and NEPOOL jointly file changes.</td>
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IV. OATT Amendments / TOAs / Coordination Agreements

* 12 Order 1000 Interregional Compliance Filing (ER13-1960; ER13-1957)  
   Jul 10 ISO, NEPOOL, and PTO AC jointly file compliance changes; ISO files Amended Protocol; comment date Aug 26  
   Jul 18-25 Exelon, NEPOOL intervene  
12 Order 1000 Compliance Filing (ER13-193; ER13-196)  
   Jun 28 ISO answers LS Power’s request for clarification of the Order 1000 Compliance Order  
   Jul 9 ISO, NEPOOL, and PTO AC request extension of time, to Nov 15, 2013, to submit compliance filing; NESCOE submits comments supporting requested extension  
   Jul 16 FERC issues tolling order affording additional time to consider requests for clarification and/or rehearing of May 17 order  
   Jul 22 FERC grants extension of time, to Nov 15, 2013, to submit compliance filing

V. Financial Assurance/Billing Policy Amendments

* 13 CFTC Exemption Order Changes (ER13-1875)  
   Jul 1 ISO and NEPOOL jointly file Financial Assurance and Information Policy changes  
   Jul 22-23 Exelon, NRG, NU intervene; Freedom Logistics files protest  
* 14 Billing Policy Clarification: State Sales Tax Collections (ER13-1870)  
   Jul 1 ISO and NEPOOL jointly file Billing Policy changes  
   Jul 22-23 Exolon, NRG intervene

VI. Schedule 20/21/22/23 Changes

* 15 Schedule 21-NSTAR Annual Informational Filing (ER09-1243; ER07-549)  
   Jun 28 NSTAR submits CWIP supplement to May 31 annual informational filing  
* 15 Schedule 21-CMP Annual Informational Filing (ER09-938)  
   Jun 28 CMP files updated formula rates reflecting actual 2012 cost data and estimated 2013 cost data

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

* LFTR Implementation: 19th Quarterly Status Report (ER07-476)  
   Jul 15 ISO files its 19th quarterly report

IX. Membership Filings

* 16 July 2013 Membership Filing (ER13-1867)  
   Jun 28 New Members: Dynasty Power; Mega Energy Holdings; Negawatt Business Solutions; Provider Power CT; and SBR Energy; Termination: South Jersey Energy Solutions  
16 June 2013 Membership Filing (ER13-1616)  
   Jun 28 FERC accepts West Oaks termination
## X. Misc. - ERO Rules, Filings; Reliability Standards

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<tr>
<td>16</td>
<td>Suspension Notice: DownEast Power Company (not docketed)</td>
<td>Jul 24</td>
<td>ISO files notice that DownEast Power Company was suspended from the New England Markets on Jun 19 at 8:30 am</td>
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### FFT Report: June 2013

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<td>16</td>
<td>FERC approves addition of “Bulk-Power System,” “Reliability Standard,” and “Reliable Operation” to Glossary of Terms</td>
<td>Jul 9</td>
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<tr>
<td>16</td>
<td>Revised VSLs/VRFs (RD13-5 et al.)</td>
<td>Jun 24</td>
<td>FERC approves modifications</td>
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<td>16</td>
<td>Interpretation: CIP-002-4 R3 (RD12-5)</td>
<td>Jun 25</td>
<td>FERC grants clarification requested by NERC and EEI; denies clarification/rehearing requested by ISO/RTO Council</td>
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<td>19</td>
<td>NOPR: Revised Reliability Standard: BAL-003-1 (RM13-11)</td>
<td>Jul 18</td>
<td>FERC issues NOPR; comment date [60 days after its publication in the Federal Register]</td>
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<td>20</td>
<td>NOPR: Remand of Interpretation of BAL-002-1a (RM13-6)</td>
<td>July 8</td>
<td>NERC, EEI, ISO/RTO Council, MISO, NC Balancing Area, Northwest Power Pool Balancing Authorities, NRECA, and WECC file comments</td>
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<td>20</td>
<td>NOPR: Revised Reliability Standards: Version 5 CIP Standards (-002 through -011) (RM13-5)</td>
<td>Jul 18</td>
<td>Trade Associations request extension of deadline to comply with CIP Version 4 Standards pending outcome of this proceeding; comment date Aug 5</td>
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<td>21</td>
<td>Order 779: Geomagnetic Disturbance Reliability Standards (RM12-22)</td>
<td>Jul 16</td>
<td>FERC issues tolling order to permit it additional time to consider MISO rehearing request</td>
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<tr>
<td>21</td>
<td>NOPR: Revised Reliability Standards: FAC-001-1, FAC-003-3, PRC-004-2.1a, PRC-005-1.1b (RM12-16)</td>
<td>Jul 9</td>
<td>NERC files reply comments</td>
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<td>22</td>
<td>Order 773-A: Revised “Bulk Electric System” Definition and Procedures (RM12-7; RM12-6)</td>
<td>Jul 9</td>
<td>Pacific Northwest Generating Cooperative requests rehearing of Jun 13 order granting effective date extension to Jul 1, 2014</td>
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## XI. Misc. - of Regional Interest

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<td>24</td>
<td>203 Application: Dominion / ECP (Brayton Point) (EC13-82)</td>
<td>Jul 5</td>
<td>Dominion renews request for expedited FERC action</td>
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<tr>
<td>24</td>
<td>203 Application: Maine Public Service/Bangor Hydro (EC13-81)</td>
<td>Jul 19</td>
<td>FERC authorizes MPS merger into Bangor Hydro</td>
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<td>26</td>
<td>National Grid IAs (ER13-1618 et al.)</td>
<td>Jun 28</td>
<td>FERC accepts Thundermist, Brockton Agreements</td>
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<td>Jun 28</td>
<td>NGrid supplements filing</td>
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<td>203 Application: Maine Public Service/Bangor Hydro (EC13-81)</td>
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<td>Bangor Hydro submits report addressing MPUC action on ring-fencing provisions and other merger conditions</td>
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<td>FERC accepts Highland Agreement</td>
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<td>Jul 9</td>
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26 Bangor Hydro Waiver Permitting 2
OATTs Post-MPS Merger (ER13-1125) Jul 18 FERC grants requested waiver permitting BHE to have 2 OATTs post-MPS merger

28 FERC Enforcement Action: Barclays Bank et al. (IN08-8) Jul 16 FERC finds Barclays and certain Individual Traders violated the Anti-Manipulation Rule and assesses a record amount of civil penalties -- $435 million against Barclays (plus disgorgement of $34.9 million, plus interest), $15 million against one Trader and $1 million the remaining 3 Traders

XII. Misc. - Administrative & Rulemaking Proceedings

29 RTO/ISO Centralized Capacity Markets (AD13-7) Jul 19 FERC issues supplemental notice of Sep 25 technical conference

30 NOPR: Revisions to Pro Forma SGIA and SGIP (RM13-2) Jun 27-28 July 3 DC Office of People’s Counsel, CA PUC submit comments Solar Energy Industries Association files reply comments

31 Order 784: 3rd-Party Provision of Ancillary Services etc. (RM11-24; AD10-13) Jul 18 FERC issues Order 784; effective [120 days after publication in Federal Register]

* 32 NOPR: Incorporation of WEQ Version 003 Standards (RM05-5) Jul 18 FERC issues NOPR; comment date Sep 24, 2013

XIII. Natural Gas Proceedings

34 NOPR: Gas/Electric Operational Info Sharing (RM13-17) Jul 18 FERC issues NOPR; comment date Aug 26, 2013

34 Natural Gas and Electric Market Coordination (AD12-12) Jul 5 ISO/RTOs, including ISO-NE, submit responses to follow-up questions from the May 16 meeting

XIV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XV. Federal Courts (Appeals of FERC Decisions)

MEMORANDUM

TO: NEPOOL Participants Committee Member and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: July 26, 2013

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 July 26, 2013. If you have questions, please contact us.1

I. Complaints

- FERC-Directed Changes to Fuel Cost Recovery for Certain Reliability Responses (EL13-72)

  On June 14, the FERC initiated, in response to Dominion’s fuel cost recovery filing summarized below (see ER13-1291 below), a Section 206 proceeding finding Section III.A.15 of Appendix A to Market Rule 1 “unjust, unreasonable, unduly discriminatory or preferential, because it does not provide resources an adequate opportunity to recover costs incurred to comply with [ISO] directives to ensure reliability in instances when their supply offers were not mitigated.”2 Accordingly, the FERC directed the ISO to submit, revisions to Appendix A that allow resources to submit a section 205 filing for cost recovery, including fuel and variable operation and maintenance costs for the resource, in circumstances where for reliability reasons a resource is dispatched: (1) beyond its day-ahead schedule, where there is no opportunity to refresh the offer price to reflect current costs; or (2) after the results of the day-ahead market schedule are published, where the resource did not receive a day-ahead market schedule. This provision will be in addition to the current provisions allowing cost recovery when a resource is mitigated or when a supply offer was submitted at the energy offer cap.

  The FERC indicated that its intention is for Market Rule 1 to provide enough flexibility to allow for cost recovery by resources that respond under extraordinary circumstances like those faced by the New England Market on February 8 and 9, 2013. The changes directed should be “sufficiently restrictive to discourage anticompetitive offering behavior but still allow for cost recovery” in extraordinary circumstances where, for example, “a resource submits an offer based on one fuel type but is required to run on another or cannot burn natural gas based on an Operation Flow Order restriction.”3

  On June 25, NEPOOL and the ISO jointly requested that the FERC extend the deadline for compliance with the June 14 Order to 60 days from the date of the June 14 Order, or until August 13, 2013, to permit the compliance filing to reflect the results of full stakeholder consideration of the proposed compliance changes, including consideration of those changes at the Participants Committee’s regularly-scheduled

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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”).


3 Id. at P 28.
August meeting. The requested extension was granted on July 5, 2013. As previously reported, the refund effective date was set at June 25, 2013.4

On July 15, 2013, Dominion requested clarification and/or rehearing of the Dominion Fuel Cost Recovery Order. In its request, Dominion asked the FERC to clarify that the ISO “is required to revise its Tariff to provide a resource with an opportunity to submit a Section 205 fling to recover its costs “where for reliability reasons a resource is dispatched: (1) beyond its day ahead schedule, where there is no opportunity to refresh the offer price to reflect current costs; or (2) after the results of the day-ahead market schedule are published, where the resource did not receive a day-ahead market schedule,” regardless of how the ISO characterizes the reliability reason. Dominion asserted that that the ISO’s proposal to “limit the ability of a resource dispatched for reliability to seek recovery of its actual costs only where the ISO has declared a MLCC Alert” was an “unnecessarily narrow interpretation of the” compliance requirement set forth in the Dominion Fuel Cost Recovery Order as “ISO-NE calls units to run for “reliability reasons” beyond their day-ahead schedules without calling a MLCC Alert.” Dominion sought clarification and/or rehearing “so that ISO-NE and interested stakeholders fully understand ISO-NE’s compliance obligations.” On July 18, the ISO asked the FERC to deny Dominion’s request so that the Participant Processes could be allowed to take its full course and any substantive concerns addressed once all parties have had an opportunity to comment on the ISO’s final proposal. Dominion’s request is pending before the FERC, with FERC action required on or before August 14, 2013, or the request will be deemed denied. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com), Pat Gerity (860-275-0533; pmgerity@daypitney.com) or Dave Doot (860-275-0102; dtdoot@daypitney.com).

