NEW ENGLAND POWER POOL

David T. Doot
Secretary

November 23, 2016

VIA ELECTRONIC MAIL

TO: MEMBERS AND ALTERNATES OF THE NEPOOL PARTICIPANTS COMMITTEE

RE: Supplemental Notice of December 2, 2016 NEPOOL Participants Committee Annual Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the annual meeting of the NEPOOL Participants Committee will be held on **Friday, December 2, 2016 at 10:00 a.m. at the Colonnade Hotel, 120 Huntington Avenue, Boston, MA. The meeting will be preceded by a Holiday Breakfast beginning at 9:00 a.m. that we hope you will attend**. The Participants Committee meeting will be held in the Huntington Ballroom for the purposes set forth on the attached agenda and posted with the meeting materials at http://nepool.com/NPC_2016.php. You will see from the agenda that both FERC Commissioner Cheryl LaFleur and Ned Bartlett, Massachusetts Undersecretary of Energy and the Environment, will be joining us at the beginning of the meeting. For your information, this meeting is recorded, as are all the Participants Committee meetings.

By way of reminder, the December meeting is the Participants Committee's annual meeting and, if any member wishes to change its Sector for next year, you must provide us with written notice of that request prior to the December 2 meeting. Under Section 6.3 of the current NEPOOL Agreement, any Participant request to change the Sector in which it votes becomes effective at the first annual meeting following that request.

We will hold a New Member Orientation following the meeting for anyone wishing to learn more about the NEPOOL stakeholder process. There are over 30 entities that became NEPOOL members in 2016. Representatives of these new members and anyone else wanting to learn more about the NEPOOL stakeholder process are welcome and encouraged to attend. Please let Cindy Jacobs know if you plan to attend the New Member Orientation so she can ensure sufficient space and copies of materials. Cindy can be reached at ckjacobs@daypitney.com/(860) 275-0246.

Directions to the Colonnade Hotel are included with this notice. Rooms at the Colonnade Hotel for the December 2 meeting are available at the rate of $229.00 per night, on a first-come, first-served basis **UNTIL November 28, 2016.** To take advantage of these arrangements, you can make your reservation using the following link: New England Power Pool Reservation Booking Link for December 1st to 2nd 2016 or contact the hotel directly (617-424-7000) and reference the "NEPOOL Participants Committee" block of rooms.

Respectfully yours,

/s/
David T. Doot, Secretary

FINAL AGENDA

1. To approve the preliminary minutes of the November 4, 2016 meeting. Draft minutes for the November 4 meeting, marked to show changes from the draft circulated with the initial notice, are included with this supplemental notice and posted with the meeting materials.

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

3. To receive comments from the Honorable Cheryl LaFleur, Commissioner of the Federal Energy Regulatory Commission.

4. To receive comments from Ned Bartlett, Undersecretary of Energy and Environmental Affairs for the Commonwealth of Massachusetts.

5. To receive an ISO Chief Executive Officer Report.

6. To receive an ISO Chief Operating Officer Report.

7. To receive the 2016 NEPOOL Annual Report, which will be distributed at the Participants Committee meeting and posted with the meeting materials.

8. To elect NEPOOL Participants Committee Officers for 2017. A draft resolution reflecting the outcome of earlier balloting for the Participants Committee Chair and candidates for Secretary and Assistant Secretary is included with this supplemental notice and posted with the meeting materials.

9. To adopt a NEPOOL Budget for 2017. Background materials and a draft resolution are included with this supplemental notice and posted with the meeting materials.

9A. To consider and take action, as appropriate, on Tariff changes that implement the ISO's proposed Financial Assurance methodology supporting the incorporation of Balance of Planning Period (BoPP) auctions into the Financial Transmission Rights (FTR) Market. Background materials and a draft resolution are included with this supplemental notice and posted with the meeting materials.

10. To receive a report on current contested matters before the FERC. The litigation report will be circulated and posted with the meeting materials in advance of the meeting.

11. To receive reports from committees and subcommittees.

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

PRELIMINARY

A meeting of the NEPOOL Participants Committee was held beginning at 2:00 p.m. on Friday, November 4, 2016, at the Sheraton Hartford Hotel at Bradley Airport, Windsor Locks, Connecticut,~~-~~ pursuant to notice duly given. The meeting was preceded by meetings among modified Sector groups with the ISO Board, New England ~~s~~State ~~o~~Officials, and FERC representatives. A quorum determined in accordance with the Second Restated NEPOOL Agreement was present and acting throughout the meeting. Attachment 1 identifies the members, alternates, and temporary alternates attending the meeting.

Mr. Joel Gordon, Chair, presided and Mr. David Doot, Secretary, recorded. Mr. Gordon welcomed the members, alternates and guests who were present, including the ISO Board members, New England ~~s~~State ~~o~~Officials and FERC representatives in attendance following their earlier participation in the modified Sector discussions. He thanked all those present for their participation in those prior discussions, noting that preliminary feedback from the discussions was very positive.

APPROVAL OF OCTOBER 14, 2016 MINUTES

Mr. Gordon referred the Committee to the preliminary minutes of the October 14, 2016 meeting that had been circulated in advance of the meeting. Following motion duly made and seconded, those preliminary minutes were unanimously approved without ~~discussion or~~ change or discussion.

CONSENT AGENDA

Mr. Gordon referred the Committee to the Consent Agenda that was circulated in advance of the meeting. Following motion duly made and seconded, the Consent Agenda was approved with oppositions noted by Cross-Sound Cable (CSC) and LIPA, which opposed based on their long-standing and previously voiced objections that the ~~ICR and~~Installed Capacity Requirement (ICR) and Hydro-Québec (HQ) Interconnection Capability Credits (HQICC~~-~~) Values fail to recognize for the owners of the CSC the reliability benefits associated with that cable in the a way that is comparable to how the HQ facilities are treated.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO) reported that ~~the~~no Board reports were circulated because the ISO Board and its committees did not meet between the October Participants Committee meeting and the day preceding ~~this~~the November Participants Committee meeting~~ so there were no Board reports~~. No members had any questions for Mr. van Welie.

