David T. Doot
Secretary

January 30, 2015

VIA ELECTRONIC MAIL

TO: MEMBERS AND ALTERNATES OF THE NEPOOL PARTICIPANTS COMMITTEE

RE: Supplemental Notice of February 6, 2015 NEPOOL Participants Committee Teleconference 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 Participants Committee will be held **on Friday, February 6, 2015, at 10:00 a.m.** for the purposes set forth on the attached agenda which is posted with the meeting materials at http://nepool.com/NPC_2015.php. **Please note that this meeting will be a teleconference meeting, rather than in-person as previously announced.** Because of the successful collaboration with ISO-NE and among the stakeholders at the various Technical Committees, the key matters on which the Participants Committee must act are on the Consent Agenda, allowing members to avoid the time and expense of traveling to an in-person Participants Committee meeting. The dial-in number for the February 6 Participants Committee meeting will be 1-866-803-2146; Passcode: 7169224. If you will be calling in from outside the country, please contact us for an alternate number to participate in the call. For your information, this meeting will be recorded, as are all NEPOOL Participants Committee meetings.

Before the February 6 meeting, we encourage members to review the materials related to the 2015 Business Priorities, which are included with this notice and posted on the ISO and NEPOOL websites. These materials will be presented at the February meeting, with the bulk of that discussion deferred to the March 6 in-person meeting. As appropriate, though, there may be an opportunity during the teleconference for preliminary comments and clarifying questions on those materials.

Respectfully yours,

/s/
David T. Doot, Secretary

FINAL AGENDA

1. To approve the draft minutes of the Participants Committee meeting held on January 9, 2015. Draft minutes for the January 9 meeting marked to show changes from the draft circulated with the initial notice, are included with this supplemental notice and posted at http://nepool.com/NPC_2015.php.

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

3. To receive an ISO Chief Executive Officer Report.

4. To receive an ISO Chief Operating Officer Report.

5. To discuss 2015 Business Priorities. A presentation of the 2015 Work Plan is included with this supplemental notice.

6. To consider, and take action as appropriate, on revisions to Schedule 1 (Scheduling, System Control and Dispatch Service) of the ISO's Self-Funding Tariff (Section IV of the Tariff) to incorporate new OATT Schedule 25, as recommended by the Budget & Finance Subcommittee at its January 22, 2015 meeting. These are companion changes to the ETU process improvements unanimously recommended by each of the Technical Committees, as reflected in Consent Agenda items 2-4. Background materials and a draft resolution related to the Schedule 1 materials are included with this supplemental notice and posted with the meeting materials.

7. 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 posted in advance of the meeting.

8. To receive reports from committees and subcommittees.

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

PRELIMINARY

A meeting of the NEPOOL Participants Committee was held via teleconference beginning at 10:00 a.m. on Friday, January 9, 2015. A quorum determined in accordance with the Second Restated NEPOOL Agreement was present and acting throughout the meeting. Attachment 1 identifies the members, alternates, and temporary alternates who participated in the teleconference meeting.

Mr. Joel Gordon, Chairman, presided and Mr. David Doot, Secretary, recorded. Mr. Gordon welcomed those on the teleconference, including members, alternates and guests, and reviewed appropriate protocol for the teleconference meeting.

APPROVAL OF MINUTES OF DECEMBER 5, 2014

Mr. Gordon referred the Committee to the preliminary minutes of the December 5, 2014 meeting that were circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of the December 5, 2014 meeting were unanimously approved without change.

CONSENT AGENDA

Mr. Gordon referred the Committee to the Consent Agenda that was circulated and posted in advance of the meeting. Following motion duly made and seconded, the Consent Agenda was unanimously approved without discussion or comment.

REPORT OF THE ISO CHIEF EXECUTIVE OFFICER

Mr. van Welie referred the Committee to the summaries of the December 18, 2014 and January 6, 2015 ISO Board and Board Committee meetings, which had been circulated and posted in advance of the meeting. There were no questions or comments on that report.

Mr. van Welie reported that the ISO, NEPOOL Officers, and NECPUC representatives met the prior day to review a draft 2015 Work Plan (Work Plan). He stated that the ISO would refine the draft Work Plan based on feedback it received at that meeting and circulate it for Participants' review late in January and for presentation at the February 6 Participants Committee meeting.

REPORT OF THE ISO CHIEF OPERATING OFFICER

Dr. Vamsi Chadalavada, ISO Chief Operating Officer, reviewed highlights from the January COO report, which ~~was~~had been circulated and posted in advance of the meeting. Focusing on report highlights, which he noted reflected experiences through December 30 (except Daily Net Commitment Period Compensation (NCPC) through December 26), he stated that in December: (i) Energy Market value was $498 million, down $662 million from December 2013; (ii) natural gas prices were 2.6% lower than November 2014 average values; (iii) Real-Time Hub locational marginal prices (LMPs) on average were 6.5% lower than November 2014 LMPs; (iv) average daily (peak hour) Day-Ahead cleared physical Energy, as a percentage of forecasted load, was 99.7% in December 2014, up from 96.7% in November 2014; (v) daily NCPC for December 2014 (through December 26) totaled $12.2 million, up $5.4 million from November 2014 and down $7.9 million from December 2013; (vi) first contingency payments, totaling $11.4 million, were $8.2 million higher than November's; (vii) second contingency payments totaled $43,000, down from the $3 million in November; (viii) voltage support payments totaled $798,000, up $154,000 from November; and (ix) NCPC payments were 2.5% of the total Energy Market value.

He reported that the ISO scheduled for discussion at the January 21 Planning Advisory Committee meeting the 2015 Regional System Plan scope of work. He said that the final 2013

Emissions Report was posted on December 30 and a Distributed Generation Forecast Working Group meeting was scheduled for February 27. He went on to report that the ninth Forward Capacity Auction (FCA9) for the 2018/19 Capacity Commitment Period (CCP) was scheduled to begin on February 2, and that the show of interest window for the tenth Forward Capacity Auction (FCA-10) for the 2019/2020 CCP was scheduled to be open from February 17 through March 3.

Members then asked clarifying questions. Responding to questions concerning NCPC, Dr. Chadalavada explained that the new Energy Market Offer Flexibility (EMOF) Market Rules allowed for negative pricing, and that there were almost 43 hours of negative pricing in Real-Time. As a result, there were higher make-whole payments reflected as NCPC. Also in response to questions, he reported that there was a reduced need in December for supplemental commitments for reliability in the Day-Ahead Market.

Turning next to the 2014/15 Winter Reliability Program, Dr. Chadalavada highlighted the following:

- In the oil component of the program, 81 units were participating in the program, with a total of 3.8 million barrels of oil eligible for compensation after program limits were applied, for a maximum cost exposure to consumers of $68.7 million (when all available oil was added to the amount that could be compensated, a total of nearly 4.4 million barrels of oil was available as of December 1)

- In the liquefied natural gas (LNG) component, 6 units were participating, with a total of 500,000 MMBtu of LNG, for a maximum cost exposure of $1.5 million

- In the demand-side component, 3 assets were participating, with 14 MW that could be provided, for a maximum cost exposure of $75,600

Responding to a prior request to break~~out~~ out Winter Program commissioning costs by year, Dr. Chadalavada reported expected maximum commissioning costs of $3.56 million in 2014/15 and $2.19 million in 2015/2016, for a total of $5.7~~3~~5 million. He said that actual commissioning costs incurred under the Program through January 1, 2015 were $980,000. Providing additional detail, he noted that, of the 6 units participating in the Dual-Fuel Commissioning (DFC) Program, 4 units were to be commissioned for 2014/15 (1,039 MW) and 2 units were to be commissioned for 2015/16 (735 MW), representing a total winter seasonal claimed capability of 1,774 MW. A member requested further breakdown of the expected commissioning costs after the $980,000 already incurred, which Dr. Chadalavada committed to do, if possible, in the February COO report. In response to further questions, Dr. Chadalavada explained that the two units that were not yet commissioned in the DFC Program as of January 1 for Winter 2015/16 were qualified for prorated compensation over two years.

Also in response to a prior request, he reported that 550,401 barrels of Winter Program oil were used in December, with none of the LNG used. He explained in response to a question that this oil was consumed notwithstanding very mild weather because there was no limitation requiring that Winter oil be used solely for reliability; units in the Program could burn oil for whatever reason they chose. He explained, by way of example, that a dual-fuel unit in the Program that had oil and was expecting the next shipment of oil by a date certain was not prevented from using the Program oil. He stated that ~~the~~ ISO dispatch is based on economics and not whether the fuel to be consumed was available under the Program.

Turning to an update on the experiences under the new EMOF provisions, Dr. Chadalavada responded to inquiries about the negative pricing experiences. He reported that the hourly markets continued to function well, with some minor glitches that had not created problems, either from a commitment and dispatch standpoint or from a Participant standpoint, in terms of offers into the system. The number of resources using the additional flexibility allowed in hourly energy offers was increasing, growing from 36-40 units previously using both the intraday offers and the negative pricing, to 51 units. He said that these resources were changing and shaping their offers consistent with what the ISO expected based on the gas trading day. He said that he was pleased to see the functionality being used in the markets, which he indicated helped to improve efficient price formation.

Focusing more specifically on negative pricing, he reported that, in December, there were 20 hours of negative pricing in the Day-Ahead Energy Market and 43 hours of negative pricing in the Real-Time Energy Market, which he attributed to resource owners becoming more familiar with the functioning of the EMOF provisions. He explained generally how prices were being formed behind some constraints, especially in Maine. He explained that, with export constraints, like those in certain pockets of Maine, if the units behind the export constraint do not provide the ISO with any range of dispatchability, congestion behind those constraints would be much higher. To alleviate the congestion, especially in the Day-Ahead Energy Market, the ISO must re-dispatch the system outside of the supply pocket. He reported that, in two instances, prices in the load pocket were between $-300 and $-900, which indicated that the costs of dispatching the system were much greater outside of that pocket. He stated that the size of negative prices would be moderated by increased dispatchability offered by resources into the Day-Ahead Energy Market. He offered to provide additional detail in a follow-up session, which was requested by members.

Members asked clarifying questions. A member asked why on January 2 there were negative prices around $-1,600. Dr. Chadalavada committed the ISO to review that and to report its findings at the February meeting. On a chart reflecting dispatchable versus non-dispatchable generation, a member expressed surprise that dispatchable generation did not increase dramatically with the introduction of the EMOF provisions. Dr. Chadalavada responded that the report on dispatchable versus non-dispatchable generation depended, in part, on the level of loads during the reporting period, and he was uncertain as to whether the relatively light loads in December accounted for the larger percentage of non-dispatchable units providing energy. He said that experiences in January and February would provide additional insights as to whether the EMOF provisions would increase the percentage of dispatchable versus non-dispatchable generation.

A member questioned the accuracy of the chart reflecting weather normalized summer and winter peak loads. Dr. Chadalavada explained that the referenced chart reflected the forecasted actual summer peak, not the weather normalized summer peak. He reported that the 2015 weather normalized summer peak was expected to be 27,970 MW and committed to have the chart updated in the next report.

LITIGATION REPORT

Mr. Doot referred the Committee to the February 3 Litigation Report that had been circulated and posted in advance of the meeting. He highlighted the numerous complaint proceedings that were resulting in many pleadings and requests of the FERC. He reported that the FERC had issued an order accepting the ICR values for the FCA9 CCP. He said that the order reflected the FERC's expectation that the ISO would address the impact of distributed generation forecasts on future ICRs, and that expectation had been discussed during the business planning session the prior day. He reported that Mr. Eric Runge, NEPOOL Counsel, will provide a more complete summary of that order to the Reliability Committee. In response to a member's inquiry, Mr. Doot indicated that NEPOOL Counsel's summary would identify for the Reliability Committee the misinterpretation of NEPOOL's position in the FERC order. Specifically, Mr.

Doot explained that FERC summarized NEPOOL's position as a protest, which it had not been, and one that substantively opposed the ICR because it did not include a reduction to reflect the recent distributed generation forecasts. NEPOOL's pleading explained that NEPOOL did not support the ICR values, and requested that future ICR values account for a distributed generation forecast, but did not otherwise take a substantive position on the ICR values. He said that this distinction would also be conveyed in the order summary.

Members were encouraged to contact NEPOOL Counsel with comments or questions on any of the reported matters.

COMMITTEE REPORTS

For the Transmission Committee, Mr. Jose Rotger reported that the Elective Transmission Upgrade (ETU) reform-related Tariff changes would be voted on January 20. Mr. Ken Dell Orto reported that the next Budget & Finance Subcommittee meeting was scheduled for January 22.

Mr. Doot reported that, at the business planning meeting the day before, the large number of Working Groups, Task Forces, and Subcommittees had been a topic of discussion. He said that ISO and NEPOOL Counsel had committed to work together to identify and assemble the mission statements/charters for the various working groups, task forces and subcommittees, including their reporting structures. The plan was for this information to be assembled and reported so that everyone could gain a better understanding of the stakeholder efforts in New England.

OTHER BUSINESS

Mr. Doot reported that the next Participants Committee meeting was scheduled for February 6, 2015 at The Colonnade Hotel, with the discounted room block open for reservations until February 3. He encouraged all members to look for the 2015 Work Plan at the end of January and to review that Plan for a better understanding of the planned priorities and work effort and for discussion at the February meeting.

There being no further business, the meeting adjourned at 10:45 a.m.

Respectfully submitted,

____

David T. Doot, Secretary

MEMBERS AND ALTERNATES PARTICIPATING IN
JANUARY 9, 2015 PARTICIPANTS COMMITTEE TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
American PowerNet Management	Supplier			Mary H. Smith
Ashburnham Municipal Light Plant	Publicly Owned		Gary Will	
Associated Industries of Massachusetts	End User			Roger Borghesani
Boylston Municipal Light Department	Publicly Owned		Gary Will	
BP Energy Company	Supplier			Nancy Chafetz
Brookfield Energy Marketing/Cross-Sound Cable	Supplier	Aleksandar Mitreski		
Calpine Energy Services, LP	Supplier	John Flumerfelt	Brett Kruse	
Central Maine Power Company	Transmission	Eric N. Stinneford		
Chicopee Municipal Lighting Plant	Publicly Owned		Gary Will	
Conn. Municipal Electric Energy Cooperative	Publicly Owned	Brian Forshaw		
Conservation Services Group	AR			Doug Hurley
Consolidated Edison Energy, Inc.	Supplier	Jeff Dannels		
Cross Sound Cable	Supplier	Jose Rotger		
Dominion Energy Marketing, Inc.	Generation	Ronald Hart		
DTE Energy Trading, Inc.	Supplier			Nancy Chafetz
Dynegy Marketing and Trade	Supplier			William Fowler
Emera Maine	Transmission	Jeffrey A. Jones	Stacy Dimou	
Energy America, LLC	Supplier			Nancy Chafetz
EnerNOC, Inc.	AR	Herb Healy		
Entergy Nuclear Power Marketing LLC	Generation		Ken Dell Orto	
EquiPower Resources Management, LLC	Generation		William Fowler	
Essential Power, LLC	Generation	M.Q. Riding	William Fowler	
Exelon Generation Company	Supplier		William Fowler	
First Wind Energy Marketing	AR	John Keene		
Galt Power, Inc.	Supplier	Nancy Chafetz		
GDF SUEZ Energy Marketing NA, Inc.	Generation	Thomas Kaslow		
Generation Group Member	Generation		Abby Krich	
Granite Ridge Energy, LLC	Supplier		William Fowler	
Groton Electric Light Department	Publicly Owned		Gary Will	
H.Q. Energy Services (U.S.) Inc.	Supplier	Louis Guilbault	Robert Stein	
Harvard Dedicated Energy Ltd	End User	Mary H. Smith		
High Liner Foods (USA)	End User		William P. Short III	
Holden Municipal Light Department	Publicly Owned		Gary Will	
Holyoke Gas & Electric Department	Publicly Owned			Gary Will
Hull Municipal Lighting Plant	Publicly Owned		Gary Will	
Industrial Energy Consumer Group	End User	Donald J. Sipe		
Ipswich Municipal Light Department	Publicly Owned		Gary Will	
Littleton (NH) Water & Light Department	Publicly Owned		Craig Kieny	
Long Island Lighting Company (LIPA)	Supplier	William Killgoar		
Maine Skiing, Inc.	End User	Donald J. Sipe		
Mansfield Municipal Electric Department	Publicly Owned		Gary Will	
Marblehead Municipal Light Department	Publicly Owned		Gary Will	
Massachusetts Attorney General's Office	End User	Fred Plett	Christina Belew	
Mass. Municipal Wholesale Electric Company	Publicly Owned	Gary Will		
Middleborough Gas and Electric Department	Publicly Owned		Gary Will	
New England Power Company	Transmission	Tim Brennan	Tim Martin	
New Hampshire Electric Cooperative, Inc.	Publicly Owned	Steve Kaminski		
New Hampshire Office of Consumer Advocate	End User	Paul R. Peterson	Sarah Jackson	

**MEMBERS AND ALTERNATES PARTICIPATING IN
JANUARY 9, 2015 PARTICIPANTS COMMITTEE TELECONFERENCE MEETING**

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Noble Americas Gas & Power Corp.	Supplier		Becky Merola	
NRG Power Marketing, Inc.	Generation	Dave Cavanaugh		
NU/NSTAR	Transmission	James Daly	Calvin A. Bowie	Joe Staszowski
Paxton Municipal Light Department	Publicly Owned		Gary Will	
Peabody Municipal Light Plant	Publicly Owned		Gary Will	
PowerOptions, Inc.	End User	Cindy Arcate		
Princeton Municipal Light Department	Publicly Owned		Gary Will	
PSEG Energy Resources & Trade LLC	Supplier	Joel Gordon		
Repsol Energy North America	Gas Industry Part.	Sam Moreton		
Russell Municipal Light Dept	Publicly Owned		Gary Will	
Shrewsbury Electric & Cable Operations	Publicly Owned		Gary Will	
Small LR Group Member	AR	Doug Hurley		
Small RG Group Member	AR	Erik Abend		
South Hadley Electric Light Department	Publicly Owned		Gary Will	
Sterling Municipal Electric Light Department	Publicly Owned		Gary Will	
Tangent Energy Solutions, Inc.	Provisional Group	Brad Swalwell		
Templeton Municipal Lighting Plant	Publicly Owned		Gary Will	
The Energy Consortium	End User	Roger Borghesani	Mary Smith	
The United Illuminating Company	Transmission	Christian Bilcheck		
Utility Services Inc.	End User			Paul Peterson
Vermont Electric Cooperative	Publicly Owned	Craig Kieny		
Vermont Electric Power Company, Inc.	Transmission	Francis Ettori		
Vermont Energy Investment Corporation	AR		Doug Hurley	
Vermont Public Power Supply Authority	Publicly Owned	David Mullett		
Vitol Inc.	Supplier	Joseph Wadsworth		
Wakefield Municipal Gas and Light Department	Publicly Owned		Gary Will	
West Boylston Municipal Lighting Plant	Publicly Owned		Gary Will	
Westfield Gas & Electric Department	Publicly Owned		Gary Will	

CONSENT AGENDA

From the notice of actions of the January 13-14, 2015 ***Markets Committee***[1] meeting, dated January 14, 2015, which has been previously circulated:

1. Market Rule 1 Revisions (Forward Reserve Obligation Charge Enhancements)

Support revisions to Market Rule 1 to account for certain complexities related to cascading and locational reserve accounting differences and their impact on the Forward Reserve Obligation Charge, as recommended by the Markets Committee at its January 13-14, 2015 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.

From the notice of actions of the January 20, 2015 ***Transmission Committee***[2] meeting, dated January 20, 2015, which has been previously circulated:

2. Revisions to ISO Tariff §§ I and II and TOA (ETU Process Improvements)

Support revisions to Sections I and II of the ISO Tariff and the Transmission Operating Agreement (TOA) to support improvements to the Elective Transmission Upgrade (ETU) process, as recommended by the Transmission Committee at its January 20, 2015 meeting, with such further non-substantive changes as the Chair and Vice-Chair of the Transmission Committee may approve.

The motion to recommend Participants Committee support was approved unanimously, with two abstentions (Generation Sector - 1; Supplier Sector - 1).

From the notice of actions of the January 20, 2015 ***Reliability Committee***[3] meeting, dated January 20, 2015, which has been previously circulated:

3. Revisions to MR 1 § III.12 (ETU Process Conforming Changes)**

Support ETU process conforming changes to Market Rule 1, Section III.12, as recommended by the Reliability Committee at its January 20, 2015 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, with one abstention in the Supplier Sector.

****Due to an administrative oversight, the unanimous, January 20, 2015 recommendation of the Reliability Committee (RC) with respect to the ETU process conforming changes, as described in the RC's January 20 notice of actions, was incorrectly identified on the prior version of the Consent Agenda as changes to Sections I and II of the ISO Tariff and the TOA, rather than as changes to Section III.12 of the Tariff. This item has been revised to correct that description.**

[1] Markets Committee Notices of Actions are posted on the ISO website at: http://www.iso-ne.com/committees/markets/markets-committee.

[2] Transmission Committee Notices of Actions are posted on the ISO website at: http://www.iso-ne.com/committees/transmission/transmission-committee.

[3] Reliability Committee Notices of Actions are posted on the ISO website at: http://www.iso-ne.com/committees/reliability/reliability-committee.

CONSENT AGENDA (cont.)

From the notice of actions of the January 22, 2015 ***Markets Committee***[1] meeting, dated January 22, 2015, which has been previously circulated:

4. <u>Revisions to MR 1 and ISO Tariff § I.2.2 (ETU Process Conforming Changes to FCM Rules)</u>

Support revisions to the Market Rule 1 FCM rules and related provisions in ISO Tariff Section I.2.2 to support the ETU process improvements recommended by the Transmission Committee, as recommended by the Markets Committee at its January 22, 2015 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, with one abstention in the Supplier Sector.

Summary of ISO New England Board and Committee Meetings

February 6, 2015 Participants Committee Meeting

Since the last Participants Committee meeting, the System Planning and Reliability Committee, the Markets Committee, the Audit and Finance Committee, the Compensation and Human Resources Committee, and the Board of Directors met in Holyoke on January 15.

The System Planning and Reliability Committee received an overview of the proposed scope of work for the 2015 Regional System Plan, which includes a new discussion on photovoltaic generation, and an expanded discussion regarding the interrelationship of natural gas with the electric system and associated planning issues. The Committee received an update regarding compliance with standards issued by the North American Energy Reliability Corporation. The Committee also discussed the standards development process, new modeling standards requiring more precise data from generators, and further plans to streamline compliance monitoring tasks. Next, the Committee received an update regarding the Greater Boston Reliability Project. The Committee reviewed background information regarding the development of the Project and discussed the Company's review of solutions. Finally, the Committee held an executive session to assess achievement of 2014 corporate goals.

The Markets Committee received reports from the internal and external market monitors, and discussed the implementation of the energy market offer flexibility rule changes and the effect on frequency of mitigation events. The Committee also discussed factors contributing to minimum generation conditions. Next, the Committee was provided with an update on preparations for the Forward Capacity Auction to be held in early February. The Committee then completed its annual review of the scope and coverage of Internal and External Market Monitoring Units for adequacy, and reviewed the External Market Monitor's role in evaluating the mitigation process. There was a general discussion regarding the purpose of the annual reports produced by each market monitor, and the reporting on the relative performance of the New England market compared to other regions with competitive wholesale electricity markets. During executive session, the Committee assessed achievement of 2014 corporate goals.

The Audit and Finance Committee reviewed its scope of responsibilities and meeting schedule for 2015. Next, the Committee met with representatives of AON, the Company's insurance broker, and reviewed insurance coverage for cyber security incidents and directors' and officers' liability. The Committee requested management to provide more information regarding potential losses in the event of a network business interruption or a breach. The Committee was updated regarding 2014 and 2015 budget performance, and then conducted its annual review of the structure of the Company's compliance and risk management programs. The Committee reviewed the components of the risk management program, related activities, and potential risks covered. The Committee also received an outline of the various components of the Company's compliance program, including responsibilities of and coordination among departments. Next, the Committee discussed proposed revisions to its charter to bring cyber security within the scope of the Committee's oversight, and agreed to recommend the changes for approval by the Board of Directors. During executive session, the Committee assessed achievement of 2014 corporate goals.

The Compensation and Human Resources Committee met in executive session to review a variety of compensation-related matters. The Committee also reviewed the goal achievement process and the various metrics for measuring achievement. Finally, the Committee held an initial discussion regarding corporate performance for 2014 and officer compensation for 2015.

The Board of Directors approved the corporate goals for 2015. The Board also discussed cyber security issues.

NEPOOL Participants Committee Report

February 2015

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

- Highlights — Page 3
  - 2014/15 Winter Reliability Program Update — Page 9
- Winter Storm Juno — Page 12
- System Operations — Page 22
- Market Operations — Page 33
- Back-Up Detail — Page 50
  - Load Response — Page 51
  - New Generation — Page 53
  - Forward Capacity Market — Page 60
  - Reliability Costs - Net Commitment Period Compensation (NCPC) Operating Costs — Page 65
  - Regional System Plan (RSP) & Interregional Planning — Page 96
  - Operable Capacity Analysis – Winter 2014/2015 — Page 120
  - Operable Capacity Analysis – Spring 2015 — Page 127
  - Operable Capacity Analysis – Appendix — Page 134

Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Energy Market Value was $804M over the period, up $300M from December 2014, but down $1.4B from January 2014
  - January natural gas prices over the period were 51% higher than December 2014 average values
  - Average RT Hub Locational Marginal Prices (LMPs) over the period were 47% higher than December 2014 averages
  - Average January 2015 natural gas prices and RT Hub LMPs over the period were down 63% and 61%, respectively, from January 2014 averages
- Average daily (peak hour) DA cleared physical energy* as percent of forecasted load was 100.2% during January, up from 99.7% during December

All data through January 28 (except NCPC which is through January 26)

*DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market

Underlying natural gas data furnished by: ICE Global markets in clear view

Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - January payments totaled $8M, down $5.7M from December and down $65.3M from January 2014
  - First Contingency payments totaled $6.7M, down $6.2M from December
    - $6.6M paid to internal resources, down $3.9M from December
      - $1.7M charged to DALO, $4.9M to RT Deviations
    - $117K paid to resources at external locations, down $2.3M from December
      - $96K charged to DALO at external locations, $21K to RT Deviations
  - Second Contingency payments totaled $558K, up $413K from the December total of $146K
  - Voltage payments were $687K, down $47K from December
  - Distribution payments totaled $1K, unchanged from December
  - NCPC payments over the period as percent of Energy Market value were 1%

Highlights, cont.

- The Planning Advisory Committee provided input on the Regional System Plan 2015 scope of work on January 21 and work is now proceeding
- Distributed Generation Forecast Working Group meeting is scheduled for February 27
- ISO will be working through the NEPOOL Reliability Committee on treatment of behind-the-meter solar PV in the gross load forecast
- FCA 9 Auction was conducted on Feb. 2
- Show-of-Interest window for FCA #10 will be open from February 17 - March 3

Forward Capacity Market (FCM) Highlights

- CCP #4 (2013-2014)
  - Less than 10 MW of resources are non-commercial at this time
- CCP #5 (2014-2015)
  - Approximately 60 MW of resources are non-commercial at this time
- CCP #6 (2015-2016)
  - The window for the third and final reconfiguration auction will be March 2-4
- CCP #7 (2016-2017)
  - Next bilateral transaction window is May 1-7
  - Second reconfiguration auction will be held August 3-5

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP #8 (2017-2018)
  - First bilateral transaction window is April 1-8
- CCP #9 (2018-2019)
  - Auction conducted on February 2
- CCP #10 (2019-2020)
  - Show of Interest window for new resource participation is February 17 - March 3
    - It is anticipated that Elective Transmission Upgrade Projects seeking capacity rights will be able to participate in the qualification process

Highlights, cont.

- The lowest 50/50 and 90/10 Winter Operable Capacity Margin is projected for week beginning February 7th, 2015.
- The lowest 50/50 and 90/10 Spring Operable Capacity Margin is projected for week beginning May 9th, 2015.

2014/15 Winter Reliability Program Update

- Max Program Cost Potential: $70.2M
  - Oil Program
    - By the October 1 deadline, 81 Units submitted intent to provide 4.1 million barrels
    - As of Dec 1:
      - 3.8 million barrels of the initial inventory requirement had been met for a maximum cost exposure of $68.7M
      - 16 program units exceeded initial requirements, representing an additional 0.68 million barrels
  - LNG Program
    - By the Oct 1 deadline, 8 Units submitted intent to provide at least 1.52 Bcf
    - As of Dec 1:
      - Participation of 6 units, representing 500,000 MMBTU, for a total cost of $1.5M
  - DR Program
    - By the Oct. 1 deadline, 3 assets submitted intent to provide 14 MW for a total cost of $75,600 (@$1800/MW-Month)

2014/15 Winter Reliability Program Update, cont.

- Dual Fuel Commissioning (DFC) Program
  - Participation:
    - 6 Units submitted intent to commission Dual Fuel Capability
      - 4 units for 2014/15 (1,039 MW)
      - 2 units for 2015/16 (735 MW)
    - Total winter seasonal claimed capability added is 1,774 MW
  - DFC Activity and related NCPC:
    - Units commissioned (as of Feb 1): 2
    - Total NCPC Commissioning Cap: $5.7M
      - 2014/15: $3.56M
      - 2015/16: $2.19M
    - NCPC incurred (Nov 1, 2014 - Jan 28, 2015): $989K
    - Remaining Commissioning Cap for 2014/15: $1.2M

2014/15 Winter Fuel Burn

- Winter Reliability Program Oil Burns
  - December 2014 - 550,401 BBLs
  - January 2014 - 288,912 BBLs

- Winter Reliability LNG Burns
  - December 2014 - 0 MMBTU
  - January 2015 - 0 MMBTU

WINTER STORM JUNO

Preparations

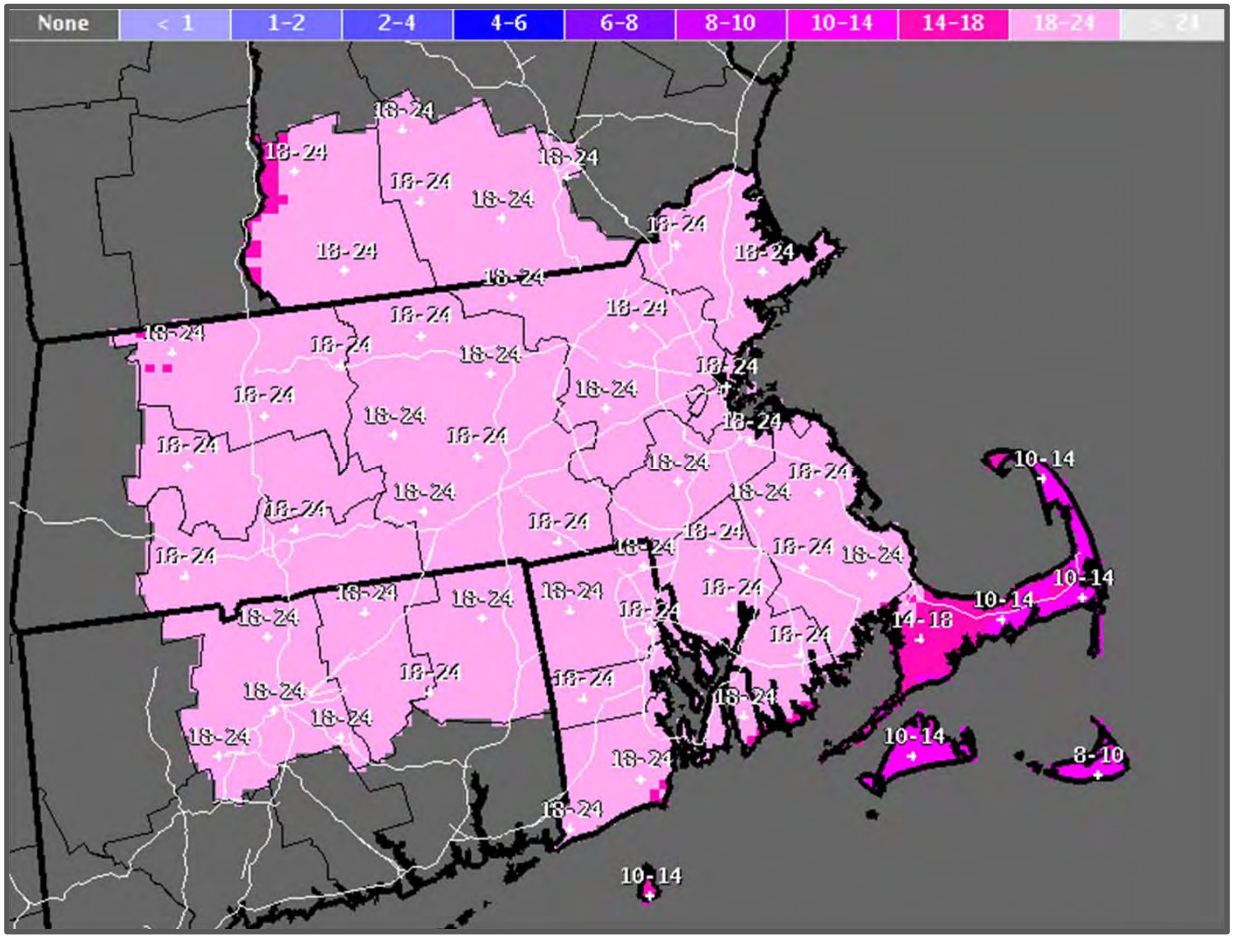
- Communications
  - Weather briefing from NOAA indicating a potential “Top 5” snowfall record with 3 to 4 inches per hour at times and very strong winds.
  - M/LCC 2 Abnormal Conditions Alert (1/26 14:00 to 1/28 12:00)
  - Daily calls with M/LCC Heads
  - Daily calls with NPCC
  - Gas companies and interstate pipeline operators
  - Nuclear Plants
- Additional Staffing
  - System Operations, beginning at 19:00 on Monday (1/26)
    - Additional Security Operator at MCC
    - Additional Supervisor and Senior Operator at BCC
  - Operations Engineering staff on site
  - Market Operations staff on site
  - IT / EMS support staff on site

Preparations, cont.

- Generator Readiness
  - All outages cancelled or postponed where possible
  - Generator readiness verified with all generators > 75 MVA
  - Black Start facilities briefed and verified to have adequate fuel
- Transmission Readiness
  - All outages cancelled or postponed where possible

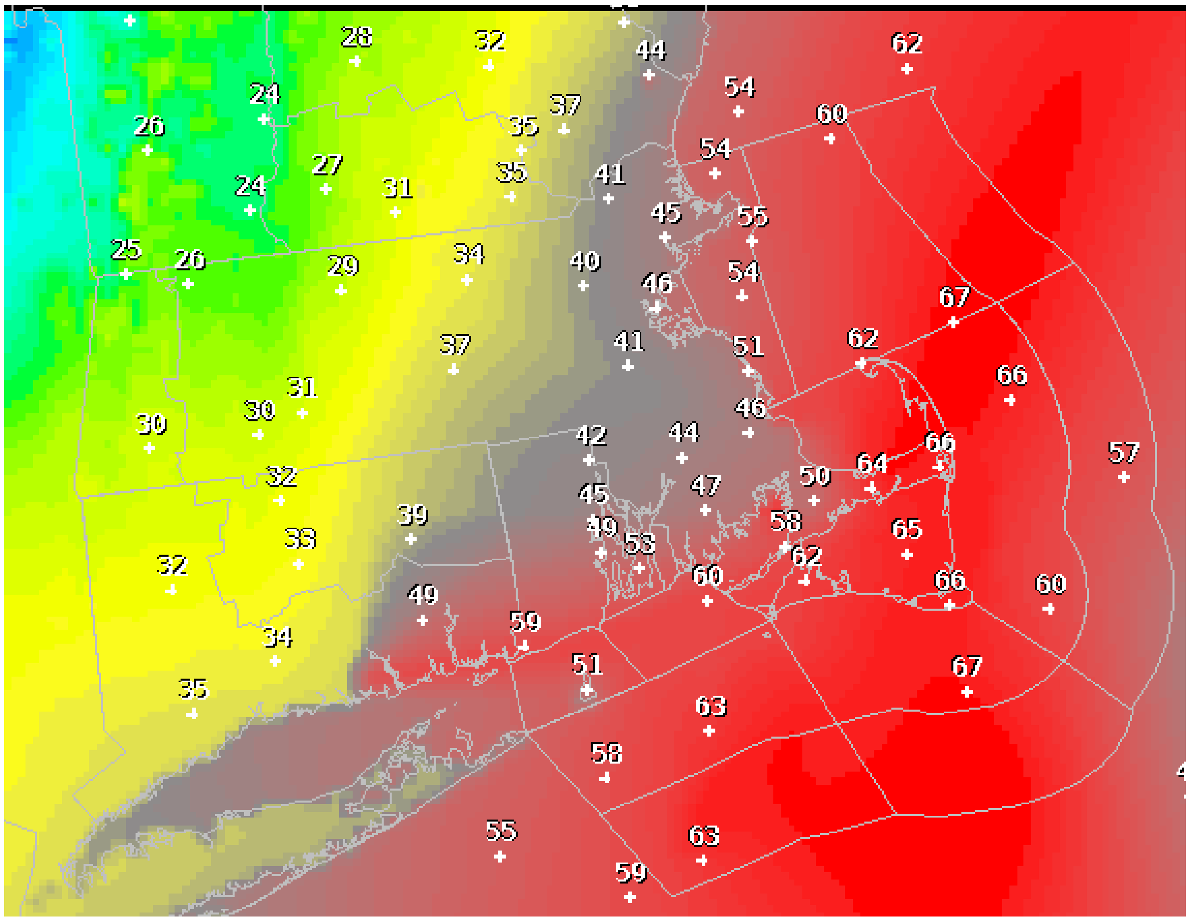
Weather Forecast (NOAA)

- Snowfall Forecast



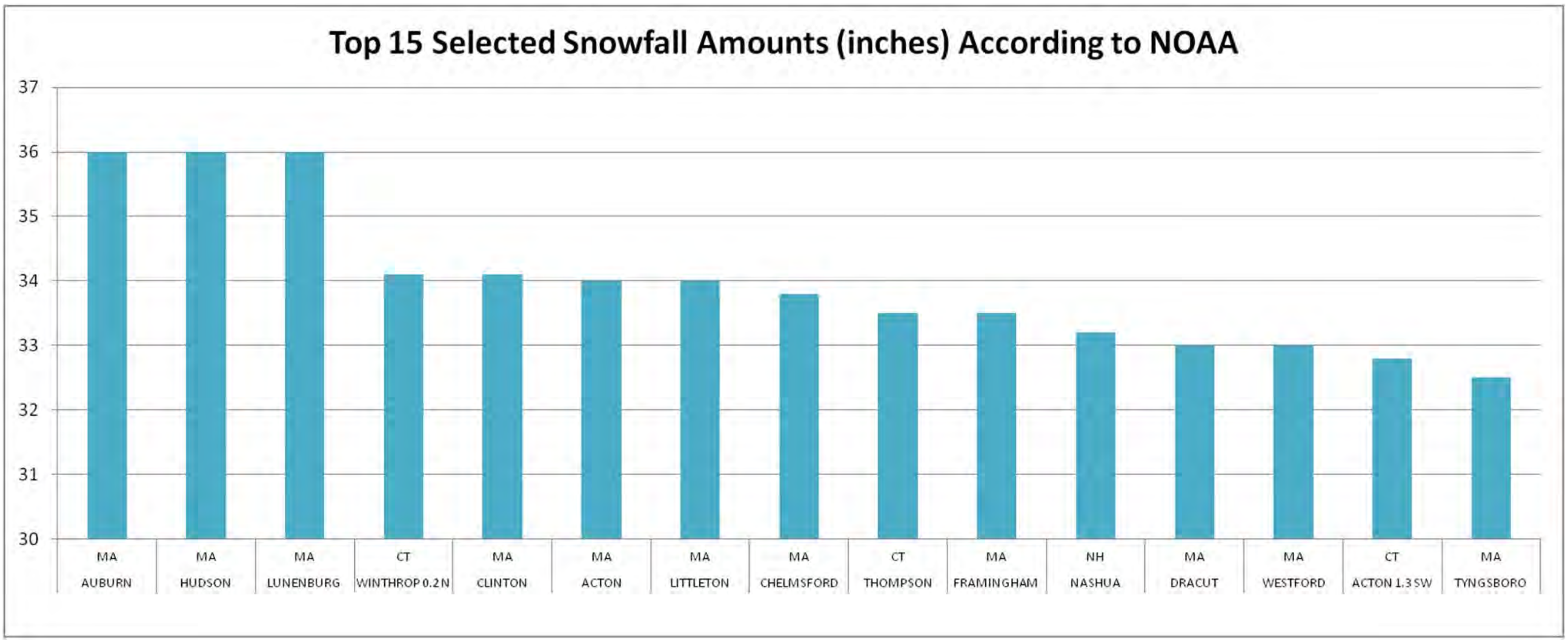
Weather Forecast (NOAA), cont.

- Wind Gust Forecast – 55 to 65 knots



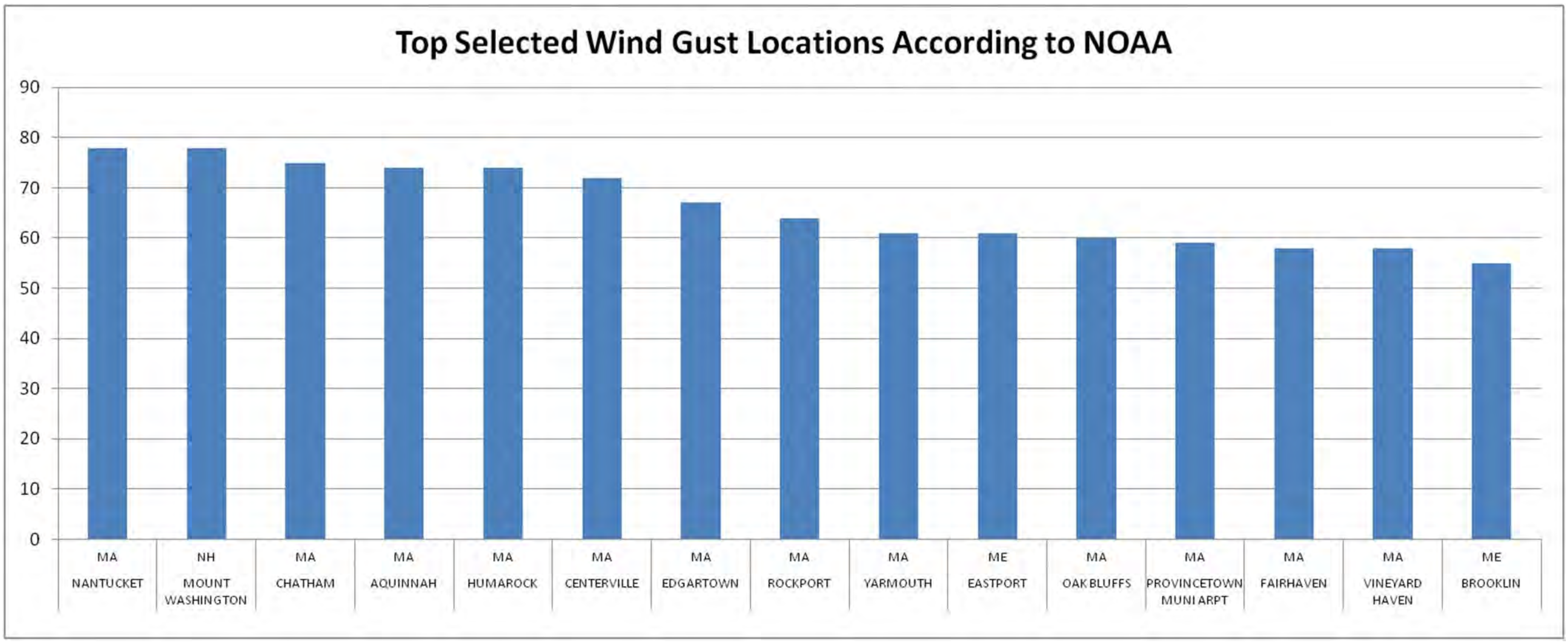
Weather Observations (NOAA)

- Snowfall Observations in New England



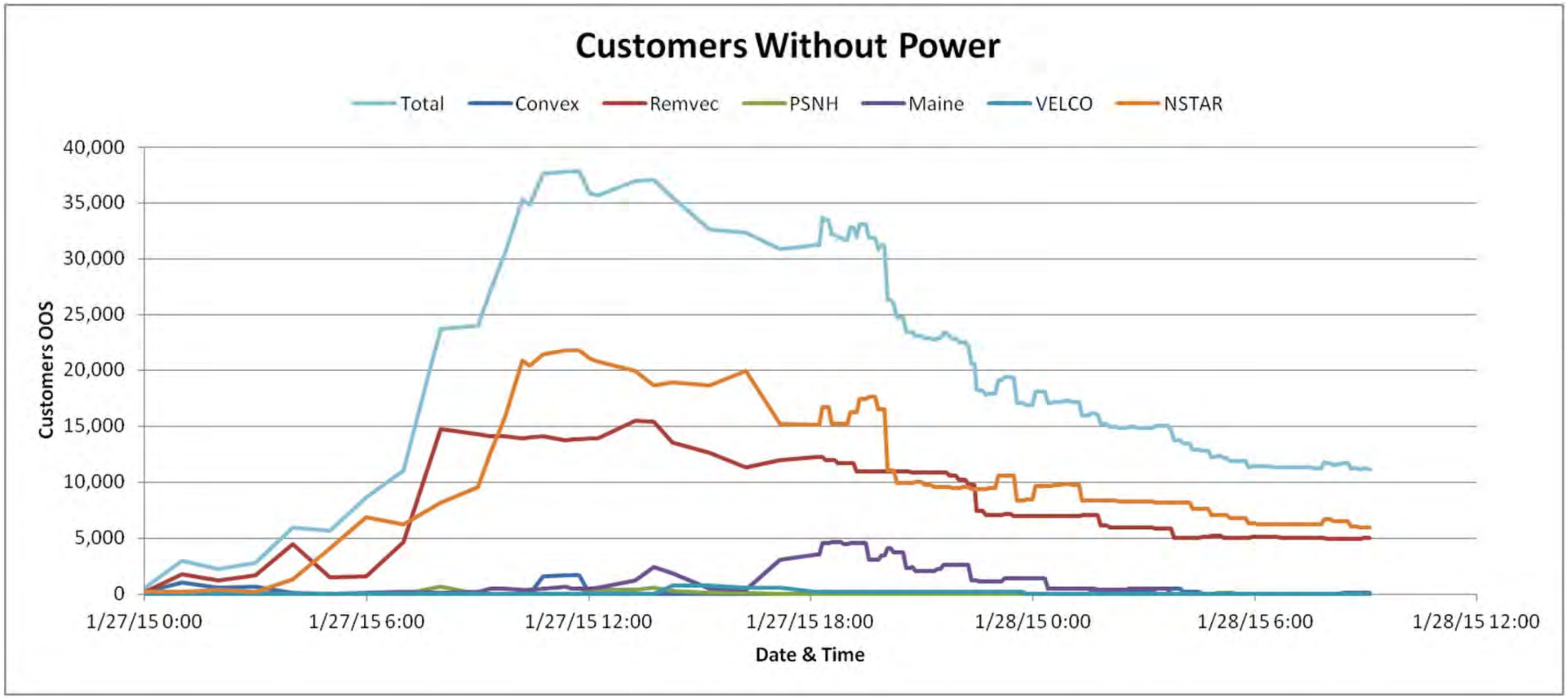
Weather Observations (NOAA), cont.

- Wind Gust Observations in New England



Customer Outages

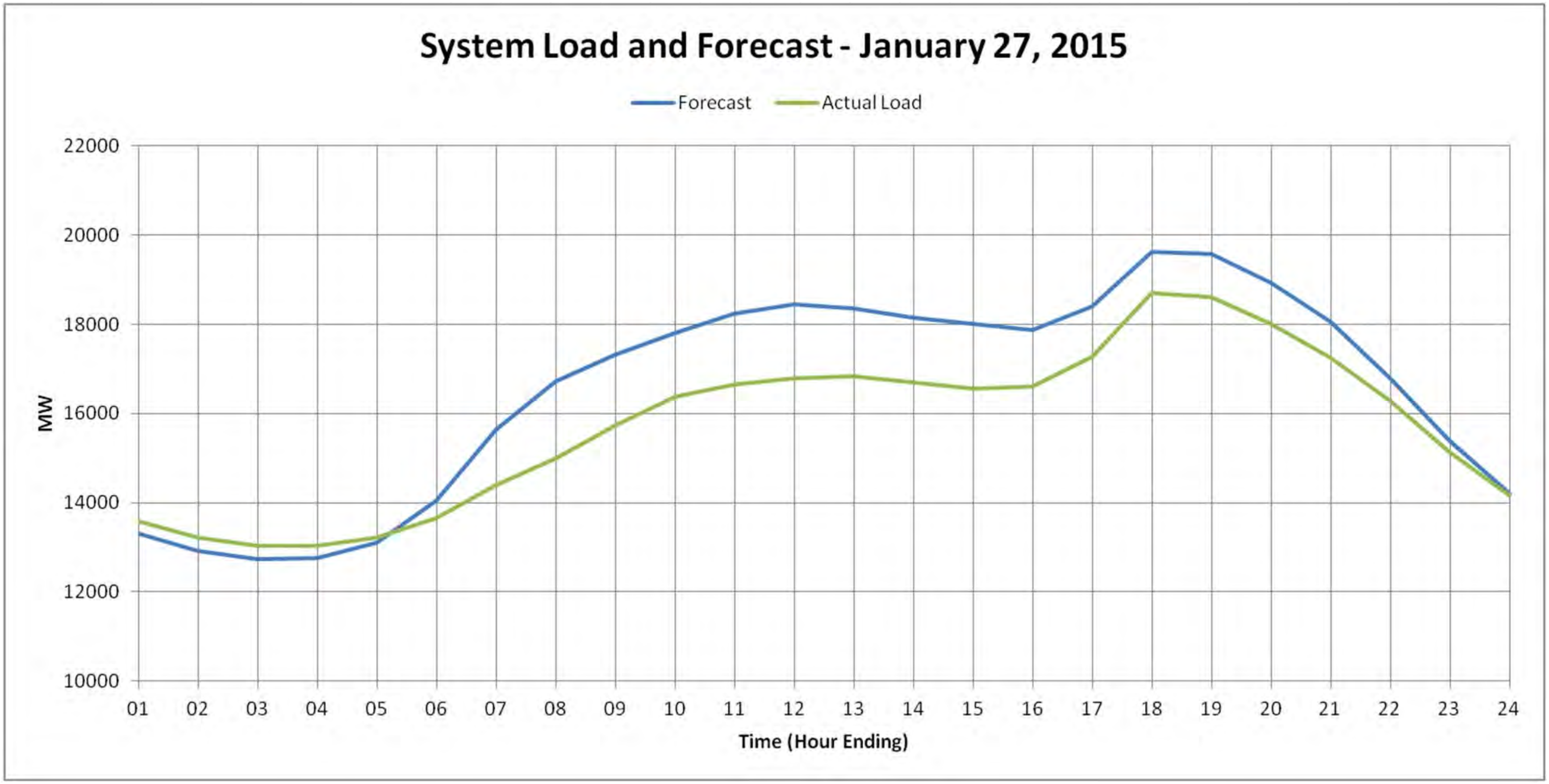
- Outage totals peaked below 40,000 customers



Observations

- Overall, system performed very well
- Storm impact was further east than forecast and expected
- Two 345kV lines tripped and remained out of service early Tuesday morning in SE Mass
- Loss of one nuclear generator
- Minor generator reductions that were recovered throughout the day

System Load


System Load and Forecast - January 27, 2015
Forecast
Actual Load
22000
20000
18000
16000
14000
12000
10000
MW
01
02
03
04
05
06
07
08
09
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Time (Hour Ending)

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature – Below normal (-4.2) Max: 52, Min: -1 Precipitation 3.51" - Below Normal Normal - 3.92" Total Snowfall – 35.54"	Hartford	Temperature – Below normal (-4.1) Max: 48, Min: 0 Precipitation 3.23" - Below Normal Normal – 3.84" Total Snowfall – 21.51"

Peak Load:	20,567 MW	January 08, 2015	18:00

MLCC2: From January 26: 14:00 To January 28: 12:00	**Abnormal Conditions Alert due to Severe Weather Storm Juno**	
OP-4 : None		
NPCC Simultaneous Activation of Reserve Events:		
1/07/15	IESO	945 MW
1/23/15	ISONE	660 MW
1/29/15	NYISO	750 MW

System Operations

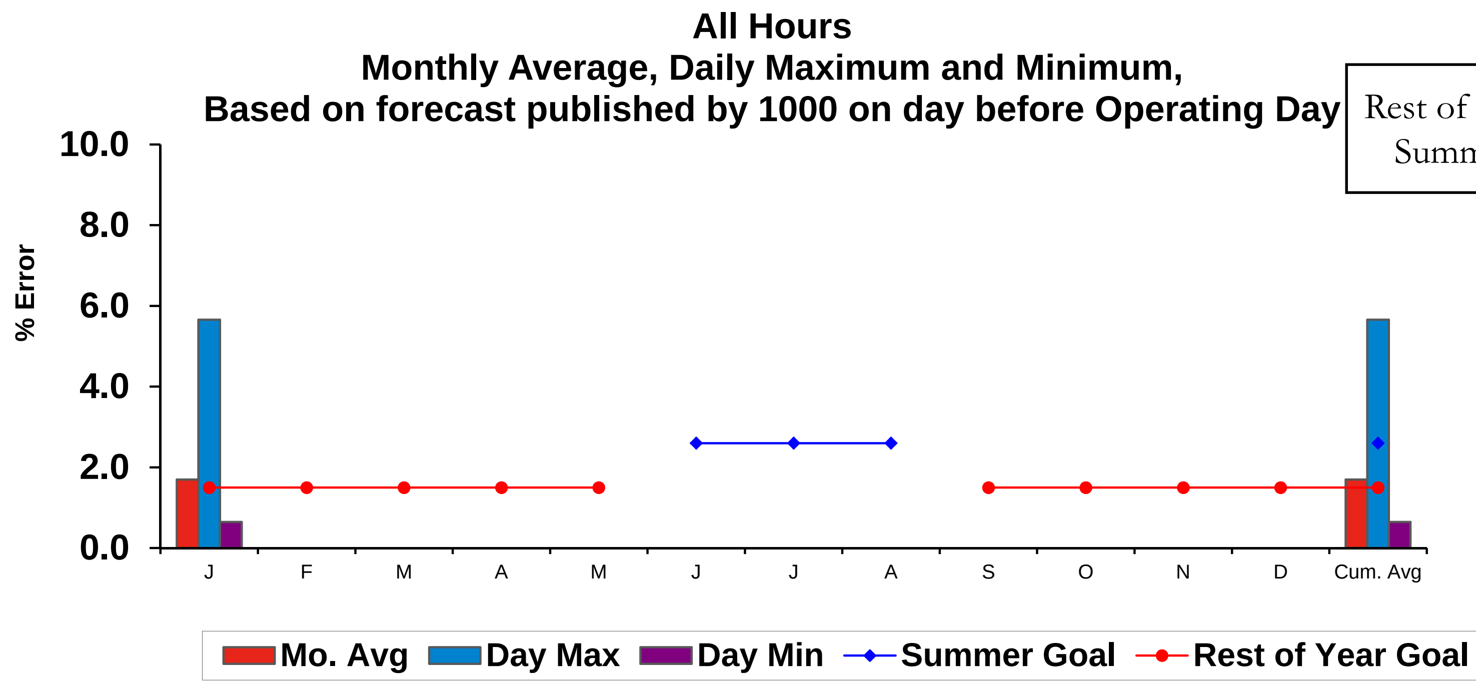
Minimum Generation Warnings & Events:

Minimum Generation Warning	**01/04/15**	**Start – 00:01, Expired – 09:00** **SS Denied**
Minimum Generation Warning	**01/04/15**	**Start – 23:00, Expired – 23:59** **SS Denied**
Minimum Generation Warning	**01/05/15**	**Start – 00:01, Expired – 05:00** **No Actions Taken**
Minimum Generation Warning	**01/18/15 – 01/19/15**	**Start – 23:00, Expired – 08:00** **Interchange Cuts Only**

2015 System Operations – Load Forecast Accuracy

Dashboard Indicator

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



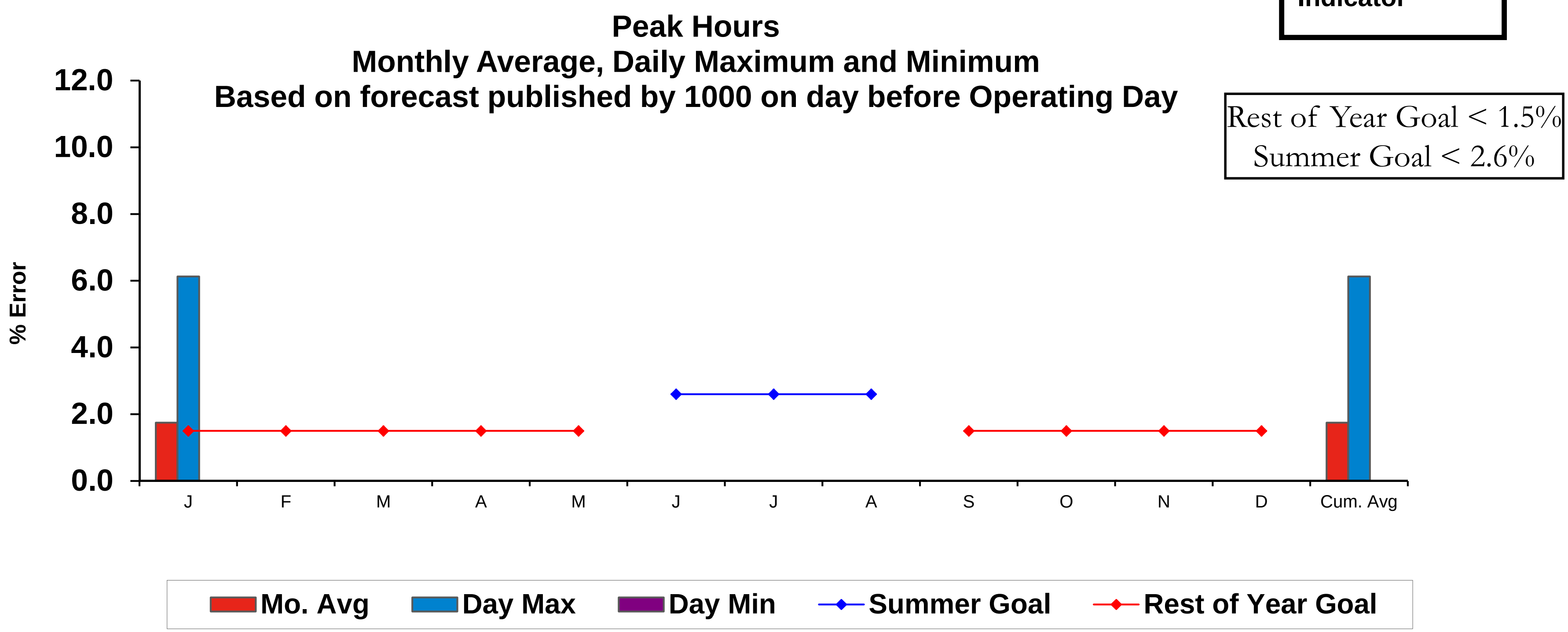
	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Mo Avg	1.70												1.70
Day Max	5.66												5.66
Day Min	0.65												0.65
Summer Goal						2.6	2.6	2.6					
Rest of Year Goal	1.50	1.50	1.50	1.50	1.50				1.50	1.50	1.50	1.50	
Rest of year Actual	1.70												1.70
Summer Actual													

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

Summer consists of June, July & August

2015 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator

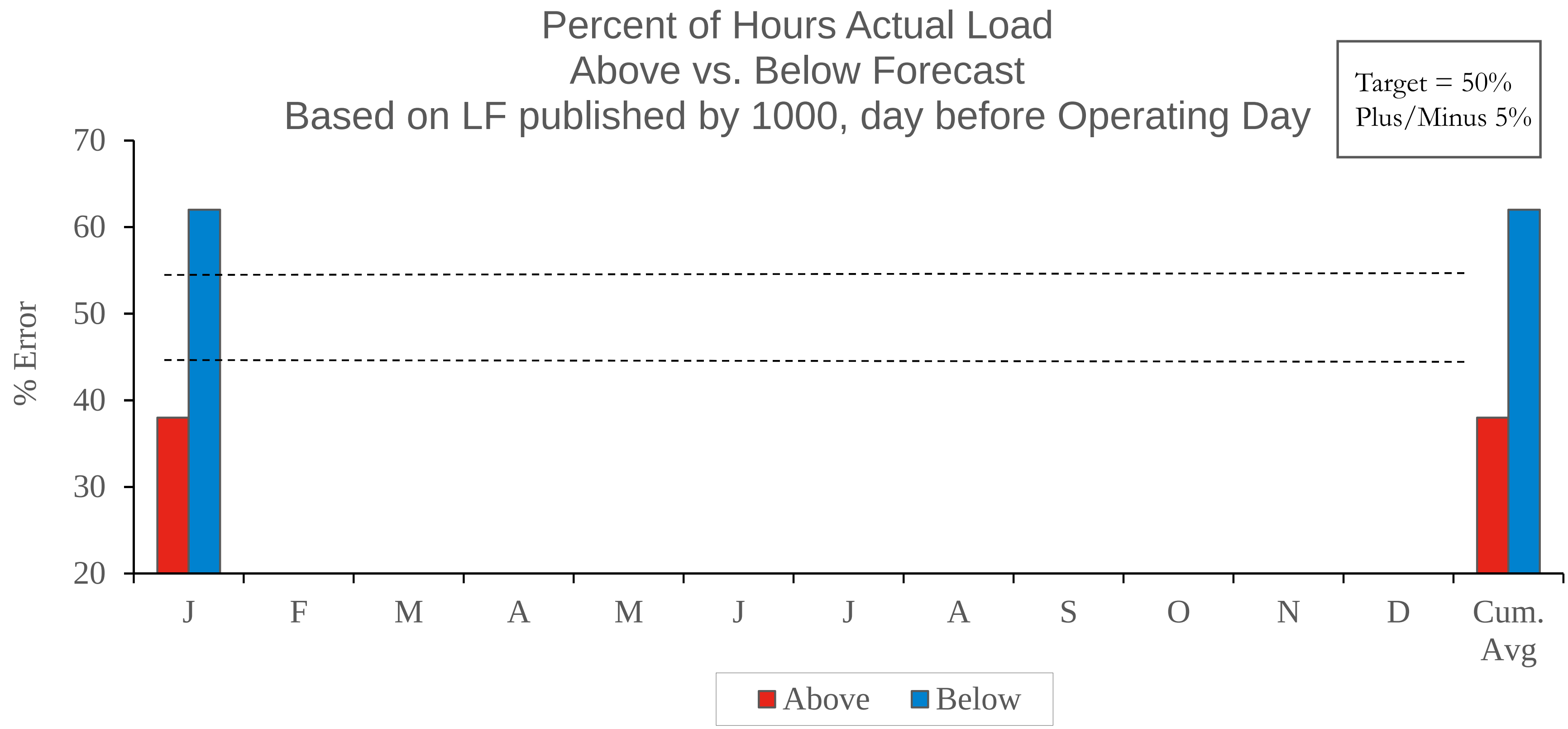


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Mo Avg	1.75												1.75
Day Max	6.13												6.13
Day Min	0.00												0.00
Summer Goal						2.6	2.6	2.6					
Rest of Year Goal	1.50	1.50	1.50	1.50	1.50				1.50	1.50	1.50	1.50	
Rest of year Actual	1.75												1.75
Summer Actual													