- NEPGA Complaint (EL13-66)

As previously reported, the New England Power Generators Association (“NEPGA”) filed on May 17, 2013, a formal complaint against the ISO pursuant to section 206 of the Federal Power Act (“FPA”) alleging that certain obligations articulated in a November 5, 2012 memorandum issued by the ISO were new and unfiled with the FERC, and thereby violated FPA section 205 and were unenforceable. NEPGA asked the FERC to “restore the status quo—what the tariff actually says today—which is that capacity resources must exercise Good Utility Practice to procure fuel or face the consequences as outlined in the tariff.” NEPGA further requested that the FERC “hold that there is no firm fuel obligation in the existing tariff (i.e., that it is not a tariff violation to be unable to procure fuel after exercising Good Utility Practice to do so).” The ISO answered the NEPGA Complaint on June 6. Interventions were filed by Algonquin, BG Energy Merchants, Brookfield, Calpine, Capital Power, ConEd, CT OCC, Distriegas, Dynegy, EPSA, Exelon, GDF Suez, Hess, HQ US (out-of-time), Iriquois, MA AG, Maxim Power, Millennium, NESCOE, NextEra, NICC, New England LDCs,5 NRECA, NRG, NU, Portland Natural Gas, Repsol, TN Gas, and Vitol. Comments on the Complaint were filed by: CT PURA, Entergy, IPPNY, INGA, MPUC, NEPOOL, New England Pipelines, PSEG, and TransCanada. In its comments, NEPOOL provided information about the stakeholder process that was followed with respect to the issues raised in the Complaint, and urged the FERC to enforce the ISO Tariff as filed. NEPOOL did not take any position on whether the ISO’s interpretation of the Market Rules effects a change in the Tariff, nor did NEPOOL take any position on NEPGA’s interpretation of the Tariff (a copy of NEPOOL’s comments is available at http://www.nepool.com/FERC_Filings - 2013.php). On June 20, NEPGA filed an answer to the ISO’s June 6 answer. The ISO answered this answer on July 2, 2013. On July 5, Calpine answered the ISO answers, asserting that the ISO mischaracterized statements made by a Calpine VP at the FERC’s April 25 Technical Conference on gas-electric market coordination. This matter is currently 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).

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4 The notice of the initiation of the proceeding and refund effective date was published in the Fed. Reg. on June 25, 2013 (Vol. 78, No. 122) p. 38,027.

NESCOE FCM Renewables Exemption Complaint (EL13-34)

Rehearing of the FERC’s February 12, 2013 order denying NESCOE’s FCM Renewable Exemption Complaint has been requested and is pending before the FERC. As previously reported, NESCOE instituted this complaint, on December 28, 2012 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 offer floor mitigation construct 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. 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), 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)

The request to consolidate this proceeding with EL11-66, as well as the Complaint itself, answers, and comments 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”) 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. To the extent the FERC does not summarily grant the reduction to 8.7%, 2012 Complainants asked that this matter be set for evidentiary hearing, and that it be consolidated for purposes of hearing and decision with EL11-66.

7 Id. at P 32.
8 Id. at P 30.
9 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.
Interventions were filed by NEPOOL, AIM, CT AG, CT OCC, CT PURA, EMCOS,\textsuperscript{10} MA AG, MOPA, MPUC, TEC, and the VT DPS. On January 16, the TOs filed their answer, asserting that the FERC 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. Alternatively, the TOs argued that the 2011 Complaint (EL11-66) must now be decided solely on the basis of the New England TOs’ cost of capital during the locked in period of October 1, 2011 through December 31, 2012, since that is the only refund period to which the 2011 Complaint will apply. 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, 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)**

On June 28, Reply Briefs were filed by Complainants, EMCOS, TOs, and FERC Trial Staff. An initial decision by ALJ Michael J. Cianci is expected on or before September 10, 2013. By way of reminder, the FERC established hearing and settlement judge procedures,\textsuperscript{11} following a complaint by a number of State, consumer, and consumer advocate parties (the “2011 Complainants”)\textsuperscript{12} seeking a FERC order reducing the 11.14% Base ROE used in calculating formula rates for transmission service in the ISO’s OATT to 9.2%. 2011 Complainants stated that “due to changes in the capital markets since the Bangor Hydro proceeding,\textsuperscript{13} the [Base ROE] is no longer just and reasonable.” After settlement judge procedures before Judge Judith A. Dowd were ultimately unsuccessful and terminated, these proceedings proceeded to now-completed hearings before Judge Cianci. 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

- **RCM Add’l Cost Recovery: Dominion (ER13-1291)**

As previously reported, the FERC issued an order on June 14 (i) granting the fuel cost recovery request of Dominion Energy Marketing, Inc. (“Dominion”) (subject to condition with respect to Dominion’s request for regulatory costs); and (ii) instituting a section 206 proceeding (see EL13-72 above) requiring the ISO to submit within 45 days certain revisions to Appendix A to Market Rule 1 to allow resources to submit a section 205 filing for cost recovery in circumstances where for reliability reasons a resource is dispatched (a) beyond its Day-Ahead schedule (where there is no opportunity to refresh the offer price to reflect current costs) or (b) after the results of the Day-Ahead Market schedule are published (where the resource did not

\textsuperscript{10} EMCOS or the “Eastern Massachusetts Consumer-Owned Systems” are Braintree, Hingham, Reading, and Taunton.

\textsuperscript{11} Martha Coakley, Mass. Att’y Gen, et al., 139 FERC ¶ 61,090 (May 3, 2012) (“Base ROE Complaint Order”). The Base ROE Complaint Order was not challenged and is final.


receive a Day-Ahead Market schedule). The FERC acknowledged that long-term changes to the Market Rules were under discussion, specifically stated it did not intend to prejudge any alternative approaches that might result from the stakeholder process and that the cost-recovery mechanism it required may be replaced by a long-term solution resulting from the on-going stakeholder process, but since those changes will not be in effect for winter 2013-14, felt compelled to act now to address critical reliability concerns in the near-term. The revisions to Appendix A are to be in addition to the current provisions allowing cost recovery when a resource is mitigated or when a supply offer was submitted at the energy offer cap. The ISO was directed to submit the revisions in a compliance filing whose deadline has been extended to August 13, 2013.

As noted in additional detail in Section I above, Dominion requested clarification and/or rehearing of the Dominion Fuel Cost Recovery Order on July 15, 2013. Dominion’s request is pending before the FERC, with FERC action required on or before August 14, 2013, or the request will be deemed denied. 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).

- **2013 Capital Budget (ER13-192)**
  As announced at the Participants Committee Summer Meeting, the uncontested Settlement Agreement between the ISO, the New England State Parties, the MA AG, and NEPOOL (together, the “Settling Parties”) to resolve the issues in this and the 2013 Administrative Cost Budget proceedings (“ISO 2013 Budget Settlement”; see ER13-185 below for further details on the Settlement) was approved by the FERC on June 27. If there are any questions on this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **2013 Administrative Costs Budget (ER13-185)**
  As noted immediately above, the uncontested settlement agreement to resolve the contested matters in this proceeding (as well as the 2013 Capital Budget proceeding) was approved by the FERC on June 27. Highlights of the Settlement include:
  
  - With respect to 2013’s budget:
    - The 2013 Administrative Revenue Requirement will be reduced by $2.25 million; the 2013 Capital Budget, by $600,000. The reduction in the Administrative Revenue Requirement (i) will not constrain ISO operations or the 2013 work plan; and (ii) will not result in surcharges. Reduced revenues will be treated as a guaranteed true-up credit, to be reflected in subsequent years’ rates, and the reduction in the capital budget will be reflected in the second quarter 2013 capital funding tariff filing.
  
  - With respect to future budgets:
    - The process for annual review of the ISO’s administrative and capital budgets was revised to provide greater opportunity and responsibility for informed input by all stakeholders within the budget setting process. The budgets will be filed together in one FERC proceeding going forward.
    - A defined-contribution pension plan for new employees effective January 1, 2014 will be implemented (moving away from the current defined-benefit pension plan).

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14 *Fuel Cost Recovery Order; see Note 2 supra.*
15 *Id. at P 29.*
Costs for charitable contributions and golf tournaments will no longer be budgeted for or included in rates.

If there are any questions on this matter, please contact Dave Doot (860-275-0102; dtidoot@daypitney.com) or Paul Belval (860-275-0381; pnbelval@daypitney.com).

- FCA1 Results Remand Proceeding (ER08-633)

As previously reported, the DC Circuit issued on December 23, 2011, a per curiam order\(^{19}\) that PSEG’s May 2010 petition for review be granted, remanding the FERC’s orders in this proceeding\(^{20}\) for further consideration. 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 an answer to PSEG’s October 15 motion. On November 1, 2012, Connecticut Generators\(^{21}\) submitted comments supporting PSEG’s request and a few of the Connecticut Generators moved to intervene out-of-time. This matter remains pending before the FERC.

- ISO Issuance of Securities: $39 Million to Refinance Capital Expenditures Financings (ES13-34)

On July 1, the ISO requested the necessary FERC authorization to issue up to $39 million in senior unsecured notes in order to refinance the aggregate principal amount of senior notes previously authorized and issued\(^{22}\) The ISO stated that the refinancing will allow it to reduce its interest costs funded through its operating budget. No comments on this filing were submitted on or before the July 22 comment date and this matter is pending before the FERC. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

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### III. Market Rule Changes, Interpretations and Waiver Requests

- FCA Objective Function (ER13-1880)

On July 1, the ISO and NEPOOL jointly filed revisions to Market Rule 1 to allow the FCA market clearing engine to select a final solution that maximizes social surplus\(^{23}\) (rather than minimize total costs) (“FCA Objective Function Changes”). The filing indicates the Changes should have little effect on actual clearing outcomes, but will achieve those outcomes with less complexity and risk. A September 2, 2013 effective date was requested. The FCA Objective Function Changes were supported by the Participants.

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\(^{23}\) “Social surplus” (sometimes called social welfare) is the sum of consumer surplus (the difference between the amount that consumers would be willing to pay and the amount they actually pay) and supplier surplus (the difference between the amount that suppliers are actually paid and the amount that they would have been willing to accept). Social Surplus is at its maximum when demand equals supply.
Committee by way of its June 27 Consent Agenda. Calpine, EPSA, Exelon, NRG, and NU submitted doc-
lessness motions to intervene, but no comments on this filing were submitted. This matter is pending before the FECA. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Energy Market Offer Flexibility Changes (ER13-1877)**
  
  Also on July 1, 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”). More 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. Although a December 3, 2014 effective date was requested, the ISO and NEPOOL asked for an order on the filing be issued on or before October 1, 2013 to inform the Committee’s projected October 4 discussion on additional offer flexibility (NCPC-related) changes. The Offer Flexibility Changes were supported by the Participants Committee at its June 7 meeting. Interventions were filed by Brookfield, Calpine, Entergy, Exelon, GDF Suez, HQ US, NRG, NU, and PSEG. Comments were submitted by Capital Power, EPSA, MA DPU, NEPGA, and NESCOE. 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).

- **Winter 2013/2014 Reliability Program (ER13-1851)**
  
  On June 28, the ISO and NEPOOL jointly filed a set of solutions intended to support reliability during the cold-weather months of December 2013 through February 2014 (the “Winter Reliability Program”). The Winter Reliability Program consists of four components: (1) a new demand response program, (2) an oil inventory service, (3) incentives for dual fuel units, and (4) market monitoring changes. An August 27, 2013 effective date was requested. The Winter Reliability Program changes were supported by the Participants Committee at its June 27 Summer Meeting. Interventions were filed by Brookfield, ConEd, Dominion, Entergy, EPSA, Exelon, Hess, HQ US, IECG, MPUC, New England Gas LDCs, NICC, NRG, NU, PPL, Repsol, Shell, and the VT PSB; comments and/or protests, by Algonquin, Capital Power, CLG, Exelon, GDF, Hess, IECG, MDPU, National Grid, NEPGA, PSEG, RESA, TransCanada, UUI, and Vitol. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **PRD Full Integration Changes & FCM Net Supply Revisions (ER13-1742)**
  
  On June 21, the ISO and NEPOOL jointly filed two sets of changes to the price-responsive demand (“PRD”) full integration Market Rules: (1) clarifying and minor clean-up changes (the “PRD Full Integration Changes”), and (2) addressing the FCM treatment of Demand Resources that can produce “net supply” (i.e., the injection of energy into the electrical grid) (the “Net Supply Revisions”). An August 21, 2013 effective date was requested. These changes were unanimously supported by the Participants Committee by way of its June 7 Consent Agenda. Interventions were filed by Exelon and NU. Verso submitted comments on July 12 supporting the revisions, and noting that its proposal in Docket No. ER12-1627 for changing the “3 of last 10 days” baseline refreshment method is consistent with and can be accepted along with the various changes clarifying the calculation of the baseline proposed in this proceeding. 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).
• **RCPF for Replacement Reserve Requirement (ER13-1736)**
  
  On June 20, the ISO and NEPOOL jointly filed changes to Market Rule 1 that establish a Reserve Constraint Penalty Factor (“RCPF”) for the replacement reserve requirement at $250/MWh. An October 1, 2013 effective date, to coincide with the start of the Forward Reserve Procurement Period that begins on that date, was requested. The ISO and NEPOOL requested a FERC order within 60 days, however, to provide those participating in the August 2013 auction with some certainty as to the rules that will apply. These changes were unanimously supported by the Participants Committee by way of its June 7 Consent Agenda. Interventions were filed by Brookfield, Dominion, Exelon, NU. 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).

• **Forward Reserve Market (FRM) Incentives Proposal (ER13-1733)**
  
  Also on June 20, the ISO and NEPOOL jointly filed changes to improve the performance incentives in the FRM. Specifically, the proposal (1) includes Real-Time Reserve Clearing Price (adjusted down from the FRM Payment Rate) in the calculation of the Failure-to-Reserve Penalty to allow the penalty for non-performance of Forward Reserve resources during periods of reserve scarcity to reflect the actual Real-Time replacement cost; and (2) adds an additional trigger when a Failure-to-Activate Penalty could be applied to non-performing Forward Reserve resources. An October 1, 2013 effective date was requested. These changes were supported by the Participants Committee at its June 7 meeting. Interventions were filed by Brookfield, Dominion, Exelon, NRG, NU, and PSEG, but no substantive comments were submitted. 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).

• **CSO Termination: RI Genco (ER13-1516)**
  
  On July 9, the FERC accepted the termination of the CSO held by Project Sponsor Rhode Island Engine Genco, LLC (“RI Genco”) for Resource 14619. As indicated in the filing, the ISO will draw down the amount of financial assurance provided by RI Genco with respect to the CSO. Unless the July 9 letter 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).

  
  On June 27, the FERC accepted changes jointly filed by the ISO and NEPOOL to include opportunity costs in the Regulation Market clearing price. This change in design is intended to provide better incentives for efficient long-run investment through a more precise reflection of the marginal cost of providing regulation in the regulation clearing price. The changes became effective July 1, 2013, as requested. The changes accomplish a key objective of Order 755 while the ISO continues to work on implementation of the regulation market changes that are the subject of the proceedings in Docket No. ER12-1643 (see below). Unless the June 27 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

• **Revised Order 755 Compliance Filing (Regulation Market Changes) (ER12-1643)**
  
  As previously reported, the FERC issued an order on June 20, 2013 conditionally accepting the region’s revised Order 755 Compliance Filing (“Revised Compliance Filing”) submitted in February. The Revised Order 755 Compliance Order found that the February 2013 proposal satisfied the clearing price and payment directives of Order 755, but did not ensure that regulation resources are allowed to include inter-temporal opportunity costs in their ex ante bids. The FERC, therefore, required the ISO to submit, on or before August 5, 2013, a compliance filing that explains how regulation resources will be allowed to incorporate inter-temporal opportunity costs into their bids and how the ISO will verify those costs, and the associated modified tariff
  
revisions. In addition, the FERC directed implementation of the changes within 6 months (mid-December 2013), rather than January 1, 2015, as requested. The FERC found it unreasonable to delay implementation, noting (i) the past and on-going market uncertainty for regulation market participants caused by delays in establishing an Order 755-compliant frequency regulation market in New England; (ii) the importance of ensuring that all frequency regulation resources receive just and reasonable and not unduly discriminatory compensation, and (iii) the fact that the interim changes proposed in ER13-1291 did not justify granting a delayed implementation date.

At the Summer Meeting, the ISO described concerns that the FERC’s direction to implement the changes by mid-December will either materially increase its implementation costs (and thereby require an increase in the 2013 budget) or require a substantial re-alignment of priorities. The Participants Committee then approved a motion to support a request by the ISO that the FERC reconsider the timing of the mid-December implementation directed in the Order 755 Compliance Order.

On July 19, the ISO requested an extension of the compliance filing effective date specified in the Order 755 Compliance Order to October 14, 2014, or in the alternative, rehearing of that requirement. On July 22, NESCOE filed a motion to intervene out-of-time and an answer in support of the requested extension and/or rehearing. NEPOOL’s comments supporting the ISO’s request will filed on or before August 5. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **FCM Conforming Changes Reflecting PRD Full Integration (ER12-1627)**

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 price-responsive demand (“PRD”) full integration rules (currently scheduled to become effective on June 1, 2017). 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,” agreed that “the proposal will assist in correcting inefficiencies inherent in the current capacity market design, and will provide substantial benefits to many parties,” and found the “proposal will be beneficial to both demand response providers and wholesale electricity customers”. 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 demand response resources that provide capacity through both demand reductions and behind-the-meter generation. Noting its concerns with other aspects of the filing, the FERC conditioned its acceptance of certain changes subject to an explanation as to:

- how the Internal Market Monitor will monitor and evaluate offers by demand response capacity resources;
- whether the “3 of last 10 days” baseline refreshment is still a viable element of its methodology to ensure accurate baselines in light of the requirement that demand resources with a Capacity Supply Obligation offer into the energy market in all hours and thus could be dispatched more frequently.

25 Id. at P 23.
26 Id. at P 33.
28 Id. at P 27.
29 Id. at P 28.
30 Id. at P 29.
31 Id. at PP 44-46.
32 Id. at P 36.
than under the current FCM market rules33 (noting its concern about the interaction between the must-offer requirement and the need for demand response resources to refresh their baselines);34

- why the removal of using transmission losses in its calculation of demand resource capacity values is justified;35
- whether, and if so how, the ISO it will otherwise adjust the total capacity requirement to reflect avoided transmission losses when procuring capacity;36 and
- how considering the duration of a shortage event when evaluating the performance of demand response resources but not generation resources provides for comparable treatment.37

The ISO was directed to submit a compliance filing providing these explanations and addressing the changes rejected within 60 days of the date of the order, which it filed on March 15, 2013. Protests on that compliance filing were submitted on April 5 by DR Supporters38 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 Supports and Verso Paper protests. On April 30, Verso answered the ISO’s April 19 answer. The ISO’s compliance filing and protests and answers related thereto are pending before the FERC. If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; dt dood@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.39 The FCA8 Revisions Order accepted the following aspects of the FCA8 Revisions as compliant with its prior FCM Orders: the ISO’s offer review trigger prices;40 unit specific offer review;41 the ISO’s proposal to subject a resource to offer floor mitigation until that resource clears in one FCA; imports’ treatment under MOPR;42 no exemptions to MOPR for new Self-Supplied Resources;43 the application of mitigation to all new resources offering into the FCM, including renewables that are procured pursuant to state policy initiatives;44 $1.00/kW-month Threshold to trigger IMM review of Dynamic De-List Bids;45 and a number of other additional

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33 Id.
34 Id. at P 35.
35 Id. at P 57.
36 Id.
37 Id. at P 58.
38 DR Supporters are Converge, EnerNOC, NICC, Wal-Mart, and the IECG.
40 FCA8 Revisions Order at PP 37-38.
41 Id. at P 53.
42 Id. at P 70.
43 Id. at P 80.
44 Id. at P 97.
45 Id. at P 126.
revisions.\(^{46}\) 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)\(^{47}\); 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, NECEA; the other, by EMCOS and Danvers. On April 11, NEPGA filed an answer to the MM WEC 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.

**FCA8 Revisions Compliance Filing.** On March 15, 2013, the ISO submitted a compliance filing that (i) revised the ISO’s proposal by addressing the offer floor of an uncleared resource that has already achieved commercial operation at the time of an FCA; (ii) provided additional justification for retaining four Capacity Zones for FCA8; and (iii) submitted the “core” Tariff provisions necessary to implement eight Capacity Zones for FCA8 should the FERC not accept the additional justification provided. On May 31, the FERC issued an order accepting the tariff revisions related to the duration of mitigation, to become effective May 30, 2013, rejected the ISO’s alternative tariff provisions which would have provided for the modeling of eight zones, and accepted the ISO’s proposal to retain four zones, subject to a further compliance filing.\(^{48}\) The FERC found that the additional evidence in the ISO’s Compliance Filing “sufficiently demonstrates that remaining with ISO-NE’s four-zone model for FCA 8 would be just and reasonable.”\(^{49}\) The FERC “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.”\(^{50}\) Accordingly, the FERC directed the ISO to consider in the stakeholder process to address how capacity zones and the associated zonal requirements are determined to consider during that process and to explain how it addressed: (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. In a subsequent filing, the ISO must: (i) develop and file revisions to the Tariff that articulate appropriate objective criteria to revise the number and boundaries of capacity zones automatically as the relevant conditions change, or (ii) file an explanation as to why such criteria are unnecessary. The ISO was directed to submit a schedule for the completion of those tasks on or before July 30, 2013.\(^{51}\) The *FCA8 Compliance Order* was not challenged and is final and unappealable.