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

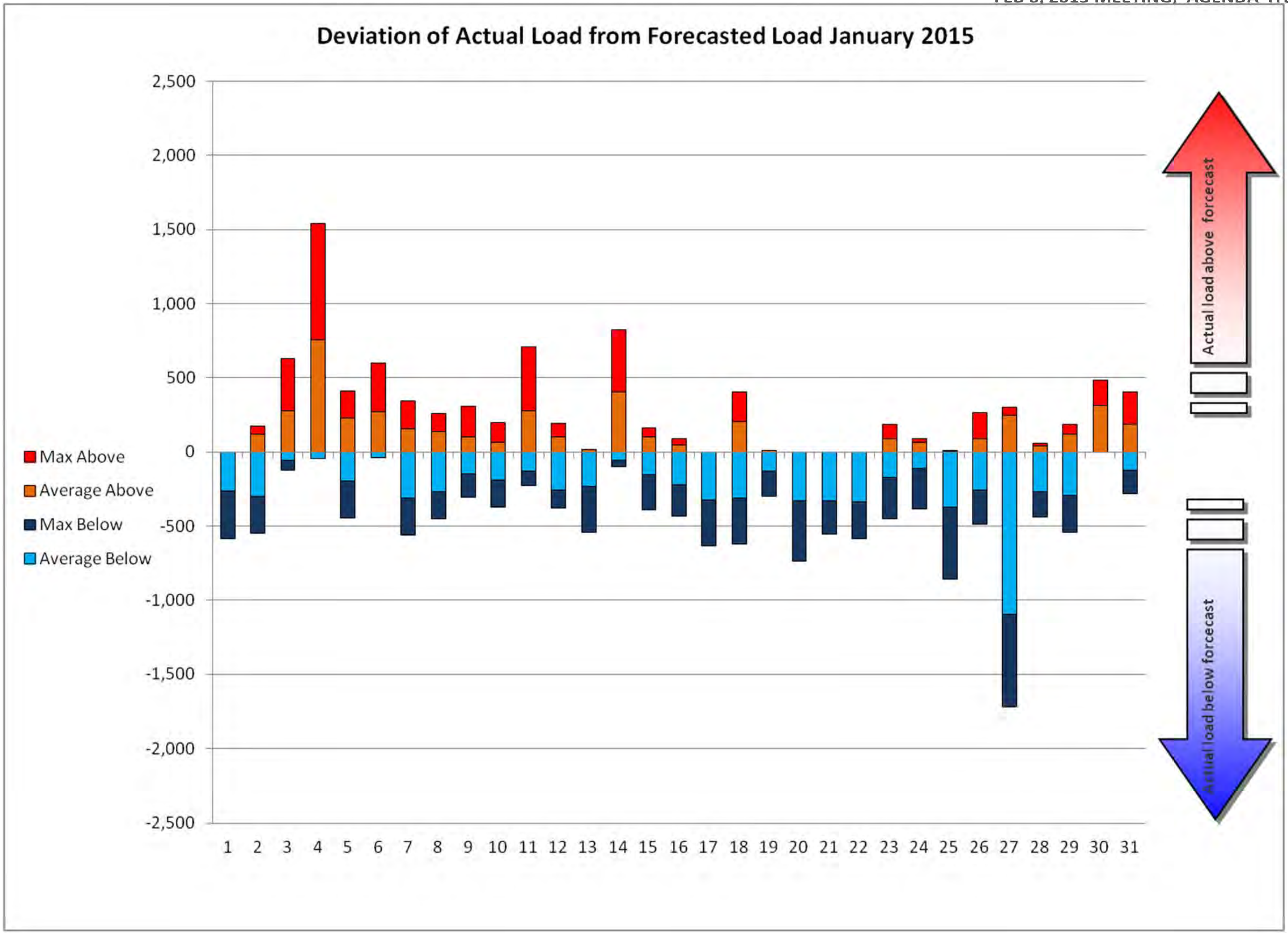
Summer consists of June, July & August

2015 System Operations - Load Forecast Accuracy

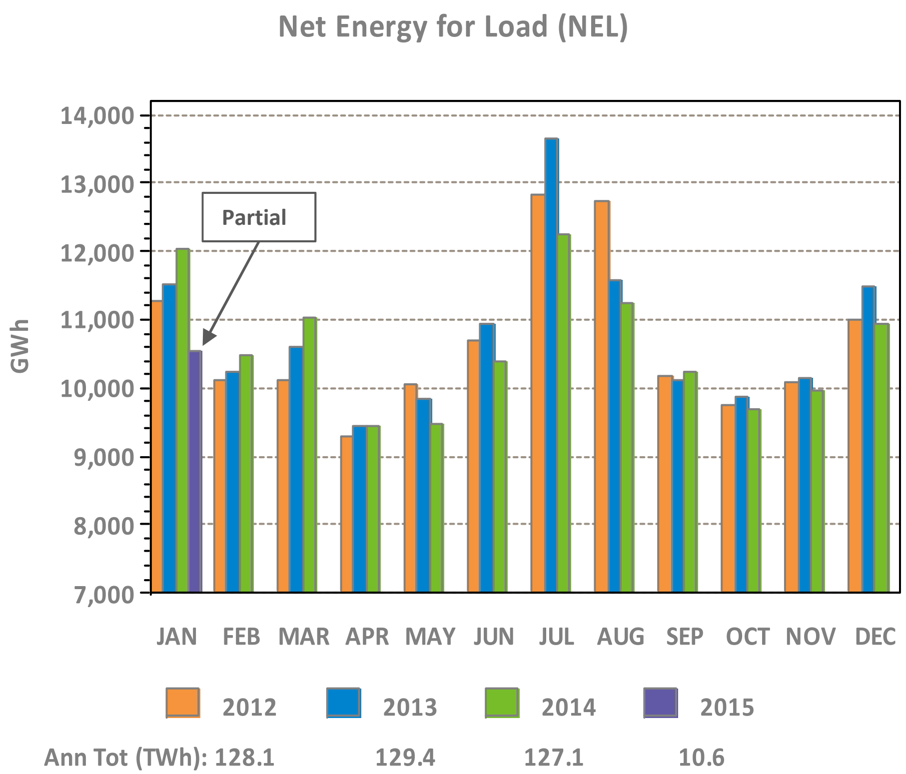


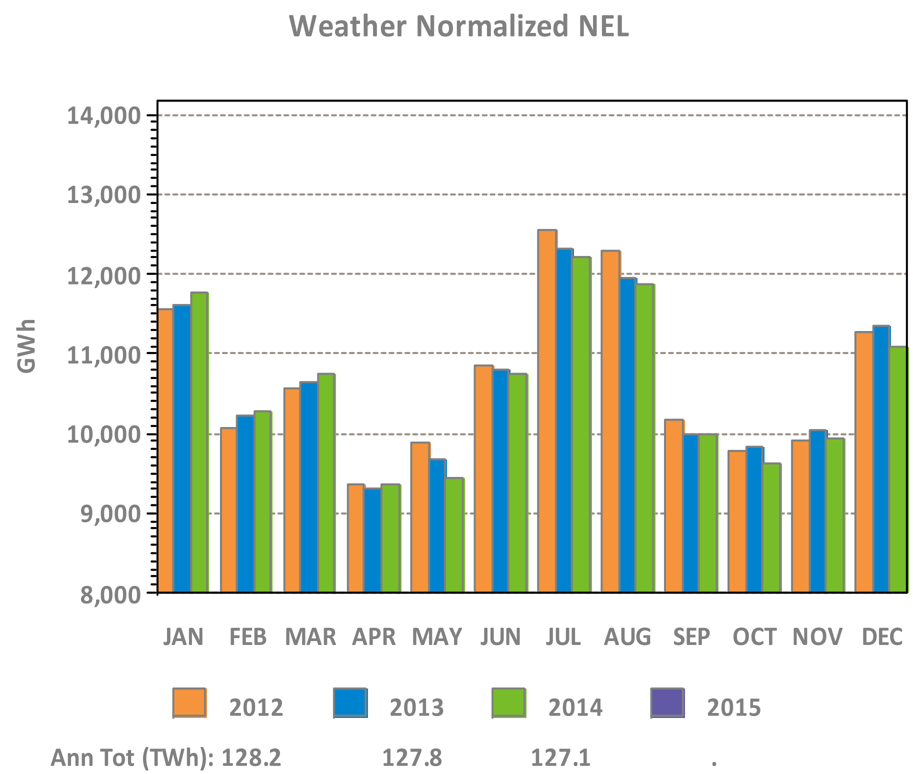
	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	37.8												38
Below %	62.2												62
Avg Above	143.0												143
Avg Below	-236.0												-236
Avg All	-81.0												-81

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


Deviation of Actual Load from Forecasted Load January 2015
2,500
2,000
1,500
1,000
500
0
-500
-1,000
-1,500
-2,000
-2,500
Max Above
Average Above
Max Below
Average Below
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
Actual load above forecast
Actual load below forecast

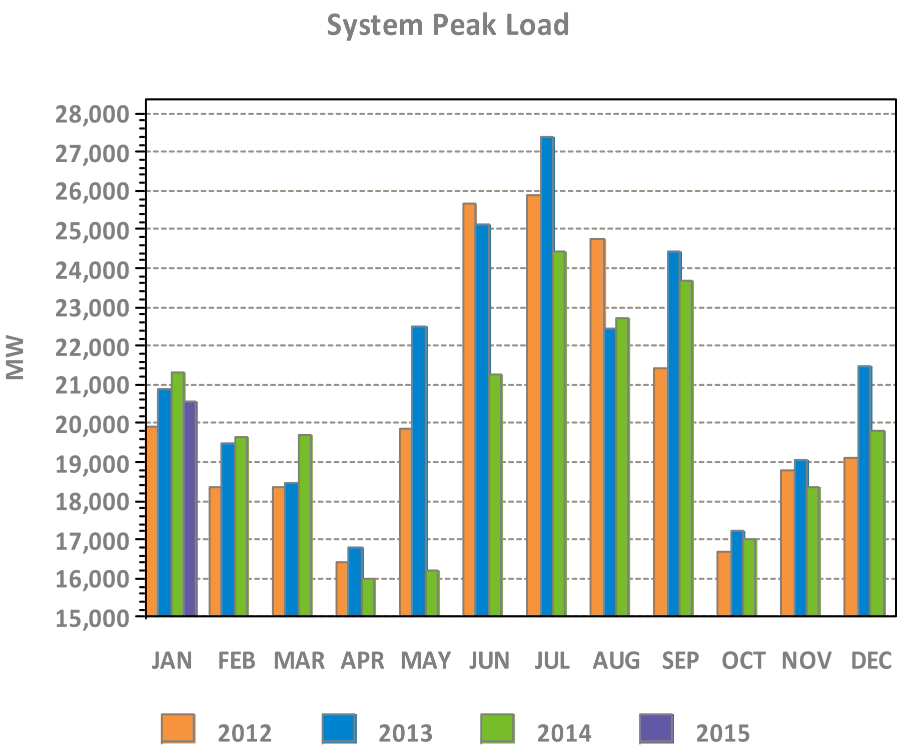
Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL

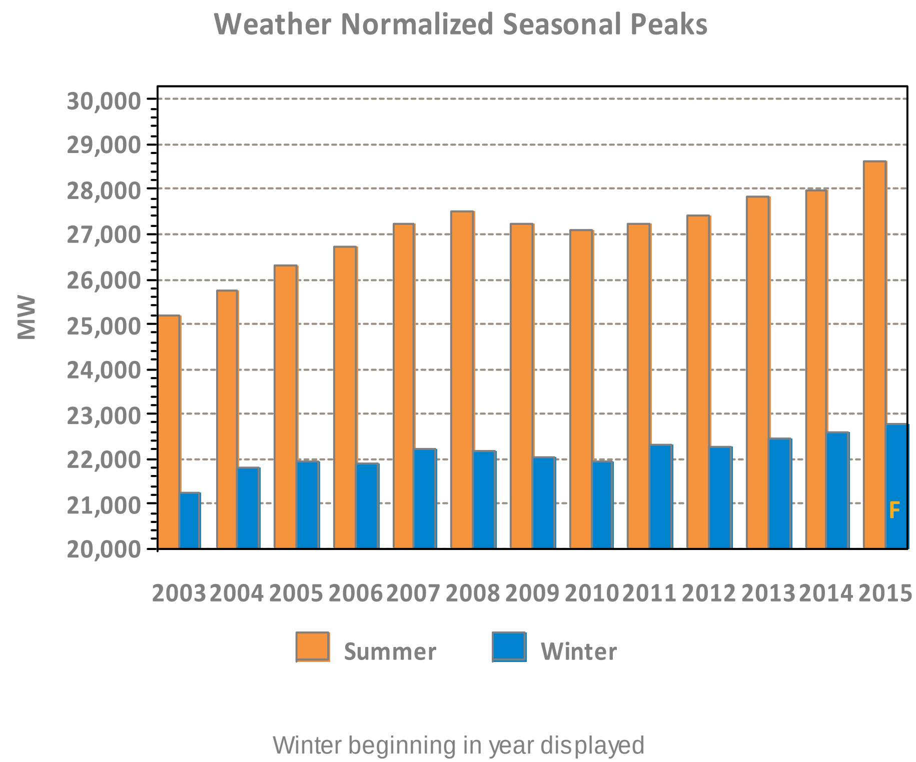




NEPOOL NEL is the total net energy required to serve load and is analogous to 'RT system load'. NEL is calculated as: Generation – pumping load + net interchange where imports are positively signed.
Current month's data may be preliminary. Weather normalized NEL may be reported on a one-month lag.

Monthly Peak Loads and Weather Normalized Seasonal Peak History

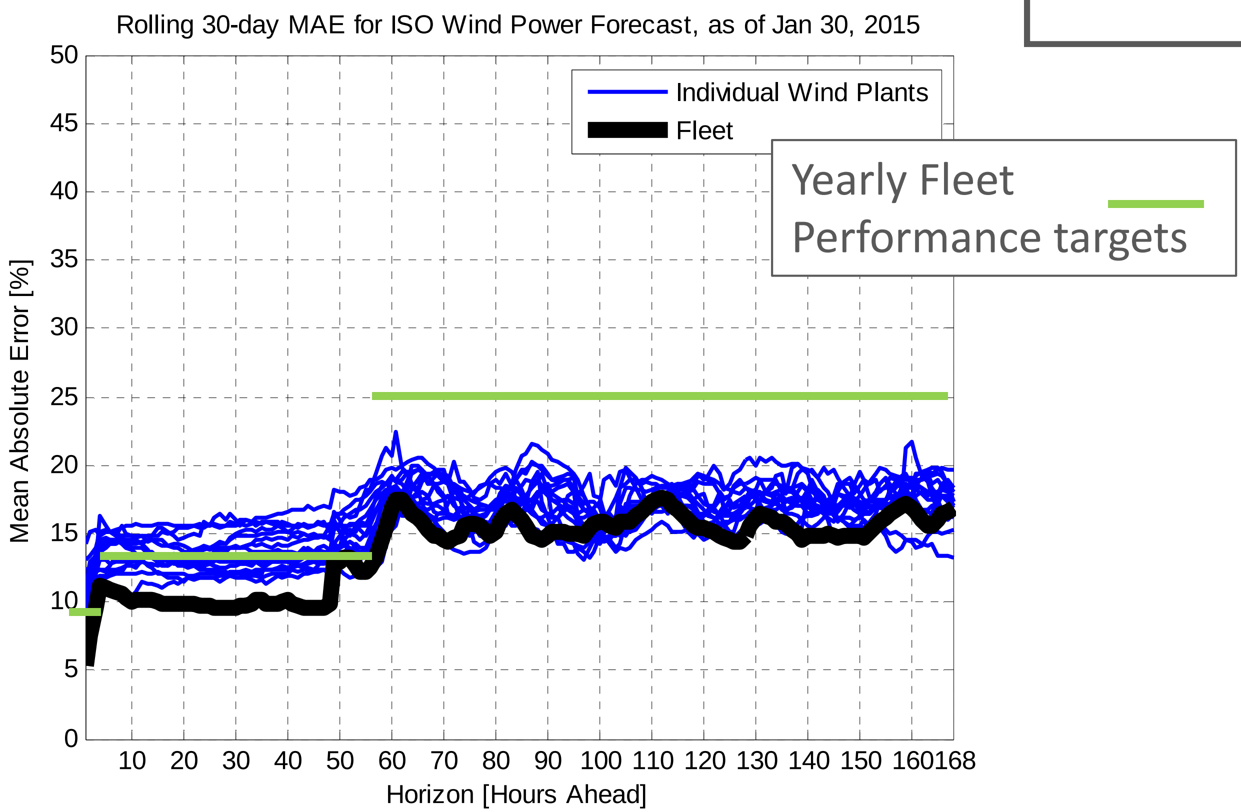




F – designates forecasted values, which are updated in April/May of the following year; represents "gross forecast"

Wind Power Forecast Error Statistics: MAE

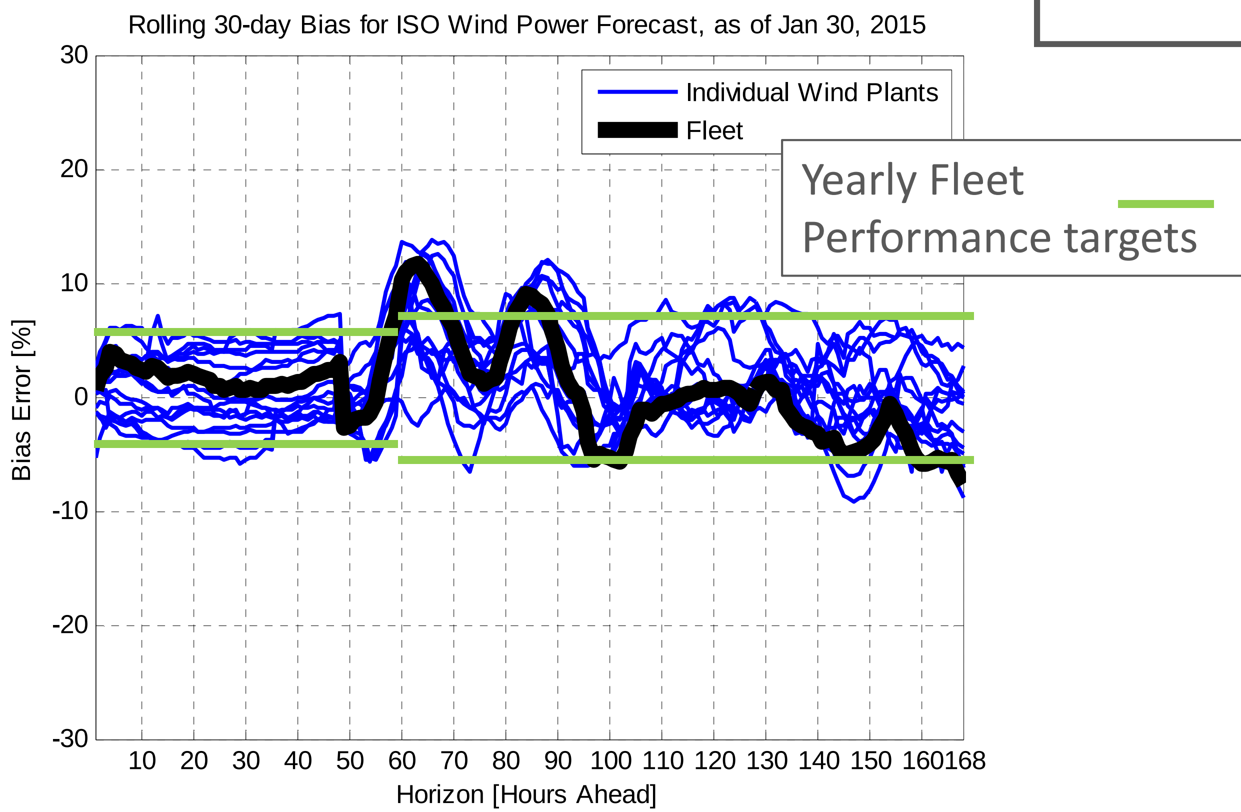
Dashboard Indicator



Ideally, MAE and Bias would be both equal to zero. As is typical, MAE increases with the forecast horizon. MAE and Bias for the fleet of wind power resources are less due to offsetting errors. Across all time frames, the ISO-NE/GH forecast is very good compared to industry standards, and continues to be well within the yearly performance targets specified in the forecast RFP.

Wind Power Forecast Error Statistics: Bias

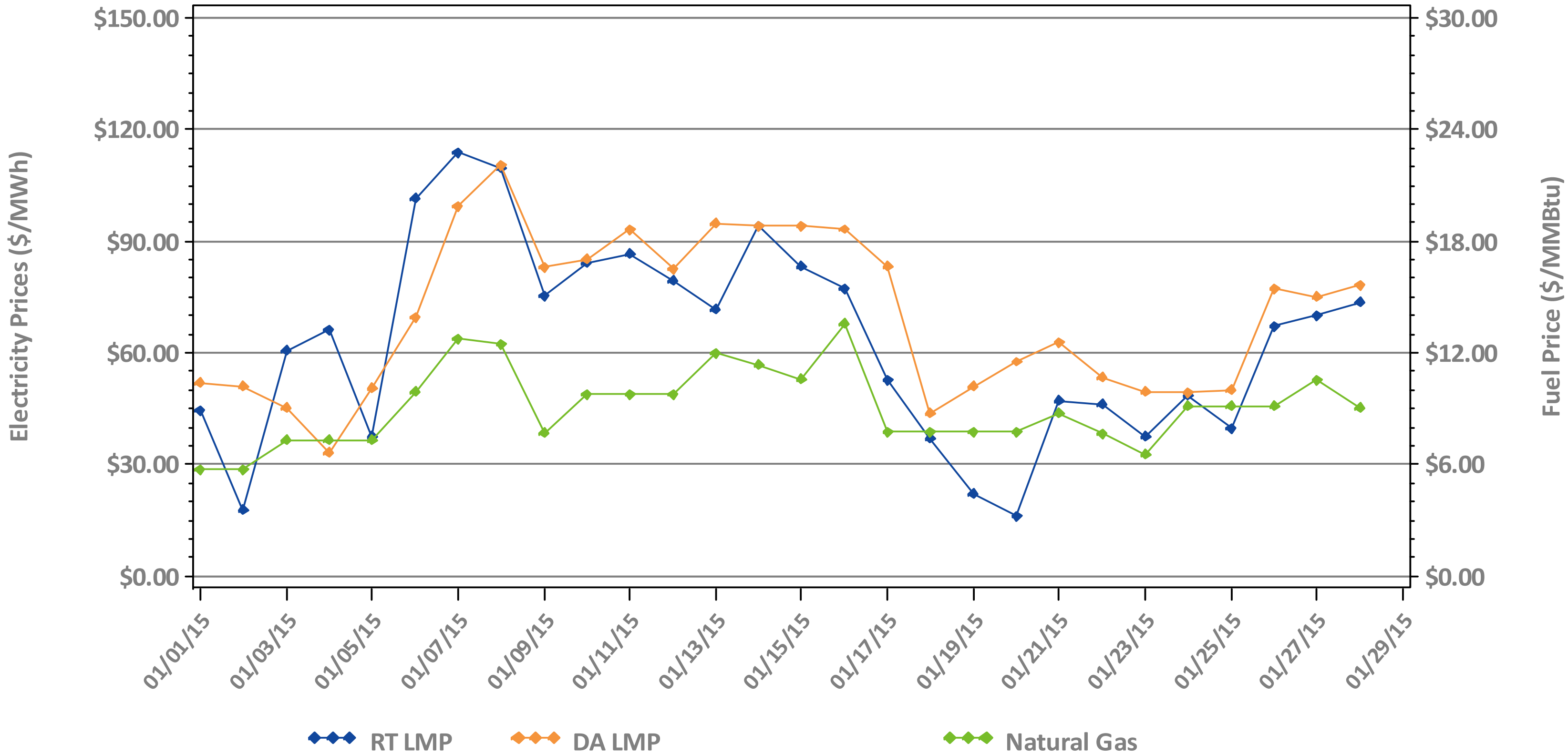
Dashboard Indicator



Ideally, MAE and Bias would be both equal to zero. Positive bias means less windpower was actually available compared to forecast. Negative bias means more windpower was actually available compared to forecast. Across all time frames, the ISO-NE/GH forecast is very good compared to industry standards, and monthly values for January are near yearly performance targets specified in the forecast RFP.

MARKET OPERATIONS

Daily DA and RT ISO-NE Hub Prices and Input Fuel Prices: January 1-28, 2015

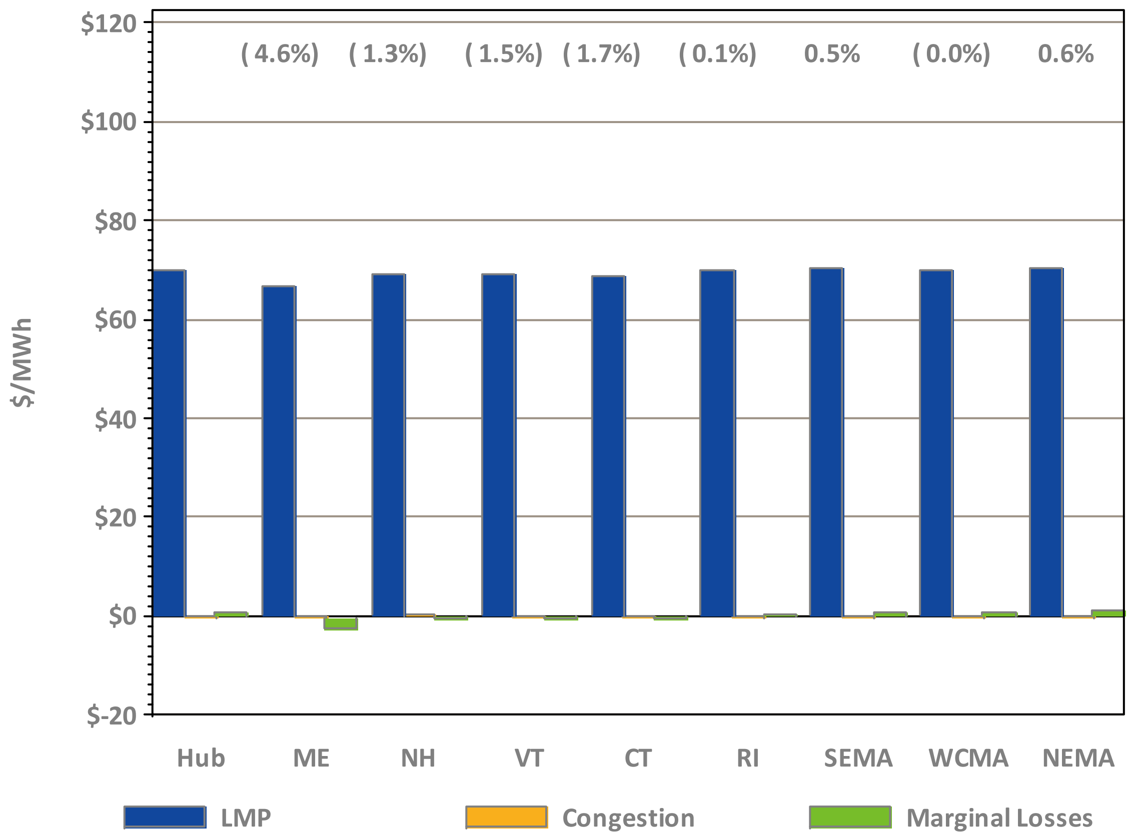


Underlying natural gas data furnished by:

ICE Global markets in clear view

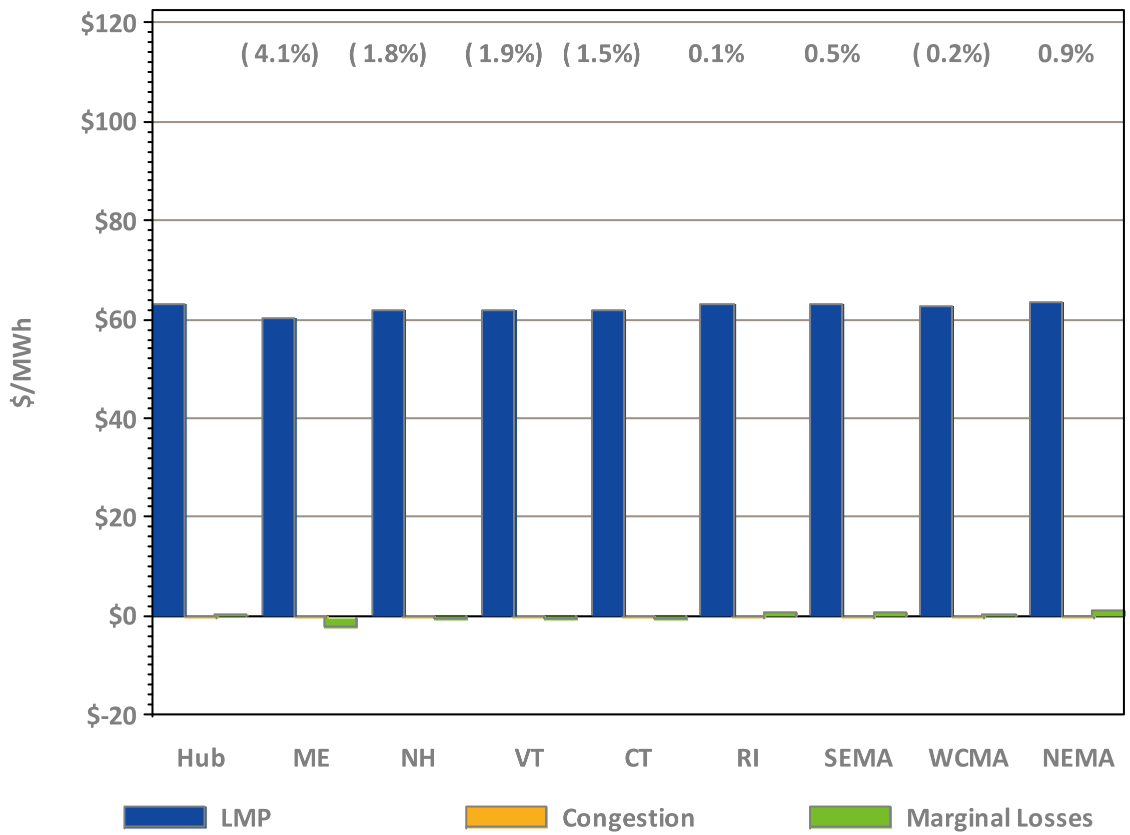
Average price difference over this period (DA-RT): $7.15
Average price difference over this period ABS(DA-RT): $13.94
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 22%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, January 2015



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

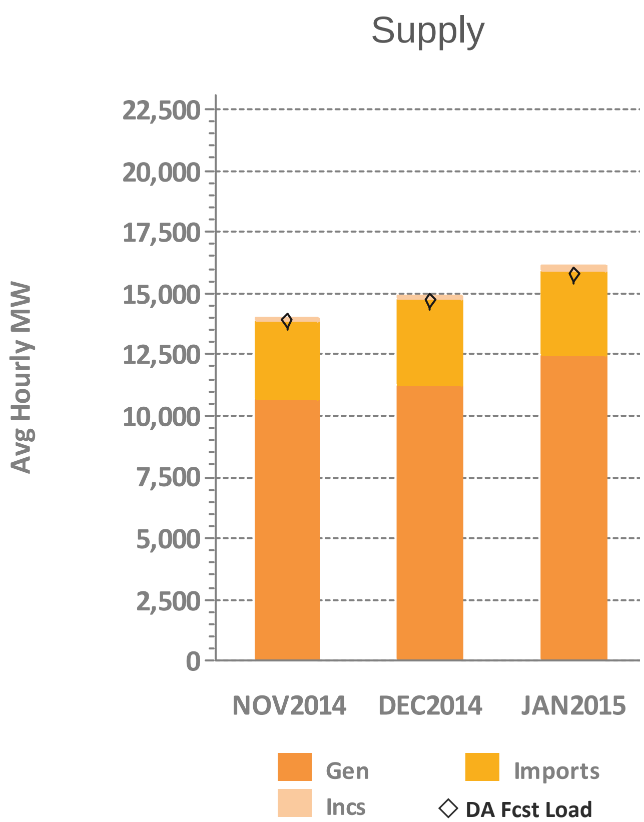
RT LMPs Average by Zone & Hub, January 2015

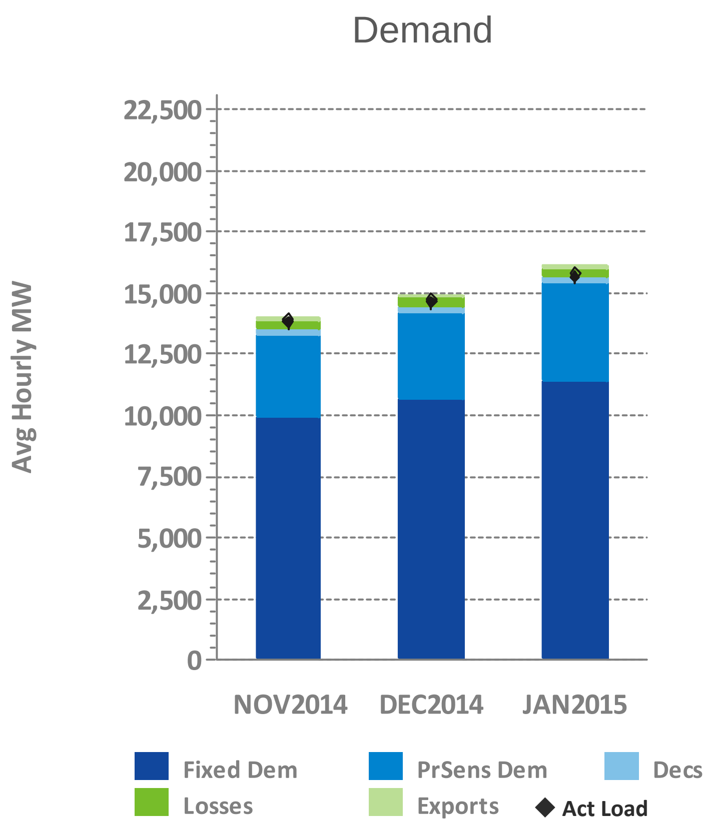


Definitions

Day-Ahead Concept	Definition
Day-Ahead Load Obligation **(DALO)**	The sum of day-ahead cleared load (including pump load), exports, and virtual purchases (excluding bulk losses)
Day-Ahead Cleared Physical Energy	The sum of day-ahead cleared generation and cleared net imports

Components of Cleared DA Supply and Demand – Last Three Months

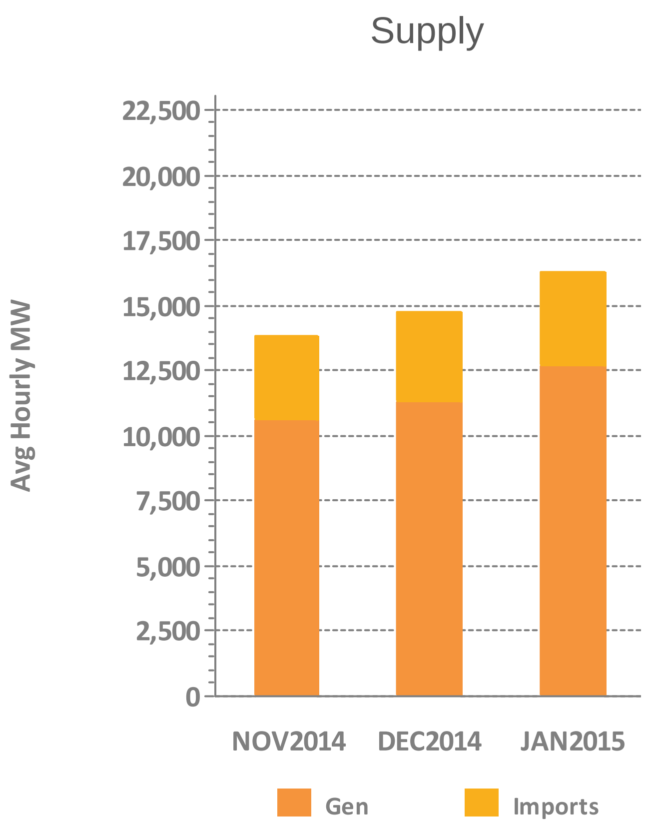


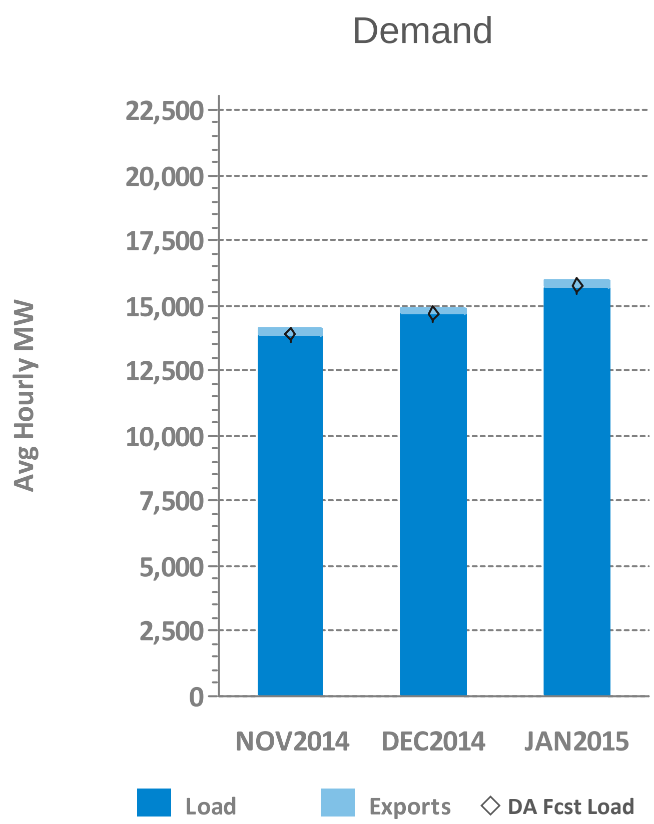


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load

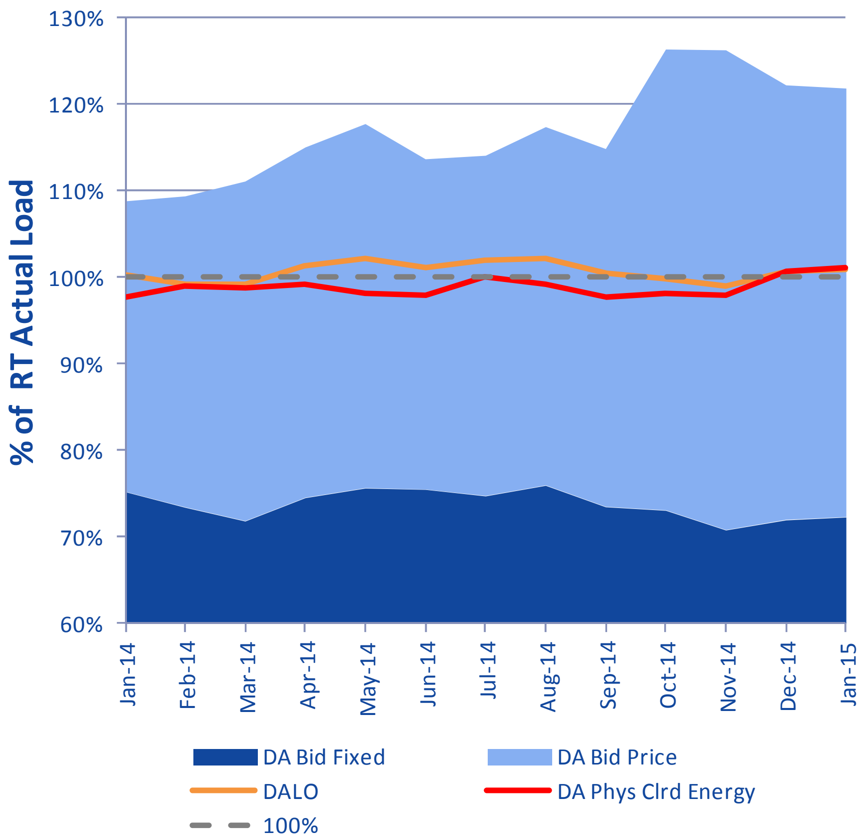
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

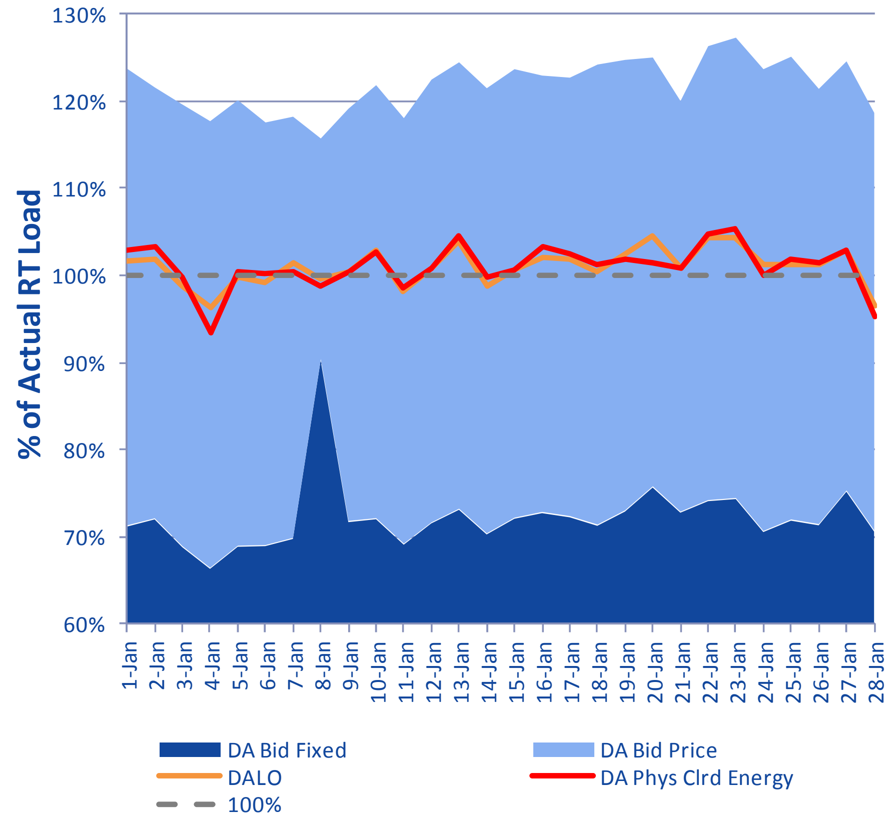
Components of RT Supply and Demand – Last Three Months





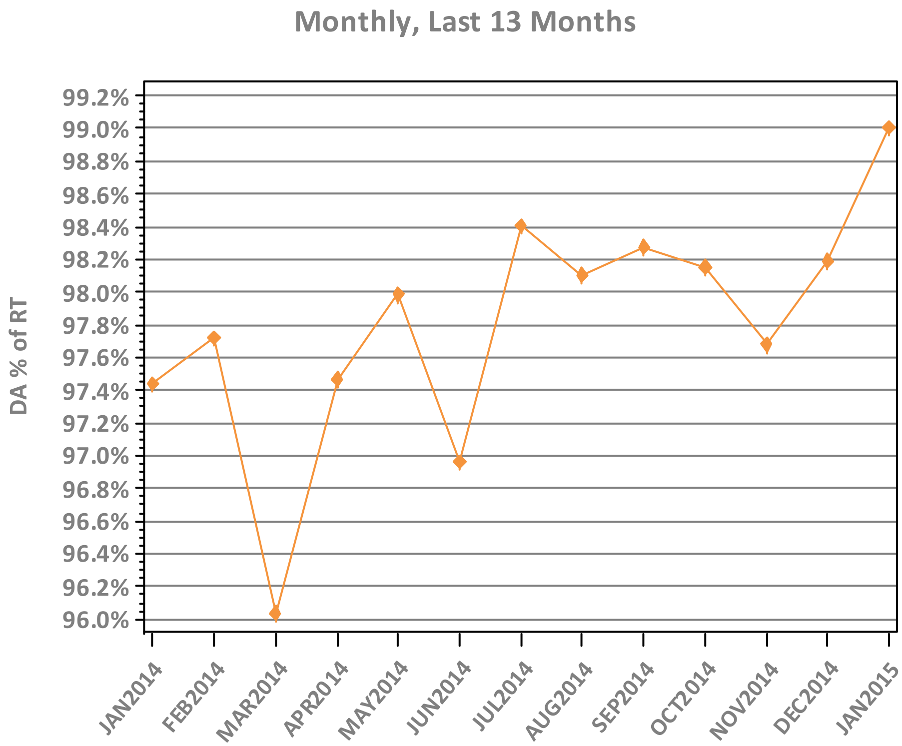
DAM Volumes vs. RT Actual Load (at Peak Hour): Monthly and Daily

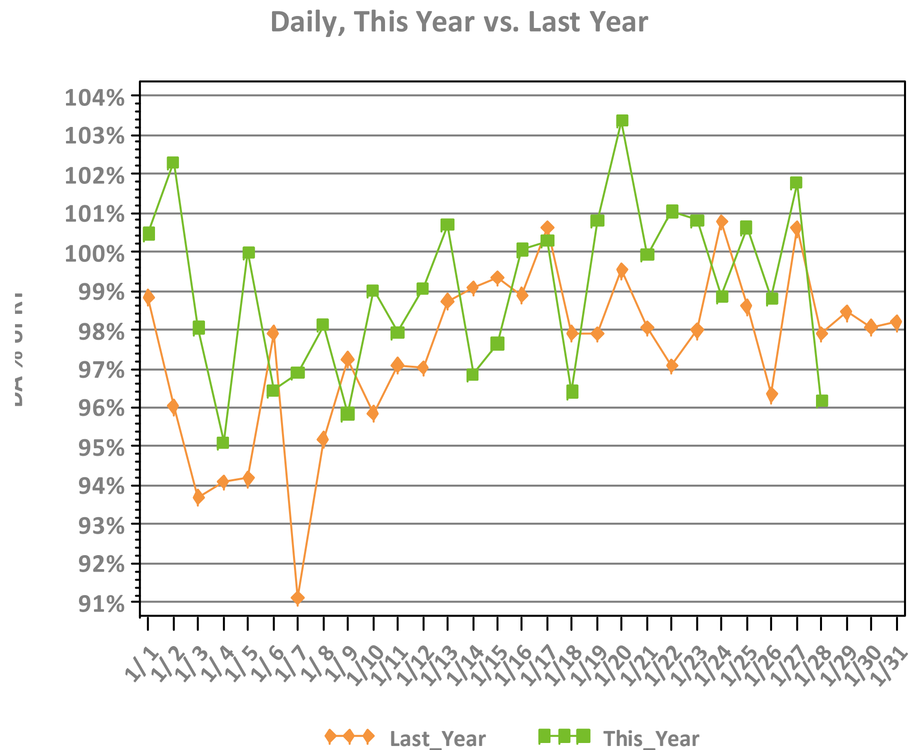




Note: Percentages were derived for the peak hour of each day (shown on right), then averaged over the month (shown on left). Values at hour of forecasted peak load.

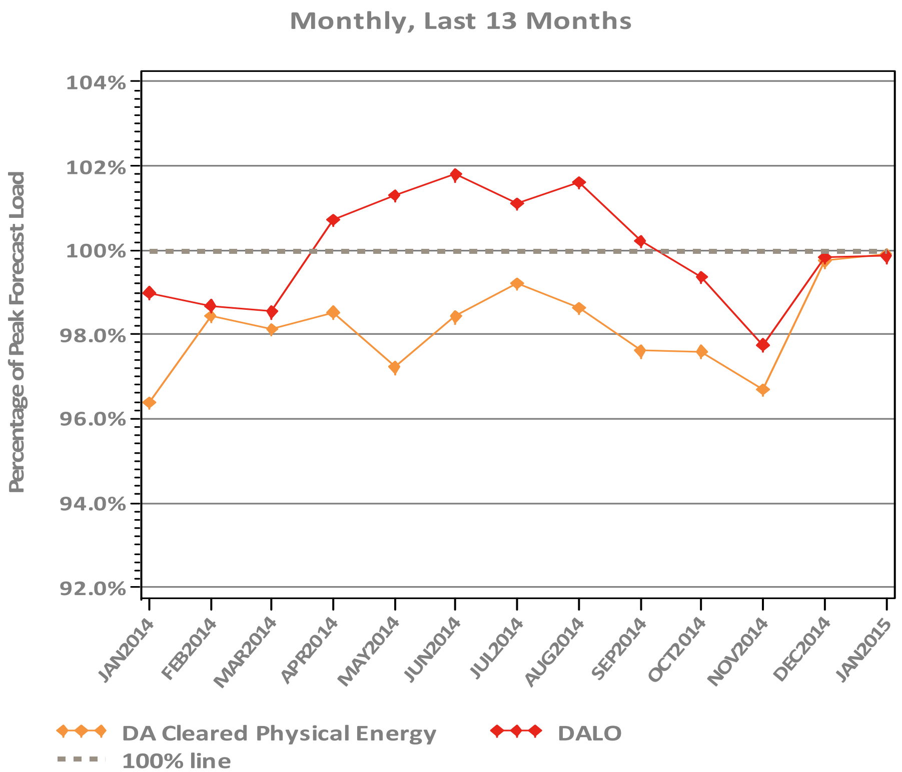
DA vs. RT Load Obligation: January, This Year vs. Last Year

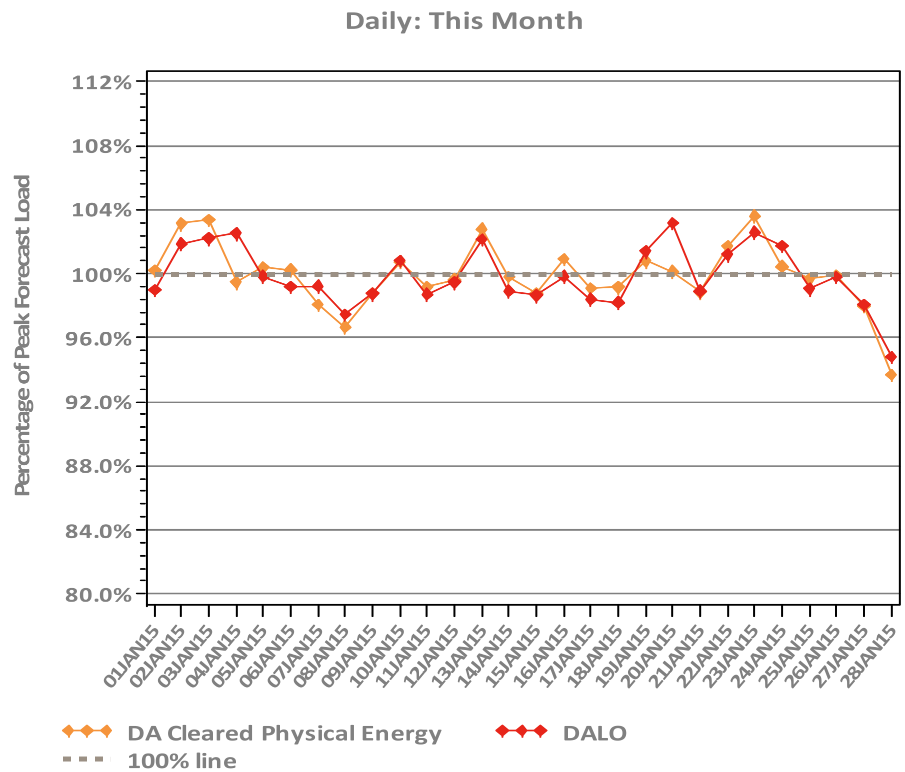




*Hourly average values

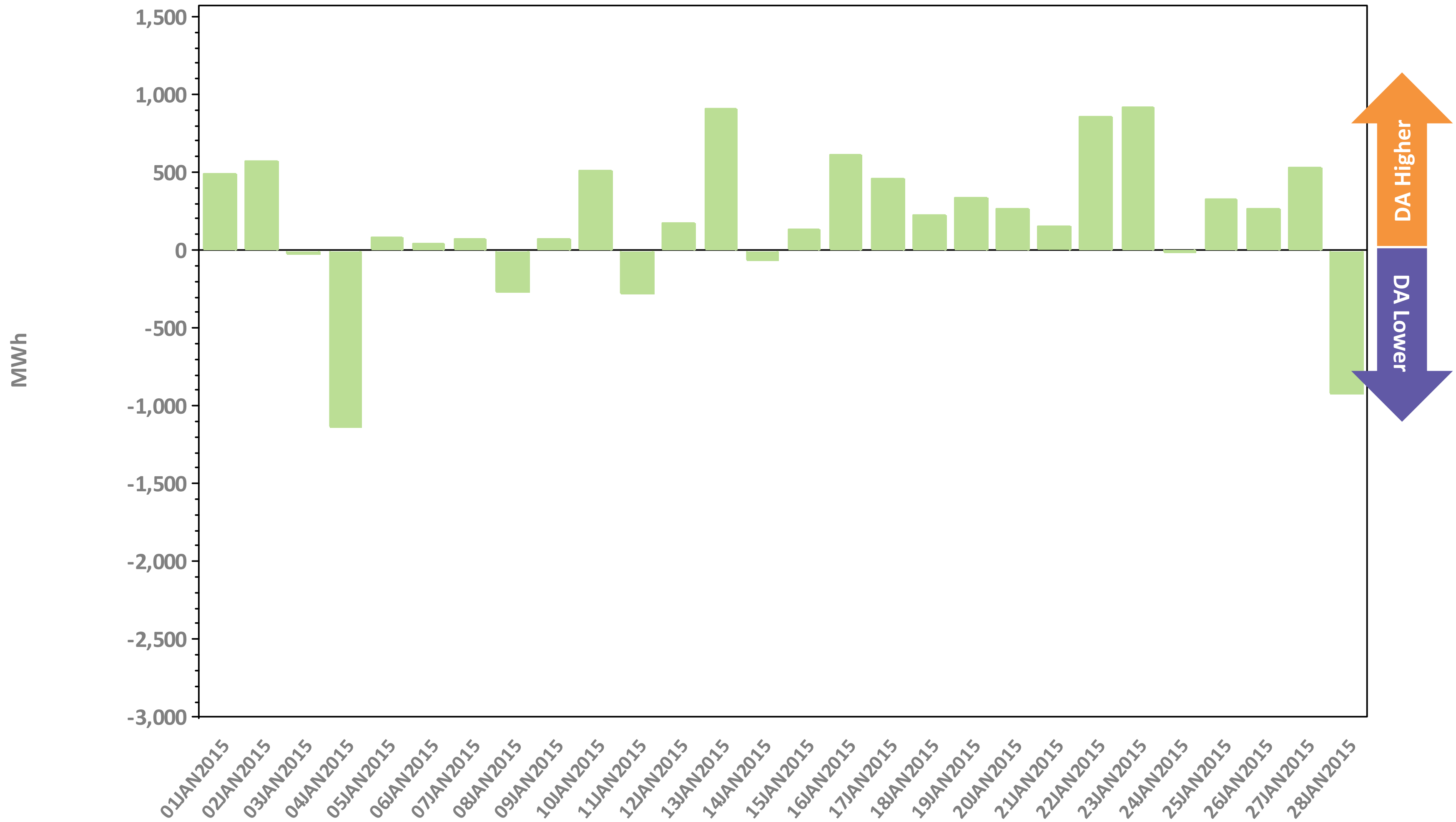
DA Volumes as % of Forecast (Peak Hour)





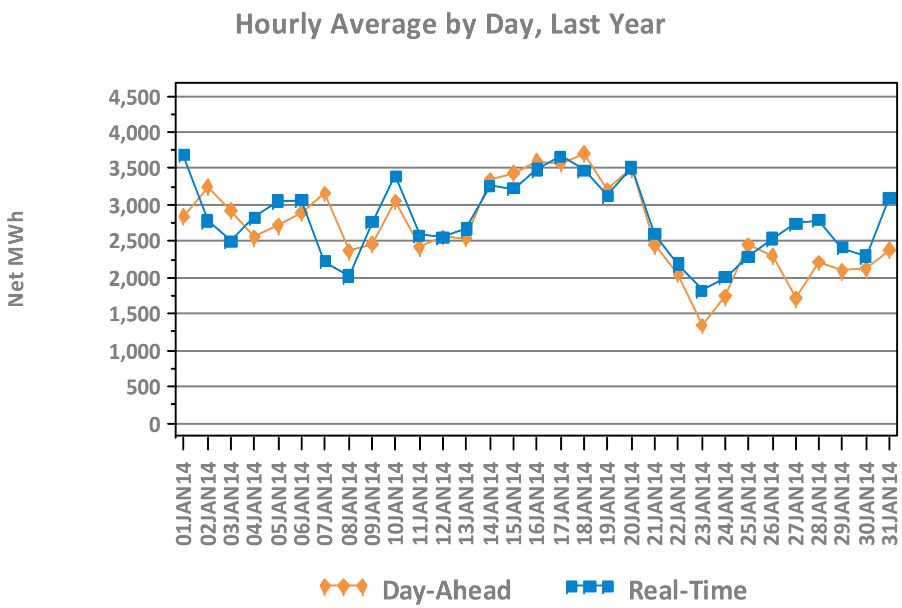
*Forecasted peak hour is reflected.

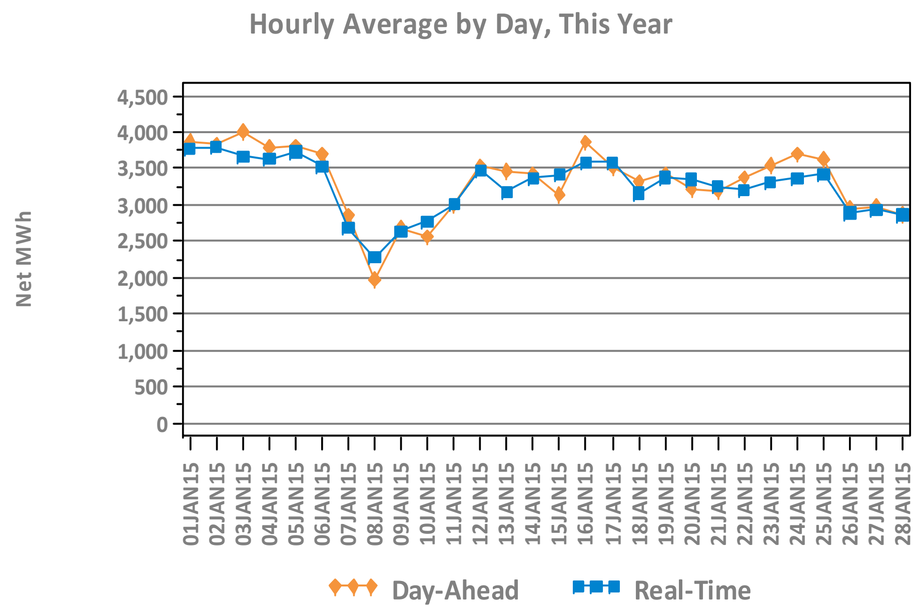
DA Cleared Physical Energy Difference from RT System Load at Peak Hour



*Negative values indicate DA Cleared Physical Energy value below its RT counterpart. Forecast peak hour reflected.

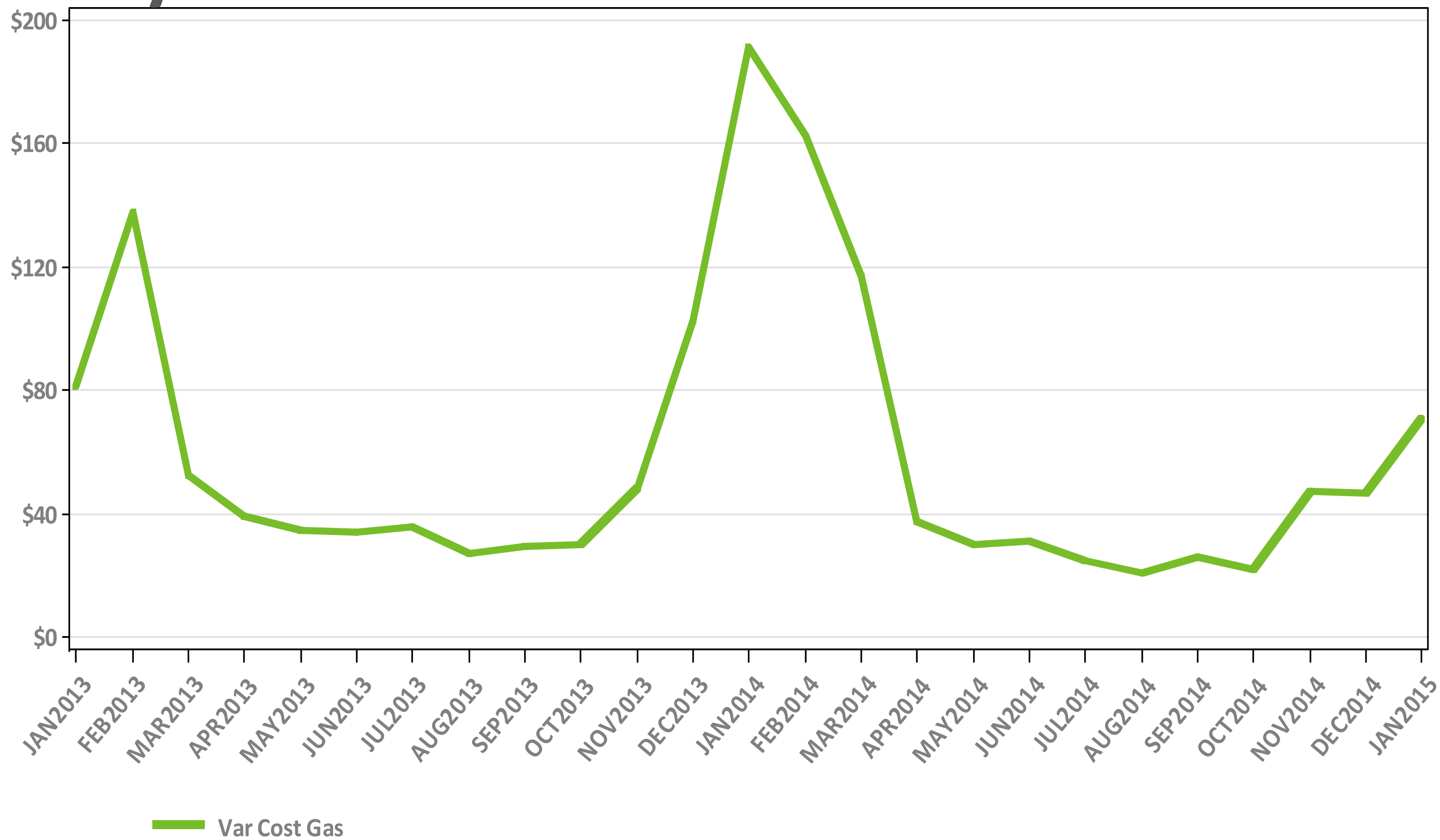
DA vs. RT Net Interchange January 2015 vs. January 2014





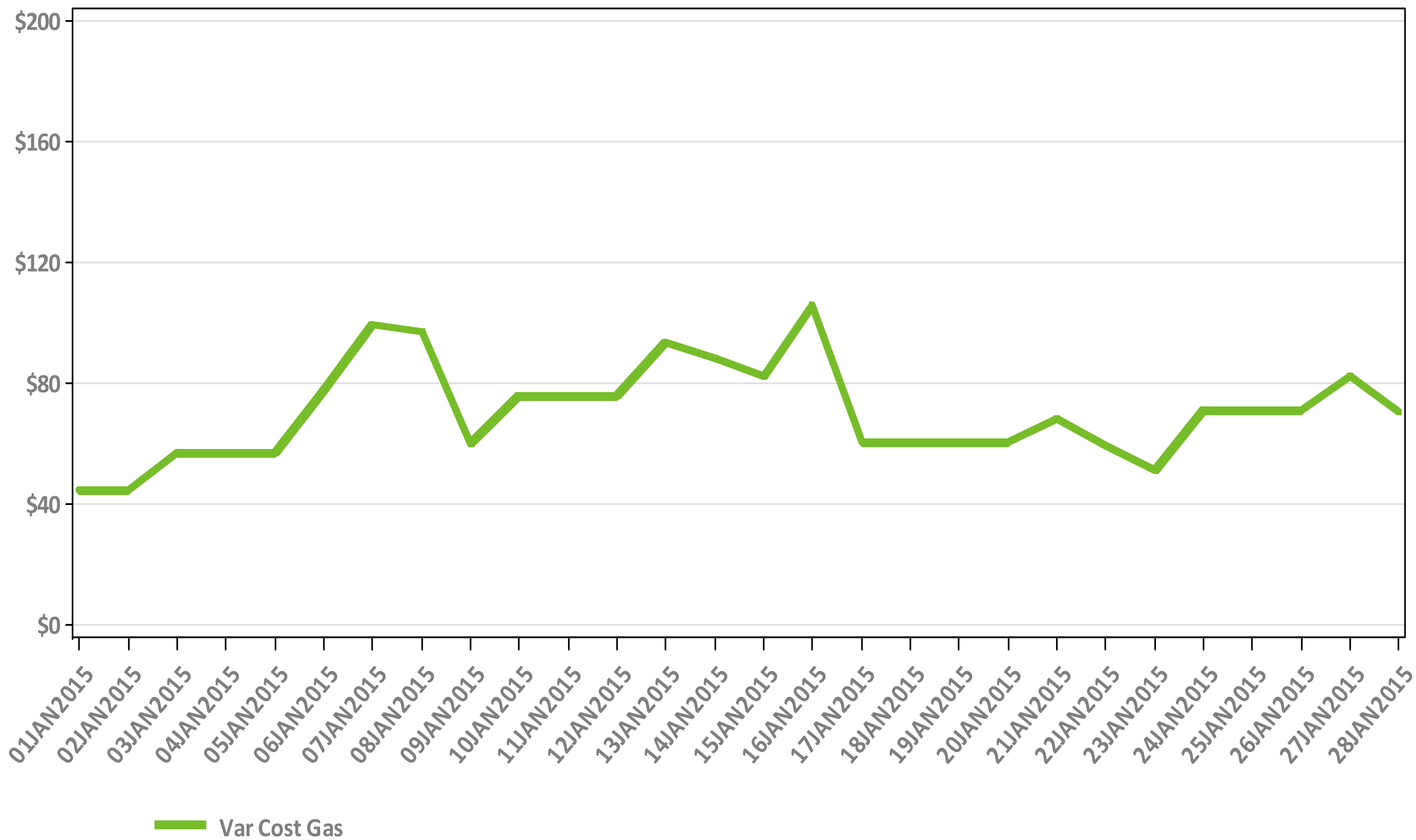
Net Interchange is the sum of daily imports minus the sum of daily exports
Positive values are net imports

Variable Production Cost of Natural Gas: Monthly



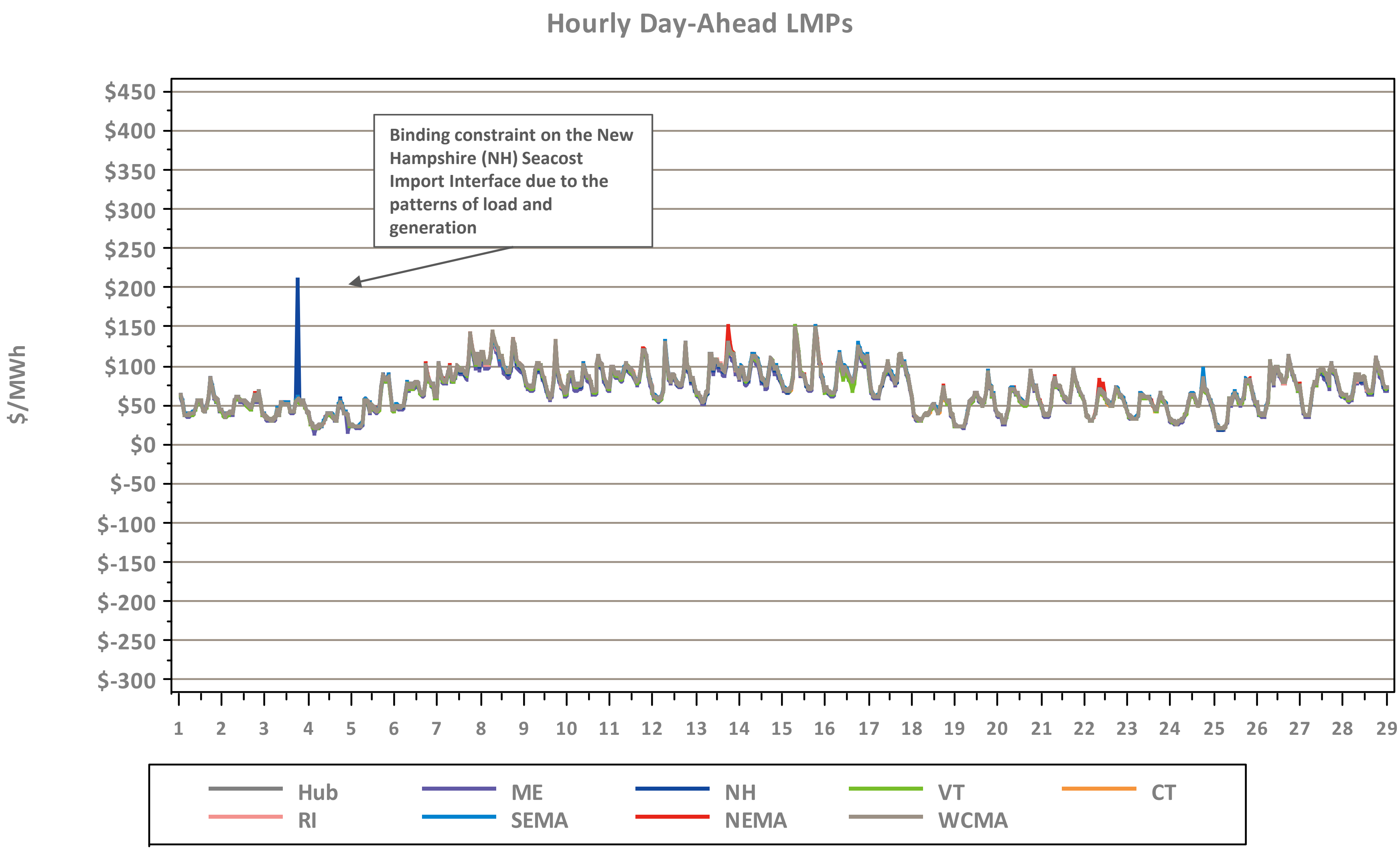
Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

Variable Production Cost of Natural Gas: Daily

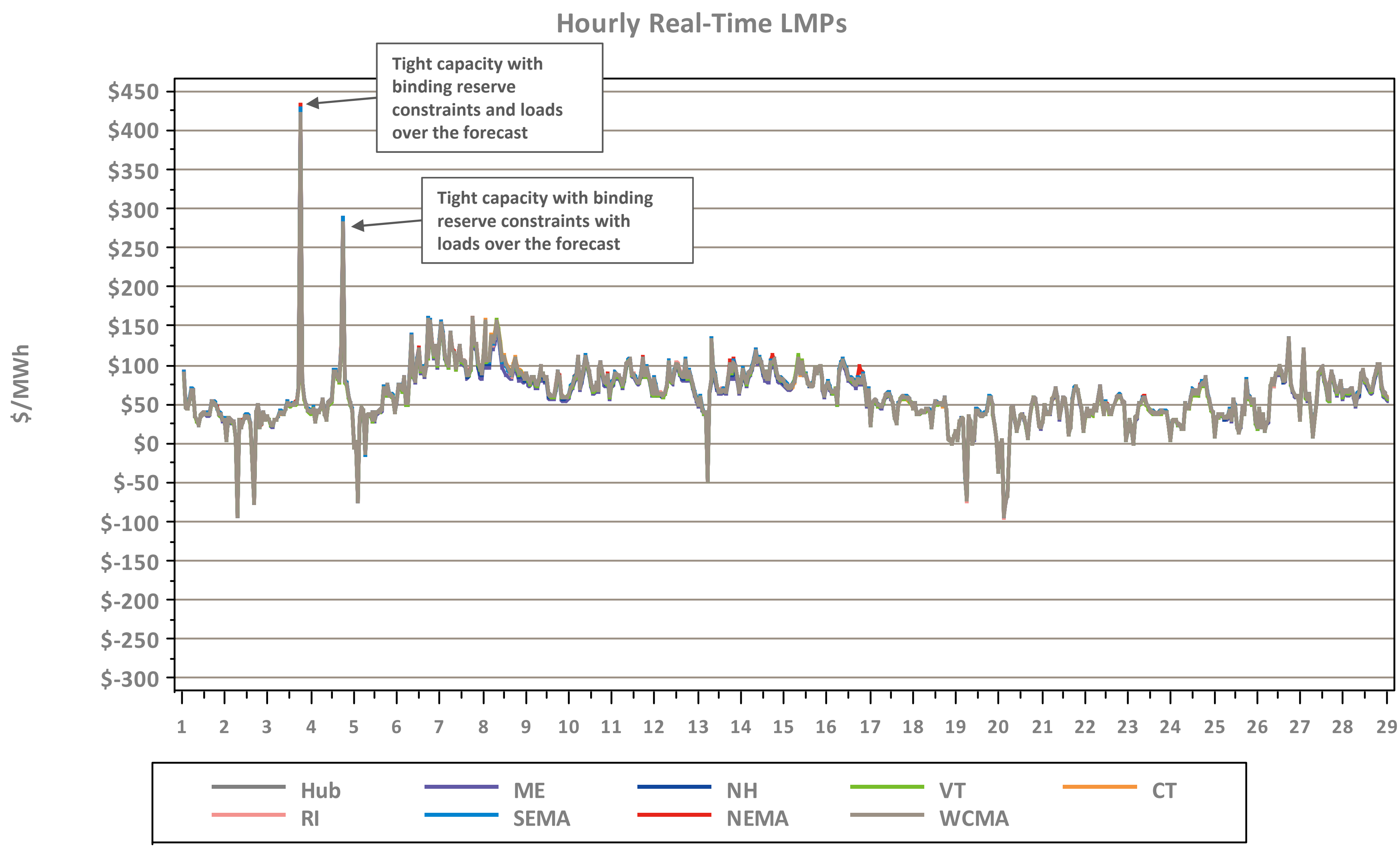


Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

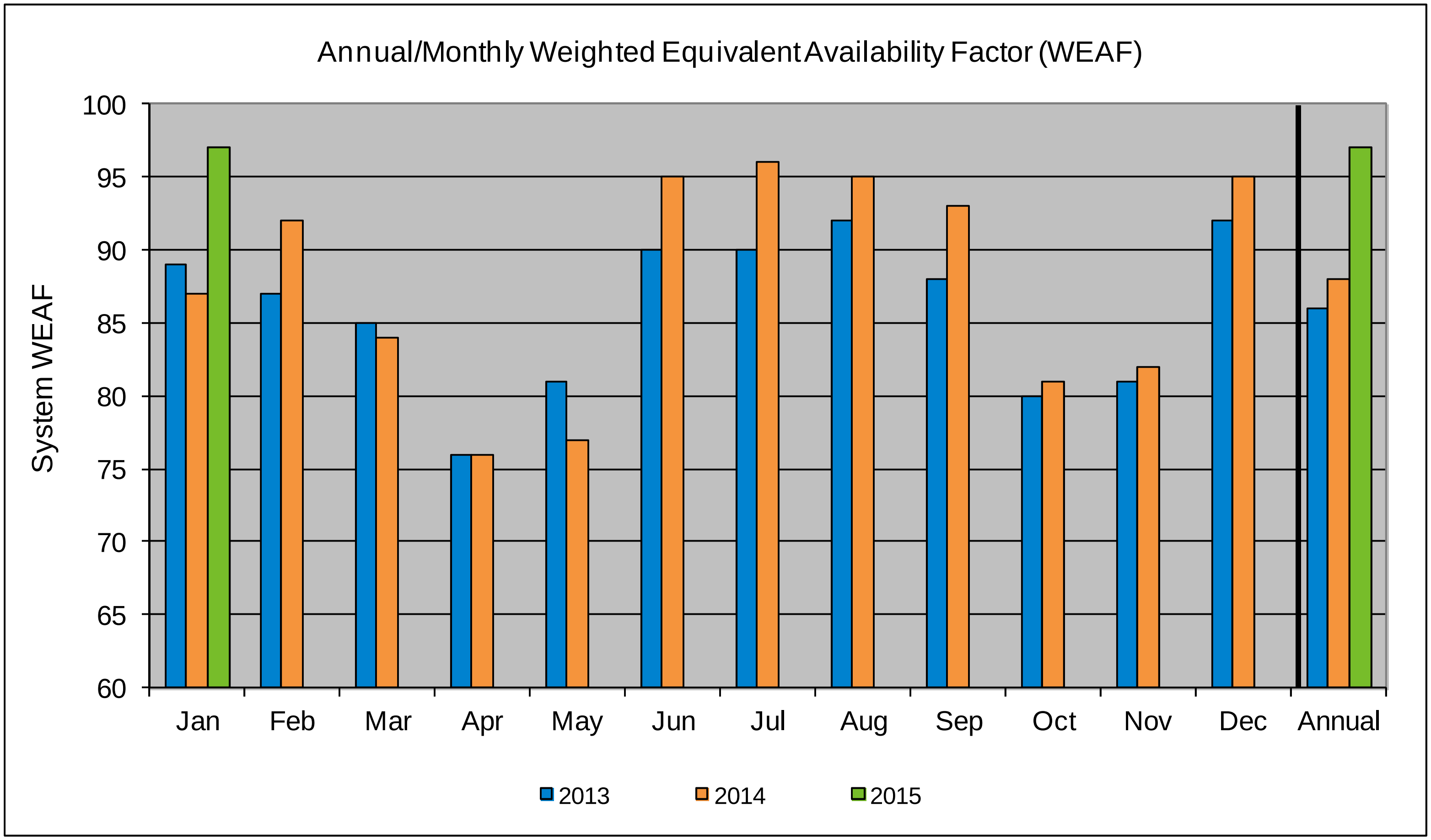
Hourly DA LMPs, January 1-28, 2015



Hourly RT LMPs, January 1-28, 2015



System Unit Availability



Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2015	97												97
2014	87	92	84	76	77	95	96	95	93	81	82	95	88
2013	89	87	85	76	81	90	90	92	88	80	81	92	86
2012	93	92	88	75	83	93	95	95	91	76	80	89	88

Data as of 1/30/15

BACK-UP DETAIL

LOAD RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for February 2015

Load Zone	RTDR*	RTEG**	On Peak	Seasonal Peak	Total
ME	117.4	6.0	103.1	0.0	226.5
NH	3.3	16.6	69.9	0.0	89.8
VT	20.8	6.2	97.8	0.0	124.9
CT	67.1	92.7	78.1	312.3	550.2
RI	10.6	11.4	83.3	0.0	105.3
SEMA	4.4	15.9	152.4	0.0	172.7
WCMA	20.9	26.4	140.2	34.9	222.4
NEMA	29.5	11.4	307.4	0.0	348.3
Total	**274.0**	**186.6**	**1,032.2**	**347.2**	**1,840.0**

* 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

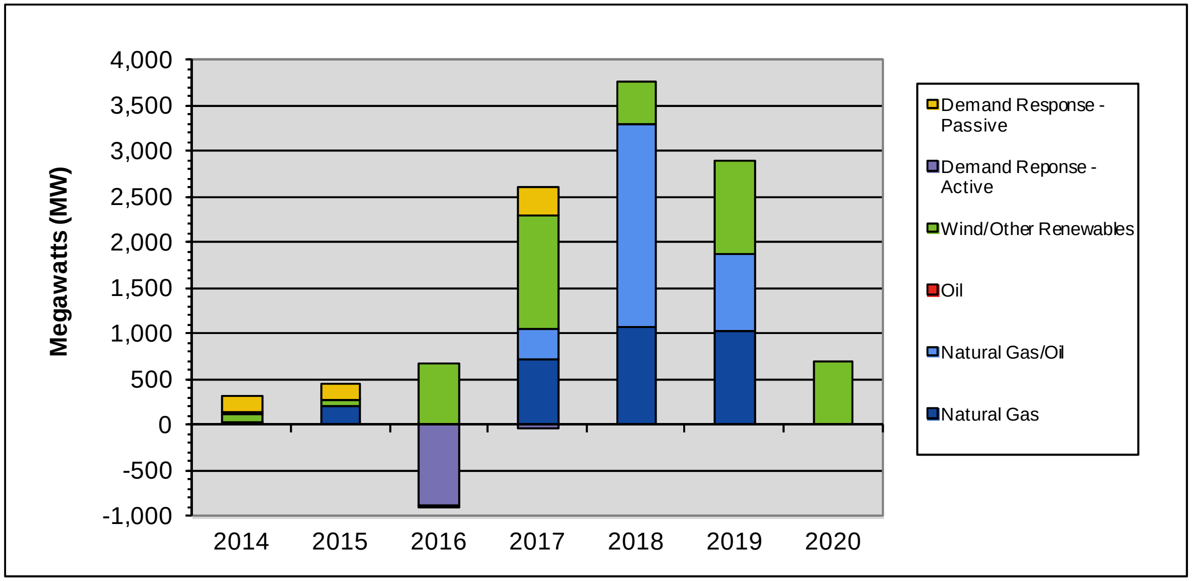
New Generation Update

Based on 2/1/15 Queue Update

- Two new projects, with a total rating of 1,032 MW, have applied for interconnection study since the last update
  - The new projects consist of one new combined cycle plant, and reconfiguration of an existing combined cycle plant. The expected in-service dates are 2016 and 2019.
- One project withdrew from the Queue
- In total, 62 generation projects are currently being tracked by the ISO, totaling approximately 10,600 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



	2014	2015	2016	2017	2018	2019	2020	Total MW	% of Total[1]
Demand Response - Passive	188	157	-12	330	0	0	0	663	6.3
Demand Response - Active	19	3	-868	-37	0	0	0	-883	-8.4
Wind & Other Renewables	93	70	667	1,230	458	1,029	698	4,245	40.4
Oil	0	0	0	0	0	0	0	0	0.0
Natural Gas/Oil[2]	2	0	10	346	2,223	837	0	3,418	32.6
Natural Gas	21	215	0	716	1,075	1,030	0	3,057	29.1
Totals	**323**	**445**	**-203**	**2,585**	**3,756**	**2,896**	**698**	**10,500**	**100.0**

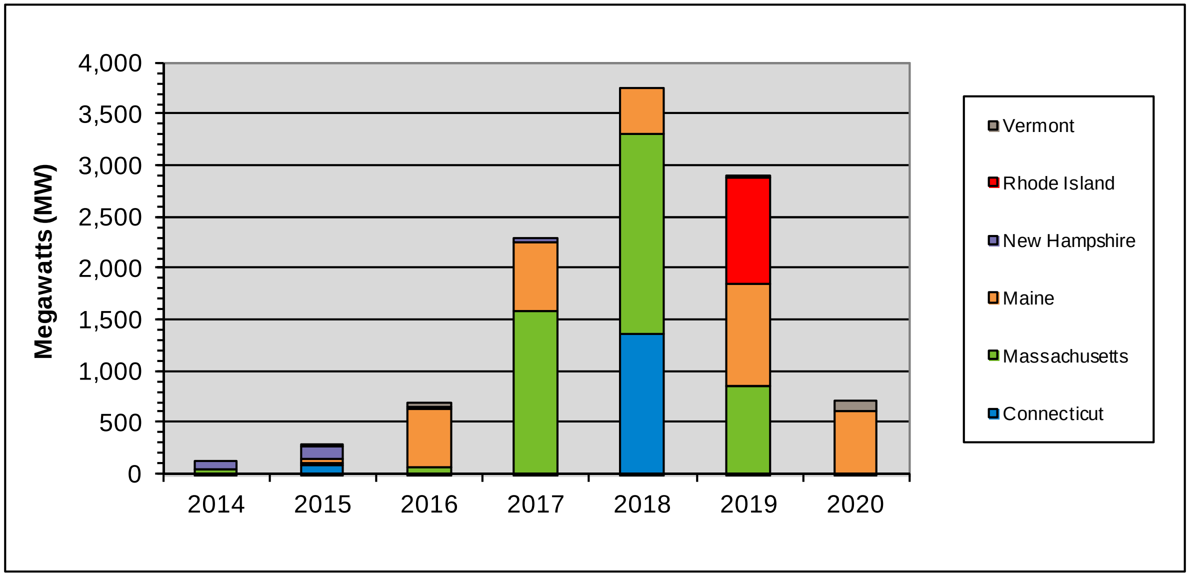
[1] **Sum may not equal 100% due to rounding**

[2] **The projects in this category are dual fuel, with either gas or oil as the primary fuel**

- 2014 values include the 116 MW of generation that went commercial in 2014
- Active DR value reflects the 600 MW limit on Real-Time Emergency Generation resources
- DR reflects changes from the initial FCM Capacity Supply Obligations in 2010-11

Actual and Projected Annual Generator Capacity Additions

By State



	2014	2015	2016	2017	2018	2019	2020	Total MW	% of Total[1]
Vermont	0	0	33	0	0	30	97	160	1.5
Rhode Island	0	27	29	0	0	1,030	0	1,086	10.1
New Hampshire	89	116	0	51	0	0	0	256	2.4
Maine	0	52	567	675	458	999	601	3,352	31.3
Massachusetts	27	6	48	1,566	1,935	837	0	4,419	41.2
Connecticut	0	84	0	0	1,363	0	0	1,447	13.5
Totals	**116**	**285**	**677**	**2,292**	**3,756**	**2,896**	**698**	**10,720**	**100.0**

[1] **Sum may not equal 100% due to rounding**

- 2014 values consist of the generation that went commercial in 2014

New Generation Projection

By Fuel Type

Fuel Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	2	70	0	0	2	70
Hydro	5	35	0	0	5	35
Landfill Gas	0	0	0	0	0	0
Natural Gas	10	3,036	0	0	10	3,036
Natural Gas/Oil	12	3,416	0	0	12	3,416
Oil	0	0	0	0	0	0
Solar	1	6	0	0	1	6
Wind	32	4,041	6	294	26	3,747
Total	62	10,604	6	294	56	10,310

- Projects in the Natural Gas/Oil category may have either gas or oil as the primary fuel
- Green denotes projects with a high probability of going into service
- Yellow denotes projects with a lower probability of going into service or new applications

New Generation Projection

By Operating Type

Operating Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	2	70	0	0	2	70
Intermediate	18	5,163	0	0	18	5,163
Peaker	10	1,330	0	0	10	1,330
Wind Turbine	32	4,041	6	294	26	3,747
Total	62	10,604	6	294	56	10,310

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

New Generation Projection

By Operating Type and Fuel Type

Fuel Type	Total		Baseload		Intermediate		Peaker		Wind Turbine	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	2	70	2	70	0	0	0	0	0	0
Hydro	5	35	0	0	4	10	1	25	0	0
Landfill Gas	0	0	0	0	0	0	0	0	0	0
Natural Gas	10	3,036	0	0	7	2,479	3	557	0	0
Natural Gas/Oil	12	3,416	0	0	7	2,674	5	742	0	0
Oil	0	0	0	0	0	0	0	0	0	0
Solar	1	6	0	0	0	0	1	6	0	0
Wind	32	4,041	0	0	0	0	0	0	32	4,041
Total	62	10,604	2	70	18	5,163	10	1,330	32	4,041

- Projects in the Natural Gas/Oil category may have either gas or oil as the primary fuel

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 5

Resource Type	Resource Type	FCA	Proration		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	**Change	ARA 2	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	2,104.141	2,001.126	-103.015	1,385.670	-615.456	1,074.461	-311.21	899.125	-175.336	699.930	-199.195
	Passive Demand	1,485.713	1,397.586	-88.127	1,345.283	-52.303	1,348.593	3.31	1,365.947	17.354	1399.564	33.617
Demand Total		**3,589.854**	**3,398.712**	**-191.142**	**2,730.953**	**-667.759**	**2,423.054**	**-307.90**	**2,265.072**	**-157.982**	**2099.494**	-165.578
Generator	*Non-Intermittent*	30,558.220	28,337.481	-2,220.739	27,917.690	-419.791	28,364.588	446.90	28,517.097	152.509	28557.855	40.758
	Intermittent	880.737	827.804	-52.933	778.165	-49.639	795.545	17.38	795.767	0.222	718.908	-76.859
Generator Total		**31,438.957**	**29,165.285**	**-2,273.672**	**28,695.855**	**-469.430**	**29,160.133**	464.28	**29,312.864**	**152.731**	**29276.763**	-36.101
Import Total		**2,011.001**	**1,831.372**	**-179.629**	**1,831.372**	**0.000**	**1,635.835**	-195.54	**1,635.835**	**0.000**	**1382.551**	-253.284
***Grand Total**		**37,039.812**	**34,395.369**	**-2,644.443**	**33,258.180**	**-1,137.189**	**33,219.022**	-39.16	**33,213.771**	**-5.251**	**32,758.808**	-454.963
Net ICR (NICR)		**33,200**	**33,200**	**0**	**33,200**	**0**	**32,209**	**-991**	**32,209**	**0**	**32,588**	**379**

* 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.

Capacity Supply Obligation FCA 6

Resource Type	Resource Type	FCA	Proration		Annual Bilateral for ARA 1		ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	**Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	2,001.510	1,918.662	-82.848	1,368.608	-550.054	1,271.984	-96.624	1,085.347	-186.64	842.791	-242.56	789.366	-53.425		
	Passive Demand	1,643.334	1,553.054	-90.280	1,521.535	-31.519	1,521.535	0.000	1,516.504	-5.03	1,700.586	184.08	1,694.766	-5.82		
Demand Total		**3,644.844**	**3,471.716**	**-173.128**	**2,890.143**	**-581.573**	**2,793.519**	-96.624	**2,601.851**	**-191.67**	2,543.377	-58.47	2,484.132	-59.245		
Generator	*Non-Intermittent*	29,866.098	27,957.613	-1,908.485	28,121.731	164.118	28,343.440	221.709	28,442.424	98.98	28,727.16	284.73	28,881.019	153.859		
	Intermittent	891.069	840.563	-50.506	827.047	-13.516	828.252	1.205	829.219	0.97	820.743	-8.48	777.924	-42.819		
Generator Total		**30,757.167**	**28,798.176**	**-1,958.991**	**28,948.778**	**150.602**	**29,171.692**	222.914	**29,271.643**	**99.95**	29,547.9	276.26	29,658.943	111.043		
Import Total		**1,924.000**	**1,768.111**	**-155.889**	**1,768.111**	**0.000**	**1,641.821**	-126.290	**1,616.821**	**-25.00**	1,399.037	-217.78	1,337.037	-62		
*****Grand Total**		**36,326.011**	**34,038.003**	**-2,288.008**	**33,607.032**	**-430.971**	**33,607.032**	0.000	**33,490.315**	**-116.72**	33,490.32	0.00	33,480.112	-10.208		
Net ICR (NICR)		**33,456**	**33,456**	**0**	**33,456**	**0**	**33,456**	**0**	33,114	**-342**	**33,114**	0.00	**33,391**	**277**		

* 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.

Capacity Supply Obligation FCA 7

Resource Type	Resource Type	FCA	Proration		Annual Bilateral for ARA 1		ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	**Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	1,116.698	1,043.719	-72.979	944.27	-99.45	932.721	-11.549								
	Passive Demand	1,631.335	1,519.740	-111.595	1,519.311	-0.43	1,543.793	24.482								
Demand Total		**2,748.033**	**2,563.459**	**-184.574**	**2,463.581**	**-99.88**	**2,476.514**	**12.933**								
Generator	*Non-Intermittent*	30,704.578	28,146.837	-2,557.741	28,127.044	-19.79	28,523.002	395.958								
	Intermittent	936.913	893.710	-43.203	903.244	9.53	913.083	9.839								
Generator Total		**31,641.491**	**29,040.547**	**-2,600.944**	**29,030.288**	**-10.26**	**29,436.085**	**405.797**								
Import Total		**1,830.000**	**1,606.862**	**-223.138**	**1,606.862**	**0.00**	**1,616.401**	**9.539**								
*****Grand Total**		**36,219.524**	**33,210.868**	**-3,008.656**	**33,100.731**	**-110.14**	**33,529.000**	**428.269**								
Net ICR (NICR)		**32,968**	**32,968**	**0**	33,529	561	33,529	0								

* 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.

Capacity Supply Obligation FCA 8

Resource Type	Resource Type	FCA	Annual Bilateral for ARA 1		ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	1,080.079												
	Passive Demand	1,960.517												
Demand Total		**3,040.596**												
Generator	*Non-Intermittent*	28,547.813												
	Intermittent	876.925												
Generator Total		**29,424.738**												
Import Total		**1,237.034**												
*****Grand Total**		**33,702.368**												
Net ICR (NICR)		**33,855**												

* 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

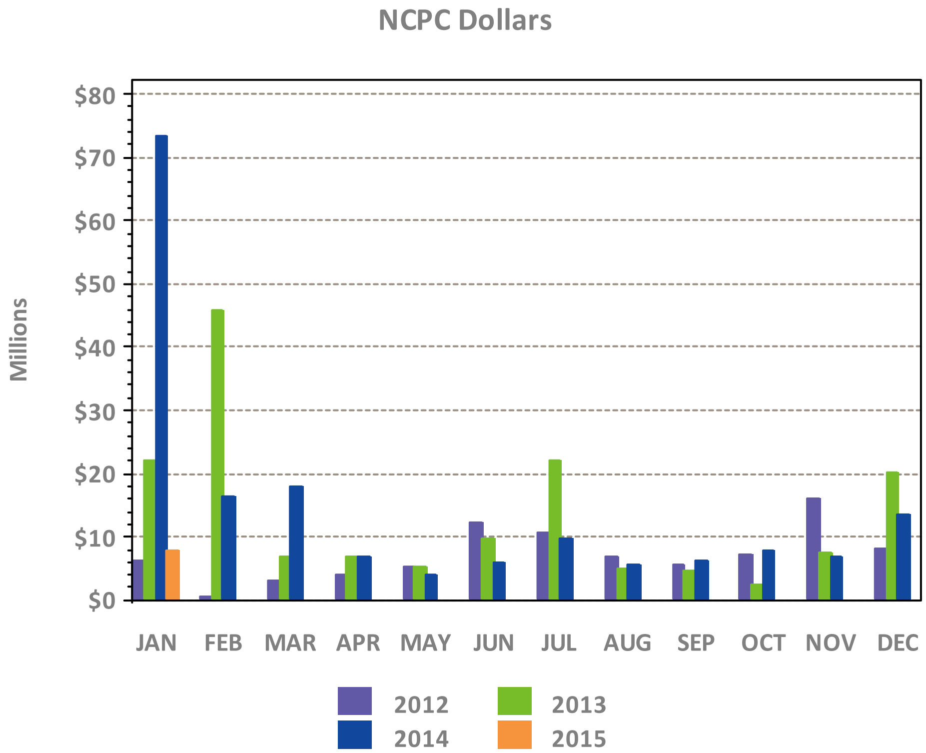
Definitions

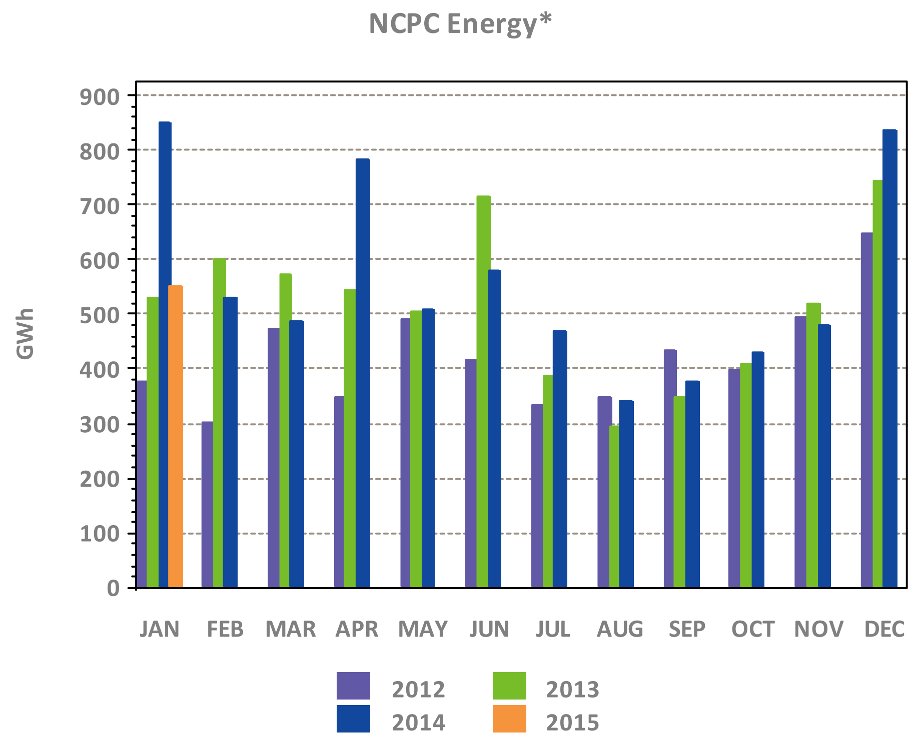
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing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

Charge Allocation Key

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

Year-Over-Year Total NCPC Dollars and Energy

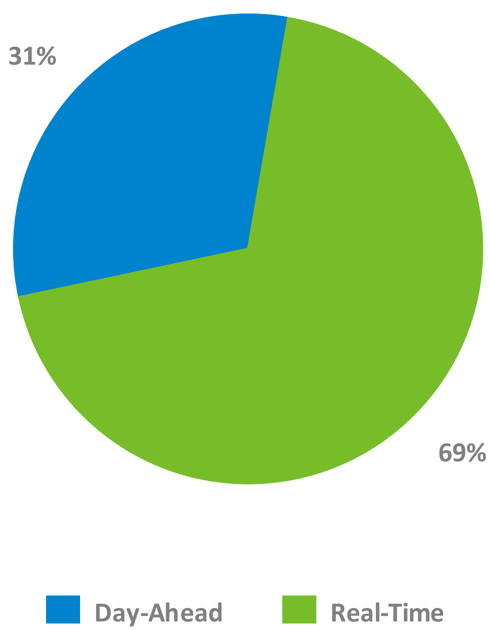




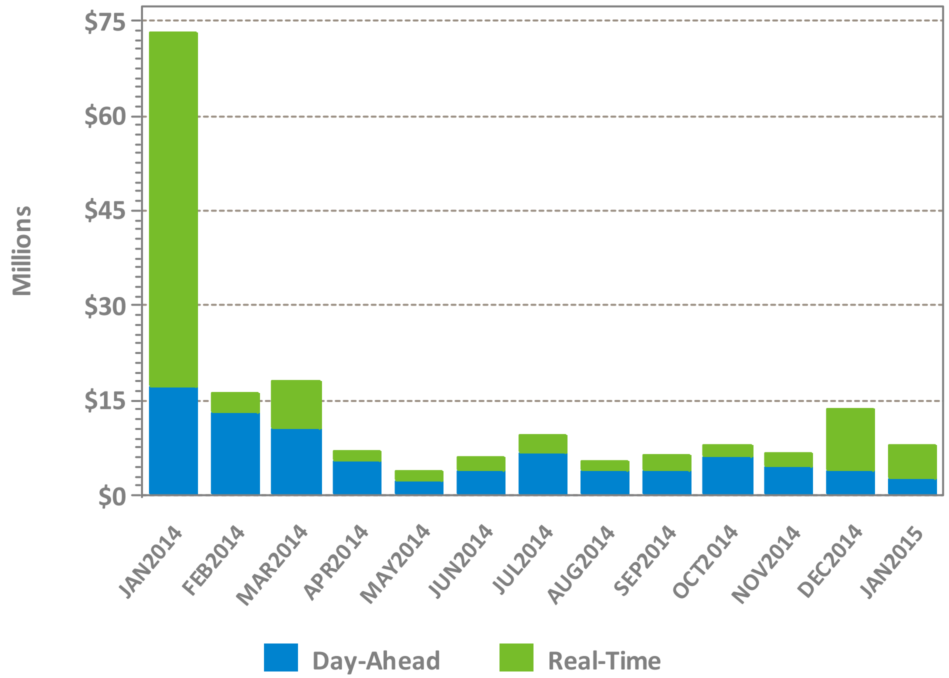
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits, assessed during hours in which they are NCPC-eligible. All NCPC components (1st Contingency, 2nd Contingency, Voltage, and RT Distribution) are reflected.

DA and RT NCPC Charges

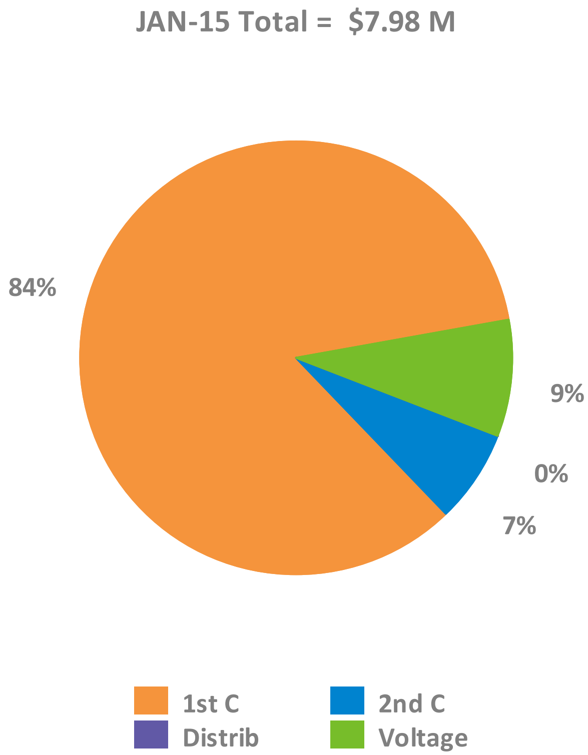
JAN-15 Total = $7.98 M

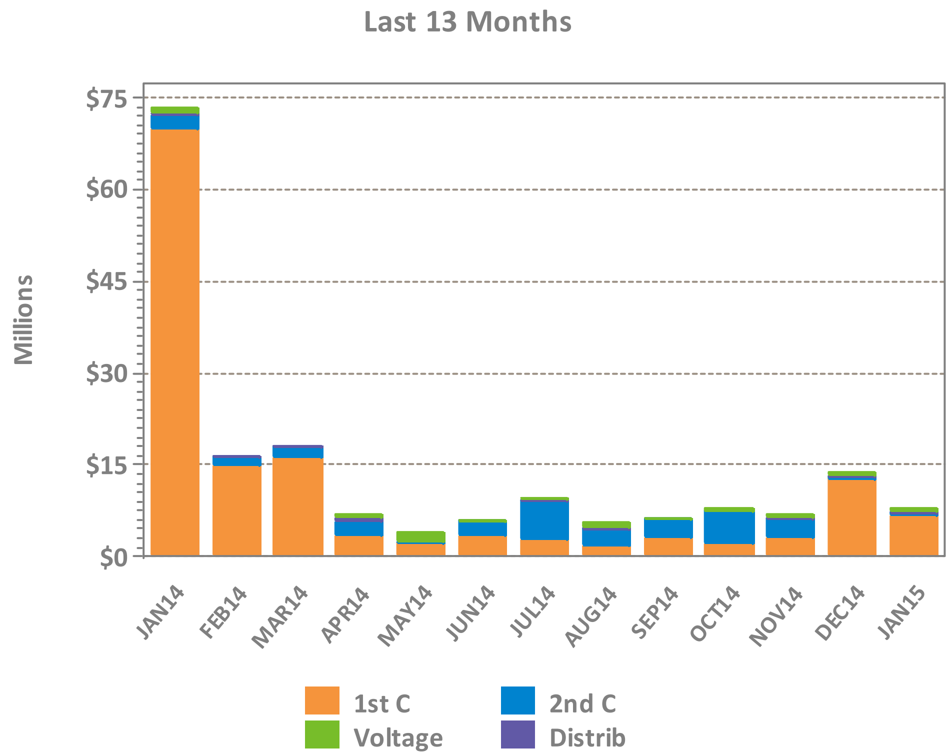


Last 13 Months



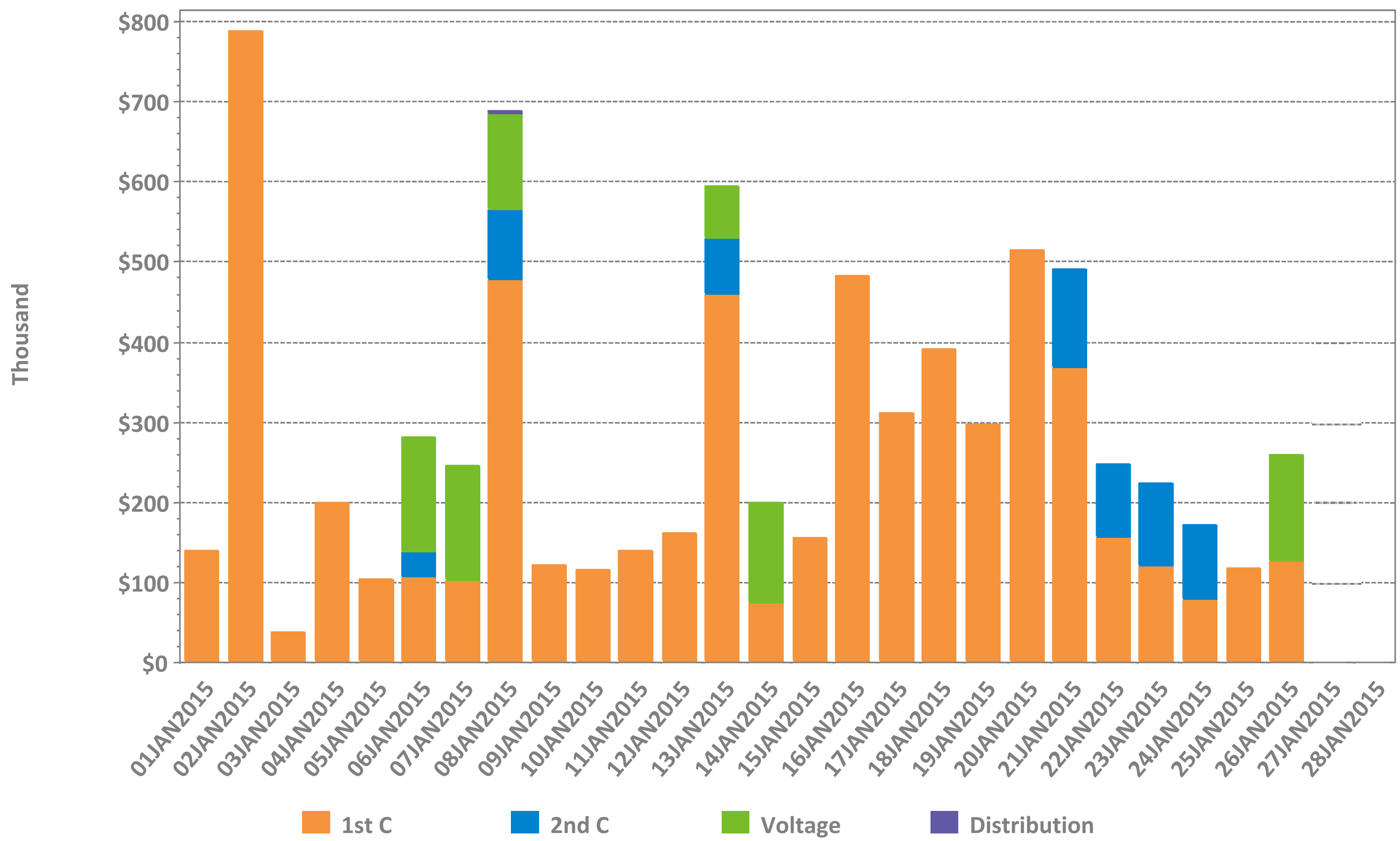
NCPC Charges by Type





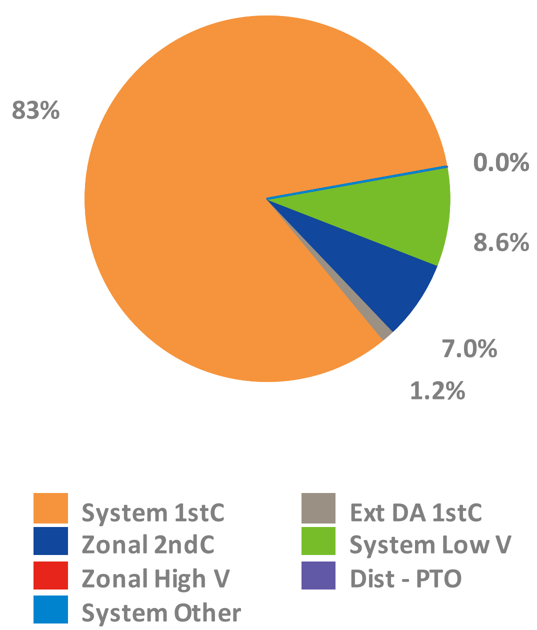
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type

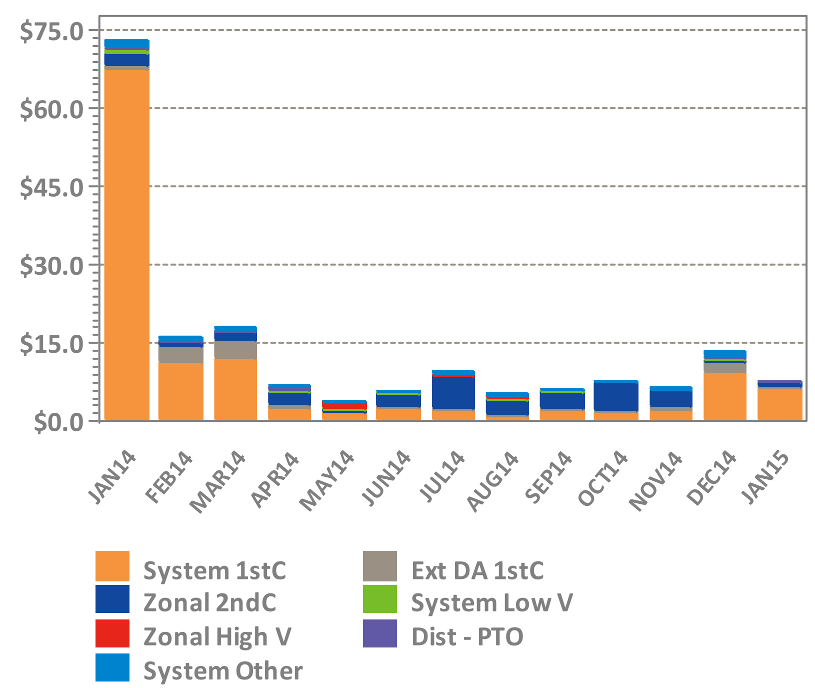


NCPC Charges by Allocation

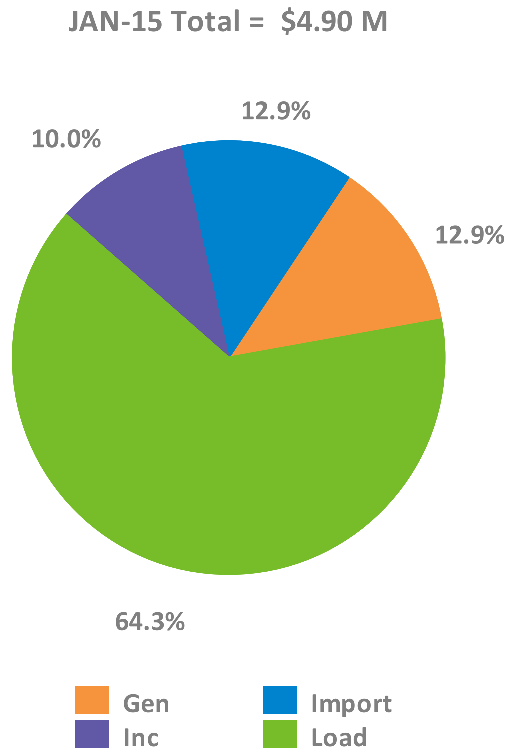
JAN-15 Total = $7.98 M

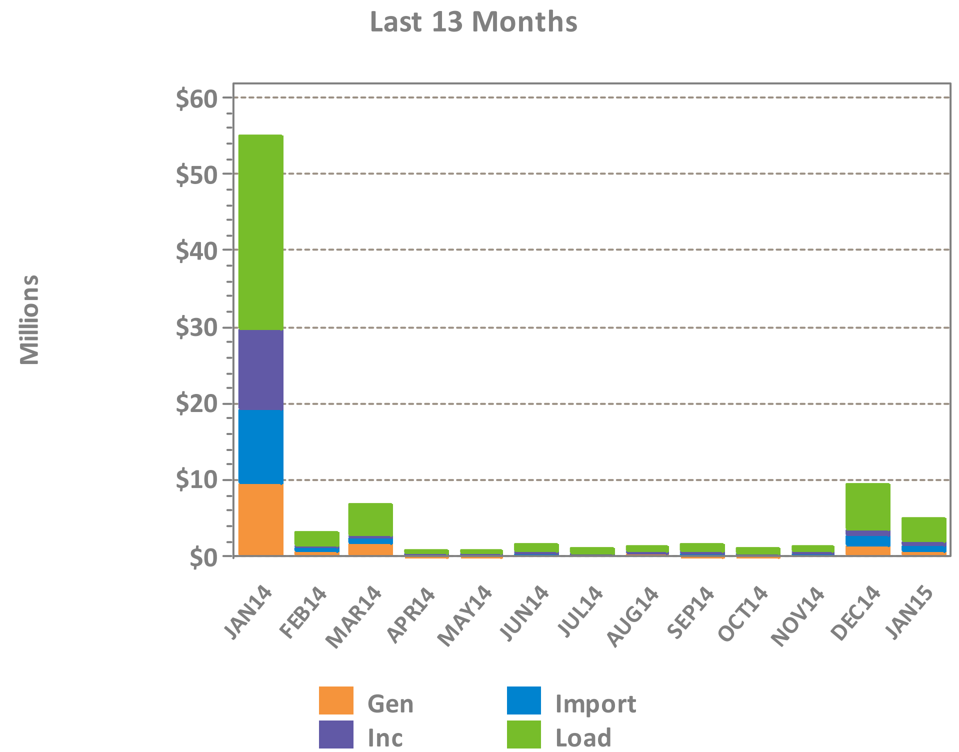


Last 13 Months



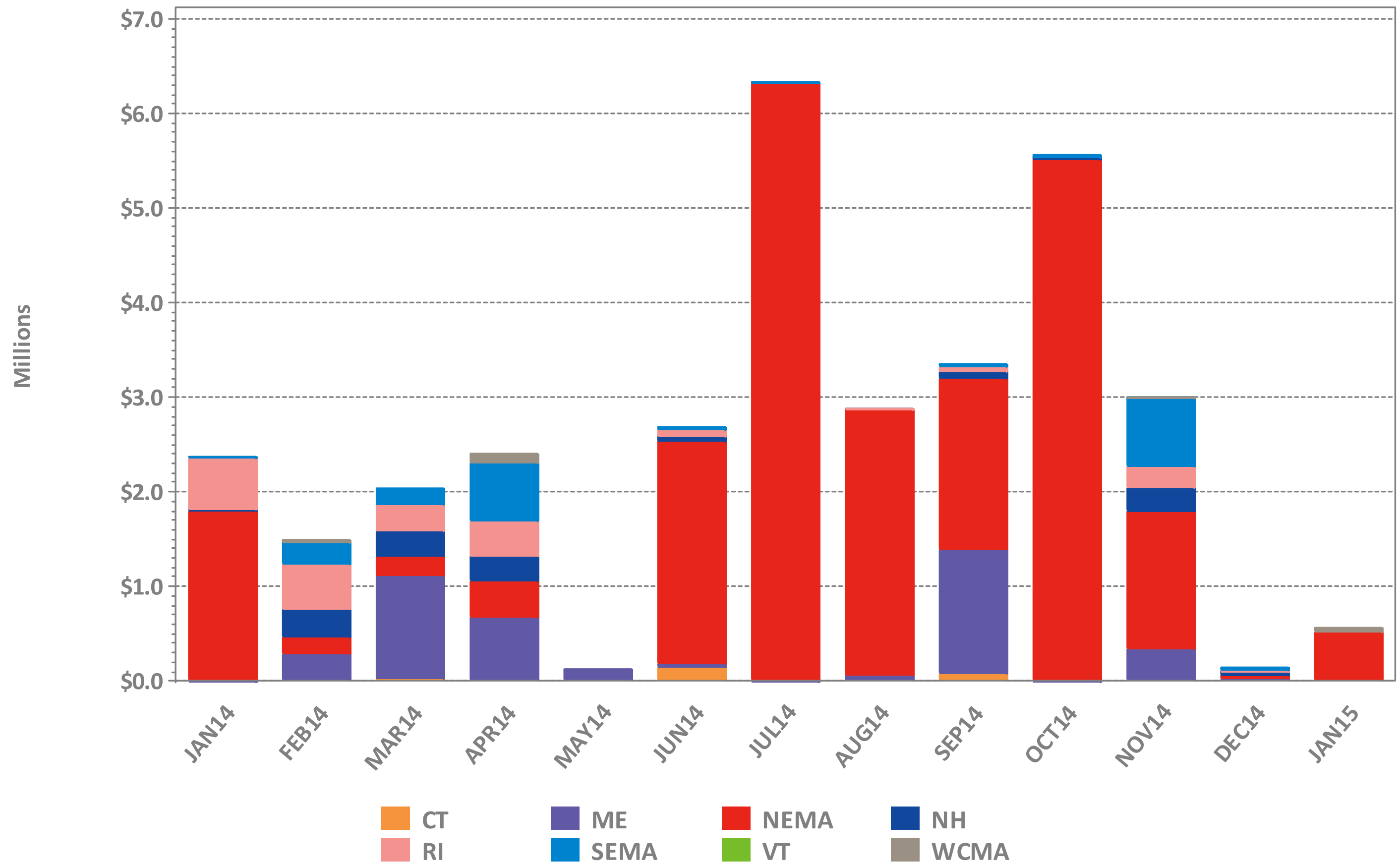
RT First Contingency Charges by Deviation Type





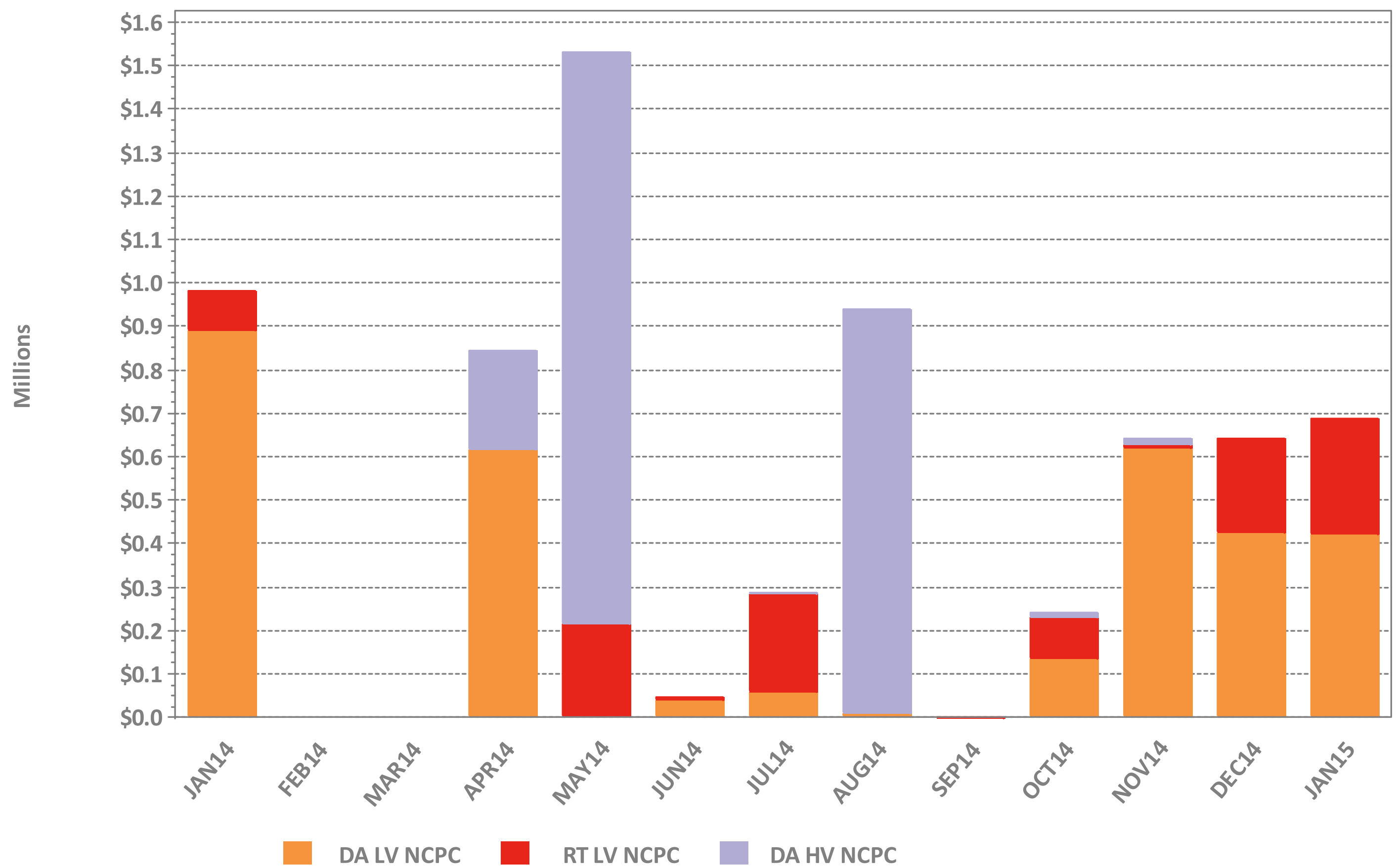
Gen – Generator deviations
Inc – Increment Offer deviations
Imp – Import deviations
Load – Load obligation deviations

LSCPR Charges by Zone

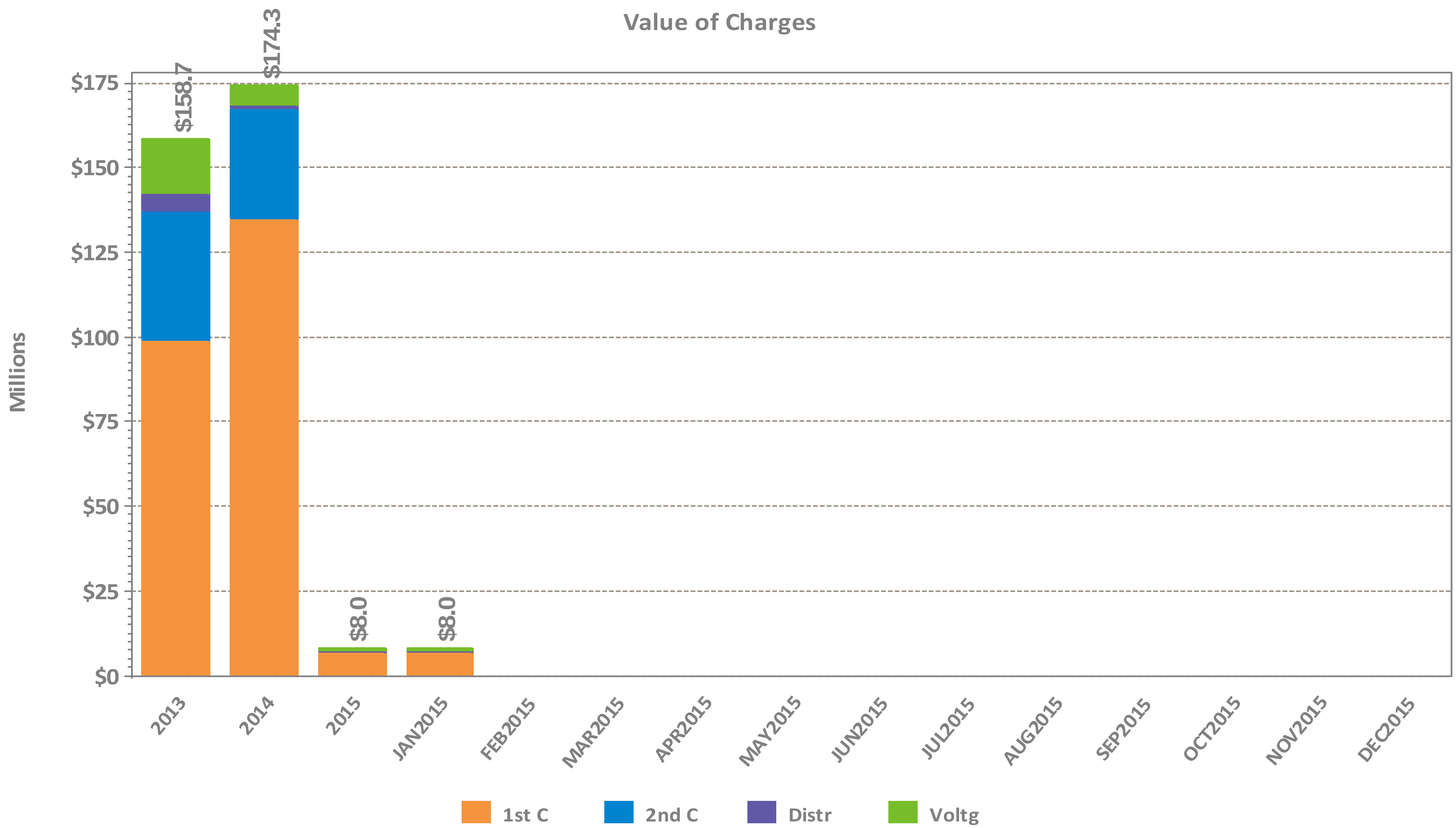


CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region
SEMA – Southeast Massachusetts Region
WCMA – Western/Central Massachusetts Region
NEMA – Northeast Massachusetts Region
EXT – External Locations

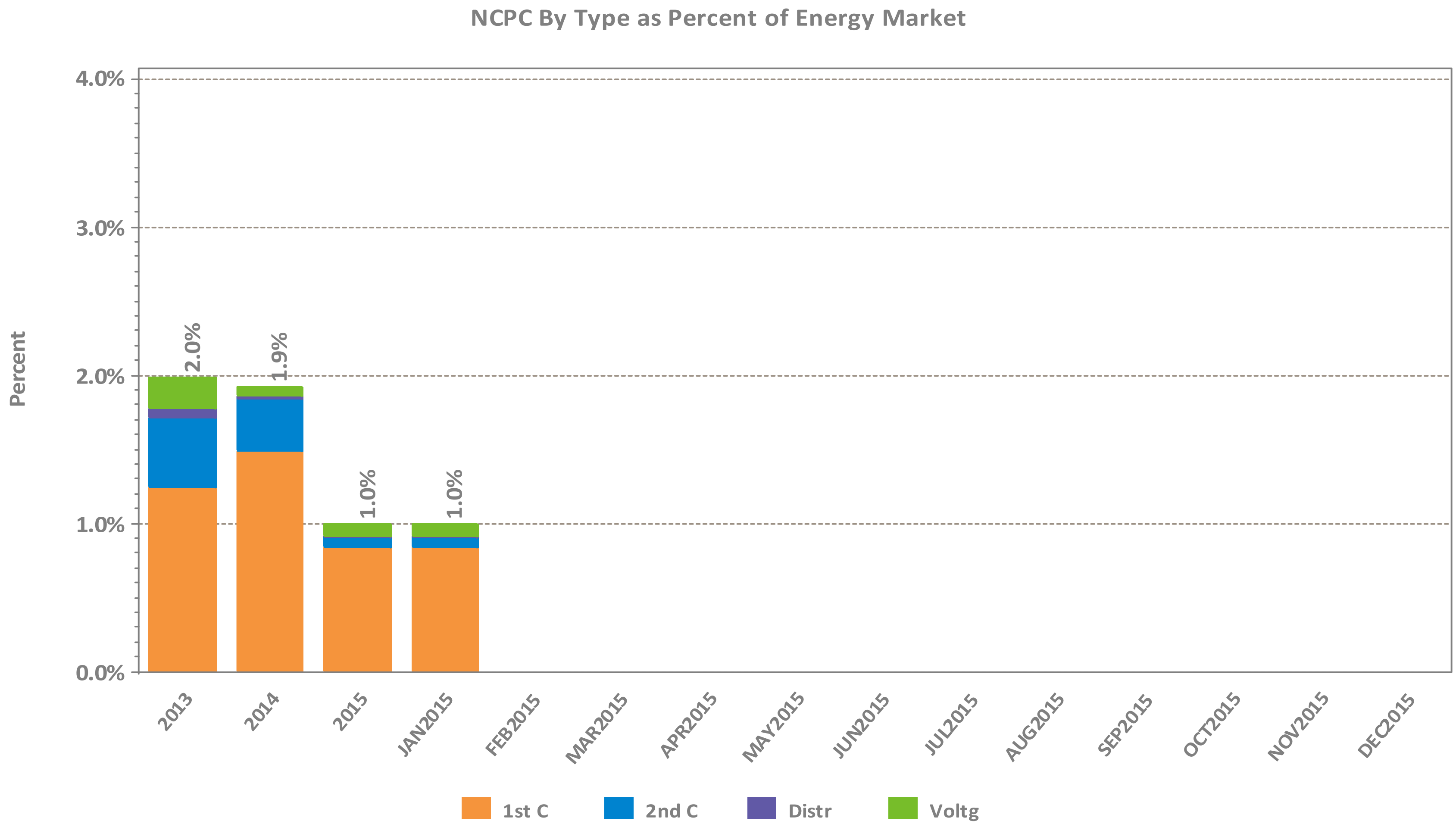
NCPC Charges for Voltage Support and High Voltage Control