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\(^{52}\) regarding the plan to study and develop proposals to resolve issues related to the modeling of internal transmission constraints and tie

\(^{46}\) *Id.* at P 127.

\(^{47}\) *Id.* at PP 63-64.

\(^{48}\) *ISO New England Inc., 143 FERC ¶ 61,198 (2013)* (“FCA8 Compliance Order”).

\(^{49}\) *Id.* at P 31.

\(^{50}\) *Id.* at P 35.

\(^{51}\) *Id.*

\(^{52}\) 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).*
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).

**IV. OATT Amendments / TOAs / Coordination Agreements**

- **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”). 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. 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. Comments on this filing will be due on or before August 26, 2013. Thus far, doc-less motions to intervene have been filed by Exelon and NEPOOL (in the Protocol proceeding). 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 has been requested of the FERC’s May 17, 2013 order on the region’s Order 1000 compliance filing53 (described in previous Reports). 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 is 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 requires 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. Although the

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additional compliance filing would otherwise be due on or about September 16, 2013, on July 9, the ISO, NEPOOL, and PTO AC requested an extension of time, to November 15, to submit the required compliance filing. NESCOE filed a contemporaneous pleading supporting that request. The FERC granted the requested extension on July 22, 2013. Accordingly, the additional compliance filing will be considered at the November 8 Participants Committee meeting and filed on or before November 15, 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. 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 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, 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).

V. Financial Assurance/Billing Policy Amendments

- CFTC Exemption Order Changes (ER13-1875)
  On July 1, the ISO and NEPOOL jointly filed two sets of revisions in response to the CFTC’s Exemption Order (see Section XI below). Changes to the Financial Assurance Policy address the requirement that all parties to agreements, contracts or transactions under the ISO Tariff be “appropriate persons,” an “eligible contract participants,” or “person[s] who actively participate in the generation, transmission or distribution of electric energy” (“FAP Changes”). Proposed Information Policy changes explicitly provided that the ISO is not required to notify Market Participants prior to providing information to the CFTC in response to a CFTC subpoena or other request for information or documentation. Both the FAP Changes and Information Policy changes were supported by the Participants Committee at the June 27 Summer Meeting. Exelon, NRG, and NU filed doc-less

motions to intervene. On July 22, Freedom Logistics filed a protest, challenging aspects of the FAP Changes. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com) or Pat Gerity (860-275-0533; pngerity@daypitney.com).

- **Billing Policy Clarification: State Sales Tax Collections (ER13-1870)**

  Also on July 1, the ISO and NEPOOL jointly filed a clarification to the Billing Policy to make clear that applicable state sales taxes related to purchases of electricity through the New England Markets will be included and collected as Non-Hourly Charges. Non-Hourly Charge-related Payment Defaults can result in the suspension or termination of a Market Participant, in accordance with the applicable Billing Policy provisions. These changes were supported by the Participants Committee at the June 27 Summer Meeting. Doc-less interventions were filed by Exelon and NRG, but no substantive comments were submitted on or before the July 22 comment date. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

### VI. Schedule 20/21/22/23 Changes

- **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. 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.” Requests for clarification and/or rehearing of the GMP Merger Order requested by VEC and WEC (“Cooperatives”) were denied on February 25, 2013. 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.

  Judge Karen V. Johnson was designated as the settlement judge, and convened a first settlement conference on October 17, 2012. A second settlement conference was held January 24, 2013. Judge Johnson’s most recent status report (issued May 30, 2013) indicates that the participants continue to negotiate and exchange documents and were optimistic that they will be able to reach a settlement in the near future; and (ii)

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56 Each of the New England states (other than New Hampshire) impose sales tax on the sale of electricity, which is deemed to be a retail sale of tangible personal. The ISO will collect and remit applicable state sales taxes in connection with purchases of electricity through the New England Markets, unless the purchase is made for subsequent resale (and a properly executed resale certificate is in place) or a state-specific sales tax exemption applies to the purchase and is properly claimed by the purchaser.


58 Id. at PP 21-22.

59 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.


61 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.
recommended that settlement judge procedures be continued. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-NSTAR Annual Informational Filing (ER09-1243; ER07-549)**
  On May 31, 2013, NSTAR submitted an informational filing containing the true-up of billings under Schedule 21-NSTAR for the period January 1, 2012 through December 31, 2012. NSTAR stated that the filing complies with the requirements of Section 4 and Attachment D of Schedule 21-NSTAR, as well as the Settlement Agreement previously approved by the FERC. On June 28, 2013, NSTAR supplemented its May 31 annual informational filing with a “CWIP Supplement” in accordance with Section 4.1(i) and (ix) of Schedule 21-NSTAR as added and supplemented by Article 4.2 of the 2008 Settlement. The CWIP Supplement was provided primarily on a project-specific basis, and included NSTAR’s 2013 long-range construction forecast. The FERC will not notice these filings for public comment, and absent further activity, no further FERC action is expected. No comments have been filed on either of these informational filings. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-CMP Annual Informational Filing (ER09-938)**
  On June 28, CMP submitted an annual update to the formula rates contained in Schedule 21-CMP. CMP indicated that the informational filing reflected actual cost data for the 2011 calendar year plus estimated cost data for the 2013 calendar year associated with CMP’s forecasted transmission plant additions and MPRP CWIP as well as the annual true-up and associated interest. CMP referred to Section 10.2 of Schedule 21-CMP for specific procedures for review and challenges to the informational report. The FERC will not notice this filing for public comment, and absent further activity, no further FERC action is expected. 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

- **Quarterly Reports Regarding Non-Generating Resource Regulation Market Participation (ER08-54)**
  The ISO filed its nineteenth report on June 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. In the 19th report, the ISO indicated that it had filed its revised Order 755 Compliance Filing on February 6 (see Section III above), which provides for uniform regulation prices and separate payments for regulation capacity and service, and would accommodate participation by all resource types, including non-generation alternative resources, in the new regulation market once it is implemented. The ISO reported that it had requested that the regulation market compliance changes become effective on or after January 1, 2015 with two weeks’ prior notice of the actual effective date to be provided by the ISO. In addition, the ISO reported that interim regulation market design changes, to include energy opportunity costs in the clearing price, were filed on April 11 in Docket No. ER13-1259 (see Section III above) and will become effective July 1, 2013, if accepted. These reports are not noticed for public comment.

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63 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”).
• LFTR Implementation: 19th Quarterly Status Report (ER07-476; RM06-08)
  The ISO filed the nineteenth of its Quarterly Status Reports regarding LFTR implementation on July 15. Subject to a number of qualifications, the ISO reported that if the third party clearing design begin vetted in the Participant Processes is supported, the third party clearing design could be implemented during Q4 2014 for the 2015 annual FTR auction, about six months later (mid-2015) for monthly auctions, and during Q4 2016 for an initial auction of LFTRs. The estimated 18-month LFTR implementation process, described in previous reports, would be initiated in 2015, presuming the third party clearing design is accepted and related FAP changes resolved. These status reports are not noticed for public comment and no comments have been filed.

IX. Membership Filings

• July 2013 Membership Filing (ER13-1867)
  On June 28, NEPOOL requested that the FERC accept (i) effective July 1, 2013, the memberships of Dynasty Power (Supplier Sector); Mega Energy Holdings (Supplier Sector); Negawatt Business Solutions (AR Sector, Small LR Group Seat); Provider Power CT (Related Person to Electricity Maine, Supplier Sector); and SBR Energy (Supplier Sector); and (ii) effective June 1, 2013, the termination of the Participant status of South Jersey Energy Solutions. This matter is pending before the FERC.

• June 2013 Membership Filing (ER13-1616)
  On June 28, the FERC accepted the termination of the Participant status of West Oaks Energy (Supplier Sector), effective May 1, 2013.

• Suspension Notice: DownEast Power Company (not docketed)
  On July 24, the ISO filed, pursuant to Section 2.3 of the Information Policy, a notice with the FERC that DownEast Power Company, LLC was suspended from the New England Markets on June 19, 2013 at 11:12 a.m. This notice was for the FERC’s information only and will not be docketed or noticed for public comment.

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; pmerity@daypitney.com).

• FFT Report: June 2013 (NP13-41)
  NERC submitted on Jun 27, 2013, its Find, Fix, Track and Report (“FFT”) informational filing for the month of June 2013. The May FFT resolves 45 possible violations of 9 Reliability Standards that posed a risk minimal risk to bulk power system (“BPS”) reliability, but which have since been remediated.64 The 20 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.

• NERC Glossary of Terms: Addition of Terms (RD13-10)
  On July 9, the FERC approved NERC’s addition to its Glossary of Terms the terms “Bulk-Power System,” “Reliability Standard,” and “Reliable Operation”. Unless the July 9 letter order is challenged, this proceeding will be concluded.

64 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.
• **Revised VSLs/VRFs (RD13-5 et al.)**

On June 24, the FERC accepted the modifications and/or additional support for VSL and VRF assignments filed by NERC on February 15, 2013. As previously reported, NERC explained that the filing would ensure consistency with FERC guidelines, and in some cases, provide the modifications and/or additional support required by prior FERC orders. The June 24 order was not challenged and this proceeding has been concluded.

• **Interpretation: CIP-002-4 R3 (RD12-5)**

On June 25, the FERC granted the clarifications requested by NERC and EEI of its March 21, 2013 order remanding NERC’s proposed interpretation of Requirement R3 to Reliability Standard CIP-002-4 (Critical Cyber Asset Identification). However, the FERC denied the ISO/RTO Council’s motion to intervene out-of-time and, consequently, denied its request for clarification and/or rehearing. As previously reported, the interpretation was intended to clarify (i) that the list of examples provided in Requirement R3 of CIP-002-4 are illustrative, and not an exhaustive list, of the types of Cyber Assets that may be Critical Cyber Assets; and (ii) the meaning of the language “essential to the operation of the Critical Asset”. In remanding the interpretation, the FERC explained that, although it agreed with the first clarification, it found the second misconstrued what is “essential to the operation” of a Critical Asset and could result in Critical Cyber Assets not being protected by the CIP Reliability Standards. For example, the FERC found that in proposing that a cyber asset that “may” be used but is not “required” for the operation of a Critical Asset is not “essential to the operation of the Critical Asset,” the proposed interpretation failed to consider that a computer (e.g., a laptop) used by utility staff or contractors to control the functions and operations of a Critical Asset is, during such usage, “inherent to or necessary for the operation of a Critical Asset,” and thus falls within the scope of the Standard. Fearing that the proposed interpretation could, in effect, create a window into an EMS network that could be exploited, the FERC remanded the interpretation.