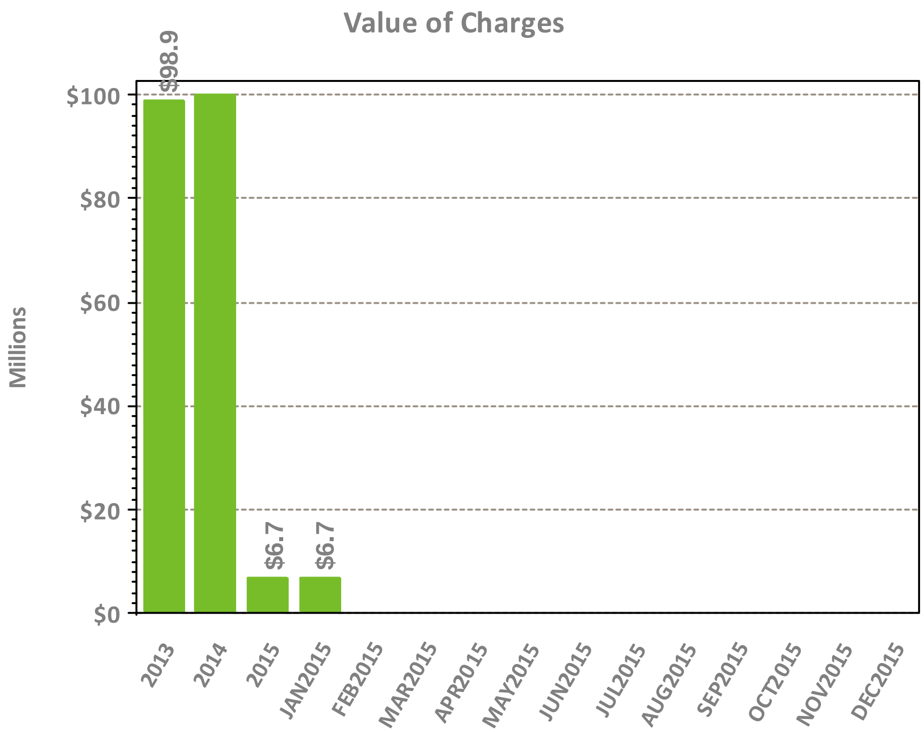
NCPC Charges by Type

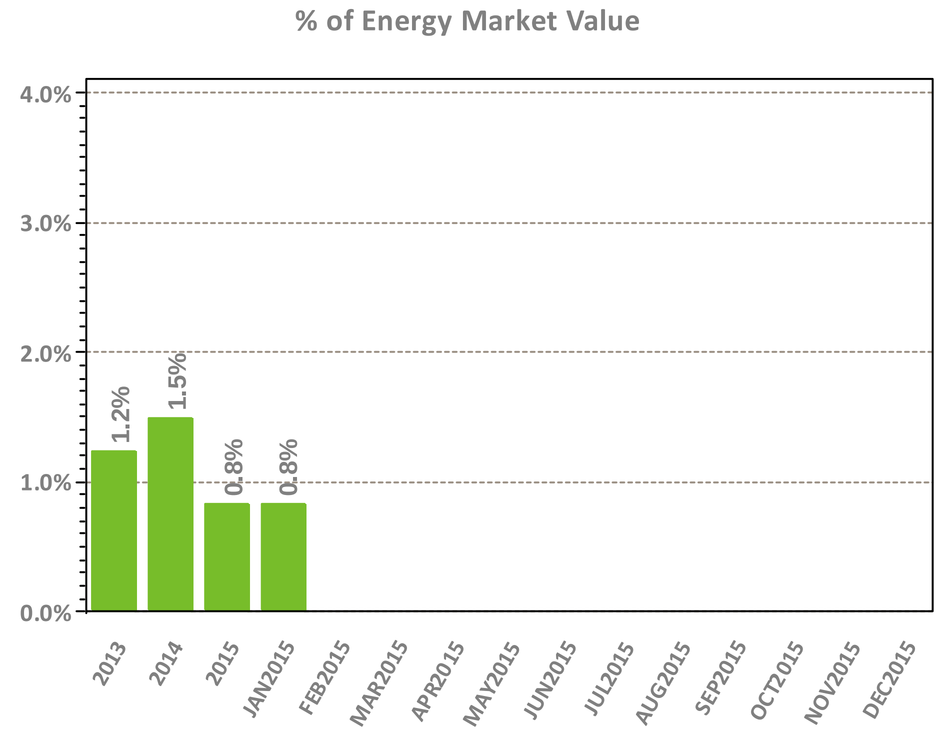


NCPC Charges as Percent of Energy Market



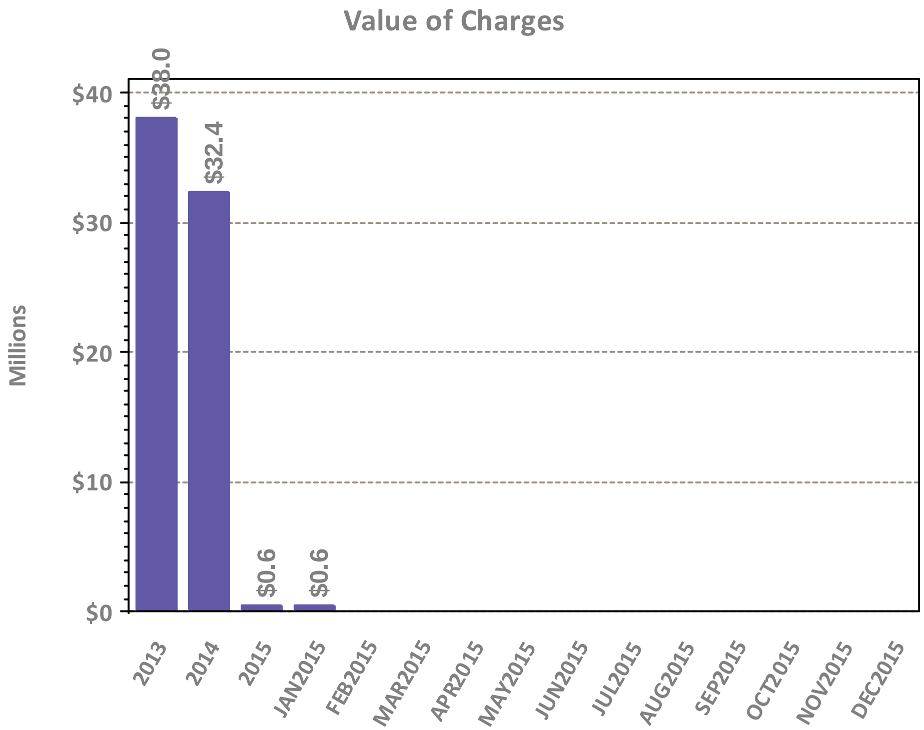
First Contingency NCPC Charges

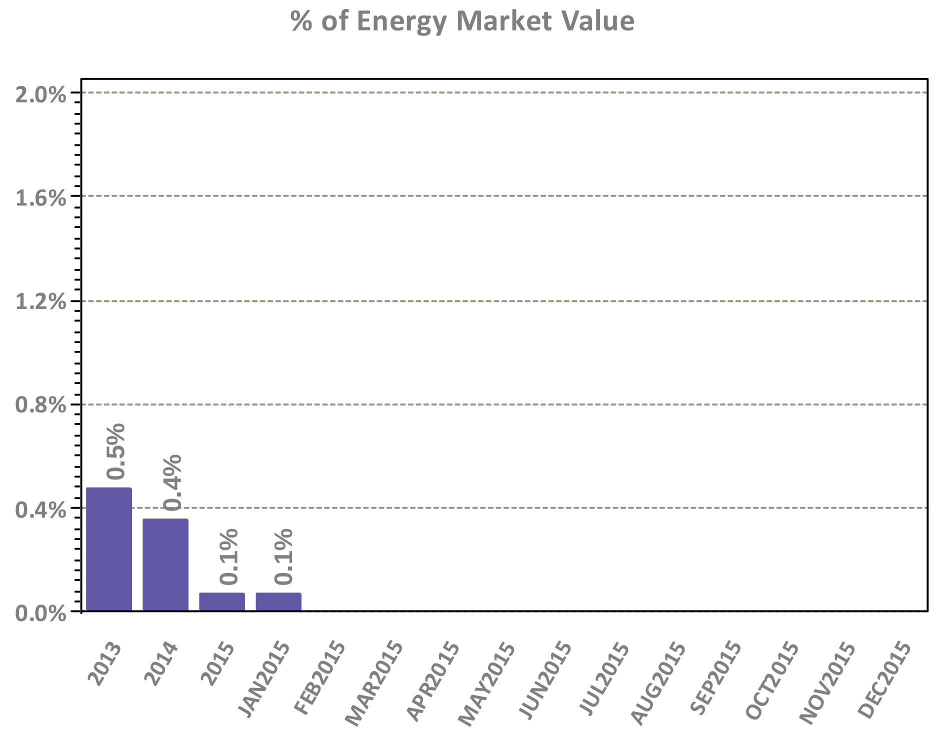




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

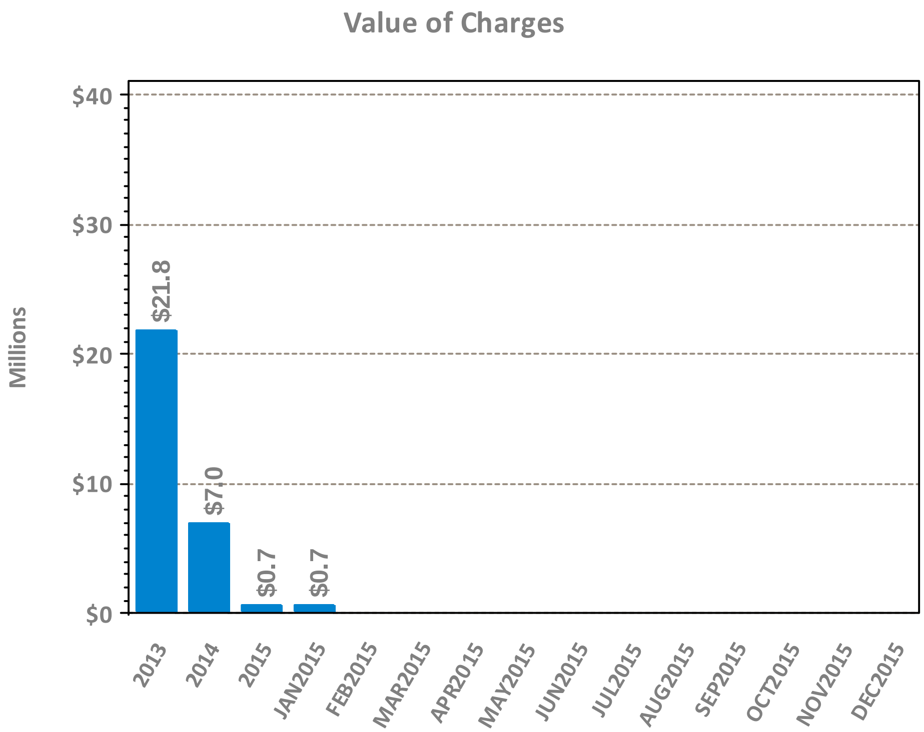
Second Contingency NCPC Charges

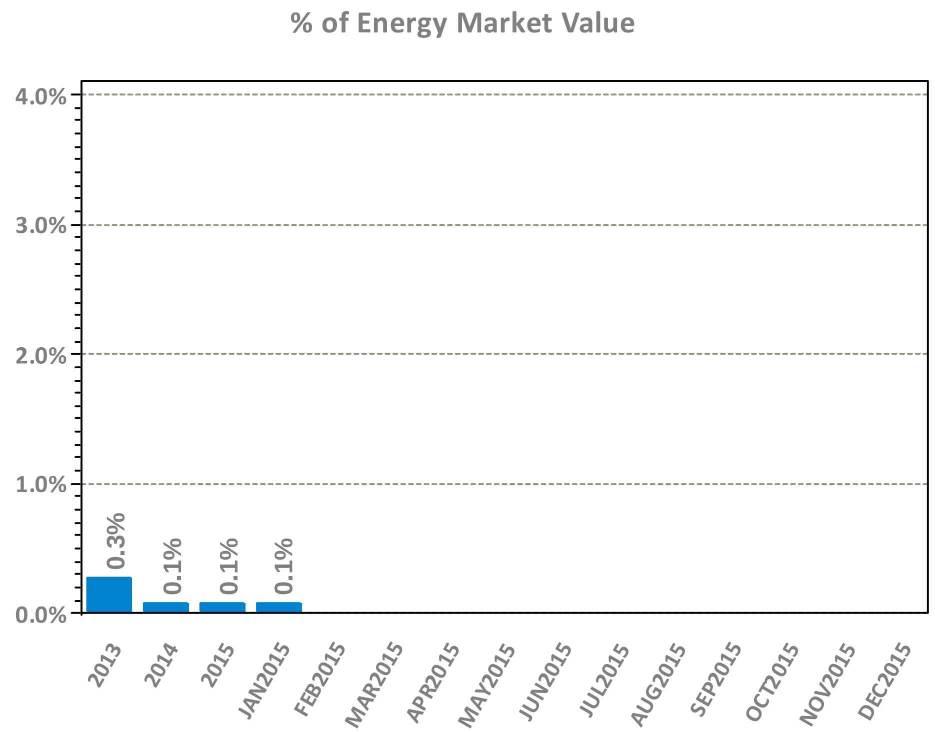




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

Voltage and Distribution NCPC Charges





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

DA vs. RT Pricing

The following slides outline:

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

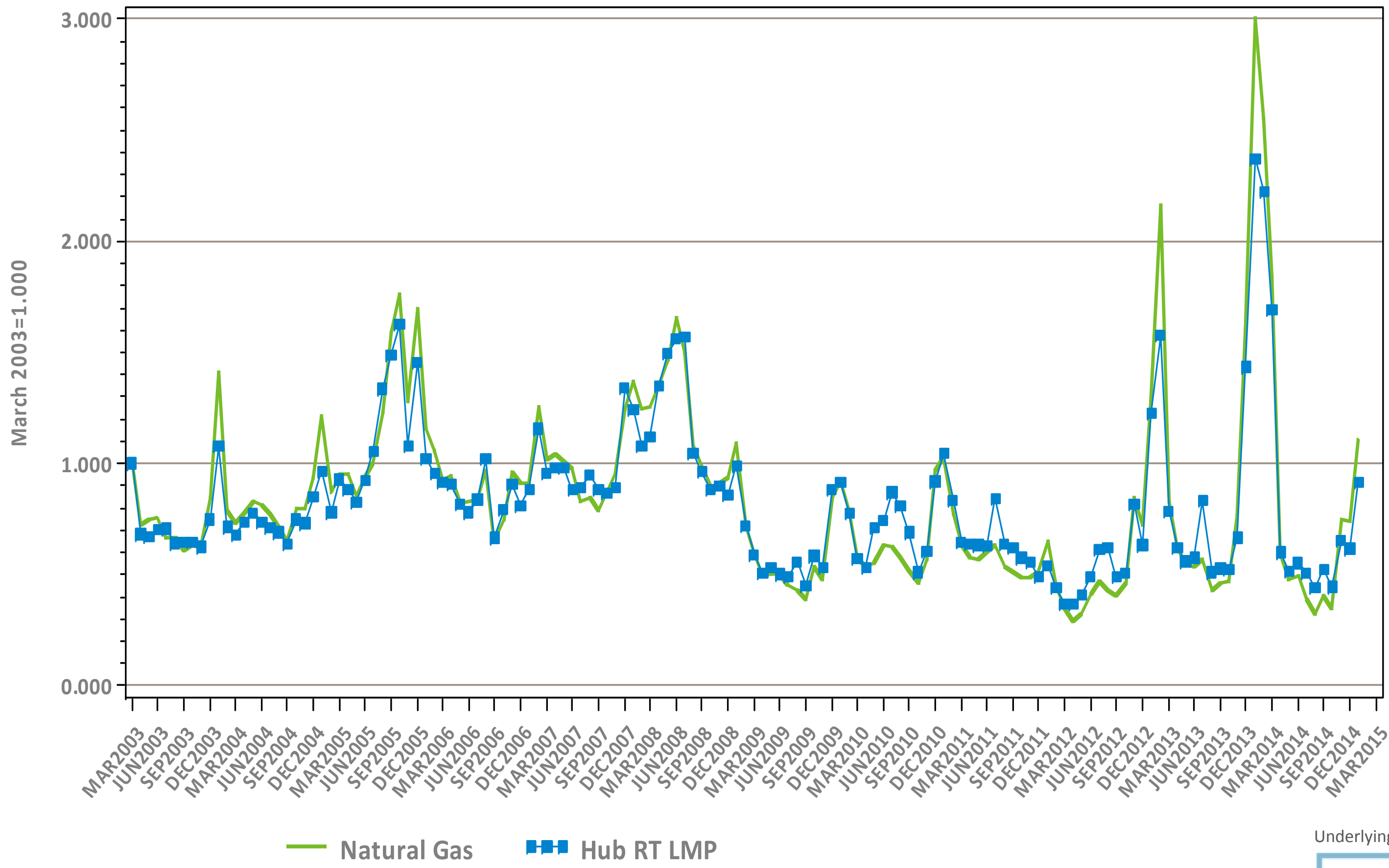
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 2013	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$56.90	$55.43	$54.48	$55.98	$55.36	$57.80	$57.02	$56.38	$56.43
Real-Time	$56.32	$55.90	$53.23	$55.15	$55.08	$56.10	$56.43	$56.12	$56.06
RT Delta %	-1.0%	0.8%	-2.3%	-1.5%	-0.5%	-2.9%	-1.0%	-0.5%	-0.7%
Year 2014	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Day-Ahead	$64.98	$64.10	$61.95	$64.12	$63.82	$64.98	$64.71	$64.66	$64.57
Real-Time	$64.03	$63.11	$59.04	$61.48	$61.60	$63.34	$63.45	$63.29	$63.32
RT Delta %	-1.5%	-1.5%	-4.7%	-4.1%	-3.5%	-2.5%	-2.0%	-2.1%	-1.9%

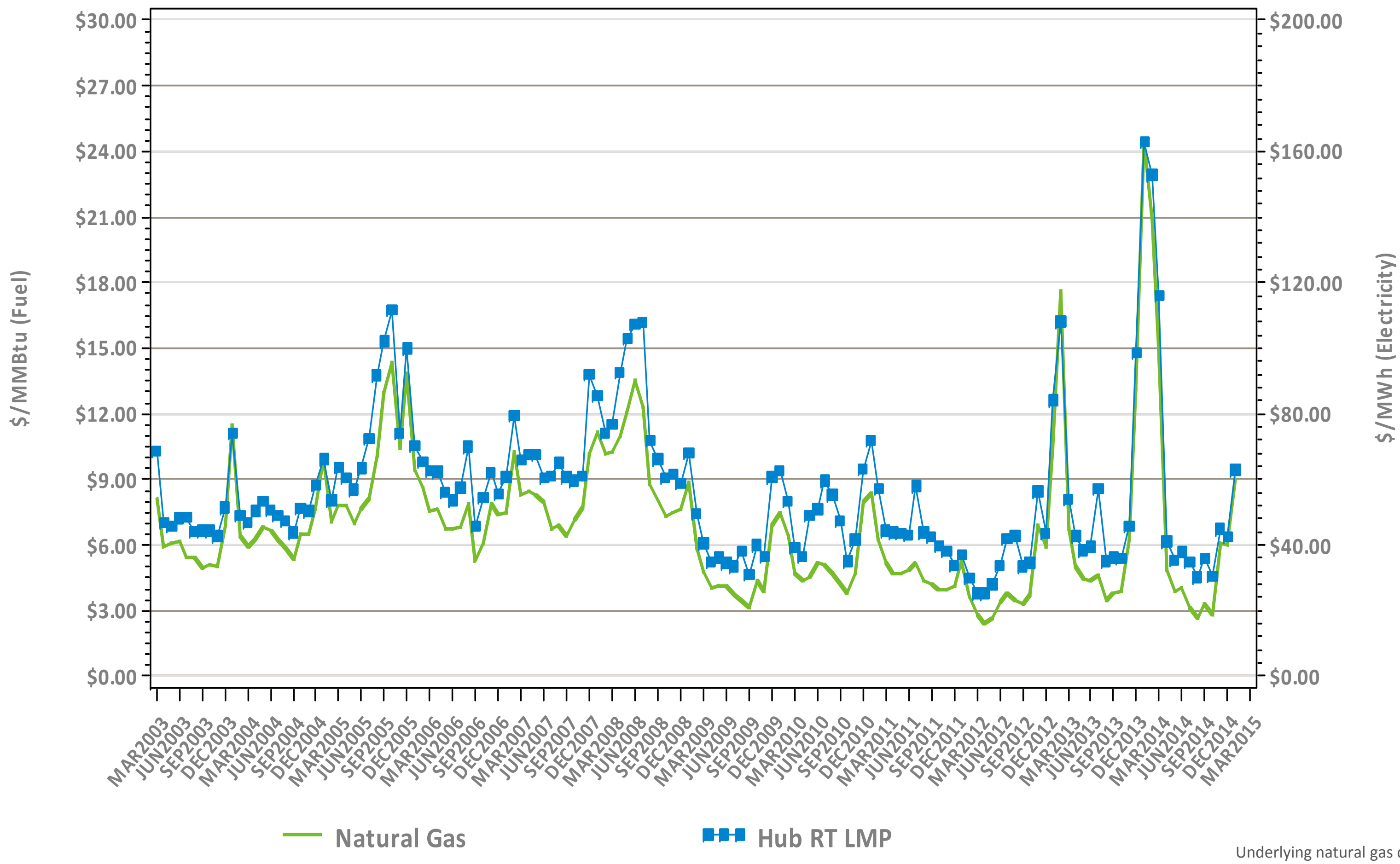
January-14	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$169.08	$166.43	$159.41	$166.87	$167.23	$170.33	$169.57	$169.09	$168.81
Real-Time	$164.26	$161.64	$138.28	$149.98	$156.45	$163.45	$163.44	$162.51	$162.88
RT Delta %	-2.8%	-2.9%	-13.3%	-10.1%	-6.4%	-4.0%	-3.6%	-3.9%	-3.5%
January-15	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Day-Ahead	$70.51	$68.87	$66.83	$69.16	$69.06	$69.99	$70.41	$70.05	$70.09
Real-Time	$63.48	$62.02	$60.36	$61.80	$61.76	$62.99	$63.25	$62.80	$62.94
RT Delta %	-10.0%	-10.0%	-9.7%	-10.6%	-10.6%	-10.0%	-10.2%	-10.4%	-10.2%
Annual Diff.	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Yr over Yr DA	-58.3%	-58.6%	-58.1%	-58.6%	-58.7%	-58.9%	-58.5%	-58.6%	-58.5%
Yr over Yr RT	-61.4%	-61.6%	-56.4%	-58.8%	-60.5%	-61.5%	-61.3%	-61.4%	-61.4%

Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by: ICE Global markets in clear view

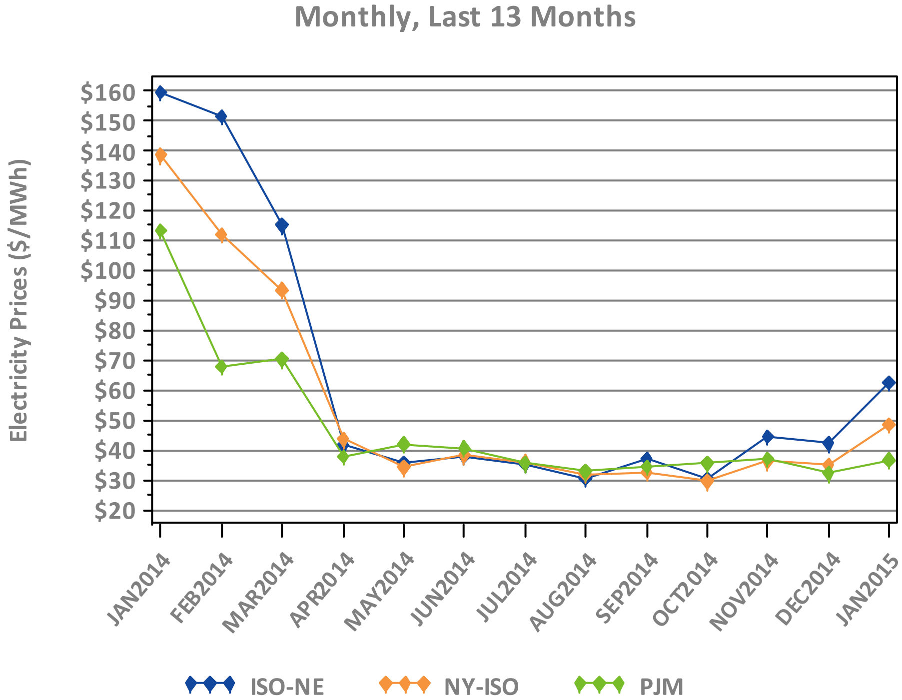
Monthly Average Fuel Price and RT Hub LMP



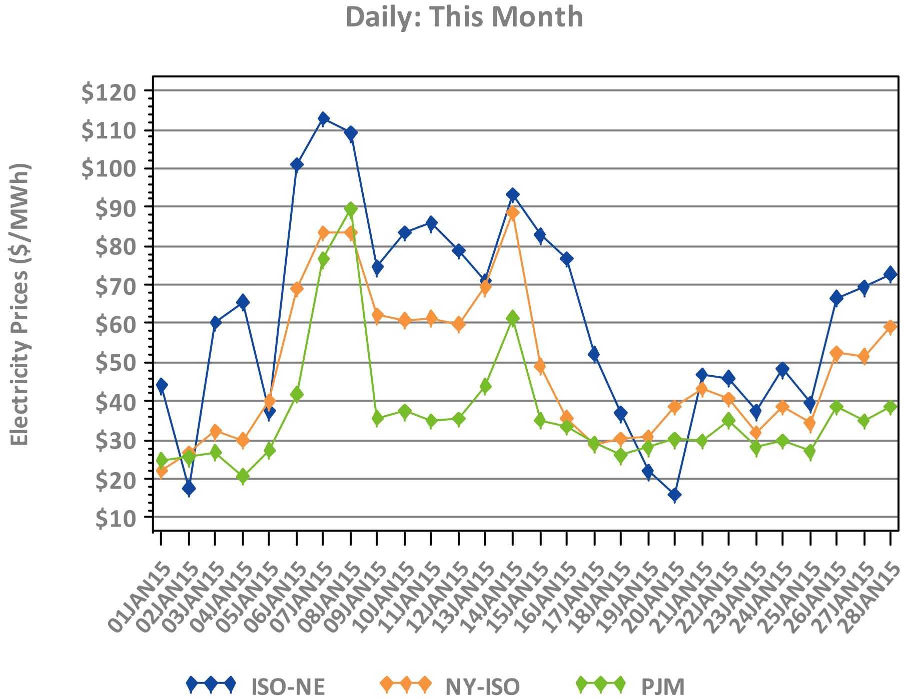
Underlying natural gas data furnished by:

ICE Global markets in clear view

New England, NY, and PJM Real Time Prices

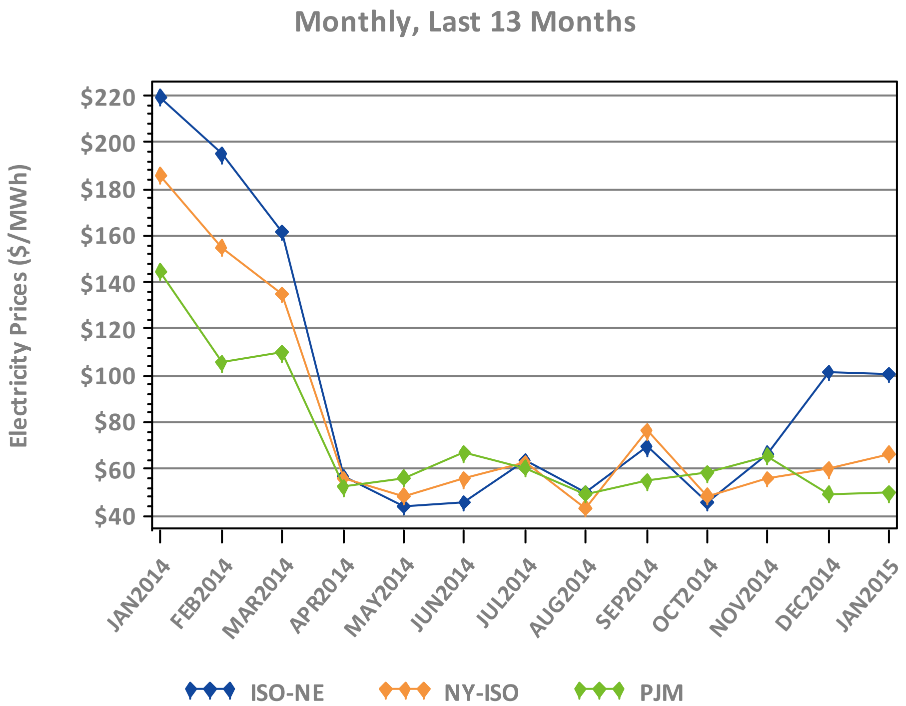


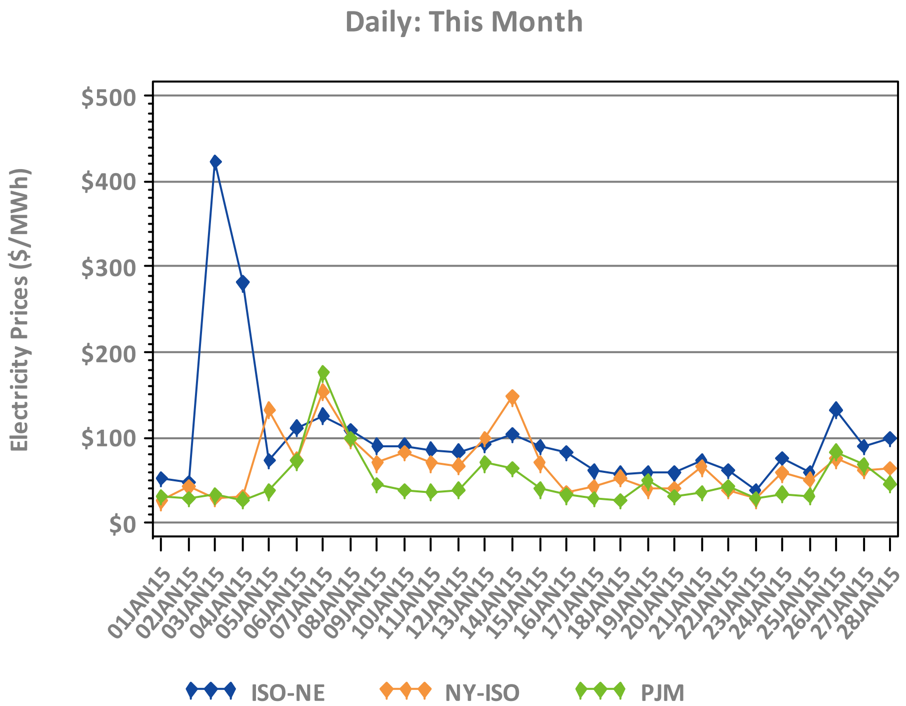
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

New England, NY, and PJM Real Time Prices (Peak Hour)





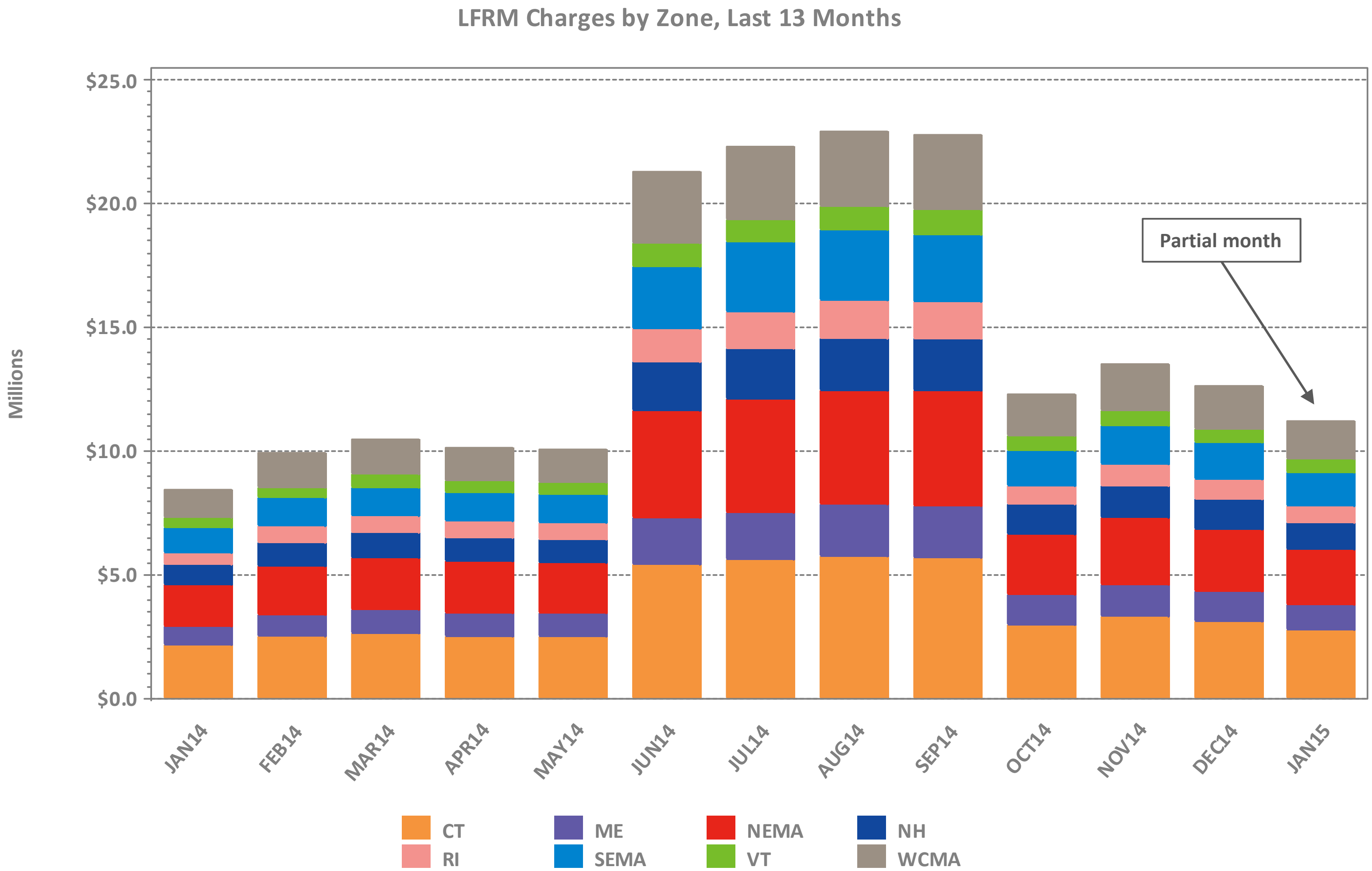
*Forecasted peak hour is reflected.

Reserve Market Results – January 2015

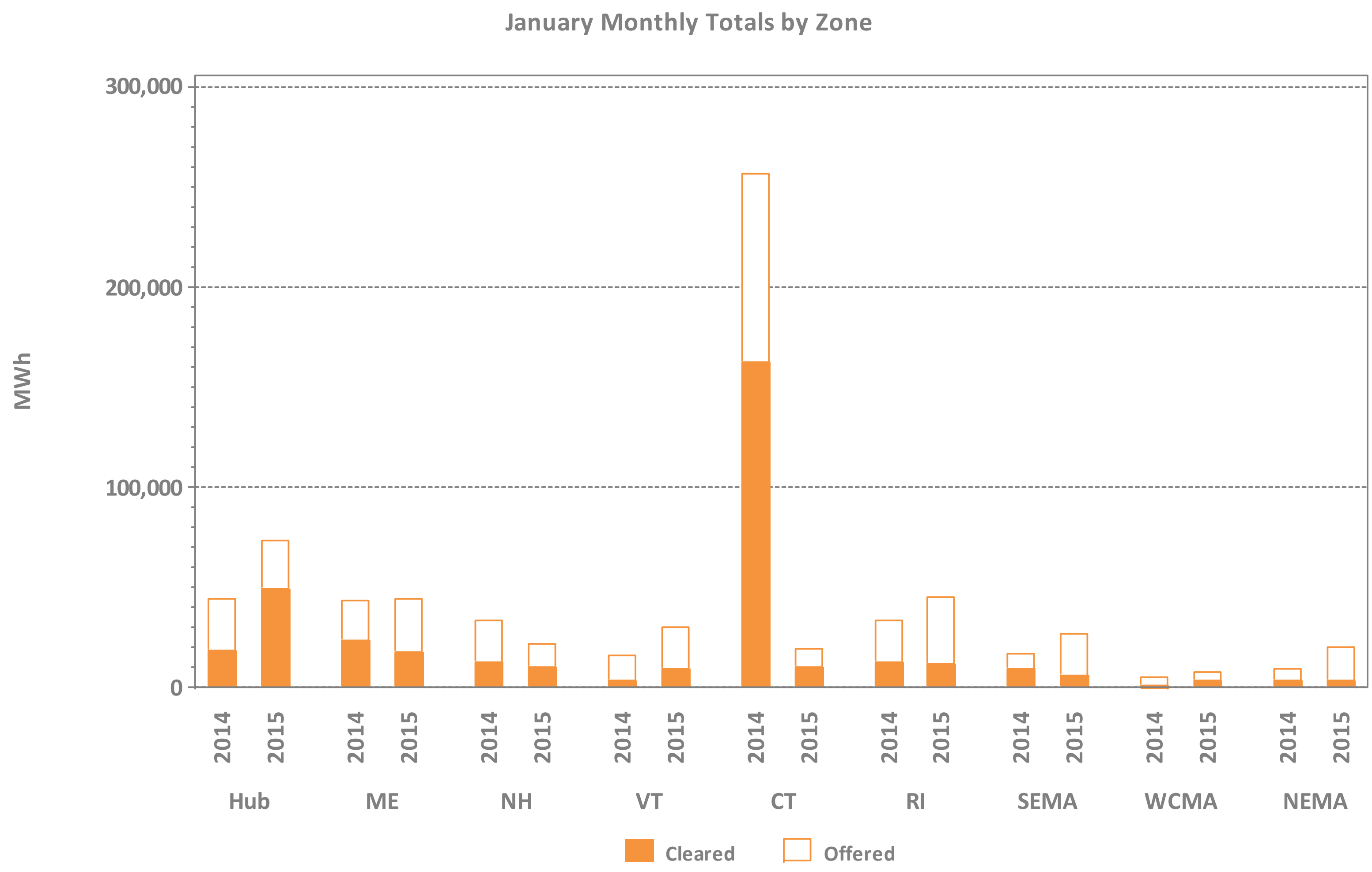
- Maximum potential Forward Reserve Market payments of $12.5M were reduced by credit reductions of $531K, failure-to-reserve penalties of $797K and failure-to-activate penalties of $0, resulting in a net payout of $11.2M or 89% of maximum
  - Rest of System: $6.59M/$6.88M (96%)
  - Southwest Connecticut: $0.57M/$1.01M (56%)
  - Connecticut: $4.03M/$4.63M (87%)
- $1.4M total Real-Time credits were reduced by $0 in Forward Reserve Energy Obligation Charges for a net of $1.4M in Real-Time Reserve payments
  - Rest of System: 89 hours, $702K
  - Southwest Connecticut: 89 hours, $333K
  - Connecticut: 89 hours, $277K
  - NEMA: 98 hours, $83K

*** “Failure to reserve” results in both credit reductions and penalties in the Locational Forward Reserve Market.**

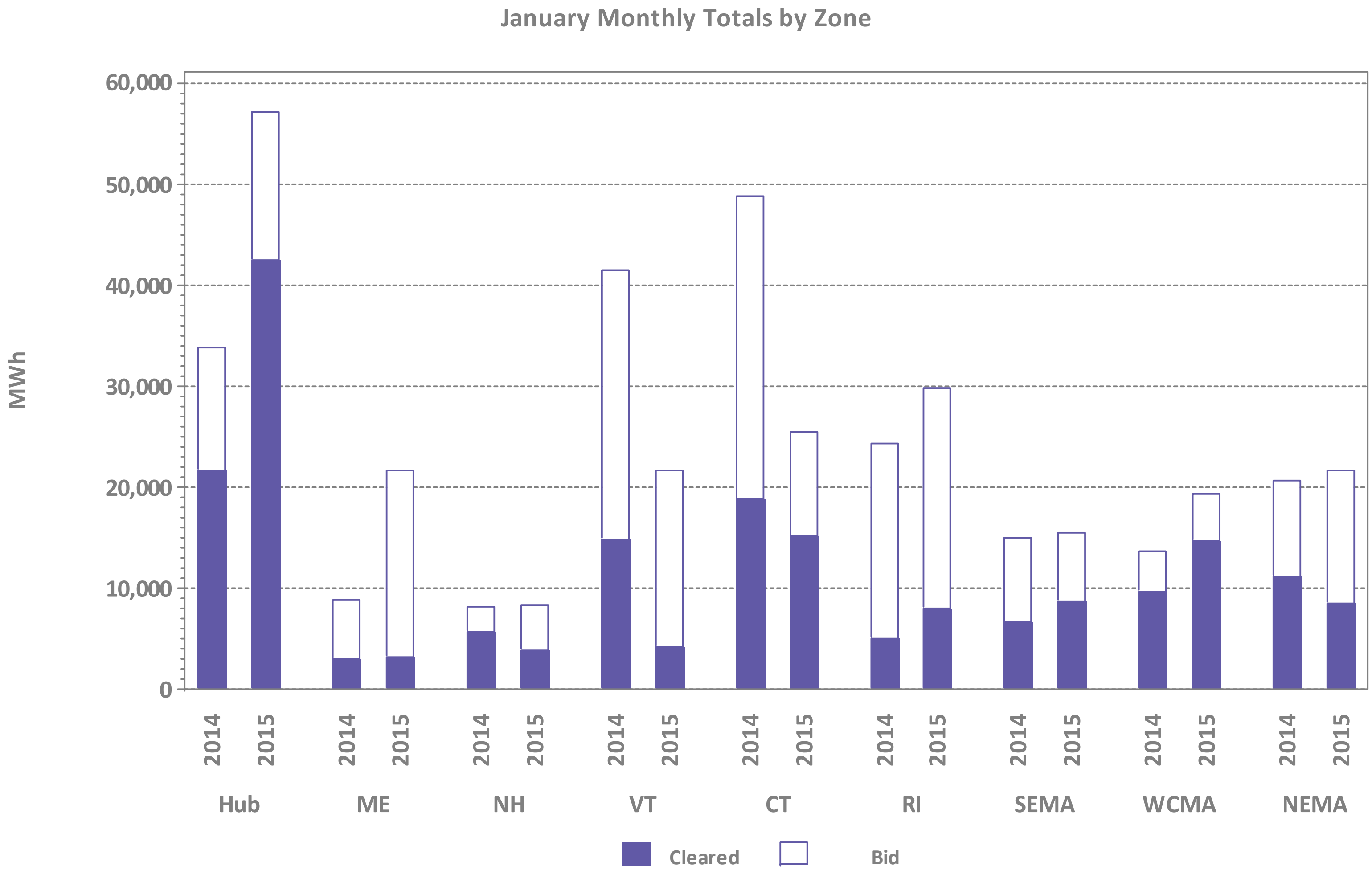
LFRM Charges to Load by Load Zone ($)



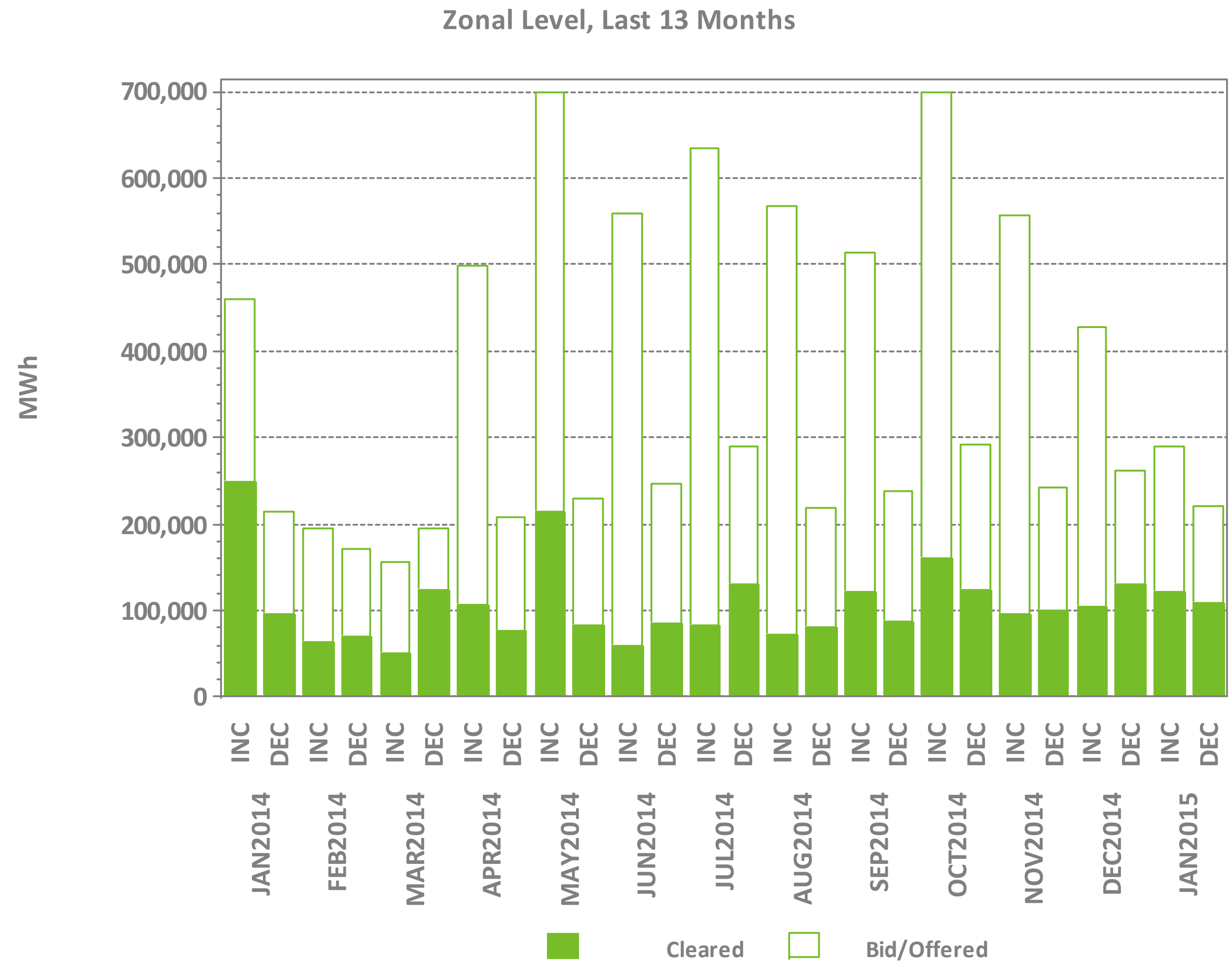
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

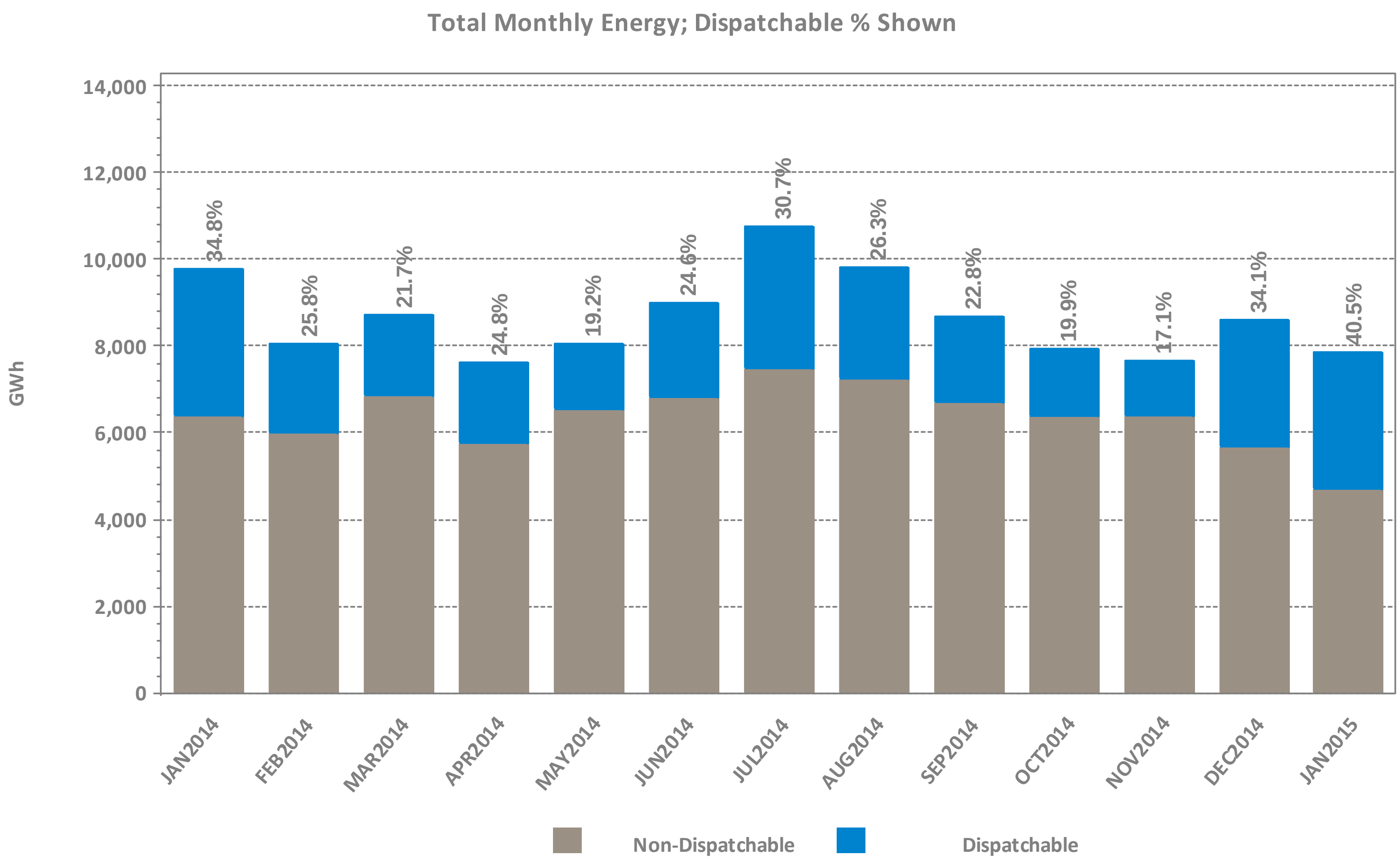


Total Increment Offers and Decrement Bids

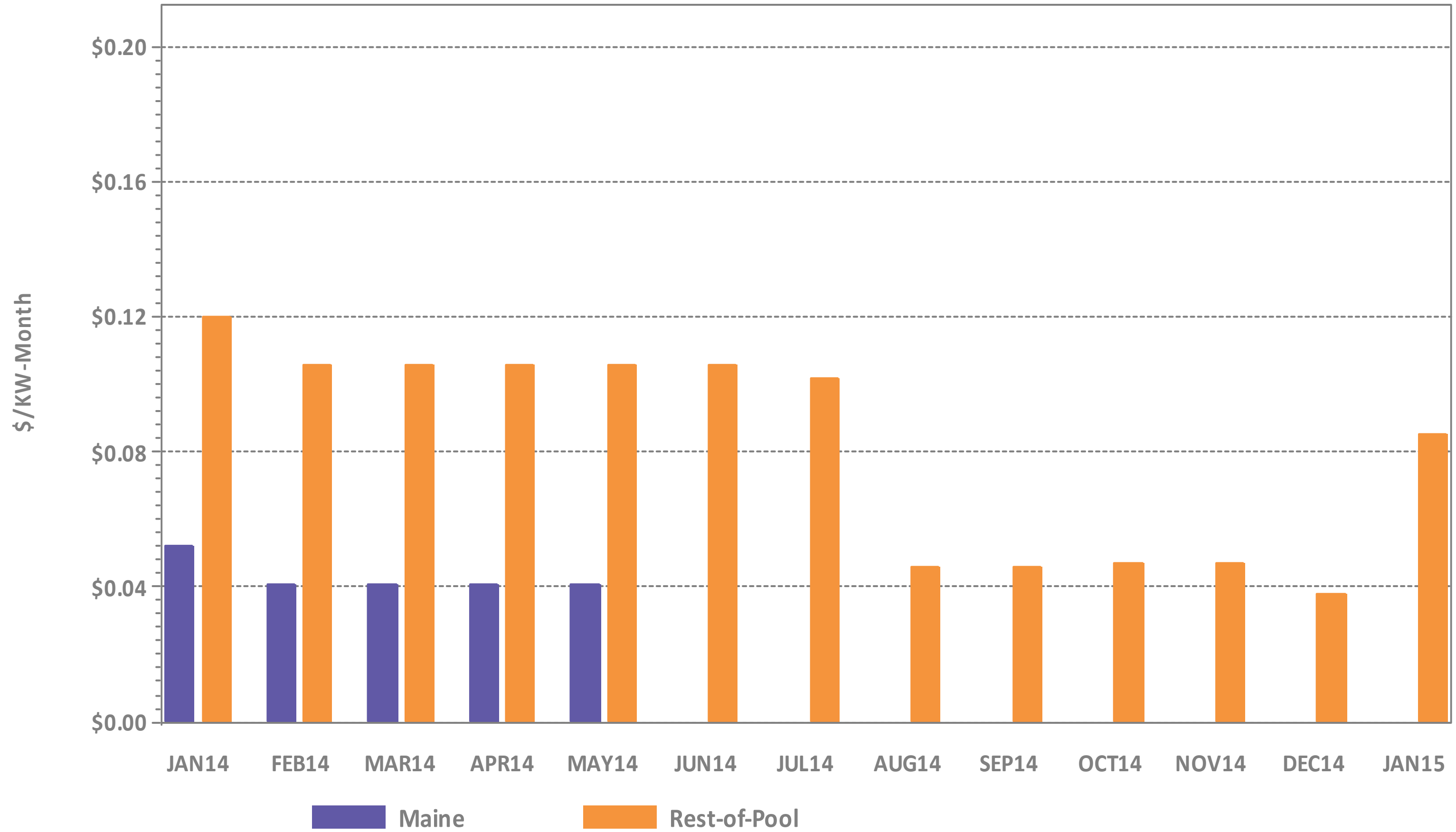


Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



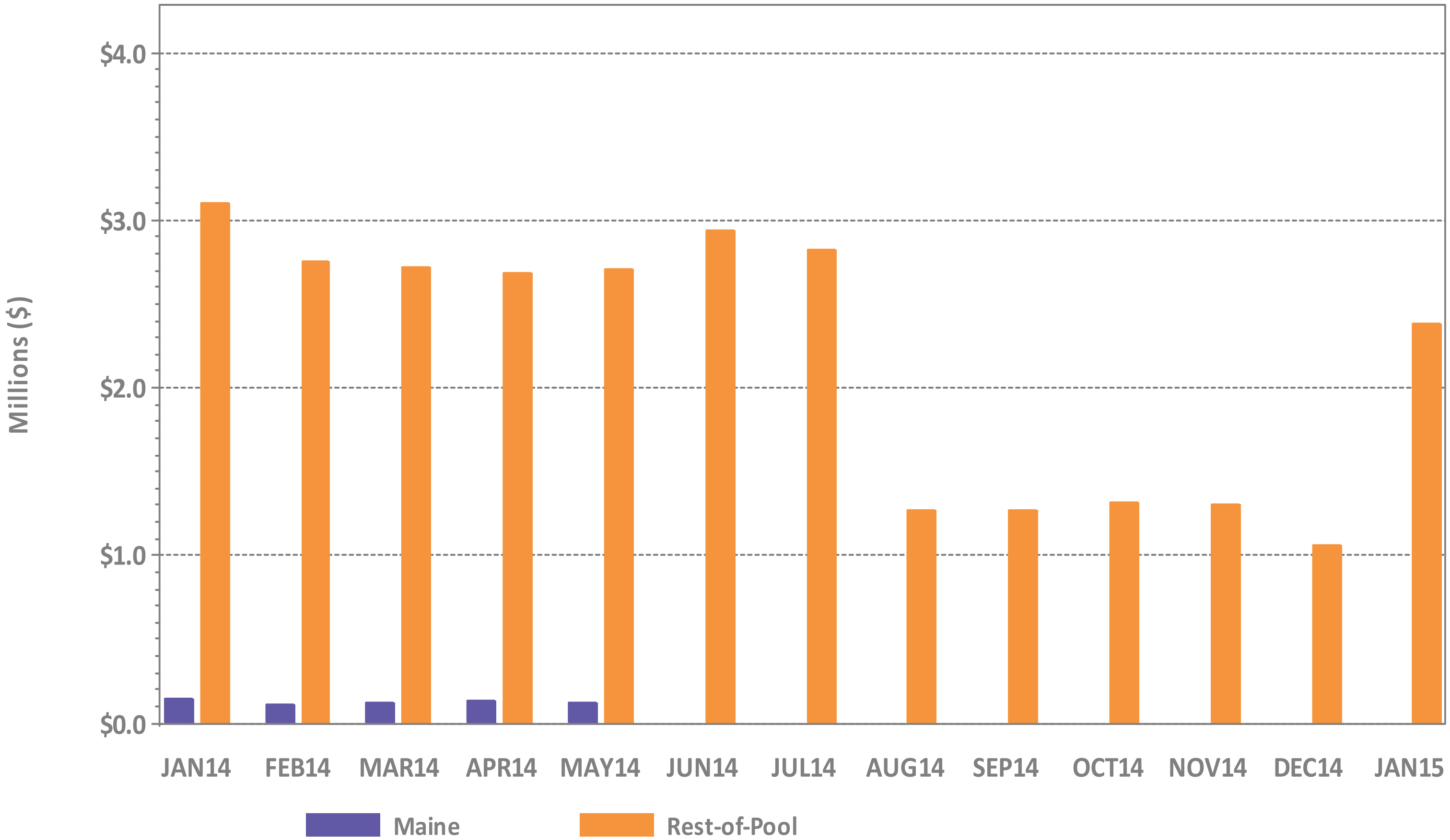
Rolling Average Peak Energy Rent (PER)



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

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

PER Adjustments



PER Adjustments are reductions to Forward Capacity Market monthly payments resulting from the rolling average PER.

REGIONAL SYSTEM PLAN (RSP) AND INTERREGIONAL PLANNING

Planning Advisory Committee (PAC)

- PAC meeting scheduled for February 18. Major agenda topics will include:
  - Review of Draft Target 2 Report for EIPC Gas/Electric Interface Study
  - New England Load Forecast Update
  - Stakeholder Process for Submission of 2015 Economic Study Requests
  - Environmental Update
  - Greater Boston Preferred Solution

Distributed Generation Forecast Working Group (DGFWG)

- The next DGFWG meeting is scheduled for February 27
  - ICF Economic Drivers of PV Report for the ISO
  - Review of Utility PV Data and DG Data Submittal Process
    - Special thanks to entities providing timely and accurate responses
  - Draft 2015 PV Forecast
  - Next Steps
- The ISO requires PV energy production information from the states by March 1
- By the release of CELT 2015, the ISO plans on producing PV forecasts
  - Forecasts will be developed for nameplate, estimated seasonal claimed capability, and energy production
  - Forecasts will be developed for the overall system, states, and reliability zones

DGFWG, cont.

- The ISO will classify PV resources by market participation type
  - FCM resources with capacity supply obligations
  - Settlement-only resources
  - Behind-the-meter resources that are already accounted for as part of the ISO load forecast
  - Remaining behind-the-meter resources
- The ISO urges DG resources to participate in the FCM
- A portion of the behind-the-meter PV forecast has been identified as a portion of the demand forecast that needs to be captured for purposes of Installed Capacity Requirement calculations
  - The ISO will work with the PSPC and the RC to receive stakeholder input in preparation for FCA #10
- PV forecast will be used in new economic studies and new transmission planning studies
- The ISO is working with the transmission owners, distribution owners, the states, and IEEE to resolve interconnection issues
- The ISO will continue participation in DOE projects that support operational and planning forecasts of PV

Other Stakeholder Groups

- Environmental Matters
  - Environmental Advisory Group will provide a regulatory update on February 3

RSP Project Stage Descriptions

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

NEEWS: Interstate Reliability Project

Status as of 1/30/15

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

Upgrade	Expected In-service	Present Stage
Build New 345 kV Line 3271 Card - Lake Road	Dec-15	3
Card 345 kV Substation Expansion	Dec-15	3
Lake Road 345 kV Substation Expansion	Dec-15	3
Build New 345 kV Line 341 Lake Road to CT/RI Border	Dec-15	3
Build New 345 kV Line 341 CT/RI Border to West Farnum	Dec-15	3
West Farnum 345 kV Substation Additions (New Line Terminations)	Dec-15	3
New Sherman Road 345 kV Substation	Dec-15	3
West Farnum 115 kV Substation Upgrades	Sep-14	4
Reconductor 345 kV Line 328 West Farnum to Sherman Road	Dec-15	3
Riverside Substation Relay Upgrades	Sep-14	4
Woonsocket Substation Relay Upgrades	Sep-14	4
Hartford Avenue Substation Relay Upgrades	Sep-14	4
Build New 345 kV Line 366 West Farnum to MA/RI Border	Dec-15	3
Build New 345 kV Line 366 MA/RI Border to Millbury 3	Dec-15	3
Millbury 3 Substation Expansion	Dec-15	3
Carpenter Hill Substation Relay Upgrades	Dec-15	3

Maine Power Reliability Program (MPRP)

Status as of 1/30/15

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

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

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

Maine Power Reliability Program, *cont.*

Status as of 1/30/15

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

New 115 kV Lines	Expected In-Service	Present Stage
Construct New Section 254 Orrington to Coopers Mills	Mar-15	3
Construct New Section 243A Livermore Falls to Junction Section 243	May-14	4
Construct New Section 251 Livermore Falls to Larrabee Road	May-14	4
Construct New Section 255 Larrabee Road to Middle Street	Mar-17	3
Construct New Section 86A Tap to Belfast	Jul-14	4
Construct New Section 256 Middle Street to Lewiston Lower	Mar-17	1

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

Maine Power Reliability Program, *cont.*

Status as of 1/30/15

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

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

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

Maine Power Reliability Program, *cont.*

Status as of 1/30/15

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

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

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

New Hampshire/Vermont 10-Year Upgrades

Status as of 1/30/15

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected In-Service	Present Stage
Eagle Substation Add: 345/115 kV autotransformer	Dec-16	2
Littleton Substation Add: Second 230/115 kV autotransformer	Oct-14	4
New C-203 230 kV line tap to Littleton NH Substation	Nov-14	4
New 115 kV overhead line, Fitzwilliam-Monadnock	Jun-15	3
New 115 kV overhead line, Scobie Pond-Huse Road	Dec-15	3
New 115 kV overhead/submarine line, Madbury-Portsmouth	Dec-16	2
New 115 kV overhead line, Scobie Pond-Chester	Dec-15	3
New 115 kV overhead line, Coolidge-Ascutney	Dec-16	1

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

New Hampshire/Vermont 10-Year Upgrades, cont.

Status as of 1/30/15

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected In-Service	Present Stage
Saco Valley Substation - Add two 25 MVAR dynamic reactive devices	Dec-15	3
Rebuild 115 kV line K165, W157 tap Eagle-Power Street	May-15	3
Rebuild 115 kV line H137, Merrimack-Garvins	Jun-13	4
Rebuild 115 kV line D118, Deerfield-Pine Hill	Nov-14	4
Oak Hill Substation - Loop in 115 kV line V182, Garvins-Webster	Apr-15	4*
Uprate 115 kV line G146, Garvins-Deerfield	Feb-15	3
Uprate 115 kV line P145, Oak Hill-Merrimack	May-14	4

* Placed in-service ahead of schedule

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

New Hampshire/Vermont 10-Year Upgrades, cont.

Status as of 1/30/15

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected In-Service	Present Stage
Upgrade 115 kV line H141, Chester-Great Bay	Nov-14	4
Upgrade 115 kV line R193, Scobie Pond-Kingston Tap	Mar-15	4*
Upgrade 115 kV line T198, Keene-Monadnock	Nov-13	4
Upgrade 345 kV line 326, Scobie Pond-NH/MA Border	Dec-13	4
Upgrade 115 kV line J114-2, Greggs - Rimmon	Dec-13	4
Upgrade 345 kV line 381, between MA/NH border and NH/VT border	Jun-13	4

* Placed in-service ahead of schedule

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

Greater Hartford and Central Connecticut (GHCC) Projects*

Status as of 1/30/15

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Greater Hartford, Middletown, Barbour Hill and Northwestern Connecticut and increases western Connecticut import capability

Upgrade	Expected In-service	Present Stage
Add a 2nd 345/115 kV autotransformer at Haddam substation and reconfigure the 3-terminal 345 kV 348 line into two 2-terminal lines	Dec-17	1
Terminal equipment upgrades on the 345 kV line between Haddam Neck and Beseck (362)	Dec-17	1
Redesign the Green Hill 115 kV substation from a straight bus to a ring bus and add a 115 kV 37.8 MVAR capacitor bank	Dec-17	1
Add a 37.8 MVAR capacitor bank at the Hopewell 115 kV substation	Dec-17	1
Separation of 115 kV double circuit towers corresponding to the Branford – Branford RR line (1537) and the Branford to North Haven (1655) line and adding a 115 kV breaker at Branford 115 kV substation	Dec-17	1
Separation of 115 kV double circuit towers corresponding to the Middletown – Pratt and Whitney line (1572) and the Middletown to Haddam (1620) line	Dec-17	1

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 1/30/15

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Greater Hartford, Middletown, Barbour Hill and Northwestern Connecticut and increases western Connecticut import capability

Upgrade	Expected In-service	Present Stage
Terminal equipment upgrades on the 115 kV line from Middletown to Dooley (1050)	Dec-17	1
Terminal equipment upgrades on the 115 kV line from Middletown to Portland (1443)	Dec-17	1
Add a new 115 kV underground cable from Newington to Southwest Hartford and associated terminal equipment including a 2% series reactor	Dec-17	1
Add a 115 kV 25.2 MVAR capacitor at Westside 115 kV substation	Dec-17	1
Loop the 1779 line between South Meadow and Bloomfield into the Rood Avenue substation and reconfigure the Rood Avenue substation	Dec-17	1
Reconfigure the Berlin 115 kV substation including two new 115 kV breakers and the relocation of a capacitor bank	Dec-17	1
Reconductor the 115 kV line between Newington and Newington Tap (1783)	Dec-17	1

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 1/30/15

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Greater Hartford, Middletown, Barbour Hill and Northwestern Connecticut and increases western Connecticut import capability

Upgrade	Expected In-service	Present Stage
Separation of 115 kV DCT corresponding to the Bloomfield to South Meadow (1779) line and the Bloomfield to North Bloomfield (1777) line and add a breaker at Bloomfield 115 kV substation	Dec-17	1
Separation of 115 kV DCT corresponding to the Bloomfield to North Bloomfield (1777) line and the North Bloomfield – Rood Avenue – Northwest Hartford (1751) line and add a breaker at North Bloomfield 115 kV substation	Dec-17	1
Install a 115 kV 3% reactor on the 115 kV line between South Meadow and Southwest Hartford (1704)	Dec-17	1
Replace the existing 3% series reactors on the 115 kV lines between Southington and Todd (1910) and between Southington and Canal (1950) with a 5% series reactors	Dec-17	1
Replace the normally open 19T breaker at Southington 115 kV with a normally closed 3% series reactor	Dec-17	1
Add a 345 kV breaker in series with breaker 5T at Southington	Dec-17	1

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 1/30/15

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Greater Hartford, Middletown, Barbour Hill and Northwestern Connecticut and increases western Connecticut import capability

Upgrade	Expected In-service	Present Stage
Add a new control house at Southington 115 kV substation	Dec-17	1
Add a new 115 kV line from Frost Bridge to Campville	Dec-17	1
Separation of 115 kV DCT corresponding to the Frost Bridge to Campville (1191) line and the Thomaston to Campville (1921) line and add a breaker at Campville 115 kV substation	Dec-17	1
Upgrade the 115 kV line between Southington and Lake Avenue Junction (1810-1)	Dec-17	1
Add a new 345/115 kV autotransformer at Barbour Hill substation	Dec-17	1
Add a 345 kV breaker in series with breaker 24T at the Manchester 345 kV substation	Dec-17	1
Reconductor the 115 kV line between Manchester and Barbour Hill (1763)	Dec-17	1

* Replaces the NEEWS Central Connecticut Reliability Project

Southwest Connecticut (SWCT) Projects

Status as of 1/30/15

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected In-service	Present Stage
Add a 25.2 MVAR capacitor bank at the Oxford substation	Dec-17	1
Add 2 x 25 MVAR capacitor banks at the Ansonia substation	Dec-17	1
Close the normally open 115 kV 2T circuit breaker at Baldwin substation	Dec-17	1
Rebuild Bunker Hill to a 9-breaker substation in breaker-and-a-half configuration	Dec-17	1
Reconductor the 115 kV line between Bunker Hill and Baldwin Junction (1575)	Dec-17	1
Loop the 1990 line in and out the Bunker Hill substation	Dec-17	1
Expand Pootatuck (formerly known as Shelton) substation to 4-breaker ring bus configuration and add a 30 MVAR capacitor bank at Pootatuck	Dec-17	1
Loop the 1570 line in and out the Pootatuck substation	Dec-17	1
Replace two 115 kV circuit breakers at the Freight substation	Dec-17	1

Southwest Connecticut Projects, cont.

Status as of 1/30/15

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected In-service	Present Stage
Add two 14.4 MVAR capacitor banks at the West Brookfield substation	Dec-17	1
Add a new 115 kV line from Plumtree to Brookfield Junction	Dec-17	1
Reconductor the 115 kV line between West Brookfield and Brookfield Junction (1887)	Dec-17	1
Reduce the existing 25.2 MVAR capacitor bank at the Rocky River substation to 14.4 MVAR	Dec-17	1
Reconfigure the 1887 line into a three-terminal line (Plumtree - W. Brookfield - Shepaug)	Dec-17	1
Reconfigure the 1770 line into 2 two-terminal lines (Plumtree - Stony Hill and Stony Hill - Bates Rock)	Dec-17	1
Install a synchronous condenser (+25/-12.5 MVAR) at Stony Hill	Dec-17	1
Relocate an existing 37.8 MVAR capacitor bank at Stony Hill to the 25.2 MVAR capacitor bank side	Dec-17	1

Southwest Connecticut Projects, cont.

Status as of 1/30/15

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected In-service	Present Stage
Relocate the existing 37.8 MVAR capacitor bank from 115 kV B bus to 115 kV A bus at the Plumtree substation	Dec-16	1
Add a 115 kV circuit breaker in series with the existing 29T breaker at the Plumtree substation	Dec-17	1
Terminal equipment upgrade at the Newtown substation (1876)	Dec-17	1
Rebuild the 115 kV line from Wilton to Norwalk (1682) and upgrade Wilton substation terminal equipment	Dec-17	1
Reconductor the 115 kV line from Wilton to Ridgefield Junction (1470-1)	Dec-17	1
Reconductor the 115 kV line from Ridgefield Junction to Peaceable (1470-3)	Dec-17	1

Southwest Connecticut Projects, cont.

Status as of 1/30/15

Plan Benefit: Addresses long-term system needs in the four study sub areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected In-service	Present Stage
Add 2 x 20 MVAR capacitor banks at the Hawthorne substation	Apr-16	1
Upgrade the 115 kV bus at the Baird substation	Dec-17	1
Upgrade the 115 kV bus system and 11 disconnect switches at the Pequonnock substation	Dec-14	4
Add a 345 kV breaker in series with the existing 11T breaker at the East Devon substation	Dec-16	1
Rebuild the 115 kV lines from Baird to Congress (8809A / 8909B)	May-18	1
Rebuild the 115 kV lines from Housatonic River Crossing (HRX) to Barnum to Baird (88006A / 89006B)	Apr-19	1

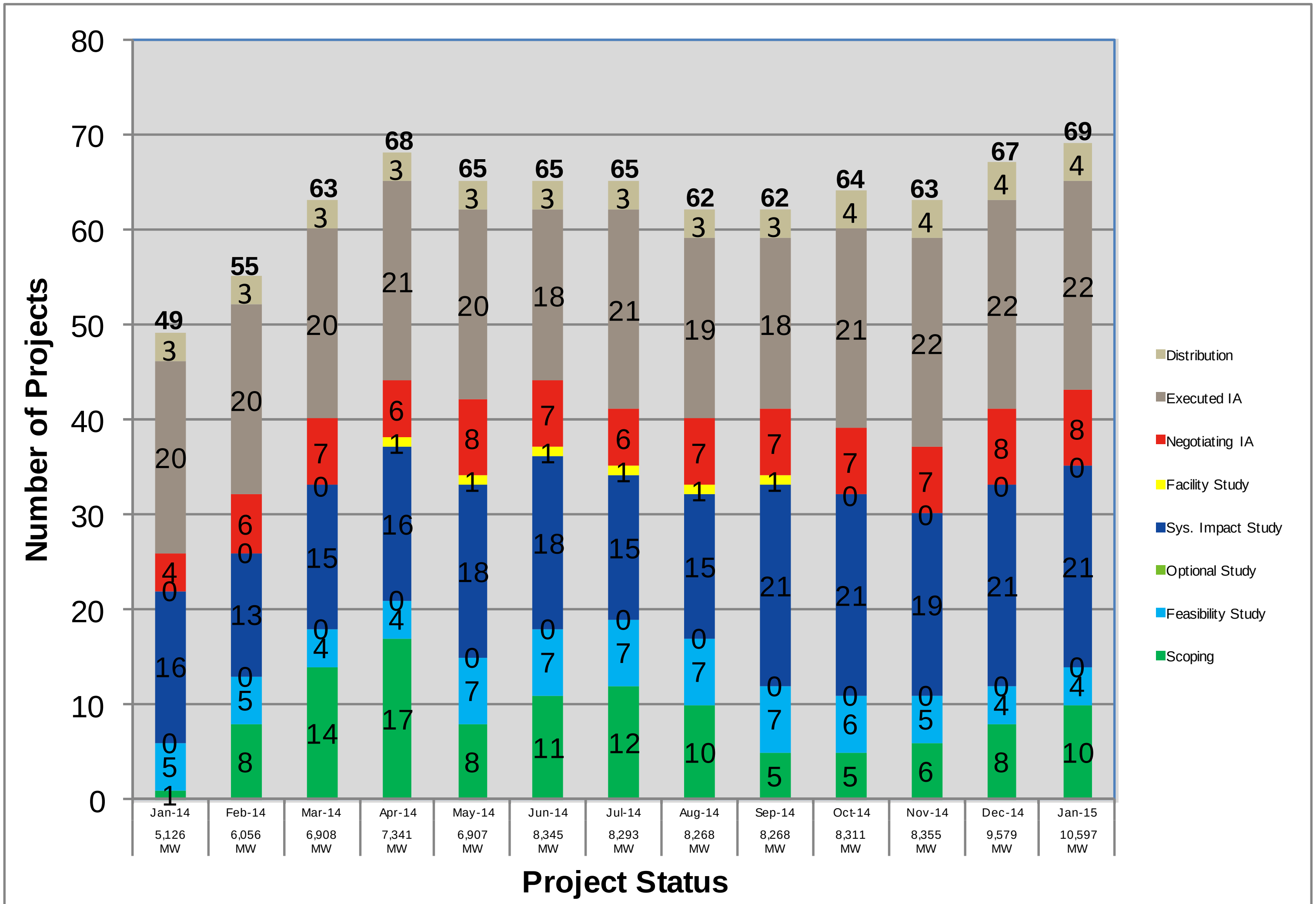
Southwest Connecticut Projects, cont.

Status as of 1/30/15

Plan Benefit: Addresses long-term system needs in the four study sub areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected In-service	Present Stage
Remove the Sackett phase shifter	Dec-17	1
Install a 7.5 ohm series reactor on 1610 line at the Mix Avenue substation	Dec-17	1
Add 2 x 20 MVAR capacitor banks at the Mix Avenue substation	Dec-17	1
Separate the 3827 (Beseck to East Devon) and 1610 (Southington to June to Mix Avenue) double circuit towers	Dec-17	1
Upgrade the 1630 line relay at North Haven and Wallingford 1630 terminal equipment	Dec-16	1
Rebuild the 115 kV lines from Devon Tie to Milvon (88005A / 89005B)	Dec-16	2
Replace two 115 kV circuit breakers at Mill River	Dec-14	4

Status of Tariff Studies



https://irtt.iso-ne.com/external.aspx

OPERABLE CAPACITY ANALYSIS

Winter 2014-2015

Winter 2015 Operable Capacity Analysis

50/50 Load Forecast (Reference)	February - 2015[2] CSO	February - 2015[2] SCC
Generator Operable Capacity MW [1]	30,328	32,486
OP CAP From OP-4 RTDR (+)	274	274
OP CAP From OP-4 RTEG (+)	187	187
Operable Capacity Generator with OP-4 DR and RTEG	30,789	32,947
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	512	512
Non Commercial Capacity (+)	4	4
Non Gas-fired Planned Outage MW (-)	290	380
Gas Generator Outages MW (-)	257	360
Allowance for Unplanned Outages (-)	3,100	3,100
Generation at Risk Due to Gas Supply (-) [4]	3,311	3,604
Net Capacity (NET OPCAP SUPPLY MW) [3]	24,347	26,019
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,589	20,589
Operating Reserve Requirement MW	2,375	2,375
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,964	22,964
Operable Capacity Margin [3]	1,383	3,055

[1] Generator Operable Capacity is based on data as of January 19th , 2015 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 February 7th, 2015.

[3] Includes OP4 actions associated with RTEG and RTDR

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

Winter 2015 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	February - 2015[2] CSO	February - 2015[2] SCC
Generator Operable Capacity MW [1]	30,328	32,486
OP CAP From OP-4 RTDR (+)	274	274
OP CAP From OP-4 RTEG (+)	187	187
Operable Capacity Generator with OP-4 DR and RTEG	30,789	32,947
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	512	512
Non Commercial Capacity (+)	4	4
Non Gas-fired Planned Outage MW (-)	290	380
Gas Generator Outages MW (-)	257	360
Allowance for Unplanned Outages (-)	3,100	3,100
Generation at Risk Due to Gas Supply (-) [4]	3,665	3,998
Net Capacity (NET OPCAP SUPPLY MW) [3]	23,993	25,625
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	21,323	21,323
Operating Reserve Requirement MW	2,375	2,375
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,698	23,698
Operable Capacity Margin [3]	295	1,927

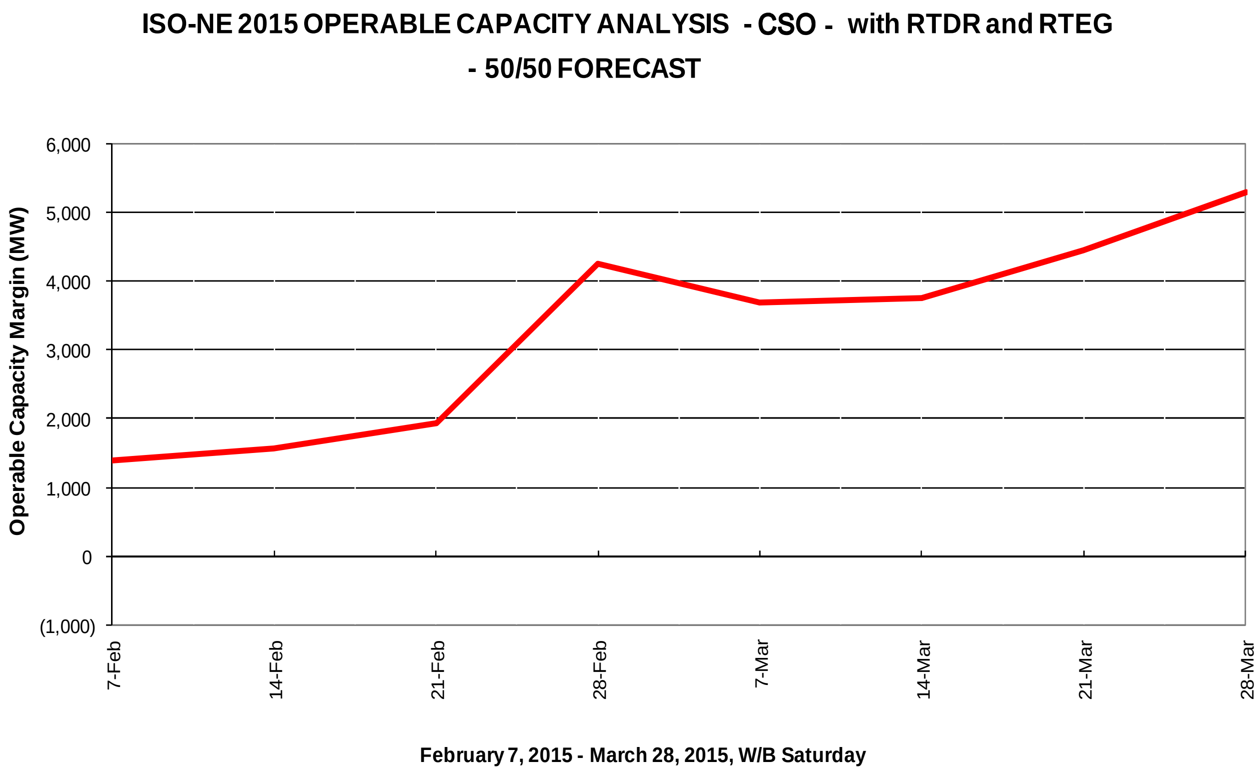
[1] Generator Operable Capacity is based on data as of January 19th , 2015 and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity.

[2] Based on week with lowest Operable Capacity Margin, week beginning February 7th, 2015.

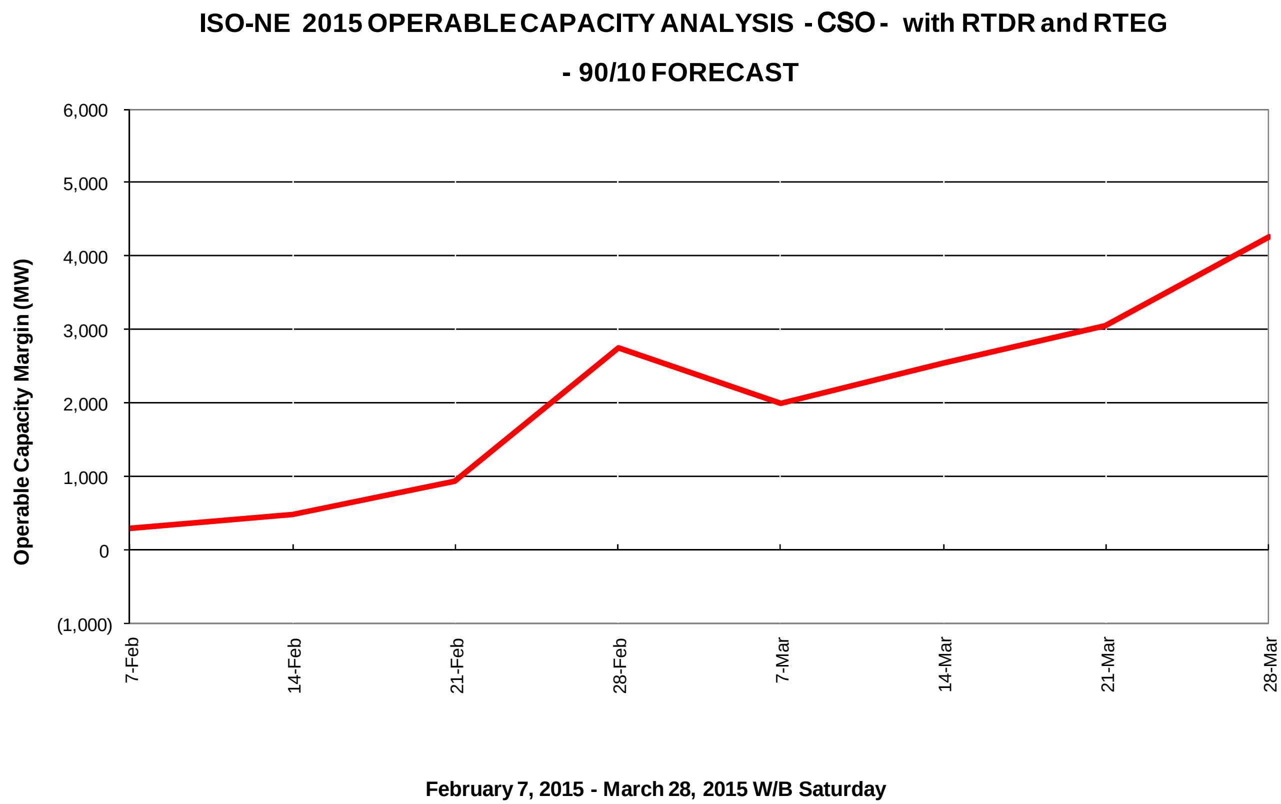
[3] Includes OP4 actions associated with RTEG and RTDR

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

Winter 2015 Operable Capacity Analysis(MW)
50/50 Forecast (Reference)



Winter 2015 Operable Capacity Analysis(MW)
90/10 Forecast (Extreme)



Winter 2015 Operable Capacity Analysis(MW)
50/50 Forecast (Reference)

ISO-NE 2015 OPERABLE CAPACITY ANALYSIS

February 6, 2015 - 50/50 FORECAST using CSO values with RTDR and RTEG

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.

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW [1]	EXTERNAL NODE AVAIL CAPACITY MW [2]	NON COMMERCIAL CAPACITY MW [3]	NON-GAS PLANNED OUTAGES CSO MW [4]	GAS GENERATOR OUTAGES CSO MW [5]	ALLOWANCE FOR UNPLANNED OUTAGES MW [6]	GAS AT RISK MW [7]	NET OPCAP SUPPLY MW [8]	PEAK LOAD FORECAST MW [9]	OPER RESERVE REQUIREMENT MW [10]	NET LOAD OBLIGATION MW [11]	OPCAP MARGIN MW [12]	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW [13]	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW [14]	OPCAP FROM OP4 REAL-TIME EMER. GEN MW [15]	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW [16]
2/7/2015	30,328	512	4	290	257	3,100	3,311	23,886	20,589	2,375	22,964	922	274	1,196	187	1,383
2/14/2015	30,328	512	4	217	537	3,100	2,944	24,046	20,560	2,375	22,935	1,111	274	1,385	187	1,572
2/21/2015	30,328	512	4	218	758	3,100	2,636	24,132	20,294	2,375	22,669	1,463	274	1,737	187	1,924
2/28/2015	30,328	812	115	895	1,152	2,200	1,563	25,445	19,291	2,375	21,666	3,779	274	4,053	187	4,240
3/7/2015	29,861	812	115	1,941	468	2,200	1,794	24,385	18,937	2,375	21,312	3,073	433	3,506	187	3,693
3/14/2015	29,861	812	115	2,527	1,117	2,200	693	24,251	18,738	2,375	21,113	3,138	433	3,571	187	3,758
3/21/2015	29,861	812	115	3,119	647	2,200	258	24,564	18,368	2,375	20,743	3,821	433	4,254	187	4,441
3/28/2015	29,861	812	115	2,696	552	2,700	0	24,840	17,795	2,375	20,170	4,670	433	5,103	187	5,290

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
3. New resources that have acquired a CSO but have not become commercial.
4.Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.
5. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
6. 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.
7. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
8. Net OpCap Supply MW Available (1 + 2 + 3 - 4 - 5 - 6 - 7 = 8)
9. Peak Load Forecast as provided in the 2014 CELT Report and adjusted for Passive Demand Resources. http://www.iso-ne.com/trans/celt/report/index.html
10. Operating Reserve Requirement based on 125% of first largest contingency plus 50% the second largest contingency.
11. Total Net Load Obligation per the formula(9 + 10 = 11)
12. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (8 - 11 = 12)
13. OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
14. OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (12 + 13 = 14)
15. OP 4 Action 6 Emergency Generation Response without the Voltage Reduction requiring > 10 Minutes based on OP4 Appendix A. Real Time Emergency Generation is capped at 600MW. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
16. OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (14 + 15 = 16)
This does not include Emergency Energy Transactions (EETs).

Winter 2015 Operable Capacity Analysis(MW)
90/10 Forecast (Extreme)

ISO-NE 2015 OPERABLE CAPACITY ANALYSIS

February 6, 2015 - 90/10 FORECAST using CSO values with RTDR and RTEG

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.

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW [1]	EXTERNAL NODE AVAIL CAPACITY MW [2]	NON COMMERCIAL CAPACITY MW [3]	NON-GAS PLANNED OUTAGES CSO MW [4]	GAS GENERATOR OUTAGES CSO MW [5]	ALLOWANCE FOR UNPLANNED OUTAGES MW [6]	GAS AT RISK MW [7]	NET OPCAP SUPPLY MW [8]	PEAK LOAD FORECAST MW [9]	OPER RESERVE REQUIREMENT MW [10]	NET LOAD OBLIGATION MW [11]	OPCAP MARGIN MW [12]	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW [13]	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW [14]	OPCAP FROM OP4 REAL-TIME EMER. GEN MW [15]	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW [16]
2/7/2015	30,328	512	4	290	257	3,100	3,665	23,532	21,323	2,375	23,698	(166)	274	108	187	295
2/14/2015	30,328	512	4	217	537	3,100	3,295	23,695	21,293	2,375	23,668	27	274	301	187	488
2/21/2015	30,328	512	4	218	758	3,100	2,894	23,874	21,017	2,375	23,392	482	274	756	187	943
2/28/2015	30,328	812	115	895	1,152	2,200	2,365	24,643	19,982	2,375	22,357	2,286	274	2,560	187	2,747
3/7/2015	29,861	812	115	1,941	468	2,200	2,814	23,365	19,615	2,375	21,990	1,375	433	1,808	187	1,995
3/14/2015	29,861	812	115	2,527	1,117	2,200	1,228	23,716	19,410	2,375	21,785	1,931	433	2,364	187	2,551
3/21/2015	29,861	812	115	3,119	647	2,200	995	23,827	19,028	2,375	21,403	2,424	433	2,857	187	3,044
3/28/2015	29,861	812	115	2,696	552	2,700	386	24,454	18,435	2,375	20,810	3,644	433	4,077	187	4,264

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
3. New resources that have acquired a CSO but have not become commercial.
4. Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.
5. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
6. 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.
7. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
8. Net OpCap Supply MW Available (1 + 2 + 3 - 4 - 5 - 6 - 7 = 8)
9. Peak Load Forecast as provided in the 2014 CELT Report and adjusted for Passive Demand Resources. http://www.iso-ne.com/trans/celt/report/index.html
10. Operating Reserve Requirement based on 125% of first largest contingency plus 50% the second largest contingency.
11. Total Net Load Obligation per the formula(9 + 10 = 11)
12. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (8 - 11 = 12)
13. OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
14. OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (12 + 13 = 14)
15. OP 4 Action 6 Emergency Generation Response without the Voltage Reduction requiring > 10 Minutes based on OP4 Appendix A. Real Time Emergency Generation is capped at 600MW. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
16. OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (14 + 15 = 16)
This does not include Emergency Energy Transactions (EETs).

OPERABLE CAPACITY ANALYSIS

Spring 2015

Spring 2015 Operable Capacity Analysis

50/50 Load Forecast (Reference)	May - 2015[2] CSO	May - 2015[2] SCC
Generator Operable Capacity MW [1]	29,678	32,486
OP CAP From OP-4 RTDR (+)	495	495
OP CAP From OP-4 RTEG (+)	196	196
Operable Capacity Generator with OP-4 DR and RTEG	30,369	33,177
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	618	618
Non Commercial Capacity (+)	115	115
Non Gas-fired Planned Outage MW (-)	3,692	4,015
Gas Generator Outages MW (-)	691	818
Allowance for Unplanned Outages (-)	3,400	3,400
Generation at Risk Due to Gas Supply (-) [4]	0	0
Net Capacity (NET OPCAP SUPPLY MW) [3]	23,319	25,677
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,112	20,112
Operating Reserve Requirement MW	2,375	2,375
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,487	22,487
Operable Capacity Margin [3]	832	3,190

[1] Generator Operable Capacity is based on data as of January 19th , 2015 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 May 9th, 2015.

[3] Includes OP4 actions associated with RTEG and RTDR

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

Spring 2015 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	May - 2015[2] CSO	May - 2015[2] SCC
Generator Operable Capacity MW [1]	29,678	32,486
OP CAP From OP-4 RTDR (+)	495	495
OP CAP From OP-4 RTEG (+)	196	196
Operable Capacity Generator with OP-4 DR and RTEG	30,369	33,177
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	618	618
Non Commercial Capacity (+)	115	115
Non Gas-fired Planned Outage MW (-)	3,692	4,015
Gas Generator Outages MW (-)	691	818
Allowance for Unplanned Outages (-)	3,400	3,400
Generation at Risk Due to Gas Supply (-) [4]	0	0
Net Capacity (NET OPCAP SUPPLY MW) [3]	23,319	25,677
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	21,876	21,876
Operating Reserve Requirement MW	2,375	2,375
Operable Capacity Required (NET LOAD OBLIGATION MW)	24,251	24,251
Operable Capacity Margin [3]	(932)	1,426

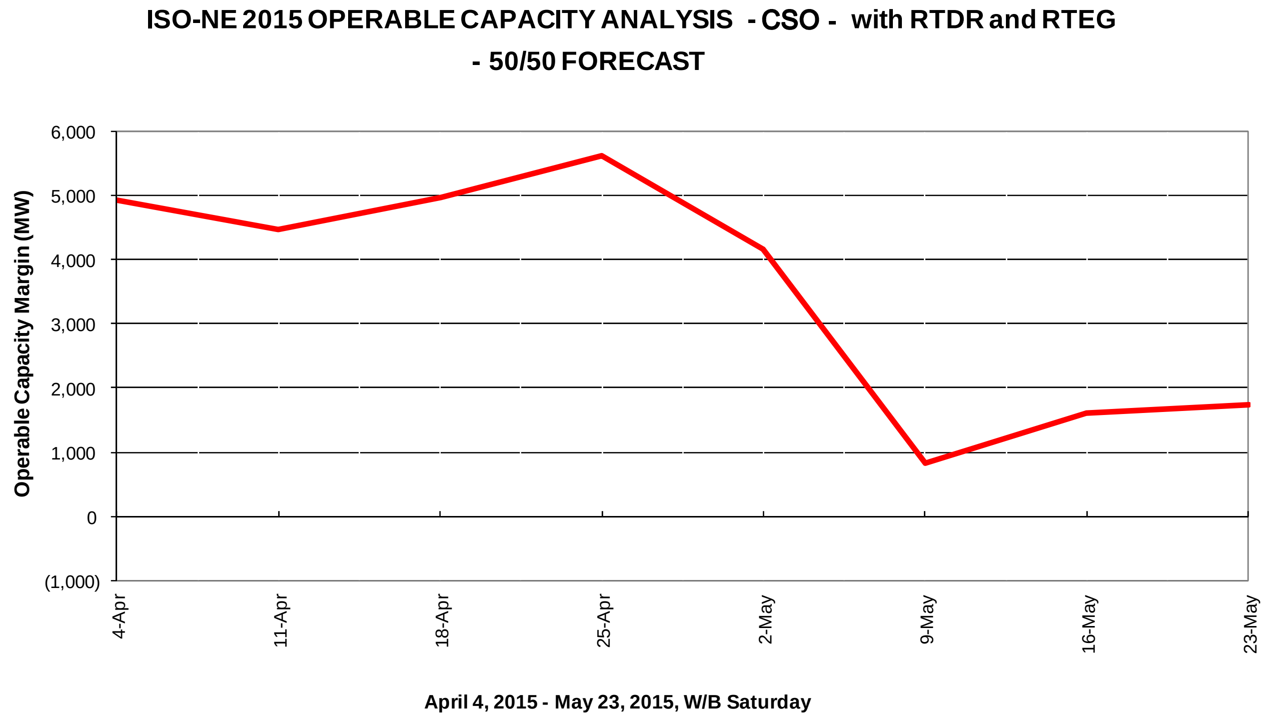
[1] Generator Operable Capacity is based on data as of January 19th , 2015 and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity.

[2] Based on week with lowest Operable Capacity Margin, week beginning May 9th, 2015.

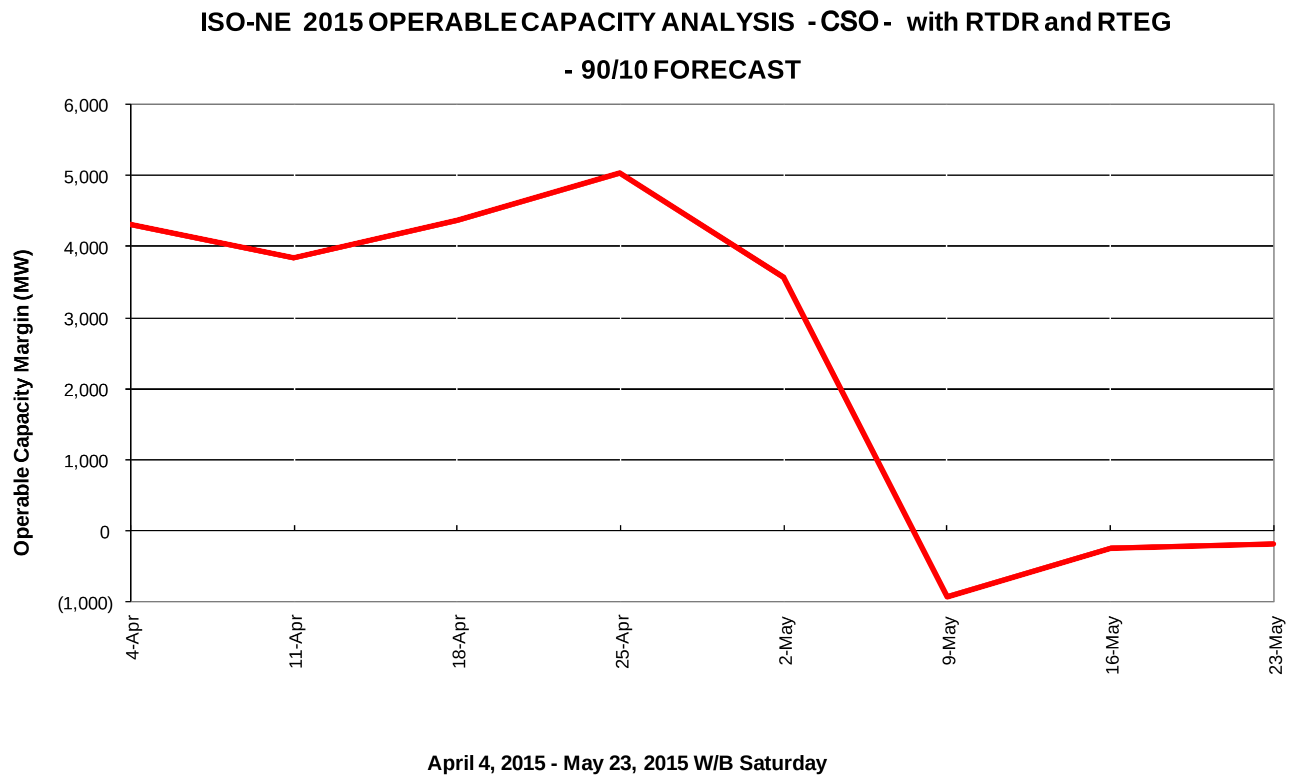
[3] Includes OP4 actions associated with RTEG and RTDR

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

Spring 2015 Operable Capacity Analysis(MW) 50/50 Forecast (Reference)



Spring 2015 Operable Capacity Analysis(MW) 90/10 Forecast (Extreme)



Spring 2015 Operable Capacity Analysis(MW)
50/50 Forecast (Reference)

ISO-NE 2015 OPERABLE CAPACITY ANALYSIS

February 6, 2015 - 50/50 FORECAST using CSO values with RTDR and RTEG

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.

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERATOR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW	OPCAP FROM OP4 REAL-TIME EMER. GEN MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
4/4/2015	29,678	812	115	2,658	1,358	2,700	0	23,889	17,275	2,375	19,650	4,239	495	4,734	196	4,930
4/11/2015	29,678	812	115	2,583	2,156	2,700	0	23,166	17,020	2,375	19,395	3,771	495	4,266	196	4,462
4/18/2015	29,678	812	115	3,168	1,590	2,700	0	23,147	16,503	2,375	18,878	4,269	495	4,764	196	4,960
4/25/2015	29,678	812	115	2,620	1,051	3,400	0	23,534	16,235	2,375	18,610	4,924	495	5,419	196	5,615
5/2/2015	29,678	812	115	4,323	838	3,400	0	22,044	16,208	2,375	18,583	3,461	495	3,956	196	4,152
5/9/2015	29,678	618	115	3,692	691	3,400	0	22,628	20,112	2,375	22,487	141	495	636	196	832
5/16/2015	29,678	812	115	1,679	1,118	3,400	0	24,408	21,116	2,375	23,491	917	495	1,412	196	1,608
5/23/2015	29,678	812	115	1,112	618	3,400	0	25,475	22,049	2,375	24,424	1,051	495	1,546	196	1,742

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
3. New resources that have acquired a CSO but have not become commercial.
4.Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.
5. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
6. 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.
7. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
8. Net OpCap Supply MW Available (1 + 2 + 3 - 4 - 5 - 6 - 7 = 8)
9. Peak Load Forecast as provided in the 2014 CELT Report and adjusted for Passive Demand Resources. http://www.iso-ne.com/trans/celt/report/index.html
10. Operating Reserve Requirement based on 125% of first largest contingency plus 50% the second largest contingency.
11. Total Net Load Obligation per the formula(9 + 10 = 11)
12. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (8 - 11 = 12)
13. OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
14. OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (12 + 13 = 14)
15. OP 4 Action 6 Emergency Generation Response without the Voltage Reduction requiring > 10 Minutes based on OP4 Appendix A. Real Time Emergency Generation is capped at 600MW.
Reserve Margins and Distribution Loss Factor Gross Ups are Included.
16. OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (14 + 15 = 16)
This does not include Emergency Energy Transactions (EETs).

Spring 2015 Operable Capacity Analysis(MW)
90/10 Forecast (Extreme)

ISO-NE 2015 OPERABLE CAPACITY ANALYSIS

February 6, 2015 - 90/10 FORECAST using CSO values with RTDR and RTEG

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.

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERATOR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW	OPCAP FROM OP4 REAL-TIME EMER. GEN MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
4/4/2015	29,678	812	115	2,658	1,358	2,700	0	23,889	17,899	2,375	20,274	3,615	495	4,110	196	4,306
4/11/2015	29,678	812	115	2,583	2,156	2,700	0	23,166	17,636	2,375	20,011	3,155	495	3,650	196	3,846
4/18/2015	29,678	812	115	3,168	1,590	2,700	0	23,147	17,102	2,375	19,477	3,670	495	4,165	196	4,361
4/25/2015	29,678	812	115	2,620	1,051	3,400	0	23,534	16,824	2,375	19,199	4,335	495	4,830	196	5,026
5/2/2015	29,678	812	115	4,323	838	3,400	0	22,044	16,796	2,375	19,171	2,873	495	3,368	196	3,564
5/9/2015	29,678	618	115	3,692	691	3,400	0	22,628	21,876	2,375	24,251	(1,623)	495	(1,128)	196	(932)
5/16/2015	29,678	812	115	1,679	1,118	3,400	0	24,408	22,962	2,375	25,337	(929)	495	(434)	196	(238)
5/23/2015	29,678	812	115	1,112	618	3,400	0	25,475	23,971	2,375	26,346	(871)	495	(376)	196	(180)

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
3. New resources that have acquired a CSO but have not become commercial.
4.Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.
5. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
6. 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.
7. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
8. Net OpCap Supply MW Available (1 + 2 + 3 - 4 - 5 - 6 - 7 = 8)
9. Peak Load Forecast as provided in the 2014 CELT Report and adjusted for Passive Demand Resources. http://www.iso-ne.com/trans/celt/report/index.html
10. Operating Reserve Requirement based on 125% of first largest contingency plus 50% the second largest contingency.
11. Total Net Load Obligation per the formula(9 + 10 = 11)
12. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (8 - 11 = 12)
13. OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
14. OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (12 + 13 = 14)
15. OP 4 Action 6 Emergency Generation Response without the Voltage Reduction requiring > 10 Minutes based on OP4 Appendix A. Real Time Emergency Generation is capped at 600MW. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
16. OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (14 + 15 = 16)
This does not include Emergency Energy Transactions (EETs).

OPERABLE CAPACITY ANALYSIS

Appendix

Possible Relief Under OP4 based on OP4 Appendix A

OP 4 Action Number	Page 1 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
1	Implement Power Caution and advise Resources with a CSO to prepare to provide capacity and notify "Settlement Only" generators with a CSO to monitor reserve pricing to meet those obligations. Begin to allow depletion of 30-minute reserve.	0 [1] 600
2	Dispatch real time Demand Resources.	**February 274 [3]** **March 433 [3]** **April - May 495 [3]**
3	Voluntary Load Curtailment of Market Participants' facilities.	40 [2]
4	Implement Power Watch	0
5	Schedule Emergency Energy Transactions and arrange to purchase Control Area-to-Control Area Emergency	1,000
6	Voltage Reduction requiring > 10 minutes Dispatch real time Emergency Generation	133 [4] **February - March 187 [3]** **April - May 196 [3]**
7	Request generating resources not subject to a Capacity Supply Obligation to voluntary provide energy for reliability purposes	0

NOTES:
1. Based on Summer Ratings. Assumes 25% of total MW Settlement Only units <5 MW will be available and respond.
2. The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
3. The RTDR and RTEG MW values are based on FCM results as of January 19th, 2014.
4. The MW values are based on a 26,658 MW system load and the most recent voltage reduction test % achieved.

Possible Relief Under OP4 based on OP4 Appendix A

OP 4 Action Number	Page 2 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
8	Voltage Reduction requiring 10 minutes or less	267 [4]
9	Transmission Customer Generation Not Contractually Available to Market Participants during a Capacity Deficiency. Voluntary Load Curtailment by Large Industrial and Commercial Customers.	5 200 [2]
10	Radio and TV Appeals for Voluntary Load Curtailment Implement Power Warning	200 [2]
11	Request State Governors to Reinforce Power Warning Appeals.	100 [2]
Total		**February 3,006 MW** **March 3,165 MW** **April – May 3,236 MW**

NOTES:
1. Based on Summer Ratings. Assumes 25% of total MW Settlement Only units <5 MW will be available and respond.
2. The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
3. The RTDR and RTEG MW values are based on FCM results as of January 19th , 2014.
4. The MW values are based on a 26,658 MW system load and the most recent voltage reduction test % achieved.

FEBRUARY 6, 2015

Discussion of the 2015 Work Plan

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Objective and Highlights

- The primary objective of this presentation is to provide the highlights of the 2015 ISO work plan and seek stakeholder input
- 2013/2014 comprised an intense set of market and planning based activities that required significant stakeholder involvement
- The second half of 2014 also transitioned to an ‘implementation year’ with several of the market and planning activities moving into implementation stage, most notably the hourly offers project
- 2015 will continue with implementation of several projects as well as continuing to improve upon our existing methods and practices
- Major projects scheduled for implementation in 2015 include Coordinated Transaction Scheduling (CTS), Generator Control Application (GCA), Forward Capacity Auction 10, LMP Calculator Replacement, and Cyber Security Related Projects

Objective and Highlights, cont.

- With respect to market design activities, the ISO's primary emphasis in 2015 is to improve energy market price formation
- Full integration of Demand Resources is currently not listed in the priorities − please refer to slide 47 regarding the ISO's current views and timelines on this issue
- FERC's final orders on Order 1000 compliance, any renewed regional efforts surrounding the New England Governor's infrastructure initiative, and other new FERC initiatives could all influence the timing of the various activities in the 2015 work plan
- The current work plan is intended to address necessary improvements, while attempting to maximize resource efficiency and accounting for software and vendor constraints
  – However, the plan can be adjusted to account for new and emerging priorities
  – Such work plan adjustments will involve trade-offs
- Slides 4-6 offer a Gantt chart view of the 2015 work plan

Planning/Operations Related Activities

2015				2016			
Q1	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**
Transmission Planning Studies/Support State Siting (Slides 7-9)							
Eastern Interconnection Planning Collaborative (Slide 10)							
	2015 Economic Studies (Slide 11)					2016 Economic Studies	
Finalize 2015 Forecast of State EE		(Slide 12)		Finalize 2016 Forecast of State EE			
Interregional Planning (Slide 13)							
Transmission Cost Allocation (Slide 14)							
FERC Order 1000 - Implement Final Compliance Orders (Slide 15)							
		2019/20 ICR and LSR		(Slide 16)		2020/21 ICR and LSR	
FCA 9 / Annual Reconfig Auctions		(Slide 17)		FCA 10 / Annual Reconfig Auctions			
Generator Interconnection Studies (Slide 18)							
RSP 15 (Slide 19)			RSP 16				
2014/15 Winter Program (Slide 20)			2015/16 Winter Program				
Gas - Electric Operations Coordination (Slide 21)							
NERC/FERC Compliance; Cyber Security (Slides 22-26)							
Elective Transmission Upgrades (Slide 27)							
Capacity Zones Determination for FCA 10 (Slide 28)				Capacity Zones Determination for FCA 11			
2015 Dist. Generation Forecast		(Slide29)		2016 Dist. Generation Forecast			
Operating Guide Updates (Slide 30)							

Operations/Planning Activities

Markets Related Activities

2015				2016	
Q1	Q2	Q3	Q4	Q1	Q2
LMPc Replacement	(Slide 32)				
Do Not Exceed Dispatch	(Slide 33)				
Elective Transmission	(Slide 34)				
3rd Party FTR Clearing	(Slide 35)				
Winter Solution 2015-18		(Slide 36)			
FCM Zonal Demand Curve		(Slide 37)			
Peak Energy Rent (CCP10+)		(Slide 38)			
Fast Start Resource Pricing			(Slide 39)		
	Dispatchable Asset Related Demand Pumps		(Slide 40)		
	CTS Conforming Changes		(Slide 40)		
Forward Reserve Market Netting Rules			(Slide 41)		
	SEMA/RI Reserve Zone		(Slide 41)		
	Sub-hourly Real-Time Settlement			(Slide 42)	
	Resource Dispatchability Requirements			(Slide 43)	
		FCM Related Modifications		(Slide 44)	
			NCPC Cost Allocation Phase II (Slide 45)		
			Multi-Hour System Ramp Pricing (Slide 46)		

Market Design Projects

Capital Projects

2015				2016	
Q1	Q2	Q3	Q4	Q1	Q2
Reg. Market	(Slide 49)				
FCA 9 Implementation	(Slide 50)				
	FCA 10 Implementation (Slide 51)				
LMP Calc. Replacement (Slide 52)					
Generator Control Application (Slide 53)					
Coordinated Transaction Scheduling (Slide 54)					
Divisional Accounting (Slide 55)					
Wind Forecasting Phase II (Slide 56)					
Cyber Security Initiatives (Slide 57)					
Power System Modeling Tools (Slide 58)					
3rd Party FTR Clearing (Slide 59)					
Business Continuity Plan Phase III (Slide 60)					
Various Database and Application Enhancements (Slides 61-64)					
Issue Resolution 2015 (Slide 65)					

Capital Projects

Transmission Planning Studies

- Updated Needs Assessments will be conducted in 2015 in accordance with the Planning Process
  - Updated regional load forecast and Energy-Efficiency (EE) forecast
  - Continue to improve the regional Solar PV forecast and review how this forecast should influence various ISO planning studies, including calculation of the regional Installed Capacity Requirement (ICR)
  - Resource mix will be adjusted for the results of the first nine Forward Capacity Market Auctions
    - New Resources
    - Non-Price Retirements and de-list bids
    - Other resource changes

Transmission Planning Studies, cont.

- Several studies are underway or nearing completion
  - Eastern Connecticut Needs Assessment Study
  - Southwestern Connecticut Solutions Study
  - Greater Boston Solutions Study
  - Pittsfield/Greenfield Solutions Study
  - Greater Hartford/Central Connecticut Solutions Study
  - SEMA/RI area, including impact of Brayton Point retirement
  - Updated regional transfer limit analysis, including stability limit analysis

Transmission Planning Studies, cont.

- Support state siting proceedings for major transmission projects, as necessary
  - Greater Boston Reliability Project (MA, NH)
  - VT/NH Reliability Project (VT, NH)
- The ISO initiated discussions regarding probabilistic planning in 2014 and plans to review load modeling and unit availability assumptions in 2015
- The ISO Transmission Planning technical guide was updated twice in 2014 and the ISO Planning Process guide will be updated based on the FERC Order 1000 ruling
  - Improvements to the planning technical guide will be valid both pre and post FERC Order 1000 implementation

Eastern Interconnection Planning Collaborative (EIPC)

- 2015 EIPC non-grant activities
  - Model Roll-up and Evaluation (contingency analysis and/or transfer analysis) for summer and winter 2025
  - Engage stakeholders to seek input on potential scenarios of interest for analysis in 2016
  - Production Cost Studies in 2015 and 2016
  - Participation in NERC Model Building Process Discussions in 2015
  - DOE Annual Transmission Data Report in 2015
- 2015 ISO Planning staff effort
  - The ISO will chair the Steady State Modeling Load Flow Working Group
  - Support of Technical Committee and Executive Committees and Production Cost Studies

2015 Attachment K Economic Studies

- 2015 Economic Study requests to be submitted by April 1, 2015
  - Because no requests were received in 2014, as part of the 2015 cycle, the ISO plans to discuss with stakeholders and states, ways to improve the approach and content of economic studies

State Sponsored Energy-Efficiency Programs

- The Regional Energy-Efficiency Initiative (REEI) efforts have highlighted the New England states' activities and investments in energy efficiency
- Data has been gathered to support the development of the 2015 EE forecast, expected to be completed in Spring 2015
- ISO will continue working with the Energy-Efficiency Forecast Working Group to review and refine the EE forecast process
- Data gathering to support development of the 2016 EE forecast to begin in Q3 2015

Interregional Planning

- There are a number of forums and activities related to interregional planning efforts beyond EIPC
  - North American Electric Reliability Corporation (NERC)
  - Northeast Power Coordinating Council (NPCC)
  - Inter-Area Planning Stakeholder Committee (IPSAC)
  - Department of Energy (DOE) Congestion Study Support
  - Northeast Gas Association (NGA)
- ISO, NYISO, and PJM will be working on implementation of the interregional planning portion of Order 1000 in 2015. These efforts are likely to continue into 2016 as we gain more experience with the new process

Transmission Cost Allocation (TCA)

Transmission Owner	Project	Pool Transmission Facilities (PTF) Cost Estimate	Target Date
VELCO	PV-20 Cable Replacement	~53M	Potential 2015 TCA Submittal
VELCO	Vermont Solutions CT River Valley	~134M	Potential 2015 TCA Submittal
NGRID	NEEWS (Rhode Island Reliability Project)	~345M	Potential 2015 TCA Submittal
NU/NGRID	NEEWS (Interstate Reliability Project)	~536M	Potential 2015 TCA Submittal
NU	Replace 115 kV 1990 Line Lattice Structures – Frost Bridge to Stevenson	~63M	Potential 2015 TCA Submittal
NU/NGRID	Advanced Boston Projects	~60M	Potential 2015 TCA Submittal

FERC Order 1000 – Implementation

- FERC Order 1000 compliance filings are complete. Awaiting any final compliance obligations for both interregional and intraregional Planning from FERC
- Given the delay in getting a final compliance order, these efforts will likely extend into 2016

2019/2020 Installed Capacity and Local Sourcing Requirements for FCA #10

- PSPC review of ISO recommendation of Installed Capacity Requirement (ICR) values – **June 2015**
- Reliability Committee (RC) review/vote – **August 2015**
- Participants Committee review/vote – **October 2015**
- File with FERC – **November 2015**
- Forward Capacity Auction #10 conducted – **February 2016**

FCM Auction Key Dates

- Commitment Period #6 (2015-2016)
  - ARA #3 – **March 2015**
- Commitment Period #7 (2016-2017)
  - ARA #2 – **August 2015**
- Commitment Period #8 (2017-2018)
  - ARA #1 – **June 2015**
- Commitment Period #9 (2018-2019)
  - Conduct Auction – **February 2015**
  - Results Filing – **February 2015**
- Commitment Period #10 (2019-2020)
  - Show of Interest Window – **February 17 – March 3, 2015**
  - FCA FERC Informational Filing – **November 2015**
  - Conduct Auction – **February 2016**

New Generation Update as of December 1, 2014

- In total, 56 generation projects are currently being tracked by the ISO totaling approximately 8,400 MW
  - 6 in scoping stage
  - 5 in feasibility study
  - 19 in system impact study/optional interconnection study
  - 0 in facilities study
  - 7 negotiating interconnection agreements (IAs)
  - 22 with interconnection agreements
  - 4 distribution interconnections

Regional System Plan (RSP) – 2015

- RSP15 and related key Planning Advisory Committee (PAC) meetings
  - RSP scope of work to be presented at the January/February PAC
  - Environmental and renewable resource updates provided to PAC and Environmental Advisory Group (EAG) on an ongoing basis
  - Initial draft report will be posted for stakeholder review in July
  - RSP review and comment meeting scheduled for August 6
- RSP15 Public Meeting scheduled for September 10

2014/15 Winter Reliability Program

- 2014/15 winter reliability program services for the period December 1, 2014 through February 28, 2015:
  - Compensation for unused oil inventory;
  - Compensation for unused liquefied natural gas (“LNG”) contract volume;
  - Incentives for commissioning dual fuel capacity before December 1, 2016;
  - A demand response program;
  - Permanent rule changes to eliminate the requirement that dual fuel units burn the higher-priced fuel when bids are based on that fuel and gas prices are volatile; and
  - Permanent rules to permit ISO-initiated audits of dual fuel capability
- ISO will provide monthly updates on the program at the NEPOOL Participants Committee meetings

Gas-Electric Coordination

- These activities are intended to only incrementally improve the operations of the power system and will not address underlying infrastructure or fuel inadequacies
  - Enhance coordination and information sharing with gas pipelines, per FERC Order 787
  - Implement new tool that mines data from various sources to estimate the availability of natural gas on a forward weekly basis for energy purposes
  - Run capacity analysis scenarios across different seasons based on information gathered from fuel surveys and pipelines
  - Establish operating plans to deal with different system conditions
  - Continue data gathering and analysis
  - Communicate with stakeholders and regulators on a regular basis

NERC/FERC Compliance; Cyber Security

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

NERC Standards: Generator Dynamics Data

- To address different Planning, Modeling, and Relay Protection standards, there are several efforts to enhance the submission and acquisition of generator dynamics data, including reactive power capability
- There is also a need to expand on the software developed to manage generator dynamic data to track protective relaying and under-frequency load shedding information

NERC Standards: Operational and Planning Studies

- To address different Planning, Modeling, and Relay Protection and Critical Infrastructure Protection standards, System Planning and Operations have significant new study work:
  - Study of long-term system needs using new contingencies and criteria
  - Verify that the Transmission Owners identified facilities for physical protection consistent with the risk assessment study methodology that they designed
  - Assess new dynamic operating characteristic information provided by generation owners
  - Study impact of Geo-Magnetic Disturbances

NERC Standards: Comparison of Steady State and Dynamic Events to Simulations

- Requires ISO to compare simulations to actual system events by 2017.
  - Major effort to migrate system topology information from Energy Management (EMS) Systems into PSSe Model (PSSe is a format widely used in planning studies)
  - Architecture differences between EMS and PSSe increase difficulty

NERC Grid Security Exercise

- NERC will be conducting its third exercise (GridEx III) on cyber and physical security
- The exercise brings together NERC, the industry, and government agencies, as well as participants from Canada and Mexico.
- Similar to GridEx I & GridEx II the objective is:
  - Exercise the readiness of the electricity industry to respond to a security incident
  - Review existing command, control, and communication plans and tools
  - Identify potential improvements in cyber and physical security plans, programs, and responder skills.
- NERC's expectation is that the ISO, as the Region's Reliability Coordinator, will actively participate in the planning and then as a participant in the exercise, which is scheduled for the November timeframe
  - The ISO will coordinate the planning, participation and execution of the exercise for New England.
  - Anticipated participants in the exercise are the Transmission Owners' Local Control Centers, certain New England governmental and law enforcement agencies and Neighboring Regions

Elective Transmission Upgrades – ETU’s

- There are a number of issues with the existing OATT language on processing requests for Elective Transmission Upgrades (ETU’s)
- ISO is working with all three NEPOOL Technical Committees on proposed tariff language changes in the ISO OATT and Market Rule 1. Technical Committee action is anticipated in January, with action at the Participants Committee in February
- ISO plans to make a FERC filing soon after the February PC meeting, with implementation to follow, to allow ETU’s to participate in FCA #10

Modeling Capacity Zones

- A new process for determining Capacity Zones was implemented for FCA #9
- Regional transfer limits will be updated in Q1 2015
- Any changes or updates to Capacity Zones for FCA #10 will be indentified in Q2 2015
- Zonal requirements for FCA #10 will be determined in Q2/Q3 2015

Distributed Generation Forecast

- The Distributed Generation Forecast Working Group (DGFWG) completed the first interim DG Forecast in spring 2014
- The DGFWG is continuing its work to refine the DG forecast process in an effort to have an improved forecast in spring 2015. Access to Solar PV production data will be an important part of this process
- ISO continues to review how this forecast should influence various ISO planning studies, including calculation of the regional Installed Capacity Requirement (ICR) and will also discuss this issue with stakeholders at NEPOOL technical committee meetings
  - Stakeholder discussions will begin in February 2015
- Technical issues have been identified regarding the interconnection and operability of solar photovoltaic resources that will require more analysis and, perhaps, lead to changes in state interconnection standards
- ISO Operations will be exploring the integration of irradiance data into the ISO weather forecast that feeds into the load forecast to better anticipate the level of solar generation in real-time

Operating Guides and Procedures Update

- Review and update Guides due to transmission and generation changes
  - MPRP; Interstate; Generation Retirements; Addition of Renewable Generators
- Review and update real-time voltage limits
  - Replace off-line voltage calculator tool with real-time calculator integrated within the EMS
- Develop temporary operating guides for system modification during construction
- Use of Phasor Measuring Units (PMUs) and other fast recording devises to benchmark and improve accuracy of generator models. These devices will also improve the ability monitor NERC Reliability Standard requirements for frequency response.

MARKET DESIGN

LMP Calculator Replacement

- This project will replace the current *ex post* LMP Calculator with a new pricing engine based on *ex ante* pricing principles and eliminate pricing discrepancies that currently exist under certain reserve and capacity constrained situations
- The stakeholder process is underway with a FERC filing targeted for March 2015 and implementation targeted for Q2 2015

Do Not Exceed Dispatch

- The ISO is proposing to modify the dispatch rules as they apply to intermittent resources such as wind and run-of-river to ensure reliable system operation while efficiently using their capability
  - The stakeholder process is underway with a FERC filing targeted for March 2015 and an implementation targeted for Q4 2015/Q1 2016

Elective Transmission Upgrades

- <Included within System Planning materials>

3rd Party Credit Clearing and FTRs

- The objective of this project is to replace the ISO's financial assurance requirements for holding FTRs with margining by a third party clearing entity
  - This shifts FTR default risk from ISO New England's Market Participants to the third party
  - This project also addresses the financial assurance issues that have prevented implementation of Long Term FTRs and Balance of Planning Period auctions
- The stakeholder process is underway with a FERC filing targeted for March 2015 and implementation targeted for Q4 2015 (for the 2016 FTR period)

Winter Solution 2015-2018

- The ISO is working with stakeholders to determine the appropriate solution to meet winter reliability needs in the upcoming winter through the winter of 2017-18
- The stakeholder process began in November 2014, with a filing targeted for as early as April 2015 and implementation in early Fall 2015

FCM Zonal Demand Curve

- The ISO has proposed zonal demand curves for the region's capacity market, as well as changes for the reconfiguration auction and bilateral rules. The ISO is also evaluating these related areas of change for FCA10:
  - Zonal Competitiveness
  - Market Power through Uneconomic Retirement
  - Comprehensive Competitiveness Test and Market Power Mitigation
  - Review of Treatment of Imports
- The stakeholder process is underway with a FERC filing targeted for Q2 2015 and implementation targeted for FCA10
  - Reconfiguration auction rules for the system demand curve will be effective for Capacity Commitment Period 9

Peak Energy Rent

- The ISO is evaluating the PER mechanism for CCP10 and beyond to determine if it should be modified or eliminated
  - The stakeholder process is underway with a FERC filing targeted for March 2015 and implementation targeted for FCA10

Fast Start Resource Pricing

- The ISO is developing solutions to improve the Real-Time Energy Market's pricing logic when fast-start resources are deployed to supply energy
  - The stakeholder process is expected to begin by Q1 2015 with a FERC filing targeted for September 2015 and implementation targeted for 2016
  - In addition to efforts already underway, this is the first in a sequence of additional steps intended to enhance price formation in the energy markets (the additional steps are consistent with the price formation memo released by the ISO memo in December 2014)

Energy Market Design Projects

- The ISO is proposing to add intertemporal parameters for DARD pumps to improve the commitment and operation for normally off-peak pumping load
  - The stakeholder process is expected to begin in Q2 2015 with a FERC filing targeted for October 2015 and implementation targeted for Q3 2016
- The ISO is proposing a set of minor market rule changes to address Coordinated Transaction Schedule implementation requirements
  - The stakeholder process is expected to begin in Q2 2015 with a FERC filing targeted for July 2015 and an implementation targeted for Q4 2015

Reserve Related Design Projects

- The ISO is evaluating the FRM price cap and the rules that net the FCA price from the FRA price to ensure that resources are able to reflect their costs in the FRM under higher priced capacity market conditions
  - The stakeholder process is expected to begin in Q1 2015 with a FERC filing targeted for August 2015 and an implementation expected no later than the Summer 2016 FRM delivery period
- The ISO is proposing adding a SEMA/RI reserve zone to correspond to the capacity zone created for the 2018/2019 commitment period
  - The stakeholder process is expected to begin in Q2 2015 with a FERC filing targeted for November 2015 and implementation expected for June 2018

Sub-hourly Real-Time Settlement

- The real-time markets (energy, reserves and regulation) are all settled hourly, even though resources are dispatched at sub-hourly intervals
  - The hourly settlement approach, especially for resources that are able to respond quickly, can result in hourly compensation inconsistent with the resource's performance on a 5-minute basis
  - The ISO is evaluating allowing sub-hourly settlement for the real-time markets for, at a minimum, generation and dispatchable asset related demand
- The stakeholder process is underway with a FERC filing targeted for November 2015 and implementation targeted for no earlier than Q4 2016

Resource Dispatchability Requirements

- The ISO is proposing to require all non-settlement only generation resources to be dispatchable
  - The stakeholder process is expected to begin in Q2 2015 with a FERC filing targeted for December 2015 and implementation targeted for 2016

FCM Related Modifications

- The ISO is evaluating aspects of the FCA and reconfiguration qualification processes, non-commercial financial assurance requirements, and the commercial operation determination rules
  - The stakeholder process is expected to begin by Q3 2015 with a FERC filing targeted for December 2015 and implementation targeted for Q1 2016

NCPC Cost Allocation: Phase II

- The ISO is performing a comprehensive review of cost allocation, identifying the cause or beneficiary of the commitment or dispatch that resulted in the NCPC costs, so that a revised allocation approach can be developed
- The stakeholder process is expected to begin in late 2015 with a FERC filing targeted for Q3 2016 and implementation targeted for no earlier than Q4 2016

Multi-Hour System Ramp Pricing

- The ISO is assessing the potential development of a new system ramping product to convey, through transparent prices, the costs incurred when the system must be redispatched in advance of a sustained load ramp
  - The stakeholder process is expected to begin in Q4 2015 with a FERC filing targeted for Q4 2016 and implementation targeted for 2017

Demand Response: Full Integration

- The ISO is leaning towards moving the effective date for the full integration of demand response into energy and operating reserves to June 1, 2018, assuming that the Supreme Court grants certiorari in EPSA v. FERC this spring. If the Supreme Court denies certiorari, then our current plan for full integration will be terminated, to be replaced to something else based on discussions with the states and stakeholders and direction provided by the FERC on remand
  - Moving the effective date of full integration to June 1, 2018 will require Tariff changes.
- The ISO is also leaning towards making near-term changes to the Demand Response Baseline rules, conditioned upon the Supreme Court granting certiorari this spring. If the Supreme Court denies certiorari, the need for a new baseline methodology will be reassessed at that time.
- The ISO plans to begin discussing contingency plans with stakeholders in early Q2, 2015 to address the potential impacts if the EPSA decision is upheld.

CAPITAL PROJECTS

Alternative Technologies and Regulation Market Project

- This project will implement modifications to the Regulation market resource selection process, Automatic Generation Control dispatch, and settlement to comply with Order 755
- This project is currently scheduled to be implemented in Q1 2015

Forward Capacity Auction 9

- This project will implement the FERC orders related to the FCM Pay-for-Performance proposal, the system wide demand curve, and zonal modeling (CT, MA, SEMA/RI and Rest of Pool)
- This project is scheduled to be implemented in Q1 2015

Forward Capacity Auction 10

- This project will implement all rules associated with FCA 10, once FERC approved, including zonal demand curves, mitigation, elective transmission upgrades, and inclusion of demand curves in reconfiguration auctions
- This project is scheduled to be implemented in Q1 2016

LMP Calculator Replacement

- This project will replace the current *ex post* LMP Calculator with a new pricing engine based on *ex ante* pricing principles and eliminate pricing discrepancies that currently exist under certain reserve and capacity constrained situations
- This project is currently scheduled to be implemented in Q2 2015

Generation Control Application (GCA) Production Phase I

- This project will expand on previous functionality and provide the following
  - An enhanced version of the optimization engine for the commitment and shutdown of fast-start units
  - Dispatch slow-moving units to relieve expected future reserve or transmission constraints
  - Automatic detection/prediction for minimum generation conditions
  - Development of next hour interchange predictor for the New York North interface
  - This project is a pre-requisite to the Coordinated Transaction Scheduling project
- This project is scheduled to be implemented in Q4 2015

Coordinated Transaction Scheduling

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

Divisional Accounting

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

Wind Integration Phase II (Do Not Exceed Dispatch)

- This project is the next phase in the progression of steps necessary to fully integrate wind power into the ISO New England system
  - Phase I incorporated wind power forecasting into the control room
- This project will design and implement functionality that will incorporate wind and hydro resources into Real-Time dispatch
- This project is scheduled to be implemented in Q4 2015

Cyber Security Related Initiatives

- VPN Upgrade: This project will undertake the replacement of network devices supporting the VPN infrastructure to mitigate vulnerabilities associated with external intrusion
- 24x7 Security Operations Center: This project will build upon existing tools and provide the capability for 24x7 monitoring of the security of ISO network
- The ISO expects to complete an implementation plan for transitioning to CIP Standard 5 in 2016
- Some aspects of this project are scheduled to be implemented in Q4 2015, while others will be implemented in 2016.