In its **Clarification Order**, NERC clarified that (i) the **CIP-002 Interpretation Order** did not state that “all laptops must be included in the scope of CIP-002-4, Requirement R2,” rather, the FERC determined only that the proposed interpretation incorrectly excluded cyber assets actually used to control Critical Assets, and that determination was sufficient to warrant a remand (FERC did not reach the question of whether other cyber assets, such as those capable of controlling Critical Assets, were “essential,” reserving judgment on that issue); and (ii) the **CIP-002 Interpretation Order’s** reference to the NERC guidelines was intended to illustrate the FERC’s concerns with the proposed interpretation (and did not remand the proposed interpretation based on the NERC guidelines nor did the Order state or imply that the NERC guidelines are mandatory and enforceable.)

• **New and Revised Reliability Standards: MOD-025-2, MOD-026-0, MOD-027-0, PRC-019-1 and PRC-024-1 (RM13-16)**

On May 30, 2013, NERC filed for approval 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:

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69 Id. at P 12.

70 Id. at P 13.
- 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).

NERC also requested approval of the associated implementation plans, Violation Risk Factors (“VRFs”) and Violation Severity Levels (“VSLs”), and 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. NERC states that the purpose of the Standards is to ensure (i) that generators will not trip off-line during specified voltage and frequency excursions or as a result of improper coordination between generator protective relays and generator voltage regulator controls and limit functions (such coordination will include the generating unit’s capabilities), and (ii) that generator models accurately reflect the generator’s capabilities and operating characteristics. The Standards will be phased in starting two years from the first day of the calendar quarter that they are approved. As of the date of this report, a comment date has not been set.


  On April 16, 2013, NERC filed for approval changes to the following four Interconnection Reliability Operations and Coordination (“IRO”) Reliability Standards and their associated implementation plans: IRO-001-3 (Reliability Coordination — Responsibilities and Authorities); IRO-002-3 (Reliability Coordination – Analysis Tools); IRO-005-4 (Reliability Coordination – Current Day Operations); and IRO-0014-2 (Coordination Among Reliability Coordinators). NERC states that the changes achieve two important overall reliability benefits: (1) they delineate a clean division of responsibilities between the Reliability Coordinator and Transmission Operators; and (2) they will 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. Together with the TOP Standards, TOs will also be assured the ability to identify a sub-set of non-IROL SOLs that are identified as important for local areas, giving them the authority to ensure that any non-IROL SOLs of concern be monitored and local consequences managed. NERC requested that the revised Standards be approved concurrently with the TOP Standards filed in RM13-14 (see below) and become effective the first day of the first calendar quarter that is 12 months following the effective date of a Final Rule in this docket. As of the date of this report, a comment date has not been set.


  Also on April 16, 2013, NERC filed for approval changes to the following four Standards and their associated implementation plans: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data); and PRC-001-2 (System Protection Coordination). NERC states that the changes upgrade the overall quality of the standards, eliminate gaps in the requirements, eliminate ambiguity, eliminate redundancies, and address Order 693 directives. 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. The corresponding changes in proposed PRC-001-2 are administrative in nature and are limited to removal of three requirements in currently-effective PRC-001-1 that are now addressed in proposed TOP-003-2, included herein for approval. NERC requested that the revised Standards be approved concurrently with the TOP Standards filed in RM13-14 (see below) and become effective the first day of the first calendar quarter that is 12 months following the effective date of a Final Rule in this docket. As of the date of this report, a comment date has not been set.
- **Revised Reliability Standard: TOP-006-3 (RM13-12)**
  On April 5, 2013, NERC filed for approval changes to TOP-006 (Monitoring System Conditions), as well as its associated implementation plan. NERC states that the changes 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. NERC requested an effective date that is the first day of the first calendar quarter following the effective date of an order in this proceeding. As of the date of this report, a comment date has not been set.

- **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. NERC stated that the changes respond to FERC directives in Order 693 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 are due [60 days after its publication in the Federal Register].

- **Supplemental NOPR: TPL-001-4 (footnote ‘b’) (RM13-9; RM12-1)**
  As previously reported, the FERC issued a supplemental NOPR on May 16 proposing to approve TPL-001-4, which changes 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), and also consolidate all of the currently effective TPL Standards (including superseding proposed TPL-001-2, which NERC had proposed in a previous NOPR to remand). As previously reported, NERC has long had a compliance obligation to address FERC concerns with the Footnote. NERC’s February 28 filing addressed those concerns. Comments on the supplemental NOPR were due on or before June 24, 2013. Comments were submitted by ITC, MISO, and NERC. This NOPR is pending before the FERC.

- **NOPR: Retirement of Reliability Standard Requirements: P 81 Project (RM13-8)**
  On June 20, the FERC issued a NOPR proposing to retire 34 requirements in 19 Standards that NERC indicated were redundant and/or otherwise could be removed with little or no effect on reliability. In addition, the FERC proposed to withdraw 41 outstanding FERC directives that NERC develop modifications to Reliability Standards as the identified outstanding directives have either been addressed in some other manner, are redundant

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71 Frequency Response and Frequency Bias Setting Rel. Std., 144 FERC ¶ 61,057 (Jul. 18, 2013)
72 Order 693 at P 375.
74 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.
75 The NOPR was published in the Fed. Reg. on May 23, 2013 (Vol. 78, No. 100) pp. 30,804-30,810.
with another directive or provide general guidance as opposed to a specific directive. Comments on this NOPR are due on or before August 27, 2013.77

- **NOPR: Revised Reliability Standard: PRC-005-2 (RM13-7)**
  
  On July 18, the FERC issued a NOPR proposing to approve 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. In addition, the FERC seeks clarification and comment on three aspects of PRC-005-2 and proposes to modify one VSL. Comments on this NOPR are due on or before September 23, 2013.79

- **NOPR: Remand of Interpretation of BAL-002-1a (RM13-6)**
  
  On May 16, the FERC issued a NOPR proposing 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-002.60 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, 2013,81 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.

- **NOPR: Revised Reliability Standards: Version 5 CIP Standards (-002 through -011) (RM13-5)**
  
  On April 18, 2013, the FERC issued a NOPR proposing to approve the Version 5 Critical Infrastructure Protection (“CIP”) Reliability Standards submitted by NERC, CIP-002-5 through CIP-011-1, which adopt new cyber security controls and extend the scope of the systems that are protected by the CIP Standards.82 Noting a concern that “limited aspects of the proposed CIP version 5 Standards are potentially ambiguous and, ultimately, raise questions regarding the enforceability of the standards”, the FERC proposed to direct NERC to develop certain modifications to the CIP version 5 Standards to address those concerns. Comments on the CIP Version 5 NOPR were due June 24, 2013.83 Comments were submitted by over 60 parties, including, among others, the

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76 Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards, 143 FERC ¶ 61,251 (Jun. 20, 2013).


78 Protection System Maintenance Reliability Standard, 144 FERC ¶ 61,055 (July 18, 2013) (“PRC-005-2 NOPR”).


following New England parties: the ISO, Dominion, Exelon, NextEra, NRG, NU, and PPL. This NOPR is pending before the FERC. On July 18, a number of Trade Associations filed a request that the FERC delay the April 1, 2014 CIP Version 4 compliance deadline pending action in this rulemaking proceeding on the CIP Version 5 Standards. Comments on that request are due on or before August 5, 2013.

- **Order 779: Geomagnetic Disturbance Reliability Standards (RM12-22)**
  
  On May 16, the FERC issued Order 779, which directed NERC to submit for approval Reliability Standards that address the impact of geomagnetic disturbances ("GMD") on BPS reliability. The FERC directed a two-staged implementation plan. In the first stage, the FERC directed NERC to file, on or before January 22, 2014 (6 months from the July 22, 2013 effective date of Order 779), one or more Reliability Standards that require BPS owners and operators to develop and implement operational procedures to mitigate the effects of GMDs consistent with the reliable operation of the BPS. In the second stage, the FERC directed NERC to file, on or before January 22, 2015 (18 months from Order 779’s effective date), one or more Reliability Standards that require owners and operators of the BPS to conduct initial and on-going assessments of the potential impact of GMDs, focusing first on the most critical BPS assets. Rehearing of Order 779 was requested by MISO on June 17, 2013. On July 16, the FERC issued a tolling order affording it additional time to consider the MISO rehearing request, which remains pending before the FERC.

  
  On July 18, the FERC approved clarifications to NERC’s Area Interchange Methodology (MOD-028-2) Standard, as well as the proposed implementation plan and retirement of the currently-effective standard. The revisions clarify the timing and frequency of Total Transfer Capability ("TTC") calculations needed for Available Transfer Capability ("ATC") calculations. The revised Standard will become effective September 1, 2013 (the first day of the first calendar quarter following FERC approval). Unless Order 782 is challenged, with any challenges due on or before August 19, this proceeding will be concluded.

- **NOPR: Revised Reliability Standards: FAC-001-1, FAC-003-3, PRC-004-2.1a, PRC-005-1.1b (RM12-16)**
  
  On April 18, 2013, the FERC issued a NOPR proposing to approve NERC’s July 30, 2012 request for approval of proposed revisions to four Reliability Standards, including VRFs, VSLs, and implementation plans, for Facility Connection Requirements (FAC-001-1), Transmission Vegetation Management (FAC-003-3), Analysis and Mitigation of Transmission and Generation Protection System Misoperations (PRC-004-2.1a) and Transmission and Generation Protection System Maintenance and Testing (PRC-005-1.1b). The proposed revisions to the Reliability Standards address the application of Reliability Standards to generator interconnection Facilities (generator tie-lines). The Standards will obviate the need to register all generators as Transmission Owners and/or Transmission Operators with respect to generator interconnection Facilities, unless individual circumstances warrant otherwise. The FERC indicated that “the proposed modifications improve reliability either by extending their applicability to certain generator interconnection facilities, or by clarifying that the existing Reliability Standard is and remains applicable to generator interconnection facilities.” The revised Standards are proposed to become effective the first day of the first calendar quarter that is one year following the effective date.

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84 “Trade Associations” were APPA, EEI, ELCON, EPSA, Large Public Power Council ("LPPC"), NRECA, and the Transmission Access Policy Study Group ("TAPS").


87 *Revisions to Modeling, Data, and Analysis Reliability Standard*, Order No. 782, 144 FERC ¶ 61,027 (July 18, 2013) (“Order 782”).

88 *Generator Requirements at the Transmission Interface*, 143 FERC ¶ 61,049 (2013).
of the revisions. Comments were filed by 13 parties on the June 24, 2013 comment date. On July 9, NERC submitted reply comments. This matter is pending before the FERC.

- **Order 773-A: Revised “Bulk Electric System” Definition and Procedures (RM12-7; RM12-6)**

  On April 18, the FERC denied rehearing in part, granted rehearing in part and otherwise reaffirmed its determinations in Order 773. In addition, the FERC clarified certain provisions of Order 773. As previously reported, Order 773 approved the following:

  - a modified and more detailed definition of “Bulk Electric System” developed by NERC;
  - NERC’s contemporaneously filed revisions to its Rules of Procedure, which creates an exception procedure to add elements to, or remove elements from, the definition of “bulk electric system” on a case-by-case basis;
  - NERC’s proposed form entitled “Detailed Information to Support an Exception Request” that entities will use to support requests for exception from the “bulk electric system” definition; and
  - NERC’s proposed implementation plan for the revised “bulk electric system” definition.

  The revised definition of “bulk electric system” removed language allowing for regional discretion in the currently-effective bulk electric system definition. The revised definition established a bright-line threshold that includes all facilities operated at or above 100 kV. The modified definition also identified specific categories of facilities and configurations as inclusions and exclusions to provide clarity in the definition of “bulk electric system.” Order 773 became effective March 5, 2013.

  In response to requests for rehearing of Order 773 filed by APPA, AWEA, Dow Chemical, Holland, Michigan Board of Public Works (“Holland”), NARUC, NERC, NRECA, NY PSC, Snohomish County PUD No. 1, Transmission Access Policy Study Group (“TAPS”), and Utility Services, as well as answers filed by Exelon, the ITC Companies, NERC, and Holland, the FERC, in Order 773-A, denied rehearing in part, granted rehearing in part, granted clarification of, and otherwise reaffirmed its determinations in Order 773. Of note, the FERC:

  - denied rehearing and affirmed that approval of the 100 kV bright-line threshold was adequately supported with a technical justification (P 23);
  - granted rehearing to the extent that, rather than direct NERC to implement exclusions E1 and E3 as described above, FERC directed NERC to modify the exclusions pursuant to FPA section 215(d)(5) to ensure that generator interconnection facilities at or above 100 kV connected to bulk electric system generators identified in inclusion I2 are not excluded from the bulk electric system, finding that the Phase 2 standard development process is an appropriate means to address its concerns (P 50);
  - clarified that currently unregistered entities or entities with facilities that are included in the BES for the first time as a result of the new definition do not have to comply with newly relevant Reliability Standards during the pendency of their exception request (which the FERC expects to be decided during the two-year transition period);
  - clarified that the exceptions process and the process for the FERC making local distribution determinations are separate, not concurrent, and result in different determinations;
  - clarified that state regulators may participate in local distribution determinations, but the question of whether a facility is local distribution is a question of fact that will be decided by the FERC;
  - clarified that, in the absence of bad faith, if a registered entity applies the BES definition and determines that an element no longer qualifies as part of the BES, upon notifying the appropriate Regional Entity the element should not be treated as part of the BES unless NERC makes a contrary determination in the exception process (P 110);

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clarified that the revised definition will become effective for NERC compliance purposes on July 1, 2013, and that the transition period discussed in the Final Rule will extend twenty-four months from that date (P117); and

- granted rehearing on the need to reassess the burden estimates relative to the Final Rule modifications regarding exclusions E1 and E3, but indicated that it would address such estimates after NERC submits its proposal to modify the BES definition pursuant to FPA section 215(d)(5) in the Phase 2 process (“Revised Information Collection Burden and RFA Analyses”) (P 123).

NERECA and APPA jointly requested rehearing and/or clarification of the revised Information Collection Burden and RFA Analyses contained in Order 773-A on May 17, 2013. On June 14, the FERC issued a tolling order affording it additional time to consider the rehearing request, which remains pending before the FERC.

Compliance Filing. On April 4, 2013, and in response to Order 773, NERC submitted a compliance filing outlining the schedule for how and when it will modify Exclusion E3 of the Bulk-Electric System definition (“BES Definition”) to remove the 100 kV minimum operating voltage in the local network definition. The schedule contemplates a filing approximately seven months from the date of Order 773-A, or late November 2013.

Request for 1-Year Extension of Effective Date. On May 23, 2013, in response to stakeholder feedback and concerns, NERC requested that the “Bulk Electric System” (“BES”) definition be made effective July 1, 2014, one year later than previously approved. The FERC requested that an order granting the extension be issued prior to June 30, 2013. Comments on that request were due on or before May 31, 2013. NERC’s request was supported by Alcola, Almeda Municipal Power, Anaheim, APPA and TAPS, Dow Chemical, Consumers Energy, ELCON, Exelon, and NARUC. On June 13, the FERC granted NERC’s request for extension of time. Accordingly, the effective date for the revised BES definition as approved in Order Nos. 773 and 773-A will be July 1, 2014 (rather than July 1, 2013). The Pacific Northwest Generating Cooperative requested rehearing of the June 13 order on Jul 9, 2013, and that request is pending before the FERC.

- NERC Rules of Procedure: Revisions to Rules of Procedure Appendices 2 and 4D (RR13-3)
  On April 8, 2013, NERC requested FERC approval of revisions to its Rules of Procedure (“ROP”), Appendices 2 (Definitions Used in the Rules of Procedure) and 4D (Procedure for Requesting and Receiving Technical Feasibility Exceptions to NERC Critical Infrastructure Standards). NERC states that Appendix 4D revisions are the result of a collaborative process among NERC, the Regional Entities and industry stakeholders to review and revise the processes for submitting, reviewing and approving or disapproving Technical Feasibility Exceptions to NERC CIP Standards. The revisions to Appendix 2, which contains all the defined terms used in the ROP, reflect the deletion of two defined terms from Appendix 4D that are not used elsewhere in the ROP, the addition of two new defined terms, and a revision to an existing defined term. A doc-less intervention was filed by EEI. Comments on the revisions were due on or before April 29, 2013, but none were submitted and this matter is pending before the FERC.

  On June 26, 2013, FERC approved proposed revisions to NERC’s Standard Processes Manual (“SPM”) set forth in Appendix 3A of the NERC Rules of Procedure (“ROP”), part of an overall package of Reliability Standards reforms developed by the NERC Standards Committee (“SC”) and approved by the NERC Board of Trustees. NERC stated that the proposed SPM revisions, collectively, were a significant improvement to the NERC Reliability Standards development process, providing for more efficient and effective use of industry resources and necessary flexibility in Reliability Standards development. The June 26 order was not challenged and is final and unappealable.

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XI. Misc. - of Regional Interest

- **CFTC Exemption**
  
  On March 28, 2013, the Commodity Futures Trading Commission (“CFTC”) issued a 142-page final order in response to a February 7, 2012 petition by the RTO/ISOs, including ISO-NE, 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 into 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. A more detailed summary of the final order was circulated to the Committee and the Dodd-Frank Working Group on April 5, 2013.

  Changes to the FAP and Information policy required to comport with the CFTC Order were filed July 1, 2013 (see ER13-1875, Section V above). 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. If there are questions on this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com) or Dave Doot (860-275-0102; dtdoot@daypitney.com).

- **203 Application: Dominion / ECP (Brayton Point) (EC13-82)**
  
  On March 21, 2013, Dominion (“Dominion”) and Brayton Point Holdings, LLC (“BPH”), an affiliate of Energy Capital Partners II (“ECP”), EquiPower Resources Management (“EquiPower”) and EquiPower’s Related Persons, requested FERC authorization of a transaction pursuant to which Dominion would sell to BPH 100% of the ownership interests in Brayton Point. Comments on this filing were due on or before May 20, 2013. Although an intervention was filed on March 28 by Local Union No. 15, International Brotherhood of Electrical Workers, AFL-CIO, it was later withdrawn on April 12. CLF submitted comments on May 20, and Dominion answered those comments on May 22. On June 12, Local Union 464, Utility Workers Union of America, AFL-CIO moved to intervene. On July 5, Dominion renewed its request for expedited FERC authorization of the transaction. As of the date of this report, this application remains pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmsgerity@daypitney.com).

- **203 Application: Maine Public Service/Bangor Hydro (EC13-81)**
  
  On July 18, the FERC authorized the merger of Maine Public Service (“MPS”) into Bangor Hydro (“Applicants”). As previously reported, Applicants indicated that the result of the transaction will be 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

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93 A copy of the 391-page “Consolidated Request” was circulated to the Committee by the ISO on Feb. 8, 2012, and is also available at [http://www.iso-ne.com/regulatory/ferc/fed/index.html](http://www.iso-ne.com/regulatory/ferc/fed/index.html).

94 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](http://www.iso-ne.com/regulatory/ferc/fed/2012/index.html).

not. In a companion order (ER13-1125),\(^96\) 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 FERC required Applicants to notify it within 10 days of the consummation of the merger, which has not yet occurred. On July 23, Applicants submitted a report notifying the FERC of the MPUC’s approval of Applicants’ proposed changes to ring-fencing provisions and other conditions. Unless the July 18 order is challenged, and pending notice that the merger has been consummated, this proceeding will be concluded. 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).\(^97\) 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).

- **Allco Renewable Energy v. National Grid (PURPA Complaint) (EL12-12)**
  On November 30, 2011, Allco Renewable Energy Limited (“Allco”) filed a complaint against Massachusetts Electric Company d/b/a National Grid (in this summary, “National Grid”). Allco seeks a FERC order that among other things would require National Grid to purchase all of the output from Allco’s multiple solar photovoltaic projects in Massachusetts at a rate equal to its long-term avoided cost rate (which it argues includes environmental compliance costs, such as costs of compliance with the MA RPS, RGGI and the MA Global Warming Solutions Act). For timing reasons described in its filing, Allco requested that a settlement judge be appointed in accordance with FERC Rule 603 as soon as possible. On December 21, 2011, National Grid submitted an answer to Allco’s complaint urging the FERC to find the complaint is without merit and to deny it in its entirety. One party, the Massachusetts Department of Public Utilities (“MA DPU”), submitted comments by the December 21, 2011 comment date, and on January 5, 2012, the MA DPU also submitted for FERC’s reference a letter from the MA DPU to Allco declining to open a rulemaking to amend the MA DPU’s regulations with respect to sales of electricity by a renewable energy qualifying facility. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **UI Declaratory Order – Sales to Elm Electric Coop (EL10-67)**
  As noted below, these proceedings have been stayed pending CT DPUC action on an agreement before it that would resolve the dispute in this proceeding. As previously reported, on May 12, 2010, the United Illuminating Company (“UI”) filed a petition for a declaratory order (“Petition”) that its sales to Elm Electric Cooperative (“Elm”), for resale to Elm’s members, is a transaction at wholesale subject to FERC jurisdiction. As indicated by UI in the Petition, Elm is a Connecticut electric cooperative formed to sell and distribute electricity to its members, who will be tenants of a large, mixed-use residential and commercial building now under construction in New Haven, Connecticut. Elm will serve its members in part by using a