Power System Modeling (NX9/NX12)

- The NX9/NX12D modeling application which currently collects transmission equipment and certain generator data will be modified to support a new NERC standard, MOD-025-2.
  - ISO New England is required to collect and store both real and reactive power capability data for generators, along with reactive capability data for synchronous condensers
  - In addition, technology updates will be done within the project timeframe.
- This project is scheduled to be implemented in Q1 2016

Third Party FTR Clearing

- This project will design and implement software that is capable of administering third-party clearing, subject to timely filing and approval of rules by FERC
- This project is scheduled to be implemented in Q4 2015

Business Continuity Plan (BCP) Infrastructure Enhancements Phase III

- This is the final phase of the BCP initiative that began in 2008
- This project will expand the infrastructure to allow market based applications to transfer operation to or from servers located either at the MCC or the BCC in real time and will improve the ability for ISO personnel to conduct business remotely in the case of an extended unavailability of the Main Control Center
- This project is scheduled to be implemented in Q4 2015

Various Application Enhancements

- New voltage/reactive tool
  - Implement a new voltage tool that will be used by the Control Room in real-time
  - Use of these real-time limits will improve the commitment and dispatch efficiency of the power system
  - This project is scheduled for implementation in Q4 2015
- Software Testing Tool
  - The purpose of this project is to automate the testing effort for various applications at the ISO, which will result in efficiencies in future project implementations
  - This project is scheduled for implementation in Q3 2015

Various Application Enhancements, cont.

- Lawson Upgrade
  - The Lawson Financial platform is the Financial System of Record for ISO New England. The platform vendor has announced that after May 31st, 2016 they will no longer support the version of their software currently in use at ISO-NE.
  - This project will upgrade the Software and Hardware related to the Lawson platform to fully supported versions.
  - This project is scheduled for implementation in Q3 2015
- Web Enhancements
  - This project will upgrade a component of the internal ISO web domain to a version that is supported by the associated vendor. This system supports certain Control Room applications and the WEBFTP function for internal and external use.
  - This project is scheduled for implementation in Q4 2015

Various Application Enhancements, cont.

- Adaptive Transmission Ratings
  - Adaptive Transmission Ratings (ATR) proposes a new methodology that will allow better utilization of the system transfer capabilities. ATR of a transmission element is adaptively selected inside of the range between LTE and STE by accounting for the system ramping capabilities and loading on that transmission element in real-time
  - This project is scheduled for implementation in Q1 2016
- PMU Data Application
  - In 2015, this project will focus on acquisition of PMU data from neighboring ISO/RTOs to enhance external visibility and PMU based wide area monitoring, improving the alarming capability of islanding and disturbance and oscillation detection
  - This project is scheduled for implementation in Q1 2016

Various Application Enhancements, cont.

- Quarterly Releases: Hardware Upgrades / Software Enhancements
  - These upgrades are intended to address various ISO hardware upgrade needs and implement software enhancements to various enterprise applications, market and reliability based applications, and data bridges that connect these applications
  - These are implemented at various points during the course of the year, based on the schedule of major projects
  - These enhancements are expected to be bundled into two quarterly releases (Q2 2015 and Q4 2015)

2015 Issues Resolution Project

- Reduce Backlog in Issues Management
  - The 2015 Issue Resolution Project is intended to continue to improve the resolution pace of issues
  - This will increase operational efficiency and accuracy, provide for minor enhancements, and reduce risk
  - This could include both software and hardware infrastructure enhancements
  - This will be implemented as multiple projects and they are scheduled for completion by the end of 2015

ACTIVITY DRIVERS

Wholesale Markets Activity Drivers

Activity	Driver	Reliability Impact	Market Efficiency Impact
LMPc Replacement	Market Monitors, ISO	Low	Medium
Wind Dispatch Rules	ISO Initiative/Public Policy	Medium	Medium
3rd Party FTR Clearing	ISO Initiative	Low	Medium
Winter Solution 15-18	ISO Initiative	High	Low
FCM Demand Curve	FERC Order	Medium	High
Peak Energy Rent	ISO Initiative	Low	Medium
Fast Start Pricing	Market Participants, ISO	Medium	High
DARD Pump Parameters	Market Participants, ISO	Low	Medium
CTS Conforming Changes	Market Monitors; FERC; ISO Initiative	Medium	Medium

Wholesale Markets Activity Drivers, cont.

Activity	Driver	Reliability Impact	Market Efficiency Impact
FRM Price Netting Rules	ISO Initiative	Low	Medium
SEMA/RI Reserve Zone	ISO Initiative	Medium	Medium
Sub-Hourly Settlement	Market Participants	Medium	Medium
Resource Dispatchability	ISO Initiative	Medium	Medium
NCPC Cost Allocation	ISO Initiative	Medium	Medium
Sub-Hourly Settlement	Market Participants	Medium	Medium
Multi-hour Ramp Pricing	Market Participants; FERC; ISO Initiative	High	High

Planning/Operations Activity Drivers

Activity	Driver	Reliability Impact
Transmission Planning Studies	NERC and NPCC and Tariff Compliance	High
Eastern Interconnection Planning Collaborative	DOE Initiative	Low
2015 Economic Studies	Tariff Compliance; Order 890	Low
2015/ 2016 EE Forecast	Public Policy	Medium
Interregional Planning	NERC, NPCC and Tariff Compliance	Medium
Transmission Cost Allocation	Tariff Compliance	Low
Implement FERC Order 1000	FERC Compliance	Medium
2019/20; 2020/21 ICR and LSR	NERC, NPCC and Tariff Compliance	High
FCA 9 / FCA 10; Annual Reconfig Auctions	Tariff Compliance	High

Planning/Operations Activity Drivers, cont.

Activity	Driver	Reliability Impact
Generator Interconnection Studies	Tariff Compliance	Medium
RSP 15 /RSP 16 Publication	Tariff Compliance	Low
2015-2018 Winter Program	ISO Initiative	High
Gas-Electric Coordination	ISO Initiative	High
NERC/FERC/NPCC Compliance; Cyber Security	NERC / FERC / NPCC Compliance	High
Elective Transmission Upgrades	ISO Initiative	Medium
Modeling Capacity Zones	FERC Order	High
Distributed Generation (DG) forecast	Public Policy	Medium
Operating Guide Updates	ISO Operations	High

Capital Project Activity Drivers

Activity	Driver	Reliability Impact	Market Efficiency Impact	Estimated 2015 Implementation Cost*
Regulation Market	FERC Order	Low	Medium	$300K
FCA 9 Implementation	Tariff Compliance	Medium	High	$400K
FCA 10 Implementation	FERC Order	Medium	High	$2.0M
LMPc Replacement	ISO Initiative	Low	Medium	$500K
Generator Control Application	ISO Initiative	High	High	$2.2M
Coordinated Transaction Scheduling	Market Monitors; FERC	High	High	$3.6M
Divisional Accounting	Stakeholders; ISO Initiative	Low	Medium	$600K

*** Estimated 2015 implementation costs; Several Projects are not chartered and budgets will be finalized as projects are chartered**

Capital Project Activity Drivers, cont.

Activity	Driver	Reliability Impact	Market Efficiency Impact	Estimated 2015 Implementation Cost*
Wind Forecasting Phase II (Do Not Exceed)	Market Participants, ISO	Medium	Medium	$1.0M
Cyber Security	NERC; ISO Initiative	High	Low	$750K
Power System Modeling	NERC; ISO Initiative	High	Medium	$1.0M
3rd Party FTR Clearing	ISO Initiative	Low	Medium	$1.8M
Business Continuity Plan Phase III	NERC Compliance	High	Medium	$2.0M
Various Application/Database Enhancements	ISO Initiative	Medium	Medium	$3.0M
Issue Resolution 2015	ISO Initiative	Medium	Medium	$1.0M

*** Estimated 2015 implementation costs; Several Projects are not chartered and budgets will be finalized as projects are chartered**

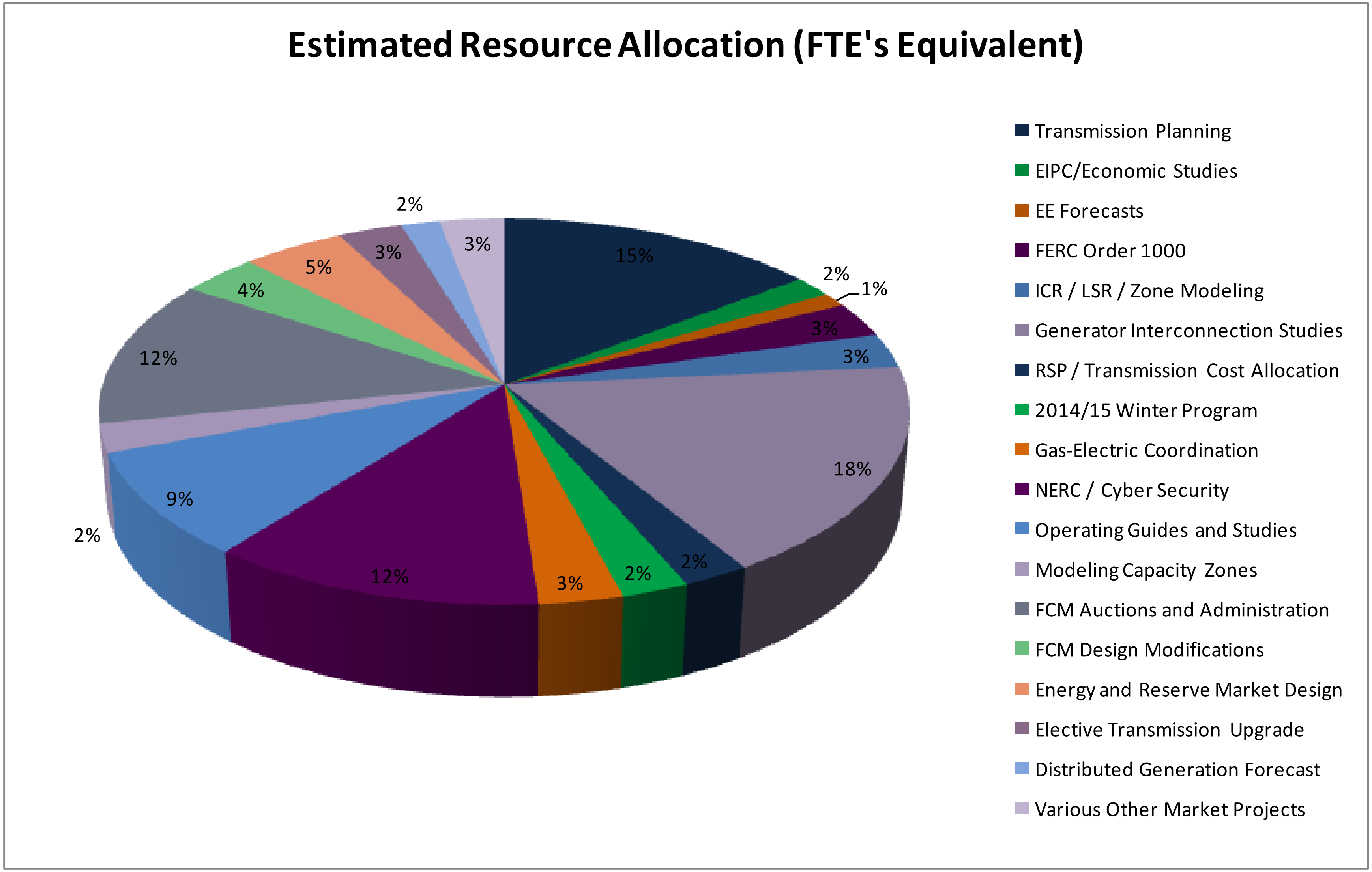
Capital Projects

- The ISO discusses changes and updates to its capital budget each quarter (with stakeholders) and files a quarterly capital projects report with the FERC
  - The quarterly report captures any changes in the cost of a project
  - The quarterly report also notes projects that are completed and new projects that are chartered
  - The most accurate quarterly costs are reflected in these quarterly reports
  - Please note that the resource estimates and costs contained in this presentation are only approximations, likely to change through the course of the year and intended to signal the current level of effort for each activity

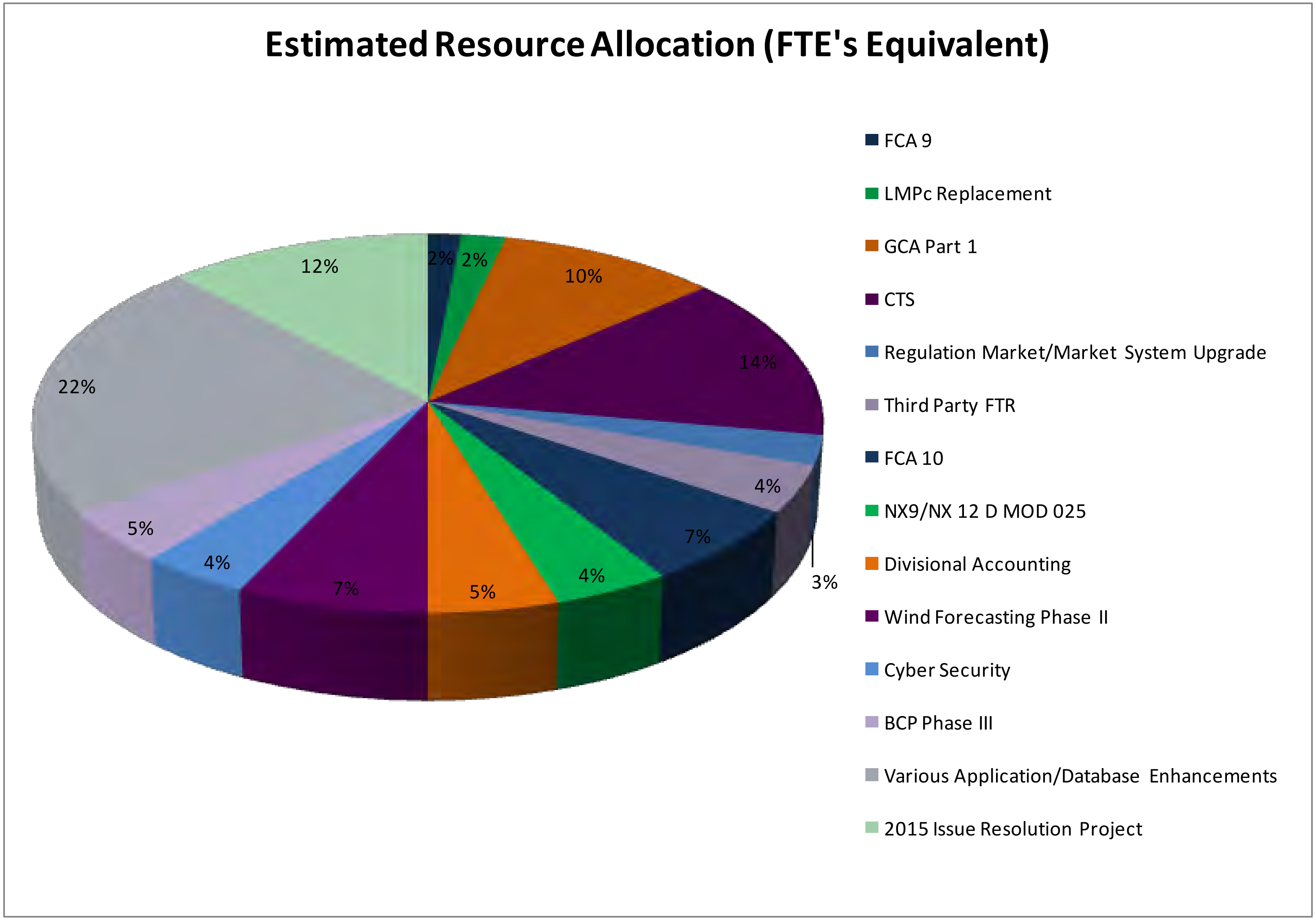
Resource Allocation Estimates

- For the activities identified in the work plan, the estimated ISO resource allocation is as follows:
  - For the capital projects identified in the work plan, the ISO expects an approximate allocation of 100 resources
  - For the non-capital activities identified in the work plan, the ISO expects an approximate allocation of 170 resources
- Slides 75 and 76 illustrate the relative resource allocation across activities contained in the work plan
  - These resources are estimates and actual allocation of resources across all activities changes frequently based on scope, schedule and emerging priorities
  - Costs associated with generator interconnection studies are mostly reimbursed by the study owner

Estimated Resource Allocation to Operating Activities



Estimated Resource Allocation to Capital Projects



M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Paul N. Belval, NEPOOL Counsel

DATE: January 30, 2014

RE: ISO New England Transmission, Markets, and Services Tariff
Changes Related to ISO Tariff Schedule 1 – Elective Transmission Upgrade Deposits

---

The Participants Committee will be asked at its February 6 meeting to support changes to Schedule 1 of ISO New England's Transmission, Markets, and Services Tariff ("ISO Tariff") related to the introduction of Schedule 25 to the ISO Open Access Transmission Tariff ("OATT"). This memorandum summarizes the proposed changes (which have been included and posted with this memorandum).

The ISO proposed the addition of Schedule 25 to the OATT, Elective Transmission Upgrade Interconnection Procedures, to support the Elective Transmission Upgrade ("ETU") project. Specifically, Schedule 25 contains the core provisions that establish the procedures and agreements for the interconnection of ETUs to the Administered Transmission System, including for the payment of certain related deposits. Schedule 25 was supported by the NEPOOL Transmission Committee on January 20, 2015 and is included on the Consent Agenda for the Participants Committee's February 6 meeting.

As a result of the addition of the new Schedule 25, a minor, clarifying change is needed to Schedule 1 of the ISO Tariff. The change clarifies that any deposits that become non-refundable under Schedule 25 of the OATT will be credited to Schedule 1 of the ISO Tariff. This approach is consistent with the treatment of other deposits under OATT Schedule 22 that become non-refundable. The ISO plans to file the change to the ISO Tariff and the OATT with the FERC shortly after the February 6 Participants Committee meeting and expects to request a February 16, 2015 effective date, to ensure that the revisions are in place for FCA-10.

The NEPOOL Budget and Finance Subcommittee (the "Subcommittee") discussed the proposed change to Schedule 1 to the ISO Tariff on its January 22 teleconference. None of the Subcommittee members on that teleconference objected to that proposed change.

The following form of resolution could be used for Participants Committee action:

> RESOLVED, that the Participants Committee supports the changes to Schedule 1 to the ISO New England Transmission, Markets, and Services Tariff related to proposed Schedule 25 to the ISO New England Open Access Transmission Tariff, as circulated to the Committee and discussed at this meeting, together with [any changes agreed to at this meeting and]such further non-substantive changes as the Chief Financial Officer of ISO New England and the Chairman of the Budget and Finance Subcommittee may approve.

Reserved Capacity (expressed in kilowatts) for an hour for each transaction scheduled to occur during the month as Through or Out Service multiplied by $0.00021 per kilowatt for each hour of service.

Schedule 1 revenues collected from Through or Out Service customers shall be credited to each Network Customer receiving Regional Network Service that month in proportion to each Network Customer's Monthly Regional Network Load in that month.

Non-Market Participant FTR fees and any portions of Long Lead Facility deposits collected by the ISO under ~~Section 3.2.3.3(2) of~~ Schedule 22 and Schedule 25 of Section II of the Tariff that become non-refundable will be credited to Schedule 1 Revenue Requirements and will be included in the Schedule 1 true-up calculations.

All general terms and conditions of the Tariff apply to this Service.

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of February 5, 2015

The following activity, as more fully described in the attached litigation report, has occurred since the report dated January 7, 2015 was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

I. Complaints

1	NEPGA Peak Energy Rent (PER) Complaint (EL15-25)	Jan 16 Jan 30	NEPOOL responds to NEPGA's Jan 7 answer FERC denies Complaint
2	New Entry Pricing Rule Complaint (EL15-23)	Jan 30	FERC denies Complaint
3	206 Proceeding: Importers' FCA Offers Review/Mitigation (EL14-99; ER15-117)	Jan 14 Jan 26	Public Citizen requests rehearing of Dec 15 order; ISO submits 30-day compliance filing; comment date Feb 4 NEPGA answers Public Citizen request for rehearing
4	Base ROE Complaints (2012 & 2014) Consolidated (EL14-86 & EL13-33)	Jan 23 Feb 2 Feb 5	FERC issues tolling order affording it additional time to consider TOs' request for rehearing of Nov 24 order in EL14-86 TOs submit testimony and exhibits Judge Sterner issues an order setting the updated data cutoff date at May 26, 2015
5	206 Investigation: FCM PI Compliance Proceedings (EL14-52; ER14-2419)	Jan 15	FERC accepts ISO compliance filing revising Market Rule 1 § 13.7 to strike language rejected by the *Oct 2 Order*
7	FCM Administrative Pricing Rules Complaint (EL14-7)	Jan 30	FERC denies NEPGA request for rehearing and/or clarification of Jan 24, 2014 *FCM Admin Pricing Rules Order*

II. Rate, ICR, FCA, Cost Recovery Filings

9	FCA9 New Import Capacity Resources Qualification Informational Filing (ER15-640)	Jan 13	FERC accepts informational filing
9	ICR-Related Values and HQICCs - 2015/16 ARA3, 2016/17 ARA2, 2017/18 ARA1 (ER15-555)	Jan 27	FERC accepts values
9	Opinion 531-A Compliance Filing: TOs (ER15-414)	Jan 13	Complainant-Aligned Parties ("CAPs") answer TOs' Dec 23 answer
9	FCA9 Qualification Informational Filing (ER15-328)	Jan 16	FERC accepts FCA9 Informational Filing and grants ISO-NE's request to qualify an add'l 5 MW of new capacity for FCA9
10	ICR, HQICCs and Related Values - 2018/19 Power Year (ER15-325)	Jan 30	NEPOOL requests clarification of Jan 2 order

III. Market Rule and Information Policy Changes, Interpretations and Waiver Requests

10	ORTP Exemption for Distributed Renewable Technology Resources (ER15-716)	Jan 8-13 Jan 13 Jan 28 Feb 4	Entergy, EPSA, NESCOE, NRG, NU intervene NEPGA submits comments ISO answers NEPGA's Jan 13 comments NEPGA answers ISO's Jan 28 comments
11	Information Policy Clean-Up Changes (ER15-600)	Jan 9 Jan 28	ISO and NEPOOL jointly file 2nd set of corrections to Dec 8 filing FERC accepts changes

	11	PRD Reserve Market Changes (ER15-257)	Jan 9	FERC accepts changes, effective Jan 12, 2015 and Jun 1, 2017 as requested
	11	CSO Deferral: ISO Proposal (ER14-2440)	Jan 14	Footprint notifies FERC that it closed on the financing nec. to proceed with construction of the new Salem Harbor Facility
	11	Winter 2014/15 Reliability Program (ER14-2407)	Jan 20	FERC grants clarification of Sep 9 order requested by NEPGA that if a winter reliability solution for winter 2015/16 and beyond is necessary, it must be a market-based solution developed through the stakeholder process and implementable beginning with winter 2015/16
	12	Demand Curve Changes (ER14-1639)	Jan 30	FERC denies rehearing, but grants clarification requested by Exelon/Entergy, of May 30 *Demand Curve Order*
	13	Exigent Circumstances Filing – FCM Admin. Pricing Rules (ER14-463)	Jan 30	FERC denies NEPGA's request for rehearing of the *Jan 24 Exigent Circumstances Order*

IV. OATT Amendments / TOAs / Coordination Agreements

No Activity to Report

V. Financial Assurance/Billing Policy Amendments

	17	FAP Minimum Capitalization Requirement Changes (ER15-593)	Jan 29	FERC accepts changes, effective Feb 5, 2015

VI. Schedule 20/21/22/23 Changes

	18	LGIA – NU/CPV Towantic (ER15-200)	Jan 8 Feb 3 Feb 5	1st settlement conference held Settle Judge Coffman issues report recommending that settlement proceedings continue 2nd settlement conference held; Chief Judge issues order continuing settlement proceedings

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

*	19	LFTR Implementation: 25th Quarterly Status Report (ER07-476)	Jan 15	ISO files its 25th quarterly report

IX. Membership Filings

*	19	February 2015 Membership Filing (ER15-937)	Jan 30	***Termination*** of the Participant status of Dominion Retail, Hess, the Cianbro Companies, the PalletOne Companies, and the Hannaford Companies; comment date Feb 20
	19	December 2014 Membership Filing (ER15-513)	Jan 8	FERC accepts (1) new members: Athens Energy; Blue Sky West; Canandaigua Power Partners; Mass Solar 1; Hawkes Meadow Energy; The Moore Company; Moore Energy; Nalcor Energy Marketing; SmartEnergy Holdings; and TEC Energy; and (2) the termination of the Participant status of TrueLight Commodities
*	20	Suspension Notices (not docketed)	Jan 12 Jan 21	Pacific Summit Energy (suspended Jan 5; reinstated Jan 12) Cape Wind (suspended Jan 20)

X. Misc. - ERO Rules, Filings; Reliability Standards

	20	FFT Report: Jan 2015 (NP15-19)	Jan 30	NERC files report
	20	Revised Reliability Standard: PRC-006-2 (RD15-2)	Jan 12	Dominion intervenes

*	21	New Reliability Standard: TPL-007-1 (RM15-11)	Jan 21	FERC files TPL-007-1 for approval
	22	*Order 802:* New Reliability Standard: CIP-014-1 (Physical Security) (RM14-15)	Jan 21	FERC issues tolling order affording it additional time to consider Foundation for Resilient Societies request for rehearing of *Order 802*
	23	NOPR: Revised Reliability Standard: BAL-001-2 (RM14-10)	Jan 26	NERC, AZ Pub. Serv. Co, BPA, Duke, EEI, MISO/PJM/ISO-NE, NatyrEner USA, NYISO, Powerex, Steel Manufactures Assoc., Tri-State Gen & Trans. Assoc., WAPA
	24	*Order 803*: Revised Reliability Standard: PRC-005-3 (RM14-8)	Jan 22	FERC approves PRC-005-3 changes

XI. Misc. - of Regional Interest

	27	203 Application: First Wind / TerraForm & SunEdison (EC15-44)	Jan 12 Feb 5	FERC approves Terra From/SunEdison acquisition of First Wind Applicants notify FERC that acquisition was consummated on Jan 29
	27	203 Application: EquiPower / Dynegy (EC14-140)	Jan 16	FERC issues deficiency letter requiring submission by Feb 16 (i) a Delivered Price Test for the PJM market, and the AP South, 5004/5005, and PJM East submarkets; and (ii) additional info regarding the transactions' effect on rates
	27	LVA/PSNH IA Complaint (EL15-9)	Jan 9	PSNH answers LVA Dec 16 response
*	28	E&P Agreement Terminations: Spruce Mountain Wind (ER15-975); Record Hill Wind (ER15-974); Highland Wind (ER15-973); Patriot Renewables (ER15-972)	Feb 4	CMP files notices of termination, each to become effective April 6, 2015; comment date Feb 25
*	28	LSA Termination: Emera/ Black Bear HVGW (ER15-962)	Feb 3	Emera and the ISO file notice of termination of LSA with Black Bear (covering the Howland Project); comment date Feb 24
*	29	IA – CL&P/Energy Stream (ER15-947)	Jan 30	CL&P (Eversource) files IA with Energy Stream to govern the interconnection of Energy Stream's 120 kV unit on the on the Quinnebaug River in Putnam, Connecticut; comment date Feb 20
*	29	HG&E Demarcation Agreement (ER15-939)	Jan 30	WMECO files Agreement with HG&E; comment date Feb 20
	29	E&P Agreement CMP/Atlantic Wind (ER15-589)	Jan 22	FERC accepts Agreement
	29	*Opinion 531-A* Compliance Filing: NGrid IFA Amendments (ER15-418)	Jan 15	FERC issues deficiency letter directing submission of additional information on or before Feb 17
*	30	FERC Enforcement Action: Maxim Power and K. Mitton (IN15-4)	Feb 2	FERC issues show cause order and notice of proposed penalties (in total, *$5.05 million* civil penalties); answer date Mar 4
	31	FERC Enforcement Action: Powhatan Energy, HEEP Fund, CU Fund, and H. Chen (IN15-3)	Jan 12 Jan 27 Jan 29 Jan 30 Feb 2	Powhatan Respondents invoke their statutory rights to prompt assessment of a penalty and a *de novo* review of that penalty in federal district court Powhatan Respondents request two-week extension of time for its answers, citing need to review yet-to-be disclosed exculpatory evidence FERC staff opposes requested extension FERC denies requested extension but permits answer by Feb 9 to materials provided with staff's Jan 29 motion Powhatan Respondents submits answers to Dec 12 *Powhatan Show Cause Order*

XII. Misc. - Administrative & Rulemaking Proceedings

32	Technical Conferences on Implications of Environmental Regulations (AD15-4)	Jan 23	Energy Policy Group submits comments
		Feb 2	FERC issues supplemental notice of Feb 19 National Overview technical conference
		Feb 5	ISO/RTO Council submits comments for Feb 19 technical conference
33	Price Formation in RTO/ISO Energy & Ancillary Services Markets (AD14-14)	Jan 16	FERC invites post-technical workshop comments by Feb 19 on any or all of the 12 questions listed in the attachment in its January 16 Notice
		Jan 29	APPA, EPSA and NRECA request extension of comment filing deadline to Mar 6
		Feb 2	CAISO, NYISO, PJM, SPP file joint motion supporting Jan 29 request
		Feb 3	ISO-NE asks for an extension of time, but only with respect to questions 5-12, to and including Mar 20, 2015
36	Order 676-H: Incorporation of WEQ Version 003 Standards (RM05-5)	Jan 15	FERC extends Version 003 standards compliance deadline to and including May 15, 2015 (with the exception of the OASIS template for which compliance is required by Mar 24, 2016)

XIII. Natural Gas Proceedings

37	NOPR: Scheduling Coordination (RM14-2)	Jan 22	ISO-NE submits response to FERC data requests regarding the impact on reliable and efficient operations of natural gas-fired generators running out of their daily nomination of natural gas transportation service during the morning electric ramp, to the extent it occurs
		Feb 2	Coalition for Enhanced Electric and Gas Reliability, the Natural Gas Council, the New England LDCs, and the APGA submit comments

XIV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XV. Federal Courts

41	FCA8 Results (ER14-1244 (consol.))	Jan 15	EPSA/NEPGA file motion supporting FERC motion to dismiss Petitions for lack of jurisdiction
		Jan 26	Connecticut and Public Citizen file motions opposing FERC motion to dismiss Petitions for lack of jurisdiction
		Jan 30	New England Congressional delegation sends letter to FERC Commissioners asking that they re-examine the FCA8 results
41	2013/14 Winter Reliability Program (14-1104, 14-1105, 14-1103 (consol.))	Jan 13	FERC requests extension of briefing schedule deadlines
		Jan 15	Court orders revised briefing schedule
42	Orders 745 and 745-A (11-1486 consol.))	Jan 15	FERC petitions Supreme Court for a writ of certiorari regarding the DC Circuit's *Order 745* decision; responses due Feb 17
43	*CPV Power Development, Inc., et al. v. PPL EnergyPlus, LLC, et al.* (Supreme Court, 14-634, 14-694)	Jan 9	AWEA files brief amicus curiae
		Jan 12	Connecticut, NY PSC file briefs amici curiae

M E M O R A N D U M

TO: NEPOOL Participants Committee Member and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: February 5, 2015

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 February 5, 2015. If you have questions, please contact us.[1]

I. Complaints

- **NEPGA Peak Energy Rent (PER) Complaint (EL15-25)**

On January 30, the FERC denied NEPGA's PER Complaint, finding that NEPGA had failed to meet its burden under section 206 of the Federal Power Act to demonstrate that the existing ISO Tariff provisions are unjust and unreasonable.[2] As previously reported, NEPGA filed a complaint, on December 3, 2014, requesting that the ISO be directed (i) to increase the daily PER Strike Price by $250/MWh for Capacity Commitment Periods 5 through 8, and (ii) to eliminate the PER Adjustment for FCA9 and beyond, or, alternatively, to continue the $250 per MWh increase in the PER Strike Price for FCA9. The changes proposed in this Complaint were considered but not supported by the Participants Committee at its October 3, 2014 meeting. On December 23, the ISO responded to the Complaint. Comments supporting the Complaint were filed by EPSA, Entergy and GDF Suez. Protests were filed by NESCOE and Connecticut.[3] NEPOOL filed comments summarizing the consideration of the NEPGA-proposed changes and, without taking a position on the changes themselves, maintaining that NEPGA had not satisfied its statutory burden to show the current Tariff provisions unlawful before forcing changes to the current filed rate. On January 7, NEPGA responded to the protests and NEPOOL's comments. On January 16, NEPOOL answered NEPGA's January 7 response.

As noted above, the FERC denied the PER Complaint. In a separate concurrence, Commissioners Clark and Moeller stated that "NEPGA and other parties have raised valid concerns regarding the continued application of the existing PER Adjustment in light of the increases in the Reserve Constraint Penalty Factors in ISO-NE's energy market put in place in 2014." The Commissioners went on to "encourage ISO-NE and its stakeholders to continue to consider potential changes to the PER Adjustment mechanism," stressing that "if NEPGA or any other party is able to provide specific evidence [regarding NEPGA's original allegations in this complaint], the Commission will consider any such complaints at that time." Challenges, if any, to the *PER Complaint Order* must be filed on or before March 2, 2015. If you have any questions concerning this

---

[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. ("ISO" or "ISO-NE") Transmission, Markets and Services Tariff (the "Tariff").

[2] *New England Power Generators Assoc., Inc. v. ISO New England Inc.*, 150 FERC ¶ 61,053 (Jan. 30, 2015) ("PER Complaint Order").

[3] "Connecticut", in this proceeding, is the Connecticut Public Utilities Regulatory Authority ("CT PURA"), the Connecticut Office of Consumer Counsel ("CT OCC"), George Jepsen, Attorney General for the State of Connecticut ("CT AG"), and the Connecticut Department of Energy and Environmental Protection ("CT DEEP").

matter, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **New Entry Pricing Rule Complaint (EL15-23)**

On January 30, the FERC denied the New Entry Pricing Rule Complaint, finding that Exelon and Calpine had failed to show that the existing pricing rules governing lock-in capacity result in unjust, unreasonable or unduly discriminatory price suppression.[4] As previously reported, Exelon and Calpine filed a formal complaint, on November 26, 2014, requesting (i) that the FERC find the New Entry Pricing Rule[5] unjust, unreasonable and unduly discriminatory; and (ii) that the FERC remedy the New Entry Pricing Rule's "price suppression on other suppliers and the market ... consistent with the approach taken in PJM." The changes proposed in this Complaint were considered but not supported by the Markets Committee. The changes were also considered by the Participants Committee at its August 1 meeting and were determined, without the need for formal action, to lack the requisite support of the Committee. Interventions were filed by ConEd, CPV Towantic, Dominion, Dynegy, Emera, LS Power, MA DPU, NRG, PSEG, and UI. On December 16, the ISO and NEPOOL filed responses to the Complaint. Supporting comments were filed jointly by EPSA and NEPGA, and by Entergy. NESCOE, CT PURA, and Public Systems[6] filed protests. On December 31, Exelon/Calpine responded to the ISO and NEPOOL responses, and to the protests and the comments filed on December 16. As noted above, the FERC denied this Complaint on January 30. Any challenges to the *New Entry Pricing Rule Complaint Order* must be filed on or before March 2. If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **NEPGA DR Capacity Complaint (EL15-21)**

The November 14, 2014 NEPGA complaint, requesting that (i) Demand Response Capacity Resources (DR) be disqualified from FCA9 and (ii) the Tariff be revised to exclude DR from FCM participation going forward (as a result of *EPSA v. FERC*), remains pending before the FERC. Interventions were filed by AEP, Brookfield, Calpine, ConEd, CSG, Direct, Dominion, EEI, ELCON, Emera, EnergyConnect, EnerNOC, Entergy, Exelon, FirstEnergy, Maryland Public Service Commission ("MD PSC"), NextEra, NRG, PPL, and Wal-Mart stores. NEPOOL filed comments on November 26 asking the FERC to reject the NEPGA Complaint without prejudice to a complaint being resubmitted if and as appropriate following consideration of specifically-proposed changes to the Tariff within the Participant Processes. NU and UI jointly protested the complaint, on December 3, requesting that the FERC either dismiss or hold the Complaint in abeyance. The ISO answered the Complaint on December 4. Also on December 4, Advanced Energy Management Alliance, NESCOE, Conn/RI,[7] Enerwise, Environmental Advocates,[8] NGrid, Public Systems; and the Sustainable FERC Project opposed the Complaint; EPSA and PSEG supported the Complaint; Genbright submitted comments. On December 15, CT PURA moved to lodge the December 15 DC Circuit Court order extending the stay of the mandate in *EPSA v. FERC*. On

[4] The FERC stated that much of the complainants' argument rested on the assertion that ISO-NE's lock-in resource requirements differ from PJM's. The FERC acknowledged that ISO-NE's and PJM's differing mechanics may yield different prices paid to existing resources, but the FERC was not persuaded that the difference itself renders ISO-NE's rules unjust and unreasonable. *Exelon Corp. and Calpine Corp. v. ISO New England Inc.*, 150 FERC ¶ 61,067 at P 35 (Jan. 30, 2015) ("*New Entry Pricing Rule Complaint Order*").

[5] ISO-NE Tariff § III.13.1.1.2.2. The New Entry Pricing Rule permits a new entrant to "lock in" the clearing price from its first Forward Capacity Auction ("FCA") for up to seven years.

[6] "Public Systems" are Connecticut Municipal Electric Energy Coop. ("CMEEC"), Massachusetts Municipal Wholesale Electric Co. ("MMWEC"), and New Hampshire Electric Cooperative ("NHEC").

[7] "Conn/RI" is CT PURA, CT AG, CT DEEP, CT OCC, and the Rhode Island Division of Public Utilities and Carriers ("RI PUC").

[8] Environmental Advocates are the Sustainable FERC Project, Sierra Club, Environmental Defense Fund, and Acadia Center.

December 19, NEPGA answered the ISO response and the other pleadings submitted in response to its Complaint. On January 7, just as they had on December 23 in the FirstEnergy Complaint (*see* Section XI below), Environmental Advocates moved to lodge the US Solicitor General's application for an extension of time in which to file a petition for writ of certiorari, the Supreme Court Clerk's notice to the DC Circuit that the extension had been granted, and the DC Circuit's order extending the stay of its mandate pending the Supreme Court's final disposition of the writ of certiorari. As noted, this matter remains pending before the FERC. If you have any questions concerning these matters, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **206 Proceeding: Importers' FCA Offers Review/Mitigation (EL14-99; ER15-117)**

As previously reported, the FERC initiated this proceeding, on September 16, 2014, pursuant to Section 206 of the FPA. The FERC directed the ISO to either revise its Tariff to provide for the review and potential mitigation of importers' offers prior to each annual Forward Capacity Auction ("FCA") or show cause why it should not be required to do so.[9] The FERC directed the ISO to submit those Tariff revisions or support for why Tariff revisions should not be required on or before October 16, 2014. September 24, 2014 is the refund effective date.[10]

On October 16, Public Citizen submitted a pleading requesting that the FERC expand this proceeding (i) to determine whether the rates produced by FCA8 are just and reasonable and if not, to fix the just and reasonable rates to be charged; and (ii) to include in this proceeding "stakeholder reform and transparency". On October 22, NEPOOL responded to Public Citizen's request for stakeholder reform, stating that the stakeholder process, and not this proceeding, in the first instance, is the appropriate vehicle for exploring such changes, and urging the FERC to reject the Public Citizen request.

ISO Response to Show Cause Order (ER15-117): On October 16, the ISO submitted rule revisions to provide for the review and potential mitigation of importers' supply offers prior to each annual FCA Forward Capacity Auction ("***ISO-NE Changes***"). The ISO-NE Changes, docketed in ER15-117, are designed specifically to determine which import suppliers have market power (that is, which are "pivotal") and to apply mitigation to those suppliers in a manner consistent with the mitigation that is applied to existing resources. An October 17, 2014 effective date was requested. Comments on the ISO's filing were due on or before November 6, 2014.

While the ISO's proposed revisions were supported by the Participants Committee at its October 15 special meeting, additional changes that would provide greater flexibility to importers in justifying their capacity offers, which were proposed by Brookfield, were supported by an even wider margin (the "***NEPOOL Changes***"). The NEPOOL Changes would allow New Import Capacity Resources (1) to subdivide their proposed capacity import offers into as many as five separately priced quantities rather than requiring the importer to submit a single offer and price, and (2) to permit the importer to partially withdraw one or more of those separately priced quantities from the ninth Forward Capacity Auction ("FCA9"), rather than requiring it to withdraw its entire Import Capacity Resource. The NEPOOL Changes were included in October 31 comments filed by NEPOOL, which urged the FERC (i) to approve both the ISO-NE Changes and the NEPOOL Changes for implementation for FCA9, and (ii) to signal its expectation that, following FCA9, ISO-NE will review with NEPOOL the impacts of those Changes on the FCA and will explore with stakeholders whether such impacts suggest further changes to the import mitigation rules before FCA10. Protests and comments on the October 16 filing were also submitted on November 6 by Brookfield, NEPGA, and Public Citizen. On November 19, the ISO answered the protests and comments filed. Brookfield answered the ISO's November 19 answer on December 5.

[9] *ISO New England Inc.*, 148 FERC ¶ 61,201 (Sep. 16, 2014) ("*September 16 Order*").

[10] The Sep. 17 notice of this proceeding was published in the *Fed. Reg.* on Sep. 24, 2014 (Vol. 79, No. 185) p. 57,075.

Order Conditionally Accepting October 16 Filing (ER15-117): On December 15, the FERC conditionally accepted, subject to two additional compliance filings, the ISO's Tariff revisions in response to the Show Cause Order that provided for the review and potential mitigation of importers' supply offers prior to each annual FCA, which the FERC found "a significant step toward decreasing the opportunity for importers to exercise market power."[11] The first compliance filing was due on or before January 14, 2015 and must correct an incorrect cross-reference in Section III.13.1.3.5.7 (Qualification Determination Notification for New Import Capacity Resources).[12] In the second compliance filing, due on or before April 1, 2015, ISO-NE must submit tariff revisions in time for implementation for FCA-10 "which allow importers to submit up to five price-quantity pairs, together with any necessary mitigation provisions to address the exercise of market power" (finding implementation for FCA9 not feasible).[13] All remaining requests and protests, including those of Public Citizen, were rejected. Public Citizen requested rehearing of the *Imports Mitigation Order* on January 14, 2015. On January 26, NEPGA answered Public Citizen's request. Public Citizen's request is pending before the FERC, with FERC action required on or before February 13, 2015, or the request will be deemed denied.

30-Day Compliance Filing (ER15-117): On January 14, the ISO submitted the first compliance filing which, as directed, corrected the cross-reference in Section III.13.1.3.5.7 (Qualification Determination Notification for New Import Capacity Resources). Comments on that filing were due on or before February 4; none were filed and the first compliance filing is pending before the FERC.

If you have any questions concerning these matters, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com), Pat Gerity (860-275-0533; pmgerity@daypitney.com), or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Base ROE Complaints (2012 and 2014) Consolidated (EL13-33 and EL14-86)**

As previously reported, the FERC issued an order on November 24, 2014, establishing a trial-type, evidentiary hearing, consolidating EL14-86[14] with EL13-33,[15] and setting a refund effective date for EL14-86 of July 31, 2014.[16] The FERC found that the Complaint in EL14-86 "raises issues of material fact that cannot be resolved based upon the record before us and that are more appropriately addressed in the hearing ordered … [b]ecause of the existence of common issues of law and fact, we will consolidate this proceeding with the proceeding in Docket No. EL13-33-000 for purposes of hearing and decision." In addition, the FERC indicated that "it is appropriate for the parties to litigate a separate ROE for each refund period."[17] The TOs requested rehearing of the November 24 order on December 24. On January 23, 2015, the FERC issued a tolling order affording it additional time to consider the TOs' rehearing request, which remains pending before the FERC.

---

[11] *ISO New England Inc.*, 149 FERC ¶ 61,227 (Dec. 15, 2014) ("*Imports Mitigation Order*"), *reh'g requested*.

[12] *Id.* at P 53.

[13] *Id.* at PP 41-45, 64.

[14] As previously reported, the Massachusetts Attorney General ("MA AG"), together with a group of State Advocates, Publicly Owned Entities, End Users, and End User Organizations (together, the "2014 ROE Complainants"), filed a complaint on July 31, 2014 to reduce the current 11.14% Base ROE to 8.84% (but in any case no more than 9.44%) and to cap the Combined ROE for all rate base components at 12.54%. 2014 ROE Complainants state that they submitted this Complaint seeking refund protection against payments based on a pre-incentives Base ROE of 11.14%, and a reduction in the Combined ROE, relief as yet not afforded through the prior ROE proceedings.

[15] The 2012 Base ROE Complaint challenged the TOs' 11.14% return on equity, and seeks a reduction of the Base ROE to 8.7%.

[16] *Mass. Att'y Gen. et al. -v- Bangor Hydro et al.*, 149 FERC ¶ 61,156 (Nov. 24, 2014), *reh'g requested.*

[17] *Id.* at P 27 (for the refund period covered by EL13-33 (i.e., Dec. 27, 2012 through Mar. 27, 2014), the ROE for that particular 15-month refund period should be based on the last six months of that period; the refund period in EL14-86 and for the prospective period, on the most recent financial data in the record).

Base ROE Complaint (2012) (EL13-33). In response to a December 2012 Complaint by Environment Northeast ("ENE"), Greater Boston Real Estate Board, National Consumer Law Center, and the NEPOOL Industrial Customer Coalition ("NICC", and together, the "2012 Complainants"), the FERC, on June 19, 2014, established hearing and settlement judge procedures.[18] The 2012 Base ROE Complaint challenged the TOs' 11.14% return on equity ("Base ROE"), and sought a reduction of the Base ROE to 8.7%. In the *2012 Base ROE Initial Order*, the FERC found that the Complaint "raises issues of material fact that cannot be resolved based upon the record before us and that are more appropriately addressed in the hearing and settlement judge procedures ordered."[19] The FERC directed the parties to present evidence and any discounted cash flow ("DCF") analyses in accordance with the guidance provided in the *2012 Base ROE Initial Order*.[20] Settlement judge procedures in this proceeding were unsuccessful and were terminated October 24, 2014. The TOs July 21 request for rehearing of the *2012 Base ROE Initial Order*, remains pending before the FERC pursuant to an August 20, 2014 tolling order issued by the FERC.

Hearings. Trial Judge Sterner issued a December 4 order adopting a procedural schedule that leads to hearings beginning June 23, 2015 and an initial decision by November 30, 2015. The active Participants filed a preliminary joint statement of issues on December 9 and a discovery plan on December 18. On December 19, the Complaint-Aligned Parties,[21] EMCOS, TOs, and FERC Trial Staff submitted briefs regarding the appropriate cut-off date for data to be used in filing updates to studies in prior testimony in this proceeding. On December 30, Complaint-Aligned Parties and EMCOS submitted their direct testimony, including work sheets and work papers. Since the last Report, the TOs filed their Answering Testimony and Exhibits (with summaries) on February 2. And, with respect to the data cut-off date, Judge Sterner issued an order on February 5 setting the updated data cutoff date at May 26, 2015 (the day the Update of Studies in Prior Testimony is due).

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).

- **206 Investigation: FCM Performance Incentives (Compliance Proceedings) (EL14-52; ER14-2419)**

As previously reported, the FERC instituted this proceeding, pursuant to section 206 of the Federal Power Act ("FPA"), in its May 30 *PI Order* on the FCM Performance Incentives Jump Ball filing, having concluded that the ISO's existing Tariff, specifically the current FCM payment design, "is unjust and unreasonable, because it fails to provide adequate incentives for resource performance, thereby threatening reliable operation of the system and forcing consumers to pay for capacity without receiving commensurate reliability benefits."[22] The FERC directed the ISO to submit "Tariff revisions reflecting a modified version of its [PFP] proposal and an increase in the Reserve Constraint Penalty Factors, consistent with NEPOOL's proposal."[23] The FERC-established refund effective date is June 9, 2014.[24] Requests for clarification and/or

[18] *Environment Northeast, et al. v. Bangor Hydro-Elec. Co.*, et al., 147 FERC ¶ 61,235 (June 19, 2014) ("*2012 Base ROE Initial Order*"), *reh'g requested*.

[19] *Id.* at P 26.

[20] *Id.*

[21] "Complaint-Aligned Parties" are the CT AG, CT OCC, CT PURA, ME OPA, MA DPU, MMWEC, NHEC, NH OCA, NH PUC, RI PUC, VT DPS, Acadia Center (formerly Environment Northeast), The Energy Consortium, Associated Industries of Massachusetts ("AIM"), and the Industrial Energy Consumer Group ("IECG").

[22] *ISO New England Inc. and New England Power Pool*, 147 FERC ¶ 61,172 at P 23 (May 30, 2014) ("*PI Order*"), *clarification and reh'g requested*.

[23] *Id.* at P 1.

[24] The June 3 notice of this proceeding was published in the *Fed. Reg.* on June 9, 2014 (Vol. 79, No. 110) pp. 32,937-89.

rehearing of the *PI Order* were filed by: NEPOOL, Connecticut and Rhode Island,[25] Dominion, MMWEC, Indicated Generators,[26] NEPGA, NextEra, Potomac Economics, and PSEG/NRG. On July 28, the FERC issued a tolling order affording it additional time to consider the rehearing requests, which remain pending before the FERC.

***FCM PI Jump Ball Compliance Filing I* (ER14-2419-001)**. On October 2, 2014, the FERC accepted in part, subject to condition, and rejected in part, the ISO's July 14, 2014 compliance filing ("Compliance Filing I") that, as previously reported, had been filed in response to directives in the *PI Order*.[27] While accepting nearly all of the provisions proposed in Compliance Filing I, the *October 2 Order* rejected the ISO's compliance proposal concerning improper price signals caused by binding intra-zonal transmission constraints. The FERC found that an exemption was not necessary for resources on the export side of an intra-zonal transmission constraint during a Capacity Scarcity Condition and directed the ISO to submit a further compliance filing to revise Market Rule Section 13.7 by removing the language that reflected that aspect of the ISO's July 14 compliance proposal and restoring language in Sections III.13.7.2.2(a) and III.13.7.2.2(b) ISO-NE originally proposed by the ISO in its January 17 Filing. The Tariff sections accepted were accepted effective June 9, 2014, December 3, 2014, and June 1, 2018, as requested. Connecticut/Rhode Island[28] and Public Systems[29] requested rehearing of the *October 2 Order* on November 3, 2014. On December 3, the FERC issued a tolling order affording it additional time to consider the rehearing requests, which remain pending before the FERC.

***FCM PI Jump Ball Compliance Filing II* (ER14-2419-002)**. On January 15, the FERC accepted the ISO's -day compliance filing required by the *October 2 Order* that revised Market Rule 1 Section 13.7 to strike language rejected by the *October 2 Order*. As requested, the compliance filing change was accepted effective as of June 1, 2018 (which is the same effective date granted for the related revisions accepted in the *October 2 Order*). Challenges, if any, to the January 15 order are due on or before February 17, 2015.

If you have any questions related to these proceedings, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com), Pat Gerity (860-275-0533; pmgerity@daypitney.com), or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **206 Investigation: Consistency of ISO-NE (DA) Scheduling Practices with Natural Gas Scheduling Practices to be Adopted in Docket RM14-2 (EL14-23)**

As previously reported, on March 20, 2014, the FERC initiated this proceeding, pursuant to Section 206 of the FPA, to ensure that the ISO's scheduling, particularly its Day-Ahead scheduling practices, correlate with any revisions to the natural gas scheduling practices to be ultimately adopted by the FERC in RM14-2 (*see* Section XIII below).[30] Noting its concern about the lack of synchronization between the Day-Ahead scheduling practices of interstate natural gas pipelines and electricity markets, the FERC directed each ISO and RTO, including ISO-NE, within 90 days after publication of a Final Rule in Docket RM14-2 in the *Federal Register:*

---

[25] "Connecticut and Rhode Island" are: the Connecticut Public Utilities Regulatory Authority ("CT PURA"), the Conn. Office of Consumer Counsel ("CT OCC"), George Jepsen, Att'y Gen. for the State of Conn. ("CT AG"), the Conn. Department of Energy and Environmental Protection ("CT DEEP"), the United Illuminating Company ("UI") and the Rhode Island Div. of Pub. Utils. and Carriers ("RI PUC").

[26] "Indicated Generators" are: Exelon Corp. ("Exelon"), EquiPower Resources Management, LLC ("EquiPower"), Essential Power, LLC ("Essential Power"), and Dynegy Marketing and Trade, LLC and Casco Bay Energy Company, LLC (together, "Dynegy").

[27] *ISO New England Inc.*, 149 FERC ¶ 61,009 (Oct. 2, 2014) ("*October 2 Order*""), *reh'g requested*.

[28] "Connecticut/Rhode Island" are the CT PURA, CT AG, CT OCC, CT DEEP, and the RI PUC.

[29] "Public Systems" are CMEEC, MMWEC, NHEC, and VEC.

[30] *Cal. Indep. Sys. Op. Corp. et al.*, 146 FERC ¶ 61,202 (Mar. 20, 2014). The New England 206 proceeding was docketed as EL14-23.

> (1) to make a filing that proposes tariff changes to adjust the time at which the results of its day-ahead energy market and reliability unit commitment process (or equivalent) are posted to a time that is sufficiently in advance of the Timely and Evening Nomination Cycles, respectively, to allow gas-fired generators to procure natural gas supply and pipeline transportation capacity to serve their obligations, or (2) to show cause why such changes are not necessary. In their responses, each ISO and RTO must explain how its proposed scheduling modifications are sufficient for gas-fired generators to secure natural gas pipeline capacity prior to the Timely and Evening Nomination Cycles.[31]

The Commission expects to issue a final order in this section 206 proceeding within 90 days of the filings required under the March 20 order. Interventions by over 40 parties, including one by NEPOOL, were filed in the New England-specific docket. This matter is pending action in RM14-2. If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com), Joe Fagan (202-218-3901; jfagan@daypitney.com), or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **FCM Administrative Pricing Rules Complaint (EL14-7)**

On January 30, the FERC denied NEPGA's request for rehearing and/or clarification of the January 24, 2014 FCM Administrative Pricing-related orders.[32] As previously reported, in the *NEPGA FCM Admin Pricing Rules Order*,[33] the FERC found that the administrative pricing provisions for situations of Inadequate Supply and Insufficient Competition were unjust and unreasonable. While the FERC declined to adopt NEPGA's proposed revisions, it adopted the revisions proposed by the ISO in its Exigent Circumstances Filing in ER14-463 and also declined to find the existing Capacity Carry Forward Rule unjust and unreasonable.[34] In its request for rehearing and clarification of the *NEPGA FCM Admin Pricing Rules Order*, NEPGA requested the FERC: (i) require prospective auctions to utilize ORTP-based prices; (ii) direct the ISO to implement for FCA9 a sloped demand curve for all aspects of the FCM, including for individual capacity zones; and (iii) require the ISO to eliminate the zero-bid requirement and implement the bidding protocols requested by NEPGA in its initial Complaint in this proceeding. In denying rehearing, the FERC (i) disagreed with NEPGA's assertion that the FERC did not justify its use of a balancing approach in rejecting NEPGA's proposal for ORTP-based administrative pricing; (ii) rejected NEPGA's arguments concerning the Capacity Carry Forward Rule and New Entrant Pricing; and (iii) found that NEPGA had not shown the ISO's new entrant pricing to be unjust and unreasonable (distinguishing ISO-NE's and PJM's new entrant pricing rules). 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).

- **NESCOE FCM Renewables Exemption Complaint (EL13-34)**

Rehearing of the FERC's February 12, 2013 order denying NESCOE's FCM Renewable Exemption Complaint[35] remains pending before the FERC. As previously reported, NESCOE instituted this December 28, 2012 complaint in response to the ISO's December 3, 2012 FCM compliance filing that implemented buyer-side mitigation without an exemption for state-sponsored public policy resources. NESCOE asserted that the ISO's proposed Minimum Offer Price Rule ("MOPR") would likely exclude from the FCM new renewable resources developed pursuant to state statutes and regulations, and thereby result in customers being forced to purchase more capacity than is necessary for resource adequacy and proposed an alternative

[31] *Id.* at P 19.

[32] *New England Power Generators Assoc., Inc. v. ISO New England Inc.*, 150 FERC ¶ 61,064 (Jan. 30, 2015).

[33] *New England Power Generators Assoc., Inc. v. ISO New England Inc.*, 146 FERC ¶ 61,039 (Jan. 24, 2014) ("*Jan 24 NEPGA FCM Admin Pricing Rules Order*"), *reh'g denied*, 150 FERC ¶ 61,064 (Jan. 30, 2015).

[34] *Id.* at P 1.

[35] *New England States Comm. on Elec. v. ISO New England Inc.*, 142 FERC ¶ 61,108 (Feb. 12, 2013), *reh'g requested.*

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.[36] 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),[37] on which it concurrently issued an order conditionally accepting in part and dismissing in part the ISO's proposed compliance filing. Rehearing was requested by NESCOE, the CT PURA, and the MA DPU on March 14, 2013. On March 29, 2013, NEPGA filed an answer challenging NESCOE's request for rehearing. On April 15, 2013, 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 (2011) (EL11-66)**

As previously reported, the FERC issued *Opinion 531-A*[38] setting the Transmission Owners' base ROE at 10.57%, with a maximum ROE including incentives not to exceed 11.74%. *Opinion 531-A* affirmed that the 4.39 % projected long-term growth in GDP was the appropriate long-term growth projection to be used in the two-step DCF methodology for determining the TOs' ROE. The FERC directed the TOs to (i) submit a compliance filing with revised rates reflecting a 10.57% base ROE and a total ROE (inclusive of transmission incentive ROE adders) not exceeding 11.74%, effective October 16, 2014, and (ii) to provide refunds, with interest, for the 15-month refund period in this proceeding (October 1, 2011 through December 31, 2012). On November 6, the TOs requested an extension of time to issue and file the required regional and local refunds and refund reports. The FERC granted that request on November 26, 2014, setting the following deadlines: April 30, 2015, for regional refunds; June 30, 2015, for the regional refund report; July 31, 2015, for local refunds; and September 30, 2015, for the local refund report.

As previously reported, the FERC's June 19, 2014 *Opinion 531*,[39] affirmed in part, and reversed in part, Judge Cianci's *Initial Decision*[40] in this proceeding. The August 6, 2013 *Initial Decision* found unjust and unreasonable the 11.14% ROE, and found that the ROE should be 10.6% for the October 2011 through December 2012 "locked in/refund period" and 9.7% from January 2013 forward, subject to further updating or modification by the FERC.[41] In *Opinion 531*, the FERC announced a new approach that it will use for determining public utilities' base ROE and a change in its' practice on post-hearing ROE adjustments. With respect to the New England TOs', the FERC applied its new that approach to the facts of this proceeding to determine the NETOs' base ROE (10.57%), and established a paper hearing, addressed in *Opinion 531-A*, to allow the participants a limited opportunity to address application of the new ROE approach in those circumstances.[42] The TOs' requested rehearing and clarification of *Opinion 531-A* on November 17, 2014. On December 15, 2014, the FERC issued a tolling order affording it additional time to consider the TOs' request, which remains 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).

---

[36] *Id.* at P 32.

[37] *Id.* at P 30.

[38] *Martha Coakley, Mass. Att'y Gen. et al.*, 149 FERC ¶ 61,032 (Oct. 16, 2014) ("*Opinion 531-A*").

[39] *Martha Coakley, Mass. Att'y Gen. et al.*, 147 FERC ¶ 61,234 (June 19, 2014) ("*Opinion 531*"), *order on paper hearing*, 149 FERC ¶ 61,032 (2014).

[40] *Martha Coakley, Mass. Att'y Gen. et al.*, 144 FERC ¶ 61,012 (July 5, 013) ("*Initial Decision*").

[41] *See 2011 Base ROE Initial Decision*.

[42] *Opinion 531* at P 1.

II. Rate, ICR, FCA, Cost Recovery Filings

- **FCA9 New Import Capacity Resources Qualification Informational Filing (ER15-640)**

On January 13, the FERC accepted the ISO's informational filing for qualification of certain New Import Capacity Resources in the 2018-2019 FCM Capacity Commitment Period (the "FCA9 New Import Capacity Resource Filing"). As previously reported, this additional informational filing, which resulted from changes filed and accepted in ER15-117, detailed the ISO's determination of the New Resource Offer Floor Price for each New Import Capacity Resource requesting to submit offers in FCA9 at prices below the relevant ORTP and, in the privileged version, contained supporting cost information and supporting documentation for its determinations. Unless the January 13 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).

- **ICR-Related Values and HQICCs - 2015/16 ARA3, 2016/17 ARA2, and 2017/18 ARA1 (ER15-555)**

On January 27, the FERC accepted the Installed Capacity Requirement ("ICR"), Local Sourcing Requirements ("LSR"), Maximum Capacity Limits ("MCL") (collectively, the "ICR-Related Values") and Hydro Quebec Interconnection Capability Credits ("HQICCs") for the third annual reconfiguration auction ("ARA") for the 2015/16 Capability Year to be held March 2, 2015, the second ARA for the 2016/17 Capability Year to be held August 3, 2015, and the first ARA for the 2017/18 Capability Year to be held June 1, 2015. Unless the January 27 order is challenged, this proceeding will be concluded. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Opinion 531-A* Compliance Filing: TOs (ER15-414)**

On November 17, 2014, the New England TOs submitted tariff changes (to both the regional and local rates in the ISO OATT) in response to *Opinion 531-A*. Specifically, Section II.A.2.(a)(iii) of the Attachment F Implementation Rule was revised to reflect an ROE of 11.07% – the 10.57% base ROE directed by the Commission in *Opinion 531-A* plus the 50 basis point adder for ISO-NE participation. The TOs also revised Section II.A.2.(a)(iii) of the Attachment F Implementation Rule to require the PTOs to calculate their total ROE each year under both regional and local rates and to reduce any ROE incentives included in regional rates to the extent necessary to ensure that the PTOs' total ROE does not exceed 11.74% (the TOs' maximum ROE as identified by the FERC). The TOs also revised a number of provisions of the Attachment F Implementation Rule to include cross-references to Section II.A.2.(a)(iii). An effective date of October 16, 2014, consistent with *Opinion 531-A*, was requested. Interventions were filed by the IECG, Complainant-Aligned Parties, and EMCOS. Protests were filed by EMCOS and the Complainant-Aligned Parties. On December 23, the TOs answered the protests of EMCOS and Complainant-Aligned Parties. Complainant-Aligned Parties answered the TOs' December 23 answer on January 13. This matter is 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).

- **FCA9 Qualification Informational Filing (ER15-328)**

On January 16, the FERC accepted the ISO's informational filing regarding for qualification in FCA9 (the "FCA9 Informational Filing").[43] As previously reported, the Informational Filing contained the ISO's determinations that four Capacity Zones, Southeastern Mass./Rhode Island ("SEMA/RI"), Connecticut, Northeastern Mass./Boston ("NEMA/Boston") and Rest of Pool, will be modeled for FCA9. Connecticut, SEMA/RI and NEMA/Boston will be modeled as import-constrained Capacity Zones; no export-constrained Capacity Zones will be modeled (and, accordingly, no MCLs were established). The Informational Filing reported that there will be 32,555 MW of existing capacity in FCA9 competing with 8,547 MW of new capacity under a procurement limit of 34,189 MW (ICR minus HQICCs). In accepting the FCA9 Informational Filing, the FERC found that the ISO "complied with its obligations under Tariff section

[43] *ISO New England Inc.*, 150 FERC ¶ 61,021 (Jan. 16, 2015)

III.13.8.1 to submit information related to its qualification determinations and provide sufficient supporting documentation"[44] and granted the ISO's "request to qualify new resources identified in Attachment D of its Informational Filing for an additional 5 MW in total capacity value."[45] Unless the January 16 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).

- **ICR-Related Values and HQICCs - 2018/19 Power Year (ER15-325)**

As previously reported, the FERC accepted, on January 2, 2015, the ICR, HQICCs and related Local Sourcing Requirements ("LSR") values for the 2018/19 Capability Year.[46] The FERC stated its expectation that "ISO-NE [will] fully explore the incorporation of distributed generation into the ICR calculation in the stakeholder process. We expect ISO-NE to do this on a schedule that will allow these factors to be reflected, if determined appropriate, in the ICR calculation for FCA 10."[47] In identifying that expectation, the FERC stated that "NEPOOL believes the ICR value should be reduced to account for distributed generation, especially solar photovoltaic resources, that is forecasted to be available during the 2018/2019 Capacity Commitment Period."[48] On January 30, 2015, NEPOOL requested that the FERC clarify the January 2 order by acknowledging that, while NEPOOL did not support the ICR-Related Values, neither has NEPOOL taken a substantive position on whether the ISO should be trying to more fully incorporate DG in the ICR calculation for FCA-10. NEPOOL's request for clarification is pending before the FERC, with FERC action required on or before March 2, 2015 or the request will be deemed denied. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **2014/15 Power Year Transmission Rate Supplemental Filing (ER09-1532; RT04-2)**

On January 5, 2015, the Participating Transmission Owners ("PTOs") Administrative Committee ("PTO AC") submitted a supplement to its July 31, 2014 rate filing for the 2014/15 Power Year, identifying primarily revised information from NGrid[49] that results in adjustments to the 2014/15 rates: RNS ($0.48258/kW-yr. increase), TOUT (to be increased consistent with RNS increase), and S&D ($0.04684/kW-yr. decrease). This filing will not be noticed for public comment. If there are questions on this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

III. Market Rule and Information Policy Changes, Interpretations and Waiver Requests

- **ORTP Exemption for Distributed Renewable Technology Resources (ER15-716)**

On December 23, the ISO and NEPOOL jointly submitted revisions to Market Rule 1 to allow new On-Peak Demand Resources, which include distributed solar and wind generation, to qualify for the Renewable Technology Resources exemption from the FCM minimum offer price rules. A February 21, 2015 effective date was requested. These Market Rule changes were supported by the Participants Committee at the December 5, 2014 annual meeting. Interventions were filed by Entergy, EPSA, Exelon, NESCOE, NRG, and NU. On January 13, NEPGA submitted comments. The ISO answered NEPGA's January 13 comments on January 28, and

44 *Id.* at P 16.

45 *Id.* at P 17.

46 *ISO New England Inc.*, 150 FERC ¶ 61,003 (Jan. 2, 2015), *clarification requested*.

47 *Id.* at P 20.

48 *Id.* at P 7.

49 NEP's revisions impacting this filing are the result of a limited tariff waiver granted by the FERC in ER14-1686 that allowed NEP to initially use estimated data as the basis for calculating its Transmission Revenue Requirement but required corrected rates to be posted on the ISO-NE website no less than 45 days prior to the making of a supplemental filing and such filing to be made on or before January 12, 2015. The actual posting took place on November 21, 2014, so that the supplemental filing complies with the 45-day posting requirement.

NEPGA answered the ISO's January 28 comments on February 4. 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).

- **Information Policy Clean-Up Changes (ER15-600)**

On January 28, the FERC accepted clean-up changes to the Information Policy jointly filed by the ISO and NEPOOL. The changes were accepted February 9, 2015, as requested. Unless the January 28 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).

- **PRD Reserve Market Changes (ER15-257)**

On January 9, the FERC accepted a series of revisions to the full integration Market Rules for price-responsive demand ("PRD") (the "PRD Reserve Market Changes") jointly submitted by the ISO and NEPOOL.[50] As previously reported, the PRD Reserve Market Changes (i) permit PRD to provide Operating Reserves and participate in the Forward Reserve Market on an equal footing with generators and other supply-side resources, (ii) simplify the way in which PRD resources, that can push back energy onto the grid from behind-the-meter generators, participate in the New England Markets, and (iii) make a number of changes to facilitate the full integration of PRD into the markets. The PRD Reserve Market Changes were accepted January 12, 2015 and June 1, 2017, as requested. Unless the January 9 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).

- **CSO Deferral: ISO Proposal (ER14-2440)**

The request for rehearing of the FERC's September 12, 2014 order accepting revisions to the FCM Market Rules and Financial Assurance Policy to allow a new capacity resource to seek a one-year deferral of the start of its CSO[51] remains pending. As previously reported, the revisions were accepted without change or condition, effective July 17, 2014, as requested. On October 14, 2014, PSEG and NRG requested rehearing of the September 12 order. On November 13, the FERC issued a tolling order affording it additional time to consider the rehearing request, which remains pending before the FERC. Since the last Report, Footprint submitted a notice that it had closed, on January 9, on the financing necessary to proceed with construction of the new Salem Harbor Facility. FootPrint credited FERC's issuances in this and its individual CSO deferral proceeding as critical to its achieving that milestone. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Winter 2014/15 Reliability Program (ER14-2407)**

On January 20, 2015, the FERC granted[52] the clarification requested by NEPGA of the *Winter 2014/15 Reliability Program Order*.[53] As previously reported, NEPGA requested, in response to the *Winter 2014/15 Reliability Program Order*, that the FERC "issue an order confirming that it expects ISO-NE to develop and propose market rule changes based on competitive market principles, rather than another out-of-market mechanism, to meet New England's winter 2015-2016 system reliability needs." (In its October 24 answer, the ISO urged the FERC to reject NEPGA's request asserting that the FERC, despite its preference for a market-

---

[50] *ISO New England Inc. and New England Power Pool Participants Comm.*, 150 FERC ¶ 61,007 (Jan. 9, 2015).

[51] *ISO New England Inc.*, 148 FERC ¶ 61,185 (Sep. 12, 2014), *reh'g requested*.

[52] *ISO New England Inc. and New England Power Pool Participants Comm.*, 150 FERC ¶ 61,029 (Jan. 20, 2015).

[53] *ISO New England Inc. and New England Power Pool Participants Comm.*, 148 FERC ¶ 61,179 (Sep. 9, 2014) ("*Winter 2014/15 Reliability Program Order*"), *clarification granted*, 150 FERC ¶ 61,029 (Jan. 20, 2015). The *Winter 2014/15 Reliability Program Order* conditionally accepted the Tariff revisions jointly filed by the ISO and NEPOOL intended to maintain reliability through fuel adequacy by creating incentives for dual-fuel resource capability and participation, offsetting the carrying costs of unused firm fuel purchased by generators and providing compensation for demand response services ("Winter 2014/15 Reliability Program").

based solution, did not impose a requirement that the proposal be market-based, and urging the FERC to give the region the flexibility to determine the problem to be solved and how much it is willing to pay to solve it). In the January 20 order, the FERC clarified that its directive in the *Winter 2014/15 Reliability Program Order* "intended that ISO-NE would determine whether a winter reliability solution is necessary for the 2015-2016 winter and future winters, and, if so, develop an appropriate market-based solution through the stakeholder process that can be implemented beginning with the 2015-2016 winter. While the two-settlement capacity market design could help address winter reliability concerns in the future, that design will not be fully implemented until the 2018-2019 Capacity Commitment Period."

Progress reports with respect to the stakeholder process "to develop a proposal to address reliability concerns for the 2015-2016 winter and future winters, as necessary"[54] will be filed every 60 days during 2015, with the next report to be filed on or before February 6 (and summarized in Section VIII). The ISO's analysis and recommendations with respect to the appropriateness of the 1.75 volatility ratio of the higher-priced fuel index (included as part of new market monitoring changes) will be included as part of the IMM's Annual Markets Report. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Demand Curve Changes (ER14-1639)**

On January 30, the FERC denied rehearing of the *Demand Curve Order*, but clarified (agreeing with Exelon and Entergy) that a resource that elects to utilize the renewables minimum offer price rule exemption should not also be allowed to utilize the new resource lock-in).[55] As previously reported, the FERC conditionally accepted, on May 30, 2014, the revisions to the FCM rules jointly submitted by the ISO and NEPOOL that establish a system-wide sloped demand curve ("Demand Curve Changes").[56] The Demand Curve Changes define the shape of the system-wide sloped demand curve (with key points defined by CONE and the 0.1 days/year LOLE target) illustrated below, extend the period during which a Market Participant may "lock-in" the capacity price for a new resource from five to seven years, establish a limited renewables, and eliminate, at the system-wide level, the administrative pricing rules that were necessary in certain market conditions under the vertical demand curve construct. The Demand Curve Changes were accepted effective June 1, 2014, as requested, for implementation prior to associated FCA9 deadlines.

In granting clarification of the *Demand Curve Order*, the FERC directed the ISO to submit, on or before March 2, 2015, a compliance filing clarifying that a resource may not utilize both the renewable resource exemption and the new resource price lock-in. Proposed changes in response to the January 30 order will be considered by the Markets Committee at its February 10-11 meeting.

Informational Report on Progress Toward Developing Zonal Demand Curves. On December 2, the ISO reported that additional time, beyond the January 2, 2015 submission expected by the FERC, will be needed to "complete the process [to submit zonal demand curve changes] and ensure that certain issues that have been identified by the ISO and its market monitors can be addressed." The ISO noted its continued hope that zonal demand curve changes would be filed with the FERC and implemented prior to FCA-10.

If you have any questions concerning these matters, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

---

[54] The schedule and progress reports will be for informational purposes only, and not noticed for comment or subject to Commission action. *Winter 2014/15 Reliability Program Order* at n. 46.

[55] *ISO New England Inc. and New England Power Pool Participants Comm.*, 150 FERC ¶ 61,065, at P 27 (Jan. 30, 2015).

[56] *ISO New England Inc. and New England Power Pool Participants Comm.*, 147 FERC ¶ 61,173 (May 30, 2014) ("*Demand Curve Order*"), *reh'g denied but clarif. granted*, 150 FERC ¶ 61,065 (Jan. 30. 2015).

- **FCM Performance Incentives Jump Ball Filing (ER14-1050)**

Rehearing of the *FCM PI Order* remains pending. As previously reported, the ISO and NEPOOL submitted on January 17, 2014, two alternative versions of Market Rule changes intended to improve the operating performance of capacity resources in New England -- the "ISO-NE Proposal" and the "NEPOOL Proposal". Both Proposals sought to further address existing reliability, investment and resource performance challenges in New England. However, the two proposals offered fundamentally different approaches. The ISO-NE Proposal would redefine capacity as a different product where payments are affected by whether a resource is providing energy and/or operating reserves in Real-Time three years hence. Through its "pay-for-performance" mechanism, the ISO Proposal abandoned longstanding capacity market principles in New England and the other RTO markets and converts the FCM from a market designed to ensure long-term resource adequacy to one that is driven primarily by prospective and largely unpredictable actual production. Resources not producing energy or reserves at the time of a "Capacity Scarcity Condition" for any reason would be subject to significant penalties, even if that scarcity condition occurs during very low load conditions, or is caused by transmission outages or even by errors in the ISO's load forecasting. The NEPOOL Proposal, in contrast, built upon a series of Market Rule changes, either made or are pending, proposed changes that would enhance the current market design and achieved the objective of improving the performance incentives for resources in the ISO-NE electricity markets. The Proposals were submitted pursuant to "jump ball provision" of the Participants Agreement (Section 11.1.5).

On May 30, 2014, the FERC issued an order in response to the jump ball filing.[57] The FERC concluded that the existing Tariff, specifically the current FCM payment design, "is unjust and unreasonable, because it fails to provide adequate incentives for resource performance, thereby threatening reliable operation of the system and forcing consumers to pay for capacity without receiving commensurate reliability benefits" and instituted a proceeding under Section 206 of the FPA (*see* EL14-52 in Section I above). Concluding that neither the ISO-NE Proposal nor the NEPOOL Proposal, standing alone, had been shown to be just and reasonable, the FERC, drawing features from each Proposal, went on to direct the ISO to submit by July 14, 2014 Tariff revisions reflecting a modified version of the ISO-NE Proposal and an increase in the Reserve Constraint Penalty Factors, consistent with NEPOOL's Proposal. Specifically, the compliance filing was to include (1) changes to implement ISO-NE's proposed two-settlement capacity market design with certain modifications, and (2) changes to increase the RCPF values for Thirty-Minute Operating Reserves to $1,000/MWh and for Ten-Minute Non-Spinning Operating Reserves to $1,500/MWh. The FERC established a June 9, 2014 refund effective date.[58] Requests for clarification and/or rehearing of the *PI Order* were filed by: NEPOOL, Connecticut and Rhode Island, Dominion, MMWEC, Indicated Generators, NEPGA, NextEra, Potomac Economics, and PSEG/NRG. On July 28, 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.

Compliance Filing (ER14-2419). On July 14, the ISO submitted a filing in response to the PI Order. That filing is summarized in Section I above.

If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com), Harold Blinderman (860-275-0357; hblinderman@daypitney.com), Eric Runge (617-345-4735; ekrunge@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Exigent Circumstances Filing – FCM Admin. Pricing Rules (ER14-463)**

On January 30, the FERC denied NEPGA's request for rehearing[59] of the *Jan 24 Exigent Circumstances Order*.[60] As previously reported, the FERC accepted, on January 24, 2014, revisions to the

[57] *See PI Order*.

[58] *See* n. 4 *supra*.

[59] *ISO New England Inc.*, 150 FERC ¶ 61,066 (Jan. 30, 2015) ("*Exigent Circumstances Rehearing Order*").

[60] *ISO New England Inc. and New England Power Pool Participants Comm.*, 147 FERC ¶ 61,173 (May 30, 2014) ("*Demand Curve Order*"), *reh'g denied*, 150 FERC ¶ 61,066 (Jan. 30, 2015).

FCM administrative pricing rules that (i) addressed what the ISO identified as a "gap" in the Insufficient Competition rules; (ii) set an administrative rate of $7.025/kW-month to be applied if there is Insufficient Competition (as the ISO proposed to redefine it) or Inadequate Supply in FCA8; and (iii) made additional clarifying changes to the FCM administrative pricing rules (collectively, the "FCM Pricing Rule Changes").[61] The FCM Pricing Rule Changes became effective January 24, 2014, as requested. In accepting the filing, the FERC established a $7.025/kW administrative pricing rate for FCA8, replacing existing Tariff provisions that it found unjust and unreasonable in the Administrative Pricing Rules Complaint order (*see* EL14-7 in Section I above).[62] Demand curve changes, proposed in response to directives in the *Jan 24 Exigent Circumstances Order* were filed and conditionally accepted (*see* ER14-1639 above). NEPGA requested clarification and rehearing of the *Jan 24 Exigent Circumstances Order* on February 24, 2014.

In denying rehearing of the *Jan 24 Exigent Circumstances Order*, the FERC emphasized its expectation that "ISO-NE will submit the zonal demand curve changes in time to allow for review, approval, and implementation for FCA 10."[63] The FERC issued on tolling order on March 24, 2014 affording it additional time to consider the NEPGA rehearing request, which remains pending before the FERC. If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com), Harold Blinderman (860-275-0357; hblinderman@daypitney.com) or Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **FCM Redesign Compliance Filing: FCA8 Revisions (ER12-953 et al.)**

Requests for rehearing of the *FCA8 Revisions Order* remain pending. As previously reported, the FERC, on February 12, 2013, conditionally accepted in part, and rejected in part, revisions to the FCM and FCM-related rules in the Tariff ("FCA8 Revisions") filed by the ISO and the PTO AC.[64] 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;[65] unit specific offer review;[66] the ISO's proposal to subject a resource to offer floor mitigation until that resource clears in one FCA; imports' treatment under MOPR;[67] no exemptions to MOPR for new Self-Supplied Resources;[68] the application of mitigation to *all* new resources offering into the FCM, including renewables that are procured pursuant to state policy initiatives;[69] $1.00/kW-month Threshold to trigger IMM review of Dynamic De-List Bids;[70] and a number of other additional revisions.[71] 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);[72] and the ISO's request to

[61] *Jan 24 Exigent Circumstances Order*.

[62] The order also accepted the ISO's proposed changes to correct the IC Gap and the remaining administrative pricing provisions. Addressing the questions concerning the "Exigent Circumstances" underlying the filing, the FERC found that the ISO had satisfied the prescribed criteria for an Exigent Circumstances filing: "ISO-NE justifiably determined that failing to immediately implement a change prior to FCA 8 could affect the short-term competitiveness and efficiency of the markets and, in the long-term, affect system reliability." *Id.* at P 52.

[63] *Id.* at P 41.

[64] *ISO New England Inc.*, 142 FERC ¶ 61,107 (Feb. 12, 2013) ("*FCA8 Revisions Order*").

[65] *FCA8 Revisions Order* at PP 37-38.

[66] *Id.* at P 53.

[67] *Id.* at P 70.

[68] *Id.* at P 80.

[69] *Id.* at P 97.

[70] *Id.* at P 126.

[71] *Id.* at P 127.

[72] *Id.* at PP 63-64.

model only 4 capacity zones for FCA8 (the ISO's Capacity Zones Changes were accepted in *ISO New England Inc.*, 147 FERC ¶ 61,071 (2014)). Two requests for rehearing of the *FCA8 Revisions Order* were filed on March 15, 2013, one by MMWEC, NHEC, APPA, NEPPA, and NRECA; the other, by EMCOS and Danvers. On April 11, NEPGA filed an answer to the MMWEC *et al.* request. On April 15, 2013, 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 these matters, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com), Eric Runge (617-345-4735; ekrunge@daypitney.com) or Dave Doot (860-275-0102; dtdoot@daypitney.com).

IV. OATT Amendments / TOAs / Coordination Agreements

- ***Order 676-H* Compliance: Revisions to Schedule 24 (ER15-519)**

On December 1, the ISO submitted a compliance filing requesting (i) renewal of waivers previously granted in response to Order 676, 676-C, 676-E, and 890, (ii) waiver of certain new *Order 676-H*-approved standards, and (iii) acceptance of Schedule 24 Revisions incorporating by reference the North American Energy Standards Board ("NAESB") Wholesale Electric Quadrant ("WEQ") v.003 Standards for which waiver was not requested. A February 2, 2015 effective date was requested. The Schedule 24 revisions were unanimously supported by the Participants Committee at its December 5 annual meeting. Interventions were filed by Exelon and NU. In its comments, NEPOOL reported on that support and requested that the FERC accept the ISO-NE OATT revisions and grant the requested waivers. This matter is pending before the FERC. If you have any comments or concerns, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Kristin Sullivan (617-345-4657; kmsullivan@daypitney.com).

- ***Order 676-H* Compliance: PTOs, SSPs, CSC *et al.* (ER15-517)**

Also on December 1, the PTO Administrative Committee ("PTO AC"), on behalf of the Participating Transmission Owners ("PTOs"), the Schedule 20A Service Providers ("SSPs"), Cross-Sound Cable Company, LLC ("CSC"), New England Power Company ("NGrid"), Northeast Utilities Service Company ("NUSCO"), Unitil Energy Systems, Inc., Fitchburg Gas and Electric Light Company, and the ISO (collectively, the "Filing Parties"), jointly submitted a filing to request (continued and new) waiver of, and to adopt, certain Version 003 WEQ Standards adopted NAESB incorporated by reference into FERC regulations pursuant to *Order 676-H*. Waiver requests included those previously granted for Orders 676-C and 676-E, waiver of WEQ-4 (limited in the case of CSC),WEQ-8, WEQ-11, WEQ-15, WEQ-21, the OASIS-related Standards, and various additional waivers under the individual Schedule 21 service schedules. Interventions were filed by NEPOOL and NU. Comments on this filing were due on or before December 22; none were filed and this matter is pending before the FERC. If you have any comments or concerns, please contact please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Kristin Sullivan (617-345-4657; kmsullivan@daypitney.com).

- ***Order 1000* Interregional Compliance Filing (ER13-1960; ER13-1957)**

On July 10, 2013, the ISO, NEPOOL and the PTO AC jointly filed revisions to Sections I and II of the Tariff to comply with the interregional coordination and cost allocation requirements of *Orders 1000* and *1000-A* (the "*Order 1000* Interregional Compliance Changes") (ER13-1960). In addition, the ISO, on behalf of itself, NYISO and PJM, filed an Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol ("Amended Protocol") as part of its compliance changes (ER13-1957). The *Order 1000 Interregional Compliance Changes* include (i) revisions to Attachment K to add provisions describing the interregional coordination provisions included in the Amended Protocol, as well as adding other provisions facilitating the consideration of interregional solutions to regional needs; (ii) a new Schedule 15 reflecting the methodology for allocation among ISO-NE and NYISO of the costs of approved interregional transmission projects; (iii) revisions to Schedule 12 describing the regional cost allocation within New England of the costs of approved interregional transmission projects; and (iv) conforming changes to Tariff Section I. The *Order 1000* Interregional Compliance Changes and the Amended Protocol were supported by the Participants Committee at its June 27 Summer Meeting. On August 7, the FERC extended the comment deadline on these filings to and including September 9,

2013. Doc-less motions to intervene were filed by a number of New England parties in both proceedings, including Dominion, Exelon, PPL, PSEG, and NEPOOL (in the Protocol proceeding (in which it was not a filing party)). On August 26, 2013, NEPOOL filed comments supporting the Protocol. NEPOOL added that "From a stakeholder perspective, stakeholder input into revisions to the Protocol as it evolves over time would be easier and more likely to be taken into account if it were made part of the individual regional tariffs of each of the Northeast ISOs rather than existing solely as a stand-alone three-party agreement". On September 9, NESCOE submitted comments generally supporting the filings, but reserving the right to further comment on these filings should the substance of the changes be modified as a result of further FERC (*see* ER13-193 and ER13-196 below) or federal court proceedings. Public Interest Organizations[73] raised concerns that the Protocol and related amendments "do not meet certain of the transparency and cost allocation aspects of [*Order 1000*]'s minimum requirements." On September 24, 2013, the ISO answered Public Interest Organizations' and NEPOOL's comments. These matters remain pending before the FERC. If you have any comments or concerns, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Order 1000*** **Compliance Filing (ER13-193; ER13-196)**

Rehearing of the FERC's May 17, 2013 order on the region's *Order 1000* compliance filing[74] (described in previous Reports) remains pending. As previously reported, the *Order 1000 Compliance Order* accepted the ISO-NE/PTO compliance filing as partially complying with *Order 1000*, but required changes to the compliance proposal. The primary change was the elimination of the Right of First Refusal ("ROFR") and the establishment of competitive transmission development for all regional transmission projects (with an exception to the elimination of the ROFR for transmission needed for reliability within three years of the needs assessment determination and subject to certain other limiting criteria). Additionally, the *Order 1000 Compliance Order* required that the public policy transmission proposal be revised to: (i) make the ISO, rather than the New England states, the entity that evaluates and selects which transmission projects will be built to meet transmission needs driven by public policy; and (ii) include an *ex ante* default cost allocation method, transparent to all stakeholders, developed in advance of particular transmission facilities being proposed, rather than leaving it to the states to decide cost allocation on a project-specific basis after particular projects are proposed. While requiring these fundamental changes to the public policy transmission part of the filing, the *Order 1000 Compliance Order* also allowed for the NESCOE-driven proposal for both selection of projects and cost allocation to remain in the tariff as a complementary process for voluntary transmission projects alongside the *Order 1000*-compliant process. A more detailed summary of the *Order 1000 Compliance Order* was circulated to the Participants Committee on May 20, 2013. On June 17, the ISO, LS Power, PTO AC and NESCOE each filed requests for clarification and/or rehearing of the *Order 1000 Compliance Order*. On June 28, the ISO answered LSP Power's request concerning the effective date for the *Order 1000* compliance changes. On July 16, the FERC issued a tolling order affording it additional time to consider the requests for clarification and/or rehearing, which remain pending before the FERC.

Order 1000 November 15 Compliance Order Changes. On November 15, 2013, the ISO and the PTO AC jointly submitted proposed revisions to Sections I and II of the Tariff and to the Transmission Operating Agreement ("TOA") (the "Compliance Revisions") to comply with the FERC's May 17, 2013 *Order 1000 Compliance Order*. The revisions included planning revisions (addressing competitive processes for developing new regional transmission projects), cost allocation revisions (regarding the allocation of costs for Public Policy Transmission Projects), and TOA revisions. The Planning Revisions and the Cost Allocation Revisions filed by the ISO and PTO AC were considered but not supported by the Participants Committee at its November 8, 2013 meeting.

Comments on the November 15 filing were filed by ***NEPOOL*** (seeking two sets of changes to the Planning Revisions filed by the ISO and PTO AC (i) limiting the scope of transmission projects that are

[73] "Public Interest Organizations" are Conservation Law Foundation, ENE, Natural Resources Defense Council, Pace Energy and Climate Center, and the Sustainable FERC Project.

[74] *ISO New England Inc.*, 143 FERC ¶ 61,150 (May 17, 2013) ("*Order 1000 Compliance Order*").

grandfathered under the old, non-competitive processes, so that Proposed Projects are not grandfathered but instead are open to competition; and (ii) ensuring that all Qualified Transmission Project Sponsors ("QTPS") are on an equal footing regarding consulting with the ISO in assessing regional transmission needs and solutions (together, the "NEPOOL Alternative"); but taking no position on the Cost Allocation revisions); ***CLF and The Sustainable FERC Project*** (supporting the November 15 filing and its public policy planning and regional cost allocation provisions.); EMCOS/Participating Municipals (request the ISO and TOs be required to revise Section 3.3 of Attachment K to eliminate the grandfathering for proposed Transmission Projects, and to revise Schedule 12 to ensure that public power systems not subject to state Public Policy requirements are exempted from any obligation to pay for Public Policy projects); ***Environmental Groups***[75] (each supporting the Cost Allocation Revisions, but noting continuing concern that the region's planning process fails to produce more cost-effective and efficient planning outcomes); ***LSP Transmission*** (supporting NEPOOL's Alternative, requesting a January 1, 2014 effective date for the compliance filing, and protesting the hold harmless provision contained in Attachment O, Section 9.01, the ISO's evaluation process and the proposed study deposit), ***MA DPU*** (supporting the Cost Allocation Revisions); ***NESCOE*** (without expressing a position on the Cost Allocation Revisions, affirming its support for NESCOE it having a central role in determining how public policy planning need relates to cost allocation); ***New Hampshire Transmission*** ("NHT") (protesting the November 15 filing and suggesting specific amendments to the proposal to be submitted a short time after an order on the second compliance filing is issued); ***Public Systems***[76] (requesting that the FERC adopt MMWEC's cost allocation proposal and direct the Filing Parties to include an express right of consumer-owned utilities to opt out of the non-regional allocated costs of projects satisfying policy requirements that do not apply to them); and ***VT/RI Parties***[77] (protesting the Cost Allocation Revisions). Answers to the protests and comments were filed on January 15, 2014 by the ISO, PTO AC, and MA DPU (to the VT/RI Parties). On February 4, 2014, NHT filed an answer to the January 15 answers by the ISO and PTO AC. The ISO answered the NHT February 4 answer on February 18, 2014.

These matters remain pending before the FERC. If you have any comments or concerns, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

- **FAP Minimum Capitalization Requirement Changes (ER15-593)**

On January 29, the FERC accepted changes to the Financial Assurance Policy's ("FAP") capitalization requirements intended to better protect Market Participants from the risks presented by the market participation of thinly-capitalized entities ("FAP Changes") jointly filed by the ISO and NEPOOL. Specifically, the changes (i) eliminate the exemption for meeting the minimum capitalization requirements afforded Participants with a total financial assurance ("FA") requirement of lower than $100,000; (ii) require Participants failing to meet the capitalization requirements to provide additional FA in an uncapped amount equal to 25% of the Participant's total FA requirement (excluding FTR Financial Assurance Requirements) instead of the current sliding scale structure; and (iii) for the FTR market, any Participant failing to meet the minimum capitalization requirements must provide additional FA equal to 25% of the Participant's FTR FA requirements. The FAP Changes were accepted February 5, 2015, as requested. Unless the January 29 order is challenged, this proceeding will be concluded. If you have any questions, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com) or Pat Gerity (860-275-0533; pmgerity@daypitney.com).

[75] "Environmental Groups" are ENE, Connecticut Fund for the Environment, Environment Council of Rhode Island, Health Care Without Harm, The Natural Resources Council of Maine, and The Sustainable FERC Project.

[76] In this proceeding, "Public Systems" are MMWEC and NHEC.

[77] "VT/RI Parties" are the State of New Hampshire Public Utilities Commission ("NHPUC"), the Rhode Island Public Utilities Commission ("RIPUC"), the Vermont Public Service Board ("VT PSB"), the Vermont Public Service Department ("VPSD"), Vermont Electric Power Company ("VELCO"), and Vermont Transco ("VT Transco").

VI. Schedule 20/21/22/23 Changes

- ***Opinion 531-A* Compliance Filing: CTMEEC (ER15-584)**

On December 5, 2014, the ISO submitted on behalf of the Connecticut Transmission Municipal Electric Energy Cooperative ("CTMEEC") changes to Attachment B to Schedule-21 CTMEEC to conform Schedule-21 CTMEEC to the holdings in *Opinions 531* and *531-A*. Comments, if any, on this filing were due on or before December 26; none were filed and this matter is pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- ***Opinion 531-A* Compliance Filing: GMP (ER15-412)**

On November 17, 2014, the ISO submitted on behalf of Green Mountain Power ("GMP") changes to Schedule-21 GMP, in response to *Opinion 531-A*, to reflect a 10.57% ROE effective as of October 16, 2014. GMP explained that, although it was not a respondent to the complaint in Docket No. EL11-66, GMP agreed in the recently-accepted Settlement Agreement[78] to accept the ROE approved by the FERC in Docket No. EL11-66 and to provide refunds for the period of October 1, 2012 through December 31, 2012 (which it has also done). Comments, if any, on this filing were due on or before December 8; none were filed and this matter is pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **LGIA – NU/CPV Towantic (ER15-200)**

The FERC conditionally accepted, on December 24, 2014, and set for hearing and settlement judge procedures on the issue of the proposed operation, maintenance, and capital cost reimbursement charges, the unexecuted LGIA (LGIA-ISONE/NU-14-02) between CPV Towantic, CL&P and the ISO, governing the interconnection of CPV Towantic's 795 MW natural gas-fired plant located in Oxford, Connecticut.[79] Chief Judge Wagner appointed Judge David H. Coffman as the Settlement Judge. A first settlement conference was held on January 8, 2015; a second settlement conference was held on February 5. On February 3, Judge Coffman issued a report recommending that the settlement proceeding continue. On February 5, Chief Judge Wagner issued an order continuing settlement proceedings. 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

- **Future Winter Reliability Program Progress Reports (ER14-2407)**

As directed in the *Winter 2014/15 Reliability Program Order*, the ISO submitted on December 8, 2014, its first 60-day progress report on efforts to address reliability concerns for the 2015-2016 winter and future winters, as necessary. In its first report, the ISO stated that no consensus has yet emerged with respect to the exploration of alternative objectives and/or the development of alternative solution(s) for future winter periods. The ISO indicated it would continue to discuss these issues with Participants at the Markets Committee If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

[78] *ISO New England Inc., et al.*, 148 FERC ¶ 61,097 (Aug. 4, 2014).

[79] *ISO New England Inc. and Northeast Utilities Service Co.*, 149 FERC ¶ 61,274 (Dec. 24, 2014).

- **Quarterly Reports Regarding Non-Generating Resource Regulation Market Participation (ER08-54); *Order 755* Regulation Market Progress Report (ER12-1643)**

The ISO filed its twenty-fifth report regarding non-generating resource regulation market participation on December 19, 2014. 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.[80] In the 25th report, the ISO reported that it expects to implement the new regulation market design that fully complies with *Order 755* on March 31, 2015. These reports are not noticed for public comment.

- **LFTR Implementation: 25th Quarterly Status Report (ER07-476; RM06-08)**

The ISO filed the twenty-fifth of its Quarterly Status Reports regarding LFTR implementation on January 15. Subject to a number of qualifications, the ISO reported that if the third party clearing design being vetted in the Participant Processes is supported, the third party clearing design could be implemented during Q4 2015 for the 2016 annual FTR auction, about six months later (mid-2016) for monthly auctions, and during Q4 2017 for an initial auction of LFTRs. The estimated 18-month LFTR implementation process, described in previous reports, would be initiated in 2016, 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

- **February 2015 Membership Filing (ER15-937)**

On January 30, NEPOOL requested that the FERC accept the termination of the Participant status of Dominion Retail and Hess (Jan 1, 2015), and the Cianbro, PallettOne, and Hannaford Companies (Feb 1, 2015). Comments on this filing are due on or before February 20.

- **January 2015 Membership Filing (ER15-780)**

On December 30, NEPOOL requested that the FERC accept (1) the memberships of: Convergent Energy and Power LLC (AR Sector, Small LR Group Member); Denver Energy, LLC and its Related Person Peninsula Power, LLC (Supplier Sector); Quantum Utility Generation, LLC (AR Sector, RG Sub-Sector); Wallingford Energy II, LLC (Related Person to Hawkes Meadow, Provisional Group Member); and Longwood Medical Energy Collaborative (Related Person to End User Sector member Harvard Dedicated Energy Limited); and (2) the termination of the Participant status of DB Energy Trading, LLC and Open Book Energy, LLC (Dec 1, 2014); and Marden's Inc. and its Related Person Kennebec River Energy, LLC (Jan 1, 2015). This matter is pending before the FERC.

- **December 2014 Membership Filing (ER15-513)**

On January 8, the FERC accepted: (1) the memberships of: Athens Energy (Provisional Member); Blue Sky West, Canandaigua Power Partners, and Mass Solar 1 (each Related Persons to First Wind, AR Sector); Hawkes Meadow Energy (Provisional Member); The Moore Company and Moore Energy (End User Sector); Nalcor Energy Marketing (Supplier Sector); SmartEnergy Holdings (Supplier Sector); and TEC Energy; and (2) the termination of the Participant status of TrueLight Commodities.

[80] *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").

- **Suspension Notices (not docketed)**

Since the last Report, the ISO filed, pursuant to Section 2.3 of the Information Policy, two notices with the FERC noting that the following Participants were suspended from the New England Markets on the dates indicated (at 8:30 a.m.) due to a Financial Assurance Default:

Date of Suspension/ FERC Notice	*Participant Name*	*Date Reinstated*
Jan 5/12	Pacific Summit Energy LLC	Jan 12
Jan 20/21	Cape Wind Associates, LLC	Remains suspended

Suspension notices are for the FERC's information only and are not 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; *pmgerity@daypitney.com*).

- **FFT Report: January 2015 (NP15-19)**

NERC submitted on January 30, 2015 its Find, Fix, Track and Report ("FFT") informational filing for the month of January 2015. The January FFT resolves 17 possible violations of 9 Reliability Standards that posed a risk minimal risk to bulk power system ("BPS") reliability, but which have since been remediated.[81] The 4 Registered Entities involved each submitted a mitigation activities statement of completion. FFT filings are for information only and are not be noticed for public comment by the FERC.

- **Revised Reliability Standard: PRC-006-2 (RD15-2)**

On December 15, 2014, NERC filed changes to PRC-006-2 (Automatic Underfrequency Load Shedding), and its associated VRFs and VSLs, and requested the retirement of the previous version of the Standard, all in accordance with the Implementation Plan ("PRC-006 Changes"). NERC stated that the PRC-006 Changes address outstanding FERC concerns expressed in *Order 763*[82] that applicable entities are required to implement corrective actions identified by the Planning Coordinator in accordance with a schedule established by the same Planning Coordinator. NERC requested that the PRC-006 Changes be approved, and the existing PRC-006-1 be retired, effective on the first day of the first calendar quarter that is six months after the date of FERC approval. Comments on the PRC-006 Changes were due on or before January 16, 2015; none were filed and this matter is pending before the FERC.

- **Revised Reliability Standard: PRC-004-3 (RD14-14)**

As previously reported, NERC filed, on September 15, 2014, changes to PRC-004-3 (Protection System Misoperation Identification and Correction) as well as a revised definition of "Misoperation" and a new definition of "Composite Protection System" for inclusion in the NERC Glossary of Terms, and the retirement of Reliability Standards PRC-004-2.1a (Analysis and Mitigation of Transmission and Generation Protection System Misoperations) and PRC-003-1 (Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection System) as listed in the Implementation Plan ("PRC-004 Changes"). NERC stated that the PRC-004 Changes address outstanding FERC concerns and directives related to PRC-004 and PRC-003 and

[81] 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 (Mar. 15, 2012) at PP 46-56.

[82] *Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards*, Order No. 763, 139 FERC ¶ 61,098 (2012), *order on clarification*, 140 FERC ¶ 61,164 (2012).

create a single Reliability Standard requiring Transmission Owners, Generator Owners, and Distribution Providers to identify and correct causes of Misoperations of certain Protection Systems for Bulk Electric System Elements. NERC requested that the PRC-004 Changes be approved, and the existing PRC-004-2.1a and PRC-003-1 be retired, effective on the first day of the first calendar quarter that is one year after the date of FERC approval. Comments on the PRC-004 Changes were due on or before October 20, 2014; none were filed. The PRC-004 Changes are pending before the FERC.

- **New Reliability Standard: TPL-007-1 (RM15-11)**

On January 21, 2015, NERC filed for approval a new Reliability Standard -- TPL-007-1 (Geomagnetic Disturbance Operations) -- and one new definition (Geomagnetic Disturbance Vulnerability Assessment), associated VRFs and VSLs (together, the "GMD Operations Changes"). NERC stated that the GMD Operations Changes address the FERC's directive in *Order 779* that NERC develop a Reliability Standard that requires owners and operators of the Bulk-Power System to conduct initial and on-going vulnerability assessments of the potential impact of benchmark geomagnetic disturbance events on the Bulk-Power System equipment and the Bulk-Power System as a whole.[83] NERC requested the FERC approve a five-year phased implementation plan for compliance with TPL-007-1. As of the date of this Report, the FERC has not noticed a proposed rulemaking proceeding or otherwise invited public comment.

- **Revised Reliability Standard: PRC-005-4 (RM15-9)**

On December 18, 2014, NERC filed for approval changes to PRC-005-4 (Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance), one new (Sudden Pressure Relaying) and four revised definitions (Protection System Maintenance Program, Component Type, Component, and Countable Event), associated VRFs and VSLs (together, the "PRC-005 Changes"). NERC stated that the PRC-005 Changes address FERC concerns expressed in the *Order 758* proceeding that NERC's proposed interpretation of PRC-005-1 may not include all components that serve in some protective capacity.[84] NERC requested that the PRC-005 Changes be approved, effective on the first day of the first calendar quarter following FERC approval. As of the date of this Report, the FERC has not noticed a proposed rulemaking proceeding or otherwise invited public comment.

- **Revised Reliability Standard: PRC-026-1 (RM15-8)**

On December 31, 2014, NERC filed for approval a new Standard, PRC-026-1 (Relay Performance During Stable Power Swings) and associated VRFs and VSLs (the "PRC-026 Standard") in response to the FERC's directive in *Order 733*[85] to develop a Reliability Standard addressing undesirable relay operation due to stable power swings. NERC requested that PRC-026 be approved, effective as follows: R1 on the first day of the first full calendar year that is 12 months after FERC approval; R2-R4 on the first day of the first full calendar year that is 36 months after FERC approval. As of the date of this Report, the FERC has not noticed a proposed rulemaking proceeding or otherwise invited public comment.

- **Revised Reliability Standard: EOP-011-1 (RM15-7)**

On December 29, 2014, NERC filed for approval a new Standard, EOP-011-1 (Emergency Operations), a revised definition of "Energy Emergency", and associated VRFs and VSLs (together, the "Emergency Operations Changes"). NERC stated that the purpose of the Emergency Operations Changes is to address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed Operating Plans to mitigate operating Emergencies, and that those plans are coordinated within a Reliability

[83] *Reliability Standards for Geomagnetic Disturbances*, Order No. 779, 143 FERC ¶ 61,147 ("*Order 779*").

[84] *Interpretation of Protection System Reliability Standard*, Notice of Proposed Rulemaking, 133 FERC ¶ 61,223 (2010) at P 11; *Interpretation of Protection System Reliability Standard*, Order No. 758, 138 FERC ¶ 61,094 ("*Order 758*"), *order on reh'g*, 139 FERC ¶ 61,227 (2012).

[85] *Transmission Relay Loadability Reliability Standard*, Order No. 733, 130 FERC ¶ 61,221 (2010); *order on reh'g and clarification*, Order No. 733-A, 134 FERC ¶ 61,127 (2011); *clarified*, Order No. 733-B, 136 FERC ¶ 61,185 (2011) ("*Order 733*").

Coordinator Area. EOP-011-1 consolidates requirements from three existing Reliability Standards, EOP-001-2.1b, EOP-003.1, and EOP-003-2, into a single new Reliability Standard. NERC stated that the Emergency Operations Changes address seven FERC directives from *Order 693*. NERC requested that the Emergency Operations Changes be approved, effective on the first day of the first calendar quarter that is 12 months after FERC approval. As of the date of this Report, the FERC has not noticed a proposed rulemaking proceeding or otherwise invited public comment.

- **Revised Reliability Standard: PRC-002-2 (RM15-4)**

On December 15, 2014, NERC filed for approval changes to PRC-002-2 (Disturbance Monitoring and Reporting Requirements), associated VRFs and VSLs, and requested retirement of PRC-002-1 (Define Regional Disturbance Monitoring and Reporting Requirements) and PRC-018-1 (Disturbance Monitoring Equipment Installation and Data Reporting) (together, the "PRC-002 Changes"). NERC stated that the PRC-002 Changes address FERC concerns expressed in *Order 693*[86] with the "fill in the blank" aspects in PRC-002-1 and PRC-018-1.[87] NERC requested that the PRC-002 Changes be approved, effective on the first day of the first calendar quarter six months following FERC approval. As of the date of this Report, the FERC has not noticed a proposed rulemaking proceeding or otherwise invited public comment.

- ***Order 802*: New Reliability Standard: CIP-014-1 (Physical Security) (RM14-15)**

The FERC approved NERC's proposed Physical Security Reliability Standard (CIP-014-1) on November 20, 2014.[88] CIP-014 is designed to enhance physical security measures for the most critical Bulk-Power System facilities and thereby lessen the overall vulnerability of the Bulk-Power System to physical attacks. CIP-014 requires Transmission Owners and Transmission Operators to protect those critical Transmission stations and Transmission substations, and their associated primary control centers that, if rendered inoperable or damaged as a result of a physical attack, could result in widespread instability, uncontrolled separation, or cascading within an Interconnection. CIP-014 also includes requirements for: (i) the protection of sensitive or confidential information from public disclosure; (ii) third party verification of the identification of critical facilities as well as third party review of the evaluation of threats and vulnerabilities and the security plans; and (iii) the periodic reevaluation and revision of the identification of critical facilities, the evaluation of threats and vulnerabilities, and the security plans to help ensure their continued effectiveness. CIP-014 will become effective June 1, 2015. In approving CIP-014, the FERC required NERC within six months of the effective date of the Rule,[89] to remove the term "widespread" from the Standard or, alternatively, to propose modifications to the Reliability Standard that address the FERC's concerns. In addition, the FERC directed NERC to submit, by June 1, 2017, an informational filing that addresses whether there is a need for consistent treatment of "High Impact" control centers for cyber security and physical security purposes through the development of Reliability Standards that afford physical protection to all "High Impact" control centers.[90] A request for rehearing of *Order 802* was filed by the Foundation for Resilient Societies ("FRS"), which identified as problematic: (i) exemptions for Reliability Coordinators, Balancing Authorities, and Generator Operators and Generator Owners; (ii) 2-year exemptions for high impact control centers; (iii) FERC's failure to address FRS' comments on the critical role of RCs under the Standard; (iv) failure to require modeled contingency planning for physical attack scenarios; (v) lack of requirements for specific security measures for critical grid facilities; and (vi) failure to address FRS' cost-effectiveness comments. On January 21, the FERC issued a tolling order affording it additional time to consider the FRS rehearing request, which remains pending before the FERC.

---

[86] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, 72 FR 16416, FERC Stats. & Regs. ¶ 31,242, at PP 1131-1222, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007) ("*Order 693*").

[87] *Interpretation of Protection System Reliability Standard*, Notice of Proposed Rulemaking, 133 FERC ¶ 61,223 (2010) at P 11; *Interpretation of Protection System Reliability Standard*, Order No. 758, 138 FERC ¶ 61,094 ("*Order 758*"), *order on reh'g*, 139 FERC ¶ 61,227 (2012).

[88] *Physical Security Reliability Standard*, Order No. 802, 149 FERC ¶ 61,140 (Nov. 20, 2014) ("*Order 802*").

[89] *Order 802* was published in the *Fed. Reg.* on Nov. 25, 2014 (Vol. 79, No. 227) pp. 70,069-70,085.

[90] *Id.* at P 57.

- **NOPR: Revised Reliability Standard: COM-001-2 and COM-002-4 (RM14-13)**

The FERC's September 18, 2014 NOPR proposing to approve changes to COM-1 (Communications) and COM-2 (Operating Personnel Communications Protocols) (together, "COM Changes")[91] remains pending. As previously reported, proposed COM-001 establishes a clear set of requirements for what communications capabilities various functional entities must maintain for reliable communications. Proposed COM-002 improves communications surrounding operating instructions by setting predefined communications protocols, requiring use of the same protocols regardless of the current operating condition (whether normal, alert, and Emergency operating conditions), and requiring entities to reinforce the use of the documented communication protocols through training, assessment, and feedback. NERC requested that the COM Changes be approved effective as of the first day of the first calendar quarter that is 12 months after the date that the COM Changes are approved by the FERC. Comments on this NOPR were due on or before December 1, 2014,[92] and were filed by 7 parties, including by NERC, the ISO/RTO Council, EEI/EPSA, and NRECA. This NOPR is pending before the FERC.

- **NOPR: Revised Reliability Standard: MOD-031-1 (RM14-12)**

The FERC's September 18, 2014 NOPR proposing to approve changes to MOD-31 (Demand and Energy Data) ("MOD-031 Changes")[93] also remains pending. The MOD-031 Changes are designed to replace, consolidate and improve upon the "existing MOD-C Standards"[94] in addressing the collection and aggregation of Demand and energy data necessary to support reliability assessments performed by the ERO and Bulk-Power System planners and operators. Specifically, the MOD-031 Changes, in response to *Order 693*, (1) streamline the MOD Reliability Standards to clarify data collection requirements; (2) include Transmission Planners as applicable entities that must report Demand and energy data; (3) require applicable entities to report weather-normalized annual peak hour actual Demand data from the previous year to allow for meaningful comparison with forecasted values; and (4) require applicable entities to provide an explanation of, among other things: (i) how their Demand Side Management forecasts compare to actual Demand Side Management for the prior calendar year and, if applicable, how the assumptions and methods for future forecasts were adjusted.; and (ii) how their peak Demand forecasts compare to actual Demand for the prior calendar year with due regard to any relevant weather-related variations (e.g., temperature, humidity, or wind speed) and, if applicable, how the assumptions and methods for future forecasts were adjusted. Consistent with FERC's directives, NERC is also proposing to revise the definition of Demand-Side Management to include activities or programs undertaken by any applicable entity, not just a Load Serving Entity or its customers, to achieve a reduction in Demand. NERC requested that the MOD-031 Changes be approved, and the existing MOD-C Standards be retired, effective on the first day of the first calendar quarter that is 12 months after the date that the MOD-031 Changes are approved by the FERC. Comments on this NOPR were due on or before December 1, 2014,[95] and were filed by ISO-NE, NERC, EEI, ITC, Idaho Power, and Pacific Corp. This NOPR is pending before the FERC.

- **NOPR: Revised Reliability Standard: BAL-001-2 (RM14-10)**

On November 20, 2014, the FERC issued a NOPR proposing to approve changes to BAL-001-2 (Real Power Balancing Control Performance) ("BAL-001 Changes") and to require NERC to submit an informational filing that would address the impact of the proposed Reliability Standard on inadvertent interchange and unscheduled power flows.[96] As previously reported, the BAL-001 Changes add a frequency component to the

---

[91] *Communications Reliability Standards*, 148 FERC ¶ 61,210 (Sep. 18, 2014).

[92] The *Communications Reliability Standards* NOPR was published in the *Fed. Reg.* on Sep. 30, 2014 (Vol. 79, No. 189) pp. 58,709-58,716.

[93] *Demand and Energy Data Reliability Standard*, 148 FERC ¶ 61,192 (Sep. 18, 2014).

[94] The "existing Mod-C Standards" are: MOD-016-1.1, MOD-017-0.1, MOD-018-0, MOD-019-0.1, and MOD-021-1.

[95] The *Demand and Energy Data Reliability Standard* NOPR was published in the *Fed. Reg.* on Sep. 30, 2014 (Vol. 79, No. 189) pp. 58,716-58,720.

[96] *Real Power Balancing Control Performance Reliability Standard*, 149 FERC ¶ 61,139 (Nov. 20, 2014).

measurement of a Balancing Authority's Area Control Error ("ACE") and allow for the formation of "Regulation Reserve Sharing Groups." NERC requested that the BAL-001 Changes be approved, and the existing BAL-001-1 Standard be retired, effective on the first day of the first calendar quarter that is 12 months after the date that the BAL-001 Changes are approved by the FERC. Comments on this NOPR were due on or before January 26, 2015,[97] and 12 sets of comments were filed, including comments by NERC, EEI, and ISO-NE (in joint comments with MISO and PJM). This NOPR is pending before the FERC.

- ***Order 803*: Revised Reliability Standard: PRC-005-3 (RM14-8)**

On January 22, 2015, the FERC approved changes to PRC-005-3 (Protection System and Automatic Reclosing Maintenance) ("PRC-005 Changes").[98] The PRC-005 Changes include in PRC-005 the maintenance and testing of reclosing relays that can affect the reliable operation of the BPS. While the FERC was persuaded not to direct NERC to submit a report based on actual performance data, and simulated system conditions from planning assessments, it instead directed NERC to "obtain, maintain, and make available to the Commission upon request, one year following the effective date of the standard and on an annual basis thereafter, data sufficient to analyze the effectiveness of PRC-005-3".[99] In addition, the FERC directed NERC to modify PRC-005-3 to include maintenance and testing of supervisory relays associated with autoreclosing relay schemes to which PRC-005-3 applies.[100] The PRC-005 Changes will become effective, and the existing PRC-005-2 retired, as of April 1, 2016.[101]

- **NOPR: Revised Reliability Standard: MOD-001-2 (RM14-7)**

On June 19, 2014, the FERC issued a NOPR proposing to approve changes to MOD-001-2 (Modeling, Data, and Analysis — Available Transmission System Capability) ("MOD Changes") proposed by NERC. The MOD Changes replace, consolidate and improve upon the Existing MOD Standards in addressing the reliability issues associated with determinations of Available Transfer Capability ("ATC") and Available Flowgate Capability ("AFC"). MOD-001-2 will replace the six Existing MOD Standards[102] to exclusively focus on the reliability aspects of ATC and AFC determinations. NERC requested that the revised MOD Standard be approved, and the Existing MOD Standards be retired, effective on the first day of the first calendar quarter that is 18 months after the date that the proposed Reliability Standard is approved by the FERC. NERC explained that the implementation period is intended to provide NAESB sufficient time to include in its WEQ Standards, prior to MOD-001-2's effective date, those elements from the Existing MOD Standards, if any, that relate to commercial or business practices and are not included in proposed MOD-001-2. The FERC seeks comment from NAESB and others whether 18 months would provide adequate time for NAESB to develop related business practices associated with ATC calculations or whether additional time may be appropriate to better assure synchronization of the effective dates for the proposed Reliability Standard and related NAESB practices. The FERC also seeks further elaboration on specific actions NERC could take to assure synchronization of the effective dates. Comments on this NOPR were due August 25, 2014,[103] and were filed by NERC, Bonneville, Duke, MISO, and NAESB. Since the last Report, NAESB supplemented its comments with a report on its efforts to develop WEQ

---

[97] The *Real Power Balancing Control Performance Reliability Standard* NOPR was published in the *Fed. Reg.* on Nov. 26, 2014 (Vol. 79, No. 228) pp. 70,483-70,488.

[98] *Protection System Maintenance Reliability Standard*, Order No. 803, 150 FERC ¶ 61,039 (Jan. 22, 2015) ("*Order 803*"). *Order 803* also approved one new definition and six revised definitions, the assigned VRFs and VSLs, and NERC's proposed implementation plan.

[99] *Id.* at P 25.

[100] *Id.* at P 31.

[101] *Order 803* was published in the *Fed. Reg.* on Jan. 27, 2015 (Vol. 80, No. 17) pp. 4,195-4,201.

[102] The 6 existing MOD Standards to be replaced by MOD-001-2 are: MOD-001-1, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-1a and MOD-030-2.

[103] The MOD-001-2 NOPR was published in the *Fed. Reg.* on June 26, 2014, (Vol. 79, No. 123) pp. 36,269-36,273.

Business Practice Standards that will support and coordinate with the MOD Standards proposed in this proceeding. The MOD-001-2 NOPR remains pending before the FERC.

- **NOPR: Revised TOP and IRO Reliability Standards (RM13-15, RM13-14, RM13-12)**

On November 21, 2013, the FERC issued a NOPR[104] proposing (i) to approve NERC's proposed revisions to Reliability Standard TOP-006-3 (Monitoring System Conditions) filed in RM13-12, but (ii) to remand changes to the following Interconnection Reliability Operations and Coordination ("IRO") and Transmission Operating ("TOP") Reliability Standards filed in RM13-14 and RM13-15:

- IRO-001-3 (Reliability Coordination — Responsibilities and Authorities);
- IRO-002-3 (Reliability Coordination – Analysis Tools);
- IRO-005-4 (Reliability Coordination – Current Day Operations);
- IRO-0014-2 (Coordination Among Reliability Coordinators);
- TOP-001-2 (Transmission Operations);
- TOP-002-3 (Operations Planning);
- TOP-003-2 (Operational Reliability Data); and
- PRC-001-2 (System Protection Coordination).[105]

As previously reported, the changes to TOP-006-3 filed April 5, 2013 are targeted to address the respective monitoring role and notification obligation of Reliability Coordinators ("RCs"), Balancing Authorities ("BAs") and Transmission Operators ("TOPs") by clarifying that TOPs are responsible for monitoring and reporting available transmission resources and that BAs are responsible for monitoring and reporting available generation resources. In addition, the changes confirm that RCs, TOPs, and BAs are required to supply their operating personnel with appropriate technical information concerning protective relays located within their respective areas.

The changes to the IRO Standards were to achieve two important overall reliability benefits: (1) delineate a clean division of responsibilities between the Reliability Coordinator and Transmission Operators; and (2) improve system performance by raising the bar on monitoring of Interconnection Reliability Operating Limits ("IROLs") and System Operating Limits ("SOLs") in order to focus monitoring on IROLs and SOLs that are important to reliability.

The changes to the remaining TOP Standards were to upgrade the overall quality of the Standards, eliminate gaps in the requirements, eliminate ambiguity, eliminate redundancies, and address *Order 693* directives. NERC indicated in its April filing that the proposed TOP Standards are also more efficient than the currently-enforceable TOP Reliability Standards because they incorporate the necessary requirements from the eight currently-effective TOP Reliability Standards (TOP-001-1a, TOP-002-2.1b, TOP-003-1, TOP-004-2, TOP-005-2a, TOP-006-2, TOP-007-0, TOP-008-1) and the PER-001-0.2 Reliability Standard into three cohesive, comprehensive Reliability Standards that are focused on achieving a specific result.

Because the proposed TOP and IRO Reliability Standards were interrelated, and because the proposed revisions to Reliability Standard TOP-006-3 involved similar issues raised in the TOP and IRO proposals concerning monitoring of the interconnected transmission network and notification of and by registered entities, the FERC addressed all three proposals together in the one NOPR. Although the FERC acknowledged that the proposed TOP and IRO Reliability Standards contain some improvements over the current Standards, concerns

[104] *Monitoring System Conditions - Transmission Operations Reliability Standard, Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards,* 145 FERC ¶ 61,158 (Nov. 21, 2013) ("*Nov 21 NOPR*").

[105] The changes in proposed PRC-001-2 were administrative in nature and were limited to removal of three requirements in currently-effective PRC-001-1 that were to be addressed in proposed TOP-003-2.

that the changes would create reliability gaps in the Standards that are critical to reliable operation of the BPS resulted in the proposed remand of the proposed TOP Standards.[106] The FERC went on to explain that

> given the interrelationship between the TOP and IRO Reliability Standards and that NERC requests that both sets of standards be addressed together, we believe a remand of the proposed IRO standards in addition to those of the TOP will enable NERC to more comprehensively consider modifications to the standards that would address the reliability concerns identified in this NOPR. This approach, in turn, should allow NERC more flexibility in developing appropriate modifications that address our concerns since changes to the TOP standards might require, in some instances, commensurate changes to the IRO standards.[107]

Initially, comments are the *Nov 21 NOPR* were due on or before February 3, 2014.[108] However, on December 20, NERC requested that the FERC defer action in this proceeding to January 31, 2015 to allow NERC time to consider the reliability concerns raised by the FERC in the *Nov 21 NOPR* and by an independent review commissioned by NERC that identified proposed TOP-001-2, PRC-001-2, IRO-001-3, and IRO-005-4 as high risk standards requiring improvement. On January 6, 2014, the ISO/RTO Council and NRECA filed comments supporting NERC's requested deferral. On January 14, 2014, the FERC granted NERC's motion to defer action on the *Nov 21 NOPR* until January 31, 2015, including deferral of the comment due date. Comments were nonetheless submitted on February 3, 2014 by BPA and Idaho Power. On January 2, 2015, NERC submitted the fourth of its promised quarterly status reports regarding the status of revisions. In the fourth report, NERC reported that it will require additional time, at least until just after February 12, 2015, in order to obtain NERC Board of Trustees approval for proposed Reliability Standard TOP-001-3 (expected to be approved in stakeholder balloting in January). TOP-001-3 is the one remaining Standard that has not yet been approved by the stakeholders and Board. NERC reported that, without TOP-001-3, it is unable to file the remaining approved Standards (given the integrated nature of this group of Standards). If not approved in balloting in January, NERC will propose in a subsequent filing an amended path forward.

- **NOPR: BAL-002-1a Interpretation Remand (RM13-6)**

This May 16, 2013 NOPR, which proposes to remand NERC's proposed interpretation of BAL-002 (Disturbance Control Performance Reliability Standard) filed February 12, 2013 (which would prevent Registered Entities from shedding load to avoid possible violations of BAL-002), remains pending.[109] 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,[110] and were

---

[106] *Id.* at P 4.

[107] *Id.*

[108] The *Nov 21 NOPR* was published in the *Fed. Reg.* on Dec. 5, 2013 (Vol. 78, No. 234) pp. 73,112-73,128.

[109] *Electric Reliability Organization Interpretation of Specific Requirements of the Disturbance Control Performance Standard*, 143 FERC ¶ 61,138 (2013) ("*BAL-002-1a Interpretation Remand NOPR*").

[110] The *BAL-002-1a Interpretation Remand NOPR* was published in the *Fed. Reg.* on May 23, 2013 (Vol. 78, No. 99) pp. 30,245-30,810.

filed by NERC, EEI, ISO/RTO Council, MISO, NC Balancing Area, Northwest Power Pool Balancing Authorities, NRECA, and WECC. This NOPR remains pending before the FERC.

XI. Misc. - of Regional Interest

- **203 Application: First Wind / TerraForm & SunEdison (EC15-44)**

On January 12, the FERC approved a transaction[111] whereby TerraForm Power will ultimately own indirectly 100% of the voting securities of each of the First Wind Applicants[112] and First Wind will become a indirect subsidiary of Sun Edison. On February 5, TerraForm, SunEdison Inc. and the First Wind Applicants notified the FERC that the transaction was consummated, concluding this proceeding. If there are any further questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **203 Application: Dynegy/EquiPower (EC14-140)**

As previously reported, Dynegy and EquiPower requested FERC authorization for Dynegy's acquisition of EquiPower's generating assets (Dighton, Elwood, Kincaid, Lake Road, Liberty, MASSPOWER, Milford, Richland-Stryker Generation and Brayton Point). On September 24, PJM's IMM requested that this proceeding be consolidated with EC14-141 (the acquisition of certain Midwest generating assets from Duke Energy), citing common issues of law and fact and the need to evaluate the impact of the combined transactions on PJM markets. Dynegy opposed that request on September 25. That request is pending before the FERC. Interventions were filed by Public Citizen and MA AG. Comments were submitted by PJM's IMM and by UWUA Local 464. Dynegy and EquiPower responded to the PJM IMM and UWUA Local 464 comments on November 24. Both the PJM IMM and UWUA Local 464 answered Dynegy's November 24 answer on December 9. Dynegy and EquiPower filed a limited answer to the December 9 pleadings on December 12. On January 16, the FERC issued a deficiency letter requiring submission by Feb 16 (i) a Delivered Price Test for the PJM market, and the AP South, 5004/5005, and PJM East submarkets; and (ii) additional info. regarding the transactions' effect on rates. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **LVA/PSNH IA Complaint (EL15-9)**

As previously reported, Lower Village Hydroelectric Associates ("LVA") filed a complaint, on October 23, 2014, against PSNH requesting FERC direct PSNH to recognize the existing LVA IA, rescind its demand for LVA facility modifications, and close the air break switch so LVA can complete relay testing and resume generating/ selling electricity. PSNH responded to the Complaint on December 11, urging the FERC to dismiss the Complaint. LVA answered PSNH's response on December 26 and PSNH answered LVA's answer on January 9, 2015. This matter is pending before the FERC. If you have any questions concerning this Complaint, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **FirstEnergy PJM DR Complaint (EL14-55)**

On May 23, 2014, the same day that DC Circuit vacated *Order 745* (*see* Section XV below), FirstEnergy filed a complaint against PJM requesting that the FERC require the "removal of all portions of the PJM Tariff allowing or requiring PJM to include demand response as suppliers to PJM's capacity markets." FirstEnergy also requested that the results of the PJM capacity auction due to be released that same day, to the extent it included and cleared demand response resources, be considered void and legally invalid. PJM's response, and all comments and interventions were initially due on or before June 12, 2014. However,

[111] *Blue Sky East, LLC et al.*, 150 FERC ¶ 62,014 (Jan. 12, 2015).

[112] "First Wind Applicants" are: Blue Sky East, LLC; Canandaigua Power Partners, LLC; Canandaigua Power Partners II, LLC; Erie Wind, LLC; Evergreen Gen Lead, LLC; Evergreen Wind Power, LLC; Evergreen Wind Power III, LLC; First Wind Energy Marketing, LLC; Longfellow Wind, LLC; Maine GenLead, LLC; Milford Wind Corridor Phase I, LLC; Milford Wind Corridor Phase II, LLC; Niagara Wind Power, LLC; Palouse Wind, LLC; Stetson Holdings, LLC; Stetson Wind II, LLC; and Vermont Wind, LLC.

on June 11, the FERC extended that date to 30 days after the submission by FirstEnergy of an amended complaint. FirstEnergy filed its amended complaint on September 22, 2014.

Comments on the FirstEnergy Complaint were due October 22, 2014. More than 40 parties filed comments or responses to the FirstEnergy amended complaint. Many parties filed comments supporting the complaint (including Calpine, PSEG and PPL), while others opposed the complaint in its entirety (including Direct Energy and Enerwise). PJM's response argued that the complaint failed to justify the market disruption that would result from recalculating past capacity auction results, PJM was instead more focused on minimizing "litigation risk." A number of parties filed supporting comments in favor of removing demand response resources from the PJM tariff moving forward, but opposed to recalculating the results of past capacity auctions (including Exelon, the PJM IMM and NRG). Comments were also filed by National Grid and NYISO. A number of New England parties intervened, including NEPOOL (stressing that the FERC should not apply any ruling in this docket to the New England Market), Dominion, Duke Energy, Dynegy, Essential Power, Macquarie Energy, NEPGA, NESCOE, and NextEra. On November 14, FirstEnergy filed an answer to the answers, protests and comments submitted in response to its Complaint and Amended Complaint. Environmental Advocates[113] filed an answer to FristEnergy's answer on November 21. Since the last Report, CPower and Advanced Energy Management Alliance filed answers to the FirstEnergy and other answers and pleadings. On December 23, Environmental Advocates moved to lodge the US Solicitor General's application for an extension of time in which to file a petition for writ of certiorari, the Supreme Court Clerk's notice to the DC Circuit that the extension had been granted, and the DC Circuit's order extending the stay of its mandate pending the Supreme Court's final disposition of the writ of certiorari. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Jamie Blackburn (jblackburn@daypitney.com; 202-218-3905) or Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **E&P Agreement Terminations: Spruce Mountain Wind (ER15-975); Record Hill Wind (ER15-974); Highland Wind (ER15-973); Patriot Renewables (ER15-972)**

On February 4, CMP filed a notice of termination of four Engineering and Procurement Agreement ("E&P Agreements") with Spruce Mountain Wind (superseded by IA-CMP-11-04); Record Hill Wind (superseded by IA-CMP-10-01); Highland Wind (all services completed); and Patriot Renewables (all services completed). CMP requested that each of the terminations become effective April 6, 2015. Comments on these filings are due on or before February 25, 2015.

- **LSA Termination: Emera/ Black Bear HVGW (ER15-962)**

On February 3, Emera and the ISO filed a notice of termination of a Local Service Agreement ("LSA") for Local Point-to-Point Service with Black Bear HVGW, LLC ("Black Bear"). Black Bear operated the Howland Hydroelectric Project ("Howland") located on the Penobscot River in central Maine, which as of January 2, 2015, however, ceased operations in preparation for decommissioning and dismantling. On January 5, 2015, Emera Maine's electric transmission facilities were disconnected from Howland and Emera Maine ceased providing electric transmission service for use by Howland. Emera and the ISO requested that the termination become effective January 6, 2015. Comments on this filing are due on or before February 24, 2015.

[113] "Environmental Advocates" are Sustainable FERC Project, Natural Resources Defense Council ("NRDC"), Sierra Club, Environmental Defense Fund, Environmental Law and Policy Center, and Acadia Center (f/k/a Environment Northeast).