\(^{97}\) Fore River Dev., LLC, 133 FERC ¶ 61,248 (2010).
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400 kW fuel cell located at the site, and to the extent the fuel cell production is insufficient to meet the building’s load, Elm will purchase electricity from UI that will be re-sold and distributed to its members. Elm also expects to sell the excess power generated by the fuel cell in the New England Market, netting the excess against its UI bill. Elm will install four meters that will handle the building’s load and engage a third party to supply sub-meters to each of Elm’s members. UI reports that Elm has asserted in CT proceedings that the FERC either does not have jurisdiction or that it would likely disclaim jurisdiction over the matter. On December 7, 2010, UI asked the FERC to stay these proceedings, noting that UI and Elm had negotiated and executed an agreement that, if accepted by the CT DPUC, would resolve the dispute in this proceeding. The motion to stay the proceedings, and the Petition itself, remain pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **National Grid IAs (ER13-1618 et al.)**

  Over the past several months, National Grid, on behalf of its affiliates New England Power Company (“NEP”), Massachusetts Electric Company (“MECO”), and Narragansett Electric Company (“Narragan”), has submitted for filing a number of existing Interconnection Agreements (“IAs”) following National Grid’s recent determinations that the IAs could well be jurisdictional. The remaining IAs were accepted since the last report. A summary of those IAs accepted since the last report is as follows:

<table>
<thead>
<tr>
<th>Docket No.</th>
<th>National Grid Affiliate</th>
<th>IA Customer (Facility Description)</th>
<th>Schedule 21 Designation</th>
<th>Date Filed</th>
<th>Date Accepted</th>
</tr>
</thead>
<tbody>
<tr>
<td>ER13-1657</td>
<td>NEP</td>
<td>Wheelabrator Saugus Inc</td>
<td>21-NEP: IA-NEP-38-01</td>
<td>Jun 11</td>
<td>Jul 9</td>
</tr>
<tr>
<td>ER13-1656</td>
<td>Narragan</td>
<td>Blackstone Hydro</td>
<td>21-NEP: IA-NEP-44-01</td>
<td>Jun 11</td>
<td>Jul 9</td>
</tr>
<tr>
<td>ER13-1618</td>
<td>Narragan</td>
<td>Thundermist (1.15 MW hydro, Woonsocket, RI)</td>
<td>21-NEP: IA-NECO-39-01</td>
<td>May 31</td>
<td>Jun 28</td>
</tr>
<tr>
<td>ER13-1475</td>
<td>MECO</td>
<td>Highland (Attleboro Landfill)</td>
<td>21-NEP: IA-MECO-35-01</td>
<td>May 10</td>
<td>Jul 5</td>
</tr>
<tr>
<td>ER13-1425</td>
<td>MECO</td>
<td>Brockton (&lt;1 MW photovoltaic)</td>
<td>21-NEP: IA-MECO-29-01</td>
<td>May 3</td>
<td>Jun 28</td>
</tr>
</tbody>
</table>

If there are questions on these matters, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Cost Allocation Agreement NGrid/NSTAR (Line D21 Upgrades) (ER13-1557)**

  On July 18, the FERC accepted a Cost Allocation Agreement between NSTAR and NEP, designated as Service Agreement No. CRA-NEP-05, that covers the allocation of costs for reliability upgrades to Line D21 from NEP’s Bell Rock Road Station to NSTAR Electric’s High Hill Station in southeast Massachusetts. On June 28, NEP supplemented its May 24 filing noting that (i) the project estimate is $5.5 million for the National Grid side of the line and $1.53 million for the NSTAR Electric portion of the line; (ii) construction has been completed; and (iii) no charges have been or will be collected under the Line D21 Upgrades Agreement until it is accepted for filing. The Agreement was accepted effective April 30, 2013, as requested. Unless the July 18 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 Waiver Permitting 2 OATTs Post-MPS Merger (ER13-1125)**

  On July 18, the FERC the FERC waived its regulations to permit Bangor Hydro to maintain two OATTs (one for the central Maine transmission lines its currently owns, and one for the northern Maine lines

that it will own upon consummation of its merger with MPS). If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **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”, 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).

- **FERC Enforcement Action: Show Cause Order – Richard H. Silkman (IN12-13)**

  As previously reported, the Commission issued an order, on July 17, 2012, directing Dr. Silkman to show cause why (i) he should not be found to have violated the FERC’s prohibition against Electric Energy Market Manipulation by engaging in fraud in the ISO’s Day-Ahead Load Response Program (“DALRP”); and, as a result, (ii) he should not be assessed a $1.25 million civil penalty. OE Staff alleges that, from approximately July 2007 through February 2008, Dr. Silkman advised an industrial load response participant in Rumford, Maine to engage in a fraudulent practice to collect payments in the DALRP. Specifically, Staff alleges that Dr. Silkman advised the participant to curtail on-site generation during DALRP program hours when it enrolled in the DALRP, which Staff believes artificially inflated the participant’s baseline load and misrepresented the participant’s load profile. Staff also alleges that Dr. Silkman advised and assisted the participant to ensure that its baseline did not appreciably change. The participant was paid for the difference between its inflated baseline load and its normal operational load as a “load reduction” even though no load reduction actually occurred.

  On September 14, Dr. Silkman answered and opposed the Show Cause Order. On September 21, FERC Staff filed an unopposed motion for a 30-day extension of time, to November 13, 2012, to reply to the Silkman answer. That request was granted on September 26, and Staff’s reply was filed on November 13, 2012. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **FERC Enforcement Action: Show Cause Order – Competitive Energy Services (“CES”) (IN12-12)**

  As previously reported, the Commission issued an order, on July 17 2012, directing CES to show cause why (i) it should not be found to have violated the FERC’s prohibition against Electric Energy Market Manipulation by engaging in fraud in the ISO’s DALRP; and, as a result, (ii) it should not be assessed a $7.5 million civil penalty and required to disgorge $166,841 of payments received as a result of participation in the


101 18 CFR § 1c.2 (2011).

102 Richard Silkman, 140 FERC ¶ 61,033 (2012).
As previously reported, OE Staff alleges that, from approximately July 2007 through February 2008, CES advised an industrial load response participant in Rumford, Maine to engage in a fraudulent practice to collect payments in the DALRP. Specifically, staff alleges that CES advised the participant to curtail on-site generation during DALRP program hours when it enrolled in the DALRP, which Staff believes artificially inflated the participant’s baseline load and misrepresented the participant’s load profile. Staff also alleges that CES advised and assisted the participant to ensure that its baseline did not appreciably change. The participant was paid for the difference between its inflated baseline load and its normal operational load as a “load reduction” even though no load reduction actually occurred.

On September 14, CES answered and opposed the Show Cause Order. On September 21, FERC Staff filed an unopposed motion for a 30-day extension of time, to November 13, 2012, to reply to the CES answer. That request was granted on September 26, and Staff’s reply was filed on November 13, 2012. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **FERC Enforcement Action: Show Cause Order – Lincoln Paper & Tissue (“LP&T”) (IN12-10)**

  The Commission issued an order, on July 17 2012, directing LP&T to show cause why (i) it should not be found to have violated the FERC’s prohibition against Electric Energy Market Manipulation by engaging in fraud in the ISO’s DALRP; and, as a result, (ii) it should not be assessed a $4.4 million civil penalty and required to disgorge just under $380,000 of payments received as a result of participation in the DALRP (plus interest). As previously reported, OE Staff alleges that, from approximately July 2007 through February 2008, LP&T engaged in a fraudulent practice to collect payments in the DALRP by intentionally curtailing on-site generation during DALRP program hours when it enrolled in the DALRP. Staff believes that this practice artificially inflated LP&T’s baseline load and misrepresented its load profile. Staff also alleges that LP&T took actions to ensure that its baseline did not appreciably change for over six months. LP&T was paid for the difference between its inflated baseline load and its normal operational load as a “load reduction” even though no load reduction actually occurred. On August 14, Lincoln elected, pursuant to Ordering Paragraph (D), an immediate penalty assessment by the FERC, if the FERC finds a violation, which a United States district court would be authorized to review de novo.

  On September 14, LP&T answered and opposed the Show Cause Order. On September 21, FERC Staff filed an unopposed motion for a 30-day extension of time, to November 13, 2012, to reply to the LP&T answer. That request was granted on September 26, and Staff’s reply was filed on November 13, 2012. On November 28, 2012, LP&T filed an answer to FERC Staff’s November 13 reply, with FERC Staff opposing that answer on November 30. On January 10, 2013, LP&T filed supplemental information suggesting that the FERC’s decision in the recent Energy Spectrum case could not be reconciled with Enforcement Staff’s position in this case and requested that the FERC “reject any finding of manipulation against Lincoln and terminate this proceeding.” On January 25, FERC Staff objected to the January 10 LP&T filing, both procedurally and substantively. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **FERC Enforcement Action: Barclays Bank et al. (IN08-8)**

  On July 16, 2013, the FERC issued an order finding Barclays Bank PLC (“Barclays”), Daniel Brin, Scott Connelly, Karen Levine, and Ryan Smith (“Individual Traders”, and collectively with Barclays, “Respondents”) violated the FERC’s Anti-Manipulation Rule by engaging over a two-year period in a deliberate and coordinated strategy of trading physical electricity at an economic loss at four trading points in the Western United States in order to boost its financial positions at those same trading points. FERC found that Respondents’ conduct resulted in an estimated $139 million in financial losses to other market participants with positions settling off of the allegedly manipulated trading points. Accordingly, the FERC assessed a record amount of civil penalties -- $435 million against Barclays (plus disgorgement of $34.9 million, plus interest), $15 million against Connelly, and

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103 Competitive Energy Services, LLC, 140 FERC ¶ 61,032 (2012).
104 Lincoln Paper and Tissue, LLC, 140 FERC ¶ 61,031 (2012).
$1 million against each of Brin, Levine, and Smith. FERC walked through its analysis of why the penalties were well within permitted ranges. The amount disgorged is to be divvied up among the Low Income Home Energy Assistance Program (LIHEAP) of the states of Arizona (19%), California (63%), Oregon and Washington (9% each) for the benefit of their respective electric energy consumers. While the order addresses conduct in the Western markets, the lessons for New England Market Participants are no less relevant -- uneconomic transactions that intentionally impact the price or value of other related transactions are impermissible and will subject those involved, institutions and individuals, to severe penalties. Barclays is expected to challenge the order.

- **Waiver of Transmission Standards of Conduct: Bangor Hydro Request (TS11-5)**
  
  Bangor Hydro’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.
  
  Bangor Hydro requested a limited waiver from the FERC’s Standards of Conduct requirements, 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.

- **Waiver of Transmission Standards of Conduct: Green Mountain Power Request (TS04-277)**
  
  As previously reported, Green Mountain Power requested on July 27, 2012, a continued waiver of the FERC’s Standards of Conduct requirements notwithstanding the material change in facts (its merger with CVPS) upon which the FERC relied in granting Green Mountain a waiver of those requirements. Green Mountain stated that it continues to satisfy the FERC’s waiver standards because its control over transmission facilities is limited to small, discrete, stand-alone transmission facilities that are not part of the high voltage grid and are not operated by the ISO and there was no material change in these facts as a result of its merger with CVPS. A notice of this filing was finally issued on January 17, 2013, with comments due on or before February 7, 2013. No comments were submitted. However, on February 8, Green Mountain requested that the FERC defer action on this matter until after the submission and review of a supplemental filing that Green Mountain indicated would be filed “in the near future”. That supplemental filing was submitted on May 2, 2013, and comments on that filing were due June 3, 2013. Comments supporting Green Mountain’s request were filed June 2 by the Vermont Department of Public Service and June 3 by Vermont Senators Leahy and Sanders, and Representative Welch. This matter is pending before the FERC.