- **IA – CL&P/Energy Stream (ER15-947)**

On January 30, CL&P filed a non-conforming[114] interconnection agreement (IA-NU-29) to maintain and govern the interconnection of Energy Stream's 120 kW hydroelectric generation unit located on the Quinnebaug River in Putnam, Connecticut. A March 31, 2015 effective date was requested. Comments on this matter are due on or before February 20, 2015. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **HG&E Demarcation Agreement (ER15-939)**

On January 30, WMECO filed a revised Asset Demarcation Agreement by and between WMECO and Holyoke Gas and Electric Department ("HG&E"). The Agreement established the parties agreement on the demarcation of ownership of their respective electric transmission facilities, and the revisions reflect the recent construction by HG&E of a new transmission substation. WMECO requested that the Agreement be accepted for filing as of January 5, 2015. Comments on this filing are due on or before February 20, 2015. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **IA – CMP/Kennebec Water District (ER15-757)**

On December 30, CMP filed a non-conforming[114] interconnection agreement (IA-CMP-15-02) to maintain and govern the interconnection (first established in 2000) of Kennebec Water District's 800 kV facility in Waterville, Maine. A January 1, 2015 effective date was requested. Comments on this matter were due on or before January 20, 2015; none were filed and this matter is pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **E&P Agreement CL&P/CPV Towantic (ER15-715)**

On December 23, NU filed an Engineering, Design, Permitting and Siting Agreement ("E&P Agreement") between CL&P and CPV Towantic, LLC (designated as service agreement IA-NU-30). The E&P Agreement sets forth the terms and conditions under which CL&P will undertake engineering, design, permitting and siting activities to the extent that transmission upgrades are necessary to physically and electrically interconnect CPV's 795 MW natural gas-fired plant located in Oxford, Connecticut to the Administered Transmission System for FCA9. NU requested that the E&P Agreement be accepted for filing as of December 5, 2014. Comments on this filing were due on or before January 13, 2015; none were filed and this matter is pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **E&P Agreement CMP/Atlantic Wind (ER15-589)**

On January 22, the FERC accepted an Engineering and Procurement Agreement ("E&P Agreement") between CMP with Atlantic Wind LLC (designated as service agreement CMP-EP-3 under CMP's eTariff files). As previously reported, the E&P Agreement sets forth the terms and conditions under which CMP will provide engineering and procurement services to Atlantic Wind in connection with Atlantic Wind's planned 100 MW, 50 turbine Fletcher Mountain Wind Farm to be located in Concord and Lexington Townships in Somerset County, Maine. The FERC accepted the E&P Agreement effective as of December 4, 2014, as requested. Unless the January 22 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).

- ***Opinion 531-A* Compliance Filing: NGrid IFA Amendments (ER15-418)**

On November 17, 2014, National Grid submitted an amendment to the formula rates for integrated facilities service ("IFA Amendment") under Schedule III-B of New England Power's ("NEP's") Tariff No. 1. The IFA Amendment modifies the ROE components of the Tariff No. 1 formula rates so that they mirror

[114] Because the IA continues an existing interconnection arrangement, the submission of the IA does not constitute a new "Interconnection Request" or require a new three-party IA (and, as a two-party agreement, is a non-conforming SGIA).

those recently ordered in *Opinion 531-A*. The proposed IFA amendment also implements *Opinion 531-A*'s ROE cap to ensure that the total ROE does not exceed 11.74%. National Grid reports that the overall effect of the IFA Amendment is a rate decrease of approximately $2.2 million. An October 16, 2014 effective date was requested. Comments on this filing were due on or before December 8; none were filed. NU submitted a doc-less intervention on December 5. On January 15, 2015, the FERC issued a deficiency letter directing National Grid to provide additional information, on or before February 17, 2015, in order for the FERC to process the filing. 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",115 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. MISO (now called "Midcontinent Independent System Operator, Inc.") moved to lodge a NYISO "Broader Regional Markets Informational Report" filed March 19, 2014 in ER08-1281 and a related January 16, 2014 "Ontario-Michigan Interface PAR Performance Evaluation Report" ("Evaluation Report") prepared by MISO, IESO and PJM. Oppositions to that motion to lodge were filed by FERC Staff, NYISO, NY TOs, PJM, and PSEG. 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: Maxim Power and K. Mitton (IN15-4)**

On February 2, 2015, the FERC issued an order directing Maxim Power (USA), Inc., Maxim Power (USA) Holding Company Inc., Pawtucket Power Holding Co., LLC, Pittsfield Generating Company, LP, and Kyle Mitton (collectively, "Maxim Respondents")[116] to show cause (i) why they should not be found to have violated the FERC's Anti-Manipulation Rules through a scheme to obtain payments for reliability dispatches based on the price of expensive fuel oil when Maxim in fact burned much less costly natural gas; and (ii) why they should not be assessed civil penalties as follows: Maxim and its affiliates (***$5 million civil penalty, jointly and severally***); and K. Mitton (***$50,000 civil penalty***).[117] As previously reported, OE Staff alleges that Maxim engaged in three schemes in New England that violated the FERC's Anti-Manipulation Rule. In the first, during 2012-13, Maxim received millions of dollars of inflated make-whole payments from the ISO by gaming Market Rules intended to mitigate the market power of generators needed for reliability; in the second, July-August 2010, staff alleges that Maxim told the ISO it needed to offer based on high oil prices because of supposed gas supply problems, and collected make-whole payments based on those high prices, but in fact burned much less expensive gas. In many cases Maxim had already purchased gas when it submitted Day-Ahead offers based on oil prices because of supposed gas supply issues; in the third, 2010-2013, Maxim obtained inflated capacity payments by artificially raising the reported output of three of its plants by employing extraordinary measures during capacity tests that it did not use, and did not intend to use,

[115] *Midwest Indep. Trans. Sys. Op., Inc.*, 141 FERC ¶ 63,021 (Dec. 18, 2012) ("*MISO Initial Decision*") at P 923.

[116] Maxim's Related Person, Pawtucket Power Holding Company, is a member of the Generation Sector Group Seat. In addition to Pawtucket, Maxim operates units in Pittsfield, MA and Hartford, CT (Capitol District Energy Center Cogeneration Associates).

[117] *Maxim Power Corp. et al.*, 150 FERC ¶ 61,068 (Feb. 2, 2015) ("*Maxim Show Cause Order*").

during the ordinary operation of the plants. Staff also alleged that Maxim executives John Bobenic and Kyle Mitton engaged in certain of these schemes, and that Maxim also violated the FERC's Market Behavior Rules through schemes two and three. The Maxim Respondents have until March 4, 2015 to file an answer to the *Maxim Show Cause Order*. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **FERC Enforcement Action: Powhatan Energy, HEEP Fund, CU Fund, and H. Chen (IN15-3)**

On December 17, 2014, the FERC issued an order directing Houlian "Alan" Chen, HEEP Fund, Inc., CU Fund, Inc., and Powhatan Energy Fund, LLC (together, "Powhatan Respondents") to show cause (i) why they should not be found to have violated the FERC's Anti-Manipulation Rules by engaging in fraudulent Up To Congestion (UTC) transactions in PJM's energy markets and (ii) why they should not disgorge unjust profits with interest and be assessed civil penalties as follows: Powhatan Energy Fund (***$16.8 million civil penalty; $3.47 million disgorgement***); CU Fund: (***$10.08 million civil penalty; $1.08 million disgorgement***); HEEP Fund (***$1.92 million civil penalty; $173,100 disgorgement***); H. Chen (***$1 million civil penalty*** for trades executed through and on behalf of Powhatan and the Funds).[118] As previously reported, OE Staff alleges that, between June and August 2010, Powhatan Respondents engaged in manipulative Up To Congestion trading in PJM, trades which amounted to wash trading, long prohibited by the FERC. Specifically, Staff alleges that the transactions were designed to falsely appear to be spread trades, as a vehicle for collecting Marginal Loss Surplus Allocation ("MLSA") payments from PJM, by placing millions of megawatt hours of offsetting trades between the same two trading points, in the same volumes and the same hours—an intentional effort to cancel out the financial consequences from any spread between the two trading points while capturing large amounts of MLSA payments. On December 31, the answer period was extended by the FERC, so that Powhatan Respondents' answers were due on or before February 2, 2015.

On January 12, Powhatan Respondents invoked their statutory rights to prompt assessment of a penalty and a de novo review of that penalty in federal district court. On January 27, Powhatan Respondents requested a two-week extension of time for its answers, citing a need to review yet-to-be disclosed exculpatory evidence. On January 29, FERC staff opposed the requested extension, but provided additional materials. On January 30, the FERC denied the requested extension, but indicated that Powhatan Respondents would be permitted to provide by February 9 a supplemental answer in response to the materials provided with staff's Jan 29 motion. Powhatan Respondents submitted their answers to the *Powhatan Show Cause Order* on February 2. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **FERC Enforcement Action: Twin Cities (IN15-2)**

On December 30, 2014, the FERC approved four Stipulation and Consent Agreements, one between OE and Twin Cities[119] and three between OE and three Twin Cities' individual traders, Allan Cho, Jason F. Vaccaro, and Gaurav Sharma. Twin Cities, which admitted to violating the FERC's Anti-Manipulation Rule by scheduling and trading physical power in MISO to benefit related swap positions that settled off of real-time MISO prices, including the Cinergy Hub Balance-of-Day Swap traded on IntercontinentalExchange, Inc. ("ICE"), during the January 1, 2010 through January 31, 2011 period, agreed to pay a ***$2.5 million civil penalty*** and to ***disgorge $978,176*** plus interest. The individual traders, while neither admitting nor denying the alleged violations, each agreed to civil penalties and physical trading bans as follows: Vacarro (***$400,000; 5-year ban***); Cho (***$275,000; 4-year ban***); and Sharma (***$75,000; 4-year ban***). If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

[118] *Houlian Chen, Powhatan Energy Fund, LLC, HEEP Fund, LLC, and CU Fund, Inc.*, 149 FERC ¶ 61,261 (Dec. 17, 2014), *as revised*, 149 FERC ¶ 61,263 (Dec. 18, 2014) ("*Powhatan Show Cause Order*").

[119] "Twin Cities" includes Twin Cities Power – Canada, Ltd., Twin Cities Energy, LLC, and Twin Cities Power, LLC.

- **FERC Enforcement Action Pending: Staff Notices of Alleged Violations (IN__-___)**

City Power and K. Tsingas. On August 25, 2014, the FERC issued a notice that Staff has preliminarily determined that (i) City Power Marketing, LLC ("City Power") and K. Stephen Tsingas violated the FERC's Anti-Manipulation Rule by engaging in manipulative Up To Congestion trading in PJM during July 2010; and (ii) City Power violated the FERC's market behavior rules (18 C.F.R. § 35.41 (2014)) by making false statements and omitting material information during the investigation.

Recall that Notices of Alleged Violations ("NoVs") are issued only after the subject of an enforcement investigation has either responded, or had the opportunity to respond, to a preliminary findings letter detailing Staff's conclusions regarding the subject's conduct.[120] NoVs are designed to increase the transparency of Staff's nonpublic investigations conducted under Part 1b of its regulations. A NoV does not confer a right on third parties to intervene in the investigation or any other right with respect to the investigation.

XII. Misc. - Administrative & Rulemaking Proceedings

- **Technical Conferences on Implications of Environmental Regulations (AD15-4)**

The FERC initiated this proceeding, on December 9, 2014, in order to discuss, in a series of technical conferences, the implications of compliance approaches to the Environmental Protection Agency's ("EPA") proposed Clean Power Plan issued June 2, 2014.[121] The technical conferences will focus on issues related to electric reliability, wholesale electric markets and operations, and energy infrastructure. There will be one, Commissioner-led National Overview technical conference to be held on February 19. There will be three, staff-led regional technical conferences, with the Eastern region conference to be held March 11 at FERC headquarters.

Feb 19 National Overview technical conference. This conference will include discussion of the following overarching topics: (1) whether industry participants (state utility and environmental regulators, regulated entities, etc.) have the appropriate tools to identify reliability and/or market issues that may arise; (2) potential strategies for compliance with the EPA regulations and coordination with FERC-jurisdictional wholesale and interstate markets; and (3) how relevant planning entities, industry, and states coordinate reliability and infrastructure planning processes with state and/or regional environmental compliance efforts to ensure the adequate development of new infrastructure and to manage any potential reliability and operational impacts of proposed compliance plans. On January 6, 2015, the FERC issued a supplemental notice of the technical conference with a proposed agenda for the February 19 discussion. On February 2, the FERC issued a supplemental notice that updated the agenda and identified panelists for the National Overview conference. Those interested are encouraged to register by February 13. Thus far, comments have been filed by the Energy Policy Group and the ISO/RTO Council ("IRC").

Mar 11 Eastern[122] Regional conference. This conference will include discussion of the following topics: (1) potential reliability impacts in each region under various compliance approaches; (2) potential impacts on power system operations and generator dispatch in each region under various compliance approaches; and (3) potential impact on each region's current or expected infrastructure (electric transmission, natural gas pipelines, generation, etc.) to address compliance with the proposed rule, and additional infrastructure that may be required.

---

[120] *See Enforcement of Statutes, Regulations, and Orders*, 129 FERC ¶ 61,247 (Dec. 17, 2009), *order on requests for reh'g and clarification*, 134 FERC ¶ 61,054 (Jan. 24, 2011).

[121] *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, Notice of Proposed Rulemaking, 79 Fed. Reg. 34,830 (June 18, 2014).

[122] The Eastern Region includes New England, Northern Maine Independent System Administrator, New York, PJM, Southeastern Regional Transmission Planning ("SERTP"), South Carolina Regional Transmission Planning ("SCRTP"), and the Florida Reliability Coordinating Council ("FRCC").

- **RTO/ISO Common Metrics Report (AD14-15)**

As previously reported, FERC Staff published a "Common Metrics" report on August 26, 2014, the primary purpose of which is to provide a platform for review of ISO, RTO and utility performance. The Common Metrics Report provides the following two components for a performance review: (1) an analysis of the metrics data to confirm that the data provided by ISOs, RTOs and utilities in regions outside ISO and RTO markets are consistent with the definitions of the common metrics; and (2) an evaluation and confirmation that the common metrics are measuring the same activities and have the same meaning across the industry. FERC Staff determined 30 metrics meeting the criteria for common metrics. FERC Staff reported that further analysis is needed, and indicated that it would request approval for further data collection on performance metrics for the 2008-2012 and 2010-2014 periods from the Office of Management and Budget ("OMB"). Comments on the Metrics Report were filed by APPA, AWEA, EEI, ITC, NYISO, New York TOs, Southern Company.

- **Price Formation in RTO/ISO Energy & Ancillary Services Markets (AD14-14)**

On June 19, 2014, the FERC initiated a proceeding to evaluate price formation issues in RTO/ISO energy and ancillary services markets. In its notice, the FERC announced a series of staff workshops to facilitate a discussion with market operators and their stakeholders on the existing market rules and operational practices related to:

  - use of uplift payments;
  - offer price mitigation and offer price caps;
  - scarcity and shortage pricing; and
  - operator actions that affect price.

Sep 8 Workshop. The FERC held its first workshop on September 8, 2014. The September 8 workshop focused on the technical, operational and market issues that give rise to uplift payments and the levels of transparency. The workshop also previewed the scope of the remaining price formation topics. The webcast of the September 8 workshop will be archived and available for 3 months on the FERC's website at http://ferc.capitolconnection.org/. Speaker materials have been posted in the FERC's eLibrary. Also posted in eLibrary is a FERC staff report issued August 21 that analyzes "Uplift in RTO and ISO Markets."

Oct 28 Workshop. The FERC held its second workshop on October 28, 2014. The October 28 workshop focused on the technical, operational, and market issues related to offer price mitigation and offer price caps, and scarcity and shortage pricing in energy and ancillary services markets operated by RTOs/ISOs. In advance of the workshop, FERC staff posted on October 21 two reports, one on shortage pricing in RTO/ISO markets (http://www.ferc.gov/legal/staff-reports/2014/AD14-14-pricingrto-iso-markets.pdf), the other on energy offer mitigation in RTO/ISO markets (http://www.ferc.gov/legal/staff-reports/2014/AD14-14-mitigation-rto-iso-markets.pdf).

Dec 9 Workshop. The third and final workshop was held on December 9. The December 9 workshop focused on RTO/ISO operator actions that affect price. New England speakers included, among others, Joel Gordon, Tom Kaslow, David Patton, Pete Brandein, and Matt White. Speaker materials are posted in the FERC's eLibrary.

Post-Technical Workshop Comments. On January 16, the FERC invited all interested to file post-technical workshop comments on any or all of the 12 questions listed in the attachment to its January 16 Notice, with any such comments due on or before February 19. A 15-day extension of time to file such comments, to and including March 6, was jointly requested by APPA, EPSA and NRECA. CAISO, NYISO, PJM and SPP jointly filed a motion supporting the trade associations' request. On February 3, ISO-NE also asked for an extension of time, but only with respect to questions 5-12, but to and including March 20, 2015. The requests are pending before the FERC.

The FERC web page for this issue is at http://www.ferc.gov/industries/electric/indus-act/rto/energy-price-formation.asp.

- **RTO/ISO Winter 2013/14 Operations and Market Performance (AD14-8)**

On November 20, the FERC issued an order directing RTOs/ISOs to file reports on or before February 18, 2015, on the status of their efforts to address fuel assurance issues.[123] While the FERC noted that it "could take action to impose solutions, and may need to in the future if the steps RTOs/ISOs have taken or plan to take prove inadequate, [it found] that the appropriate next step is for each RTO/ISO to provide the [FERC] with additional information to explain how its market rules address fuel assurance challenges."[124] Since the last Report, INGAA submitted comments related to the November 20 order.

- **NOPR: MBR Authorization Refinements (RM14-14)**

On June 19, the FERC issued a NOPR proposing to revise its current standards, and to streamline certain aspects of its filing requirements, for obtaining market-based rates ("MBR") for sales of electric energy, capacity, and ancillary services.[125] In addition, the FERC clarified certain standards for obtaining and retaining MBR authority. Among other changes, the FERC proposes (i) to permit sellers in RTO/ISO markets with Commission-approved market monitoring and mitigation to include a statement that they are relying on such mitigation to address any potential horizontal market power concerns in lieu of submitting the indicative screens; (ii) to permit sellers to explain that their qualified capacity is fully committed in lieu of including indicative screens in their filings in order to satisfy the FERC's horizontal market power tests and to submit a change in status filing when there is a net increase of 100 MW or more; (iii) to relieve sellers of their obligation to file quarterly land acquisition reports and of the obligation to provide information on sites for generation capacity development in market-based rate applications and triennial updated market power analyses; (iv) to require a change in status filing if there is a 100 MW increase in cumulative nameplate capacity added in any relevant geographic market; and (v) require corporate org charts with all MBR applications and notices of change in status. Comments on this NOPR were due September 23, 2014.[126] Over 25 parties filed comments and Berkshire Hathaway, Barrick Mines, and EPSA filed reply comments. This NOPR is pending before the FERC.

- **NOPR: Open Access and Priority Rights on ICIF (RM14-11)**

On May 15, the FERC issued a NOPR proposing to waive the Open Access Transmission Tariff ("OATT") requirements of 18 CFR 35.28 (2013), the Open Access Same-Time Information System ("OASIS") requirements of Part 37 of its regulations, 18 CFR 37 (2013), and the Standards of Conduct requirements of Part 358 of its regulations, 18 CFR 358 (2013), for any public utility that is subject to such requirements solely because it owns, controls, or operates Interconnection Customer's Interconnection Facilities ("ICIF"),[127] in whole or in part, and sells electric energy from its Generating Facility. The Commission also proposes to find that requiring the filing of an OATT is not necessary to prevent unjust or unreasonable rates or unduly discriminatory behavior with respect to ICIF over which interconnection and transmission services can be ordered. The NOPR also proposes a 5-year safe harbor period during which an ICIF owner subject to the blanket waiver, who initially

[123] *Winter 2013-2014 Operations and Market Performance in Regional Transmission Organizations and Independent System Operators*, 149 FERC ¶ 61,145 (Nov. 20, 2014). The FERC explained that "fuel assurance" describes "the broad set of issues that have emerged in the RTOs/ISOs with respect to generator access to sufficient fuel supplies and the firmness of generator fuel arrangements. Fuel assurance is a broad concept that includes a range of generator-specific and system-wide issues, including the overall ability of an RTO's/ISO's portfolio of resources to access sufficient fuel to meet system needs and maintain reliability." Fuel assurance may also "encompass impacts on fuel availability of any industry in the supply chain, including contingencies and other risks stemming from those industries."

[124] *Id.* at P 19.

[125] *Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Elec. Energy, Capacity and Ancillary Srvcs. by Public Utils.*, 147 FERC ¶ 61,232 (June 19, 2014) ("*MBR NOPR*").

[126] The *MBR NOPR* was published in the *Fed. Reg.* on July 25, 2014 (Vol. 79, No. 143) pp. 43,536-43,572.

[127] ICIF is the term used by the FERC in the NOPR to refer to "generator tie lines".

has excess capacity on its ICIF because it intends to serve its own or its affiliates' future phased generator additions or expansions, may establish a rebuttable presumption for priority right over third parties to use that excess capacity. Comments on this NOPR were due on or before July 29, 2014.[128] Comments were submitted by over 20 parties, including: APPA, AWEA, EEI, EPSA, First Wind, NextEra, NRECA, and NRG. The MISO Transmission Owners filed comments replying to the comments of MISO and the ITC Companies. This NOPR is pending before the FERC.

- **WIRES Request for Policy Statement on ROE for Electric Transmission (RM13-18)**

On June 26, 2013, WIRES[129] petitioned the FERC to institute an expedited generic proceeding and to provide such policy and clarifications as necessary to provide "greater stability and predictability regarding regulated rates of return on equity for existing and future investments in high voltage electric transmission infrastructure." Specifically, WIRES recommended a new policy that (1) standardizes selection of proxy groups; (2) denies complainants a hearing on rates of return for existing facilities unless it is shown that existing returns are at the extremes of the zone of reasonableness; (3) allows consideration of competing infrastructure investments of other industries; (4) permits use of other rate of return methodologies; and (5) supports use of more forward-looking data and modeling. In addition, WIRES urged the FERC to support consideration of a project's actual and anticipated benefits when a complaint is filed against the ROE for an existing project. Although the WIRES petition has not been noticed for public comments, more than 16 sets of comments have been filed. On October 3, 2013, WIRES submitted a summary of the comments and analysis filed to that point in the proceeding. On October 16, the Organization of PJM States noted its position that the WIRES petition did not present a compelling reason for the FERC to initiate a generic rulemaking proceeding or abandon its Discounted Cash Flow methodology. On November 5, 2013, a letter from US Senator Angus King, urging the FERC to establish a more certain regulatory environment that provide investors the level of confidence necessary to support and encourage needed infrastructure investments, was posted in eLibrary. This matter is pending before the FERC.

- ***Order 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, *Order 771*,[130] issued December 20, 2012, granted the FERC access, on a non-public and ongoing basis, to the complete electronic tags ("e-Tags") used to schedule the transmission of electric power interchange transactions in wholesale markets. *Order 771* requires e-Tag Authors (through their Agent Service) and Balancing Authorities (through their Authority Service) to take steps to ensure FERC access to the e-Tags covered by this Rule by designating the FERC as an addressee on the e-Tags. The FERC stated that the information made available under this Final Rule will bolster its market surveillance and analysis efforts by helping it detect and prevent market manipulation and anti-competitive behavior. In addition, *Order 771* requires e-Tag information be made available to RTO/ISOs and their Market Monitoring Units, upon request to e-Tag Authors and Authority Services, subject to appropriate confidentiality restrictions. *Order 771* became effective February 26, 2013.[131] 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*.[132] *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

[128] The NOPR was published in the *Fed. Reg.* on May 30, 2014 (Vol. 79, No. 104) pp. 31,061-31,072.

[129] WIRES, the **W**orking group for **I**nvestment in **R**eliable and Economic **E**lectric **S**ystems, describes itself as a national non-profit association of investor-, member-, and publicly-owned entities dedicated to promoting investment in a strong, well-planned, and environmentally beneficial high voltage electric transmission grid. Information about its principles and members is available on its website www.wiresgroup.com.

[130] *Availability of E-Tag Info. to Comm'n Staff*, Order No. 771, 141 FERC ¶ 61,235 (Dec. 20, 2012) ("*Order 771*"), *order on reh'g and clarification*, 142 FERC ¶ 61,181 (2013).

[131] *Order 771* was published in the *Fed. Reg.* on Dec. 28, 2012 (Vol. 77, No. 249) pp. 76,367-76,380.

[132] *Availability of E-Tag Info. to Comm'n Staff*, Order No. 771-A, 142 FERC ¶ 61,181 (Mar. 8, 2013) ("*Order 771-A*").

in a timely manner to the e-Tags covered by *Order 771*.[133] 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 676-H*: Incorporation of WEQ Version 003 Standards (RM05-5)**

On September 18, 2014, the FERC issued *Order 676-H*,[134] which proposes to amend FERC regulations by incorporating by reference, with certain enumerated exceptions, ***Version 003*** of the Standards for Business Practices and Communication Protocols for Public Utilities adopted by the Wholesale Electric Quadrant ("WEQ") of the North American Energy Standards Board ("NAESB"). The Version 003 Standards update earlier versions of these standards previously incorporated by reference into FERC regulations at 18 CFR 38.2. The Version 003 standards include modifications to support Order Nos. 890, 890-A, 890-B and 890-C, including the standards to support Network Integration Transmission Service on an 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* and the recent Smart Grid Standards. Order 676-H will become effective October 24, 2014.[135] Requests for rehearing of Order *676-H* were filed by EPSA and the NYISO on October 20, 2014. On November 19, the FERC issued a tolling order affording it additional time to consider the rehearing requests, which remain pending before the FERC.

Compliance Deadlines Extended. On January 15, the FERC extended for all entities subject to these requirements the deadline for compliance with the Version 003 business practice standards, with the exception of the OASIS template (for which compliance is required by March 24, 2016), to and including May 15, 2015. All other compliance obligations set forth in *Order 676-H* remain in force.

---

[133] *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.

[134] *Standards for Bus. Practices and Communication Protocols for Pub. Utils.*, Order No. 676-H, 148 FERC ¶ 61,205 (Sep. 18, 2014) ("*Order 676-H*").

[135] *Order 676-H* was published in the *Fed. Reg.* on Sep. 24, 2014 (Vol. 79, No. 185) pp. 56,939-56,955.

XIII. Natural Gas Proceedings

For further information on any of the natural gas proceedings, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com), Jennifer Galiette (860-275-0338; jgaliette@daypitney.com) or Jamie Blackburn (202-218-3905; jblackburn@daypitney.com).

- **Inquiry Into Natural Gas Trading, and Proposal to Establish an Electronic Information and Trading Platform (AD14-19)**

On September 18, 2014, Commissioner Moeller convened a meeting to discuss issues related to how transactions are conducted on the natural gas system and potential transactional improvements to address the needs of electric generators for natural gas. The meeting included representatives/speakers from various sectors of the natural gas and electric industries (load, suppliers, marketers, exchanges, gas associations, and ISOs) and environmental interests. Representatives from NYISO and PJM were among the speakers on the electric side (ISO-NE was not present). A summary of that meeting is posted on the Litigation Updates & Reports webpage (http://nepool.com/uploads/Lit_Supp_AD14-19_20140918_Mtg_Summary.pdf). Written comments on issues discussed at the meeting, limited to 5 pages, were due on or before October 1, 2014. Comments were filed by more than 30 parties. There was no published activity in this proceeding since the last Report.

- **NOPR: Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities (RM14-2)**

On March 20, 2014, the FERC issued a series of orders addressing gas-electric coordination. At the forefront, was this NOPR, in which the FERC proposes to revise its natural gas act regulations in order to better coordinate the scheduling of natural gas and electricity markets and to provide additional flexibility to natural gas shippers.[136] Specifically, the NOPR proposes to: (i) start the Gas Day earlier, at 4:00 a.m. Central Clock Time ("CCT")[137] rather than 9:00 a.m., in order to ensure that gas-fired generators are not running short on gas supplies during the morning electric ramp periods; (ii) institute a later start to the first day-ahead gas nomination opportunity (called the Timely Nomination Cycle), from 11:30 a.m. to 1 p.m. The FERC said that because the Timely Nomination Cycle is the most liquid of the gas nomination cycles, this change will allow electric utilities to finalize their scheduling before gas-fired generators must make gas purchase arrangements and submit nomination requests for natural gas transportation service to the pipelines; and (iii) modify the current intraday nomination timeline to provide 4 (rather than 2) intraday nomination cycles in order to provide greater flexibility to all pipeline shippers. The NOPR adds an early morning nomination cycle with a mid-day effective flow time and a new late-afternoon nomination cycle during which firm nominations would have precedence over or be permitted to bump already scheduled interruptible service. Ultimately, the standard cycles will be 8:00 a.m. CCT (bump), 10:30 a.m. CCT (bump), 4:00 p.m. CCT (bump) and 7:00 p.m. CCT (no-bump).

To provide shippers additional flexibility, the NOPR also proposes to: (i) clarify its policy with respect to the "No-Bump" Rule for Pipelines with Enhanced Nomination Services (the ability of a pipeline to permit firm shippers to bump an interruptible shipper's nomination during any enhanced nomination opportunity proposed by the pipeline (beyond the standard nomination opportunities). The FERC indicated that under the revised intraday nomination timelines proposed here, pipelines offering enhanced nomination services should be permitted to bump interruptible shippers at least until the time when the bumping notice under the newly proposed Intra-Day 3 schedule is provided (in the Commission's proposal 6:00 p.m. CCT); and (ii) require Multi-Party Transportation Contracts; and (ii) FERC proposes to require all interstate pipelines to offer multi-party service agreements, providing multiple shippers the flexibility to share interstate pipeline capacity to serve complementary needs in an efficient manner.

---

[136] *Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities*, 146 FERC ¶ 61,201 (Mar. 20, 2014).

[137] CCT, pursuant to the NAESB WGQ standards, reflects daylight savings changes.

Noting that the natural gas and electricity industries are best positioned to work out the details of how changes in scheduling practices can most efficiently be made and implemented, consistent with the policies discussed in the NOPR, the FERC provided the industries 6 months to reach consensus on standards, consistent with FERC's guidance in the NOPR, including any revisions or modifications to the proposals provided herein. Comments were due November 28, 2014.[138] The FERC also noted its expectation that the electric industry (particularly the ISO/RTOs) would participate in these efforts to help ensure that the resulting consensus reasonably accommodates the interests of both industries.

On September 29, NAESB submitted a status report and record of its activities in response to Gas-Electric Scheduling Coordination NOPR. In that report, NAESB identified the modifications to the NAESB Wholesale Gas Quadrant (WGQ) Business Practice Standards specific to the NOPR. The modified NAESB WGQ Business Practice Standards propose revisions to the nomination timeline that result in three intra-day nomination cycles in addition to the timely and evening nomination cycles. The nomination cycles are not dependent upon a specific start time to the gas day and are implementable with whichever time the FERC chooses as a start of the gas day. Comments on the NAESB status report were due on or before November 28, 2014 and were filed by over 80 parties, including, among others, by ISO-NE, the ISO/RTO Council, NESCOE, Calpine, Direct, Dominion, EEI, EPSA, Essential Power, Exelon, and the New England LDCs. This matter is pending before the FERC.

On December 12, 2014, the FERC issued a data request to ISO-NE (along with other ISOs) related to the Commission's proposal to move the start of the gas day. Specifically, the FERC asked ISO-NE a series of questions regarding the frequency and timing of generators' exhausting their daily nomination of natural gas transportation service prior to the end of the gas day during 2013 and 2014. The ISO the ISO/RTO Council requested an extension of time, to and including January 22, for the RTO/ISO responses to the December 12 data requests., which the FERC granted.

On January 22, 2015, ISO-NE submitted its response to the data request.[139] The ISO stated that moving the gas day will "help minimize the risks of generators running out of gas during the morning ramp," but also stressed that it had already taken a number of actions to alleviate these issues. The ISO also acknowledged that it needs its generating resource owners and other entities to invest in firm fuel supplies and transportation and to maintain on-site fuel inventory and dual fuel capability. On February 2, comments in response to the ISO/RTO data responses were filed by four parties: the Coalition for Enhanced Electric and Gas Reliability, the Natural Gas Council, the New England Local Distribution Companies ("LDCs"), and the American Public Gas Association ("APGA").

- **NOI: Enhanced Natural Gas Market Transparency (RM13-1)**

On July 9, 2014, the FERC issued a notice that, in order to assess better whether the reporting requirement described in the NOI would enhance natural gas transparency, the FERC will seek additional information from certain natural gas marketers regarding what portion of their total natural gas sales are jurisdictional natural gas sales. To obtain that information, OE will send data requests to certain natural gas marketers who, in turn, will have 15 days to respond. The FERC indicated that, after those responses are received, it will consider what, if any, further action in this docket will be necessary and/or appropriate. As previously reported, in a November 15, 2012 NOI, the FERC sought 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") to improve natural gas market transparency. Comments in response to the NOI were received from over 30 parties.

- **Posting of Offers to Purchase Capacity (Section 5 Proceeding) (RP14-442)**

Similar to the ISO/RTO 206 Order in EL14-22 et al. (*see* Section I above), the FERC also instituted a proceeding under Section 5 of the Natural Gas Act to examine whether interstate natural gas pipelines are providing notice of offers to purchase released pipeline capacity in accordance with section 284.8(d) of the

[138] The NOPR was published in the *Fed. Reg.* on Apr. 1, 2014 (Vol. 79, No. 62) pp. 18,223-18,243.

[139] Responses to the data request were also submitted by NYISO, MISO, PJM and SPP.

Commission's regulations.[140] On or before May 19, natural gas pipelines were required to either revise their respective tariffs to provide for the posting of offers to purchase released capacity, or otherwise demonstrate that they are in full compliance with FERC regulations.[141] The FERC also requested that NAESB develop business practice and communication standards specifying: (1) the information required for requests to acquire capacity; (2) the methods by which such information is to be exchanged; and (3) the location of the information on a pipeline's website. The Show Cause Order required each pipeline to explain in its compliance filing how it will fully comply with section 284.8(d) until NAESB develops, and the FERC implements, the requested standards, including how the pipeline will provide shippers the ability to post offers to purchase capacity on the Informational Posting section of its Internet website.

In total, the FERC received, and addressed in one omnibus order, 157 compliance filings.[142] Of the 157 filings, 64 pipelines revised their respective tariffs to provide for the posting of offers to purchase released capacity in a manner that complies with section 284.8(d), and 23 pipelines demonstrated that their tariffs already comply with that section. The FERC found that, and identified in its omnibus order on the compliance filings the, 69 compliance filings that did not appear to be in full compliance with that section, and directed further compliance filings from those companies as described in the omnibus order.

- **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. Since the last Report, there was a great deal of activity in the following on-going, gas-related enforcement proceeding:

Company	***Alleged Violation(s)***	***Civil Penalty/Disgorgement***
BP America Inc. BP Corp. N. Amer. BP Amer. Production BP Energy Co. (together, "BP") (IN13-15)	The FERC established a hearing to determine whether BP violated section 4A of the Natural Gas Act and the FERC's Anti-Manipulation Rule as alleged by OE Staff. OE Staff alleged that BP traded physical natural gas at Houston Ship Channel ("HSC") to increase the value of BP's financial position at HSC, uneconomically using BP's transportation capacity, making repeated early uneconomic sales at HSC, taking steps to increase BP's market concentration at HSC. In doing so, OE staff alleged, BP suppressed the HSC Gas Daily index with the goal of increasing the value of BP's financial position at HSC. The activity occurred from mid-September 2008 through November 2008.	Show Cause Order[143] $28 million (civil penalty) $800,000 (disgorgement)

[140] *Posting of Offers to Purchase Capacity*, 146 FERC ¶ 61,203 (Mar. 20, 2014).

[141] *Id.* at P 6.

[142] *See BR Pipeline Co. et al.*, 149 FERC ¶ 61,031 (Oct. 16, 2014).

[143] *BP America Inc. et al.*, 144 FERC ¶ 61,100 (Aug. 5, 2013).

On October 29, BP and Enforcement Staff agreed to a modified procedural schedule for the hearing procedures underway. Pursuant to that schedule, hearings before Judge Cintron will begin March 30, 2015, with an Initial Decision due August 14, 2015.

- **New England Pipeline Proceedings**

  The following New England pipeline projects are pending before the FERC:

  - ***Algonquin Incremental Market Project (AIM Project) (CP14-96)***
    - Algonquin Gas Transmission filed for Section 7(b) and 7(c) certificate Feb. 28, 2014
    - 342,000 dekatherms/day of firm capacity to NY, CT, RI and MA.
    - 37.6 miles of take-up, loop and lateral pipeline facilities in NY, CT, and MA and system modifications in NY, CT and RI. The system upgrades would also require the removal of some facilities.
    - 10 firm shippers: Yankee Gas, NSTAR, Connecticut Natural Gas, Southern Connecticut, Narragansett Electric, Colonial Gas, Boston Gas, Bay State, Norwich Public Utilities, and Middleborough Gas and Electric (eight LDCs and two municipal utilities).
    - Final EIS issued on Jan 23, 2015.
    - 90-day Federal Authorization Decision Deadline April 23, 2015.
    - In-service: Nov 2016 (anticipated).

  - ***Connecticut Expansion Project (CP14-529)***
    - Tennessee Gas Pipeline filed for Section 7(c) certificate July 31, 2014
    - 72,100 dekatherms/day of firm capacity.
    - 13.26 miles of three looping segments and facility upgrades/modifications in NY, MA and CT.
    - Three firm shippers: Connecticut Natural Gas, Southern Connecticut Gas, and Yankee Gas.
    - Authorization requested by July 31, 2015.
    - Construction expected to begin Winter 2015/2016.
    - In-service: Nov 2016 (anticipated).

  - ***Constitution Pipeline (CP13-499) and Wright Interconnection Project (CP13-502)***
    - Constitution Pipeline Company and Iroquois Gas Transmission (Wright Interconnection) concurrently filed for Section 7(c) certificates on June 13, 2013.
    - 650,000 dekatherms/day of firm capacity from Susquehanna County, PA through NY to Iroquois/Tennessee interconnection (Wright Interconnection).
    - New 122-mile interstate pipeline.
    - Two firm shippers: Cabot Oil & Gas and Southwestern Energy Services.
    - Final EIS completed on Oct 24, 2014
    - Certificates granted Dec 2, 2014 (must be constructed and in service within 24 months);
    - Construction expected to begin Feb 2015.

  - ***Salem Lateral Project (CP14-522)***
    - Algonquin Gas Transmission filed application Jul 10, 2013.
    - 115,000 dekatherms/day of firm capacity.
    - 1.2 miles of pipeline to 630 MW Salem Harbor Station and other Salem, MA facilities.
    - Footprint Power sole firm customer.
    - Authorization requested by Apr 17, 2015.
    - FERC environmental assessment issued Dec 2, 2014.

- In-Service: Nov 2015 (anticipated).

XIV. State Proceedings & Federal Legislative Proceedings

No Activity to Report.

XV. Federal Courts

The following are matters of interest, including petitions for review of FERC decisions in NEPOOL-related proceedings, that are currently pending before the federal courts (unless otherwise noted, the cases are before the U.S. Court of Appeals for the District of Columbia Circuit). 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).

- **FCA8 Results (14-1244, 14-1246 (consolidated))**
  Underlying FERC Proceedings: ER14-1409[144]
  Appellants: Public Citizen and CT AG

On November 14, 2014, Public Citizen and the CT AG filed petitions for review of the FERC's action on the FCA8 Results Filing, which became effective by operation of law on September 16, 2014. These proceedings have been consolidated. A Docketing Statement Form and Statement of Issues to be Raised were filed by Petitioners by December 22, 2014. On January 2, 2015, the FERC filed a motion to dismiss the petitions for lack of jurisdiction. The FERC argued that the Court lacks jurisdiction because Petitioners did not challenge a FERC "order" within the meaning of section 313 of the FPA, or "agency action" reviewable under the Administrative Procedures Act. On January 15, EPSA and NEPGA jointly filed a motion supporting the FERC's motion to dismiss. On January 26, Connecticut[145] and Public Citizen opposed the FERC's motion to dismiss.

In a related development, members of the New England Congressional delegation sent a January 30 letter to the five FERC Commissioners asking that they re-examine the issue of the just and reasonableness of the rates produced by FCA8.

- ***2013/14* Winter *Reliability Program* (14-1104, 14-1105, 14-1103 (consolidated))**
  Underlying FERC Proceedings: ER13-1851[146] **and ER13-2266**[147]
  Appellants: TransCanada and RESA

On June 6, 2014, TransCanada and the Retail Energy Supply Association filed petitions for review of the FERC's orders on the 2013/14 Winter Reliability Program (14-1104 and 14-1105, respectively). Also on June 6, 2014, TransCanada filed a petition for review of FERC's orders on the 2013/14 Winter Reliability Program Bid Results Filings (ER14-1103). On July 3, 2014, these proceedings were consolidated. On July 7, the FERC requested a minimum of 60 days after Petitioners' opening briefs to file its brief. On July 23, leave to intervene was granted to ISO-NE, NEPGA, PSEG and Essential Power. On September 29, TransCanada, RESA, FERC, ISO-NE, Essential Power MA, PSEG and NEPGA filed a proposed joint, unopposed briefing format and schedule. A Joint Brief for Petitioners was filed on November 24 (as corrected on December 1). At the FERC's request, the Court ordered that a revised briefing schedule be applied in this case (effectively extending the overall briefing schedule by one month. Accordingly, Respondent Brief is due next, on February 13, 2015; Joint Brief

[144] Notice of Filing Taking Effect by Operation of Law, *ISO New England Inc.*, Docket No. ER14-1409 (Sep. 16, 2014); Notice of Dismissal of Pleadings, *ISO New England Inc.*, Docket No. ER14-1409 (Oct. 24, 2014).

[145] For purposes of this proceeding, "Connecticut" means the CT AG, CT PURA and CT OCC.

[146] 144 FERC ¶ 61,204 (Sep. 16, 2013); 147 FERC ¶ 61,026 (Apr. 8, 2014).

[147] 145 FERC ¶ 61,023 (Oct. 7, 2013); 147 FERC ¶ 61,027 (Apr. 8, 2014).

for Respondent-Intervenors, March 2, 2015; Joint Reply Brief for Petitioners, March 25, 2015; Deferred Appendix, April 1, 2015; and Final Briefs, April 15, 2015.

- ***Orders 773* and *773-A* (2nd Cir., 13-2316)**
  Underlying FERC Proceedings: RM12-6 and RM12-7[148]
  Appellants: NY PSC and People of the State of New York

The NY PSC and the People of the State of New York have petitioned the Second Circuit Court of Appeals for review of FERC's orders on *Orders 773* and *773-A* (Revised "Bulk Electric System" Definition and Procedures). Briefs were filed as follows: NYPSC/State of NY (May 2, 2014); NARUC (May 28); FERC (August 22); NERC (August 27); NERC reply brief (September 10, 2014); FERC and NY/NY PSC final briefs (September 24); NERC and NARUC intervenor briefs. Oral argument was held on November 20, 2014 and this matter is pending before the Court.

- **New England's Order *745* Compliance Filing (12-1306)**
  Underlying FERC Proceedings: ER11-4336[149]
  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 Court granted the motion to hold the case in abeyance. Motions to govern future proceedings will be due 30 days following the issuance of the mandate in the *Order 745* appeal.

- **Orders 745 and 745-A (11-1486 consolidated with 11-1489, 12-1088, 12-1091 and 12-1093)**
  Underlying FERC Proceedings: RM10-17-000[150]
  Appellants: EPSA, CAISO, ODEC, EEI, CA PUC

As previously reported, the DC Circuit vacated *Order 745*[151] in its entirety as impermissibly encroaching on "states' exclusive jurisdiction to regulate the retail market" in a 2-1 decision ("Decision") issued on May 23, 2014. The DC Circuit vacated *Order 745* on two separate and independent grounds. First, it held that the FERC does not have jurisdiction to regulate demand response. The Court reasoned that: (i) the states retain exclusive authority to regulate the retail market; (ii) absent an express statutory grant of authority, the FERC cannot regulate areas left to the states; (iii) the FPA provides the FERC with authority over wholesale sales of electricity, but demand response is not such a sale; (iv) the authority of the FERC to regulate wholesale power rates under the FPA cannot be read so broadly as to allow direct regulation of demand response; and (v) demand response, while not necessarily a retail sale, is part of the retail market, involving retail customers, their decision whether to purchase at retail, and the levels of retail electricity consumption. Therefore, the Court concluded, the FERC has no authority to directly regulate demand response. "FERC's authority over demand response resources is limited: its role is to assist and advise state and regional programs."

As an alternative and secondary basis for its decision against *Order 745*, the Court concluded that the FERC order was "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law." The Court found that the FERC failed to reasonably consider and address arguments that *Order 745* will result in over-compensation of demand response resources, resulting in unjust and discriminatory rates. The Court further found that the FERC failed to demonstrate how its proposed pricing construct would result in just

[148] 141 FERC ¶ 61,236 (Dec. 20, 2012); 143 FERC ¶ 61,053 (Apr. 18, 2013).

[149] 138 FERC ¶ 61,042 (Jan. 19, 2012); 139 FERC ¶ 61,116 (May 17, 2012).

[150] 134 FERC ¶ 61,187 (Mar. 15, 2011); 137 FERC ¶ 61,215 (Dec. 15, 2011).

[151] *Order 745* required RTOs and ISOs to include provisions in their tariffs that assured demand response would be paid at LMP for interrupting their loads when such interruption was cost effective.

compensation. The Decision and preliminary implications of the Decision were summarized in more detail in the memo included with the supplemental materials circulated and posted for the June 6 meeting.

On July 7, the FERC petitioned the Court for rehearing *en banc* of the May 23 Decision. On July 18, the Court, on its own motion, directed EPSA, APPA, NRECA, Old Dominion and EEI ("Petitioners") to file a joint response to the FERC petition for rehearing. That response was filed on August 4, 2014. The petition for rehearing *en banc* was denied on September 17, 2014.

On September 22, the FERC and a group of intervenors[152] filed motions to stay the issuance of the mandate for at least a 90-day period, to accommodate the time during which they may file a petition for a writ of certiorari in the Supreme Court of the United States. On September 30, Petitioners filed a motion opposing the request for stay. On October 20, 2014, the Court granted the FERC's motion to stay issuance of the mandate. As previously reported, the DC Circuit directed its clerk to withhold the mandate through January 15, 2015, and, as earlier directed, if a petition for writ of certiorari is filed, to withhold issuance of the mandate pending the Supreme Court's final disposition. On January 15, the Solicitor General of the United States, on behalf of the FERC, filed with the Supreme Court a petition for a writ of certiorari seeking review of the District Court's May 23 Decision. Responses to that write are due on or before February 7 and the issuance of the mandate will be withheld for the time being.

- **CPV Maryland, LLC v. PPL EnergyPlus et al. (Supreme Court, 14-623)**

A petition for a writ of certiorari in this case was filed on November 26, 2014 and placed on the Supreme Court's docket on November 28, 2014 as No. 14-623. The parties consented to the filing of amicus curiae briefs, and such briefs were filed by NARUC, the State of Connecticut, and APPA. Responses are now due on or before February 11, 2015.

As previously reported, on June 2, 2014, the 4th Circuit Court of Appeals affirmed the September 30, 2013 decision of the United States District Court for the District of Maryland[153] which found that a Maryland Public Service Commission ("MD PSC") order directing three Maryland distribution utilities to enter into a 'contract for differences' for capacity and energy in the PJM control area (the "CfD") with a gas-fired merchant generator selected by the MD PSC (the "MD PSC Order") violated the Supremacy Clause of the United States Constitution and cannot be enforced.[154] In affirming the District Court decision, the 4th Circuit found the MD PSC Order both field[155] and conflict pre-empted.[156]

---

[152] Intervenors include: Coalition of MISO Transmission Customers; PJM Industrial Customer Coalition; EnerNOC, Inc.; Viridity Energy, Inc.; American Forest & Paper Association; EnergyConnect, Inc.; Wal-Mart Stores, Inc.; and Steel Producers.

[153] *PPL EnergyPlus, LLC v. Nazarian*, 974 F.Supp. 2d 790 (D. Md. Sep. 30, 2013); 2013 U.S. Dist. LEXIS 140210, 2013 WL 5432346 ("*District Court Decision*"). The *District Court Decision* was summarized in past Litigation Reports.

[154] *PPL EnergyPlus, LLC v. Nazarian*, 753 F.3d 467; 2014 U.S. App. LEXIS 10155.

[155] "Field preemption" is a doctrine based on the Supremacy Clause of the U.S. Constitution that holds that any federal law, including regulations of a federal agency, takes precedence over any conflicting state law. Preemption can be implied when federal law/regulation "occupies the field" in which the state is attempting to act/regulate. Field preemption occurs when there is "no room" left for state regulation. Accordingly, a state may not pass a law or take any action in a field, like the regulation of wholesale power sales, pervasively regulated by federal law/regulation.

[156] "Conflict preemption" occurs where there is a conflict between a state law and a federal law. ("[E]ven if Congress has not occupied the field, state law is naturally preempted to the extent of any conflict with a federal statute."). Such a conflict occurs when "the challenged state law stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress. The court must look to "'the entire scheme of the statute'" and determine "'[i]f the purpose of the [federal] act cannot otherwise be accomplished--if its operation with its chosen field [would] be frustrated and its provisions be refused their natural effect. Where a state law conflicts with a federal law, the Court does not balance the competing federal and state interests. Any state law, however clearly within a State's acknowledged power, which interferes with or is contrary to federal law, must yield."

With respect to field pre-emption, the 4th Circuit stated that a "wealth of case law confirms FERC's exclusive power to regulate wholesale sales of energy in interstate commerce, including the justness and reasonableness of the rates charged."[157] It found the federal scheme (i.e. the PJM Market) "carefully calibrated to protect a host of competing interests" (representing "a comprehensive program of regulation that is quite sensitive to external tampering"),[158] and leaving "no room either for direct state regulation of the prices of interstate wholesales of [energy], or for state regulations which would indirectly achieve the same result." Accordingly, the 4th Circuit concluded that the MD PSC Order "field preempted because it functionally sets the rate that CPV receives for its sales in the PJM auction."[159] The MD PSC Order "compromises the integrity of the federal scheme and intrudes on FERC's jurisdiction" because the MD PSC Order "effectively supplants the rate generated by the auction with an alternative rate preferred by the state." The 4th Circuit rejected arguments that the CfD payments "represented a separate supply-side subsidy implemented entirely outside the federal market."[160] And, even if the presumption against preemption were to apply, the Court found that that it was "overcome by the text and structure of the FPA, which unambiguously apportions control over wholesale rates to FERC."[161]

With respect to conflict pre-emption, the 4th Circuit found that the MD PSC Order "presents a direct and transparent impediment to the functioning of the PJM markets, and is therefore preempted".[162] Preemption was appropriate because of the "extensive and disruptive" impact of the MD PSC Order on matters within federal control (the PJM markets). It found that the MD PSC Order had "the potential to seriously distort the PJM's auction's price signals, thus 'interfer[ing] with the method by which the federal statute (i.e. the PJM Markets) was designed to reach its goals."[163] "Maryland's initiative disrupts [the PJM scheme] by substituting the state's preferred incentive structure for that approved by FERC."[164] "Maryland has sought to achieve through the backdoor of its own regulatory process what it could not achieve through the front door of FERC proceedings. Circumventing and displacing federal rules in this fashion is not permissible."[165]

Petitions for rehearing *en banc* were filed by MD PSC and CPV Maryland on June 16, 2014. On June 17, 2014, the 4th Circuit stayed the mandate pending the *en banc* ruling on the Petitions. On June 30, 2014, the 4th Circuit denied the petitions for rehearing *en banc*.

- **CPV Power Development, Inc., et al. v. PPL EnergyPlus, LLC, et al. (Supreme Court, 14-634, 14-694)**

Petitions for a writ of certiorari in this case were filed on November 26, 2014 and December 10, 2014 and placed on the Supreme Court's docket as case nos. 14-634 and 14-694, respectively. Responses are now due on or before February 11, 2015. The parties consented to the filing of amicus curiae briefs, and such briefs were filed by NARUC, the State of Connecticut, APPA, AWEA, and the NY PSC.

---

157 Slip op. at p. 14.

158 *Id.* at p. 10.

159 *Id.* at p. 16.

160 *Id.* at pp. 18-19.

161 *Id.* at p. 20. The Court noted the limited scope of its holding, which "is addressed to the specific program at issue" and did not "express an opinion on other state efforts to encourage new generation." *Id.* at p. 21.

162 *Id.* at p. 27.

163 *Id*. at p. 23.

164 *Id.* at p. 24. ("Two features of the Order render its likely effect on federal markets particularly problematic. First, as noted, the CfDs are structured to actually set the price received at wholesale. They therefore directly conflict with the auction rates approved by FERC. Second, the duration of the subsidy -- twenty years -- is substantial.")

165 *Id.* at p. 25.

As previously reported, on September 11, 2014, the 3rd Circuit Court of Appeals affirmed[166] the analogous October 11, 2013 decision of the United States District Court for the District of New Jersey declaring unconstitutional (and therefore null and void) New Jersey's Long Term Capacity Agreement Pilot Program Act ("LCAPP").[167] In affirming the New Jersey District Court's decision, the 3rd Circuit concluded:

> LCAPP compels participants in a federally-regulated marketplace to transact capacity at prices other than the price fixed by the marketplace. By legislating capacity prices, New Jersey has intruded into an area reserved exclusively for the federal government. Accordingly, federal statutory and regulatory law preempts and, thereby, invalidates LCAPP and the Standard Offer Capacity Agreements.[168]

No petition for rehearing or rehearing *en banc* was filed on or before September 25, 2014. Accordingly, the mandate was issued on October 3, 2014. As noted above, petitions for *certiorari* to the U.S. Supreme Court were filed and are pending before the Supreme Court.

- **Allco Finance Limited v. Klee, (D. CT - 3:13cv1874 (JBA))**

On December 10, the United States District Court for the District of Connecticut upheld the constitutionality of Section 6 of Connecticut Public Act 13-303 ("Section 6"), which gives the Commissioner of CT DEEP the authority to solicit proposals for renewable power and to compel CL&P and UI to enter into wholesale power purchase agreements ("PPAs") for energy and/or RECs for a term of up to 20 years, serving up to 4% of Connecticut's electricity needs.[169]

By way of background, Allco submitted proposals pursuant to CT DEEP's July 2013 solicitation under Section 6, but its proposals were not selected (two other projects were). Allco challenged CT DEEP's application of Section 6 because it asserted DEEP's application was not in accordance with PURPA; because DEEP hadn't demonstrated that the PPAs represented CL&P/UIs' avoided costs, DEEP's application of Section 6 was therefore in conflict the Federal Power Act.

Ultimately, the Connecticut District Court determined that Allco's claim failed for a number of reasons. First, Allco lacked standing, having not established that it had suffered a legally protected injury within the zone of interest protected by the FPA, or that a favorable decision would redress any possible injury. Allco's claim also failed on the merits, the Court held, because the Court found that Section 6 does not seek to regulate wholesale rates, and "is consistent with the 'broad powers' of the states 'to direct the planning and resource decisions of utilities under their jurisdiction."[170] This decision is noteworthy given the outcomes in the Maryland and New Jersey CfD cases.

---

[166] *PPL EnergyPlus, LLC v. Hanna*, 977 F.Supp.2d 372 (D. NJ. Oct. 11, 2013); 2013 U.S. Dist. LEXIS 147273, ("*NJ Order*").

[167] *PPL EnergyPlus, LLC v. Hanna*, 766 F.3d 241; 2014 U.S. App. LEXIS 17557 (Sep. 11, 2014).

[168] *Id.* slip op. at 31.

[169] *Allco Finance Limited v. Klee*, No. 3:13cv1874, 2014 U.S. Dist. LEXIS 170674 (D. Conn. Dec. 10, 2014) ("*Allco*").

[170] *Id.* at *25 (quoting *Entergy Nuclear Vermont Yankee, LLC v. Shumlin*, 733 F.3d 393, 417).

INDEX
Status Report of Current Regulatory and Legal Proceedings
as of February 5, 2015

I. Complaints

206 Investigation: Consistency of ISO-NE (DA) Scheduling Practices with Natural Gas Scheduling Practices to be Adopted in Docket RM14-2 .... (EL14-23) 6
206 Investigation: FCM Performance Incentives (Compliance Proceeding)........................ (EL14-52; ER14-2419).......... 5
206 Proceeding: Importers' FCA Offers Review/Mitigation .... (EL14-99; ER15-117)............ 3
Base ROE Complaint (2011).. (EL11-66) 8
Base ROE Complaints (2012 and 2014) (Consolidated) .... (EL13-33 and EL14-86)......... 4
FCM Administrative Pricing Rules Complaint.. (EL14-7) 7
LVA/PSNH IA Complaint.. (EL15-9) 27
NEPGA DR Capacity Complaint .... (EL15-21) 2
NEPGA Peak Energy Rent (PER) Complaint .... (EL15-25) 1
NESCOE FCM Renewables Exemption Complaint.. (EL13-34) 7
New Entry Pricing Rule Complaint.. (EL15-23) 2

II. Rate, ICR, FCA, Cost Recovery Filings

2014/15 Power Year Transmission Rate Supplemental Filing .... (ER09-1532; RT04-2).......... 10
Base ROE Complaint (2011).. (EL11-66) 8
Base ROE Complaints (2012 and 2014) (Consolidated) .... (EL13-33 and EL14-86)......... 4
FCA9 New Import Capacity Resources Qualification Informational Filing .... (ER15-640) 9
FCA9 Qualification Informational Filing .... (ER15-328) 9
ICR-Related Values and HQICCs - 2018/19 Power Year .... (ER15-325) 10
ICR-Related Values and HQICCs - 2015/16 ARA3, 2016/17 ARA2, and 2017/18 ARA1 . (ER15-555) 9
Opinion 531-A Compliance Filing: TOs .... (ER15-414) 9

III. Market Rule and Information Policy Changes, Interpretations and Waiver Requests

206 Investigation: Consistency of ISO-NE (DA) Scheduling Practices with Natural Gas Scheduling Practices to be Adopted in Docket RM14-2 .... (EL14-23) 6
206 Investigation: FCM Performance Incentives (Compliance Proceeding)........................ (EL14-52; ER14-2419).......... 5
206 Proceeding: Importers' FCA Offers Review/Mitigation .... (EL14-99; ER15-117)............ 3
CSO Deferral: ISO Proposal.. (ER14-2440) 11
Demand Curve Changes .... (ER14-1639) 10
Exigent Circumstances Filing – FCM Admin. Pricing Rules .... (ER14-463) 13
FCM Administrative Pricing Rules Complaint.. (EL14-7) 7
FCM Performance Incentives Jump Ball Filing .... (ER14-1050) 13
FCM PI Jump Ball Compliance Filing I .... (ER14-2419-001)................... 5
FCM PI Jump Ball Compliance Filing II .... (ER14-2419-002)................... 5
FCM Redesign Compliance Filing: FCA8 Revisions.. (ER12-953 et al.) 14
Information Policy Clean-Up Changes.. (ER15-600) 11
ISO Response to Show Cause Order .... (ER15-117) 3
NEPGA DR Capacity Complaint .... (EL15-21) 2
NEPGA Peak Energy Rent (PER) Complaint .... (EL15-25) 1
NESCOE FCM Renewables Exemption Complaint.. (EL13-34) 7
New Entry Pricing Rule Complaint.. (EL15-23) 2
ORTP Exemption for Distributed Renewable Technology Resources .... (ER15-716) 10
PRD Reserve Market Changes .... (ER15-257) 11
Winter 2014/15 Reliability Program.. (ER14-2407) 11

IV. OATT Amendments/Coordination Agreements

Order 676-H Compliance: PTOs, SSPs, CSC et al. .... (ER15-517) 15
Order 676-H Compliance: Revisions to Schedule 24.. (ER15-519) 15
Order 1000 Compliance Filing... (ER13-193; ER13-196)........ 16
Order 1000 Interregional Requirements Compliance Filing .... (ER13-1960; ER13-1957).... 15
Order 1000 November 15 Compliance Order Changes.. (ER13-193; ER13-196)........ 16

V. Financial Assurance/Billing Policy Amendments

FAP Minimum Capitalization Requirement Changes .... (ER15-593) 17

VI. Schedule 20/21/22/23 Updates

LGIA – NU/CPV Towantic .... (ER15-200) 18
Opinion 531-A Compliance Filing: CTMEEC .... (ER15-584) 18
Opinion 531-A Compliance Filing: GMP .... (ER15-412) 18

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

Future Winter Reliability Program Progress Reports .... (ER14-2407) 18
LFTR Implementation: 25th Quarterly Status Report .... (ER07-476; RM06-08) 19
Order 755 Regulation Market Progress Report .... (ER12-1643) 19
Quarterly Reports Regarding Non-Generating Resource Regulation Market Participation (ER08-54) 19

IX. Membership Filings

December 2014 Membership Filing .... (ER15-513) 19
February 2015 Membership Filing .... (ER15-937) 19
January 2015 Membership Filing .... (ER15-780) 19
Suspension Notice (Cape Wind Associates, LLC) .... (not docketed) 20
Suspension Notice (Pacific Summit Energy LLC) .... (not docketed) 20

X. Misc. - ERO Rules, Filings; Reliability Standards

FFT Report: January 2015 .... (NP15-19) 20
New Reliability Standard: EOP-011-1 .... (RM15-7) 21
New Reliability Standard: PRC-026-1 .... (RM15-8) 21
New Reliability Standard: TPL-007-1 .... (RM15-11) 21
NOPR: BAL-002-1a Interpretation Remand .... (RM13-6) 26
NOPR: Revised Rel. Standard: BAL-001-2 .... (RM14-10) 23
NOPR: Revised Rel. Standard: COM-001-2 and COM-002-4 .... (RM14-13) 23
NOPR: Revised Rel. Standard: MOD-001-2 .... (RM14-7) 24
NOPR: Revised Rel. Standard: MOD-031-1 .... (RM14-12) 23
NOPR: Revised TOP and IRO Reliability Standards .... (RM13-15, -14, -12) 25
Order 802: New Reliability Standard: CIP-014-1 (Physical Security) .... (RM14-15) 22
Order 803: Revised Rel. Standard: PRC-005-3 .... (RM14-8) 24
Revised Reliability Standard: PRC-002-2 .... (RM15-4) 22
Revised Reliability Standard: PRC-004-3 .... (RD14-14) 20
Revised Reliability Standard: PRC-005-4 .... (RM15-9) 21
Revised Reliability Standard: PRC-006-2 .... (RD15-2) 20

XI. Misc. Regional Interest

203 Application: EquiPower/Dynegy .... (EC14-140) 27
203 Application: First Wind / TerraForm & SunEdison .... (EC15-44) 27
E&P Agreement: CL&P/CPV Towantic .... (ER15-715) 29
E&P Agreement: CMP/Atlantic Wind .... (ER15-589) 29
E&P Agreement Termination: Spruce Mountain Wind .... (ER15-975) 28
E&P Agreement Termination: Record Hill Wind .... (ER15-974) 28
E&P Agreement Termination: Highland Wind .... (ER15-973) 28
E&P Agreement Termination: Patriot Renewables .... (ER15-972) 28
FERC Enforcement Action: Maxim Power and K. Mitton .... (IN15-4) 30
FERC Enforcement Action: Powhatan Energy, HEEP Fund, CU Fund, and H. Chen .... (IN15-3) 31
FERC Enforcement Action: Twin Cities .... (IN15-2) 31
FERC Enforcement Action Pending: Staff Notice of Alleged Violations – City Power and K. Tsingas 32
FirstEnergy PJM DR Complaint .... (EL14-55) 27
HG&E Demarcation Agreement .... (ER15-939) 29

IA – CL&P/Energy Stream (ER15-947) 29
IA - CMP/Kennebec Water District (ER15-757) 29
LSA Termination: Emera/ Black Bear HVGW (ER15-962) 28
LVA/PSNH IA Complaint (EL15-9) 27
MISO Methodology to Involuntarily Allocate Costs to Entities Outside Its Control Area (ER11-1844) 30
Opinion 531-A Compliance Filing: NGrid IFA Amendments (ER15-418) 29

XII. Misc: Administrative & Rulemaking Proceedings

NOPR: MBR Authorization Refinements (RM14-14) 34
NOPR: Open Access and Priority Rights on ICIF (RM14-11) 34
Order 676-H: Incorporation of WEQ Version 003 Standards (RM05-5) 36
Order 771: Availability of E-Tag Information to FERC Staff (RM11-12) 35
Price Formation in RTO/ISO Energy & Ancillary Services Markets (AD14-14) 33
RTO/ISO Common Metrics Report (AD14-15) 33
RTO/ISO Winter 2013/14 Operations and Market Performance (AD14-8) 34
Technical Conferences on Implications of Environmental Regulations (AD15-4) 32
WIRES Request for Policy Statement on ROE for Electric Transmission (RM13-18) 35

XIII. Natural Gas Proceedings

206 Investigation: Consistency of ISO-NE (DA) Scheduling Practices with Natural Gas Scheduling Practices to be Adopted in Docket RM14-2 (EL14-23) 6
Enforcement Actions: BP (IN13-15) 39
Inquiry Into Natural Gas Trading, and Proposal to Establish an Electronic Information and Trading Platform (AD14-19) 37
New England Pipeline Proceedings 40
NOI: Enhanced Natural Gas Market Transparency (RM13-1) 38
NOPR: Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities (RM14-2) 37
Posting of Offers to Purchase Capacity (Section 5 Proceeding) (RP14-442) 38

XIV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XV. Federal Courts

2013/14 Winter Reliability Program and Bid Results 14-1104 (DC Cir.) 41
Allco Finance Limited v. Klee 3:13cv1874 (JBA)(D. CT) 45
CPV Maryland, LLC v. PPL EnergyPlus et al. 14-623 (Supreme Court) 43
CPV Power Development, Inc., et al. v. PPL EnergyPlus, LLC, et al. 14-634/694 (Supreme Ct) 44
FCA8 Results 14-1244 (DC Cir.) 41
New England's *Order 745* Compliance Filing 12-1306 (DC Cir.) 42
Orders 745/745-A 11-1486 (DC Cir.) 42
Orders 773/773-A 13-2316 (2nd Cir.) 42