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**XII. Misc. - Administrative & Rulemaking Proceedings**

- **RTO/ISO Centralized Capacity Markets (AD13-7)**
  
  On July 19, the FERC issued a supplemental notice of its September 25, 2013 technical conference on centralized capacity markets. As previously reported and announced, the purpose of the technical conference is to consider how current capacity market rules and structures are supporting the procurement and retention

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107 See 18 C.F.R. § 358 (2011) et seq.
of resources necessary to meet future reliability and operational needs. The FERC noted that the technical conference will provide 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 will focus on the goals and objectives of existing centralized capacity markets (e.g., resource adequacy, long-term price signals, fixed-cost recovery, etc.) and examine how specific design elements are accomplishing existing and emerging goals and objectives. The supplemental notice included a preliminary agenda. Those interested in speaking at the technical conference should notify the FERC by August 9, 2013. Those interested in attending the technical conference are encouraged to register. Link to speaker and attendee registration, as well as other technical conference information is available at:


- **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.

- **Increasing Market and Planning Efficiency Through Improved Software (AD10-12)**
  The FERC held its fourth annual technical conference to discuss opportunities for increasing Real-Time and Day-Ahead market efficiency through improved software June 24-26, 2013, which sadly conflicted with the Participants Committee’s Summer Meeting. This conference was intended to build on the discussions initiated in the FERC’s June 2010, 2011, and 2012 technical conferences. This year, FERC staff facilitated discussions to explore research and steps needed to implement approaches to market modeling which appear to have significant promise for potential efficiency improvements in stochastic modeling, optimal transmission switching, AC optimal power flow modeling, and the use of active and dynamic transmission ratings. Speaker materials from the 3-day conference were posted July 10-11 in the FERC’s eLibrary. Post-technical conference comments will be accepted, with a deadline of July 31, 2013.

- **NOPR: Revisions to Pro Forma SGIA and SGIP (RM13-2)**
  On January 17, 2013, the FERC issued a NOPR\(^\text{108}\) proposing to revise the *pro forma* Small Generator Interconnection Procedures (“SGIP”) and *pro forma* Small Generator Interconnection Agreement (“SGIA”) originally set forth in Order 2006 in order to ensure that the time and cost to process small generator interconnect requests will be just and reasonable and not unduly discriminatory. Specifically, the NOPR proposed modifications to the SGIP 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

\(^{108}\) *Small Generator Interconnection Agreements and Procedures*, 142 FERC ¶ 61,049 (2013) (“SGIA/SGIP NOPR”).
Small Generating Facility may be interconnected safely and reliably; and (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. The FERC also proposed to clarify or correct certain sections of the pro forma SGIP and SGIA. The FERC indicated that market changes were driving the reevaluation of the SGIP and SGIA. The FERC convened a workshop on Wednesday, March 27, 2013 to discuss certain topics related to the proposals in the NOPR. Those roundtable discussions addressed: fast track process eligibility; pre-application reports; supplemental review screens; and interconnection of storage devices. Speaker materials are available in eLibrary. Comments on the SGIA/SGIP NOPR were due June 3, 2013. Over 30 parties submitted comments, including ISO-NE (both individually and with the ISO/RTO Council), NRECA/EEI/APPA, NARUC, NRG, and UCS. Since the last report, comments were submitted by the DC Office of the People’s Counsel and the California PUC. Reply comments were filed by the Solar Energy Industries Association. This matter is pending before the FERC.

- **Order 784: 3rd-Party Provision of Ancillary Services; New Electric Storage Technology Accounting and Financial Reporting (RM11-24; AD10-13)**

  On July 18, 2013, the FERC issued Order 784, which revises 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 [120 days after publication in the Federal Register]. Compliance filings implementing the changes to OATT Schedule 3 must be submitted on or before [150 days after publication in the Federal Register]. Order 784 will become final and unappealable unless challenged on or before August 19, 2013.

- **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 on December 20, 2012. 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

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111 Order 784 was published in the Fed. Reg. on July [ ], 2013 (Vol. 78, No. [ ]) pp. [ ].

February 26, 2013. 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. 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. The 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, affirmed its basic Order 764 determinations, 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; (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; and (iii) that schedules for firm transmission service will continue to have curtailment priority over schedules for non-firm transmission service. 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 will be considered and voted during discussion agenda item 2A at the August 2, 2013 meeting. 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 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.

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115 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 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.
118 Id. at P 15.
119 Id. at P 19.
120 Id. at P 23.
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 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 are due on or before September 24, 2013.122

- **Order 676-G: Incorporation of WEQ DR and EE M&V Standards (RM05-5)**

  On February 21, 2013, the FERC issued Order 676-G,123 which amends FERC regulations to incorporate by reference the business practice standards adopted by the NAESB Wholesale Electric Quadrant ("WEQ") to categorize various demand response ("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”124 and “represent an incremental improvement to the existing standards that we incorporated by reference in Order No. 676-E.”125 Order 676-G became effective May 6, 2013.126 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, 2013.127 If an RTO/ISO requests waiver of a Standard, it will not be required to comply with the Standard until the FERC acts on its waiver request, and its OATT should specify those Standards for which it has obtained a waiver or has pending a request for waiver.128 New England’s Order 676-G compliance changes were considered and supported at the Summer Meeting.

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124 Id. at P 1.

125 Id. at P 33.


127 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)”.

128 Id. at PP 54-57.
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).

- **NOPR: Gas/Electric Operational Info Sharing (RM13-17)**
  On July 18, 2013, the FERC issued a NOPR proposing to revise 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. Recipients of the non-public, operational information would be subject to a 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 proves 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. Comments on this NOPR are due August 26, 2013.

- **Natural Gas and Electric Market Coordination (AD12-12)**
  As previously reported, the FERC issued, on November 15, 2012, an order directing further conferences and reports in the gas-electric coordination initiative. Based on the issues raised during the regional technical conferences in August, the November 15 Order directed FERC staff to conduct two technical conferences: one focusing on ways to enhance communication between the two industries; and one focusing on how to design the most efficient scheduling systems for both industries. The November 15 Order also required each ISO and RTO to appear before the FERC on May 16, 2013 and October 17, 2013 to detail their efforts and progress in improving coordination between the industries, and to discuss any natural gas transportation concerns that arise during the winter heating season and any fuel-related generator outages during the winter and spring. Finally, to monitor the progress made by the two industries, the order directs FERC staff to report to the FERC on natural gas and electric coordination activities at least once each quarter in 2013 and 2014.

  In accordance with the November 15 Order, FERC staff has held two technical conferences, one on February 13, 2013 to elicit input pertaining to information sharing and communications issues between the natural gas and electric power industries, and one on April 25, 2013 focused on natural gas and electric scheduling, and issues related to whether and how natural gas and electric industry schedules could be harmonized in order to achieve the most efficient scheduling systems for both industries. On May 16, the FERC convened, as planned, representatives from each RTO/ISO who shared experiences from the winter and spring and described progress towards refining existing practices to provide better coordination between the natural gas and electric industries and ensure adequate fuel supplies. Concerns with natural gas transportation that emerged during the winter heating season were addressed and fuel-related generator outages during the winter and spring were identified. Kevin Kirby presented “ISO New England Winter Operational Experiences and Regional Actions”, which, together with the materials of each of the other speakers, is posted in the FERC’s eLibrary. In follow-up to the May 16 presentation, the FERC, on June 6, requested that Mr. Kirby and each of the ISO/RTO presenters respond to a series of questions posed by no later than July 5, 2013. The questions to New England can be found at http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13274467. Each of the ISO/RTOs submitted their reports detailing the discussions that took place at the five regional technical conferences during summer 2012, including the Aug 20, 2012 conference in Boston, is available on the FERC’s eLibrary.

129 Communication of Operational Information Between Natural Gas Pipelines and Electric Transmission Operators, 144 FERC ¶ 61,043 (July 18, 2013) (“Gas/Electric Operational Info Sharing NOPR”).


131 Coordination Between Natural Gas and Elec. Markets, 141 FERC ¶ 61,125 (2012) (“November 15 Order”). FERC Staff’s report detailing the discussions that took place at the five regional technical conferences during summer 2012, including the Aug 20, 2012 conference in Boston, is available on the FERC’s eLibrary.

New England Gas-Electric focus group meetings continue. The last meeting was held on May 29 and the next, after a summer break, is expected to take place either at the end of August or in September. (again, all those interested and who wish to participate directly, if they have not already done so, should let us know so that they can be added to the focus group distribution list).

- **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 has been no gas-related enforcement activity since the last report.

### XIV. State Proceedings & Federal Legislative Proceedings

- **Maine: Lewiston Loop CPCN (MPUC 2011-420)**
  As previously reported, a petition for a CPCN for the Lewiston Loop Project was submitted to the MPUC on November 18, 2011 in Case No. 2011-420. The most recent hearings were held December 6, 2012. CMP submitted oral data requests on December 31, 2012. The briefing schedule in this case was suspended pending the MPUC’s decision in its Transmission Planning Standards case, 2011-494, which was issued in late February. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

### XV. Federal Courts (Appeals of FERC Decisions & Others)

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**
  **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 Case Nos. 11-1486, et al. (EPSA et al. v. FERC) (see Orders 745 and 745-A below). On August 23, 2012, the

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132 FERC ¶ 61,042 (Jan. 19, 2012); 139 FERC ¶ 61,116 (May 17, 2012).
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, 12-1279, 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
  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. The briefing schedule calls for Respondent’s briefs by September 25, Intervenors in Support of Respondent’s Brief, October 16; Reply Briefs, November 15; and Final Briefs, December 13, 2013. 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
  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.

- Orders 745 and 745-A (11-1486 consolidated with 11-1489, 12-1088, 12-1091 and 12-1093)
  Underlying FERC Proceedings: RM10-17-000
  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 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 is scheduled for September 23, 2013.

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132 136 FERC ¶ 61,051 (Jul. 21, 2011); 139 FERC ¶ 61,132 (May 17, 2012).
- Vermont Yankee Complaint (2nd Circuit, 12-707)
  Plaintiffs: Entergy Nuclear Vermont Yankee & Entergy Nuclear Operations
  Defendants: VT Governor, Attorney General, and PSB Members

  On February 24, 2012, Vermont Parties appealed the January 19, 2012 decision of the U.S. District Court for the District of Vermont that, as previously reported, found certain Vermont State Acts were preempted by the Atomic Energy Act and ordered permanent injunctive relief.\textsuperscript{136} Appellant and amicus briefs were filed and oral argument was held on January 14, 2013. This matter is currently pending before the 2nd Circuit.

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