ISO COO REPORT

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), reviewed highlights from the November COO report, which was circulated in advance of the meeting and posted on the NEPOOL and ISO websites. Focusing on report highlights, which he noted reflected data through October 26, he reported for October that: (i) Energy Market value was $182 million, down $160 million from September 2016 and down $193 million from October 2015; (ii) average natural gas prices were 17.8% lower than September 2016 average values; (iii) Real-Time Hub LMPs on average were 21.7% lower than September 2016 LMPs; (iv) average daily (peak hour) Day-Ahead cleared physical Energy, as a percent of forecasted load, was 98.9%, down from 99.5% in September; (v) daily Net Commitment Period Compensation (NCPC) totaled $10.7 million, up $5.5 million from September 2016 and relatively unchanged from October 2015; (vi) first contingency payments, totaling $2.6 million, were $943,000 higher than in September; (vii) second contingency payments, totaling $7.9 million, were up $4.6

million from September; and (viii) NCPC payments were 5.9% of the total Energy Market value.

Dr. Chadalavada highlighted that $7 million of the $7.9 million in second contingency payments was in Northeast Massachusetts and Boston (NEMA), with $6.2 million of that $7 million to be reallocated to network load under applicable rules. He reported that the uplift principally was the result of the Greater Boston Project that required 345 kV lines out of service and necessary commitment of resources within NEMA for reliability reasons. He stated that the outages resulting from that project were expected to continue until December 1, with similar levels of uplift expected in November. As previously reported, he expected a significant amount of outages in Spring 2017, and the ISO would present at the December Participants Committee meeting its assessment of what those outages could mean for out-of-merit commitments.

Turning to highlights of the 2016/17 Winter Reliability Program, Dr. Chadalavada reported that the deadline for submissions was October 1. He said that, for the oil program, 85 units had submitted their intent to provide 4.3 million barrels of oil, which translated into 3 million barrels covered by the program, with a total cost exposure of approximately $31.2 million ($10.21 per barrel). For the liquefied natural gas (LNG) program, he reported that 4 units submitted intent to provide at least 532,000 MMBTU of LNG, and based on asset submissions, and capping submissions to permissible asset thresholds, total eligible LNG would be 527,000 ~~MMBTU~~million British thermal units (MMBtu), with total cost exposure for this program anticipated to be $897,000 ($1.70 ~~MMBTU~~per MMBtu). For the demand response (DR) program, 6 assets accepted by ISO submitted intent to provide at least 23 MW of interruption capability, with total cost exposure anticipated to be $70,500. For the Dual-

Fuel Commissioning Program, he reported that 6 units had previously submitted their intent to provide dual-fuel, 5 of which ~~are~~were already on-line, with the single remaining unit required to be on line by December 1. He explained that the ISO estimated potential uplift associated with that resource to be about $150,000. After December 1, the Dual-Fuel Commissioning Program and its uplift cost allocation would be completed~~ with no further uplift costs~~.

Dr. Chadalavada concluded his presentation reporting that the ISO was on schedule to submit to the FERC, no later than November 8, a filing reflecting Installed Capacity Requirements and related values, including the Marginal Reliability Impact Curve Values, and a second filing reflecting FCA11 resource qualification. He reported the next Forward Capacity Auction (FCA) was scheduled to commence on February 6, 2017.

In response to questions, Dr. Chadalavada clarified that the ISO would report at the December Participants Committee information about Footprint Power's status, as it ~~is~~was the only new resource scheduled to come on-line. The ISO would also discuss outages related to the Greater Boston Project and the need for reliability commitments. He stated the ISO would report on the boundary conditions, but could not commit precisely to the pattern of outages in part because of ~~limits on what could be ~~disclosure~~d~~ ~~given the ISO~~restrictions under the Information Policy. He confirmed that the Local Second Contingency Protection Resource (LSCPR) uplift that he had not discussed earlier was related to scattered maintenance outages in Maine that had since been completed, so no further uplift was predicted. Concerning the dual-fuel components and a request for information on the final unit that was still trying to be commissioned, Dr. Chadalavada stated that the unit in question was a combined cycle unit that had not yet completed its audit but was expected to complete its audit and be commissioned by December 1.

NEPOOL ORDER 1000 STATUS REPORT

Ms. Mariah Winkler, Transmission Committee Chair, referred the Committee to the materials circulated in advance of the meeting concerning a proposed NEPOOL Status Report on Order 1000 implementation in New England, to be submitted in the FERC's competitive transmission development technical conference proceeding (AD16-18). She reported that an earlier draft of a filing was considered at the September 27 Transmission Committee meeting. At that meeting, the Committee decided that NEPOOL should make a filing, but prepare a second draft reflecting Participant views expressed at the meeting for a vote at the October 26 Transmission Committee meeting. The requested changes were made to the draft filing, which converted the comments into a Status Report providing a factual account of Order 1000 implementation in New England and noting issues raised by NEPOOL Participants. She reported that, at its October 26 meeting, the Transmission Committee recommended Participants Committee support for the filing of the Status Report. That recommendation would have been on the Consent Agenda but for the timing of that meeting.

The following motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports the filing of the Status Report, as recommended by the Transmission Committee at its October 26, 2016 meeting and as reflected in the materials distributed to the Participants Committee for its November 4, 2016 meeting, together with such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Transmission Committee.

The motion passed with Emera splitting its vote (Emera Maine opposed; Emera Energy in favor), and abstentions noted by the remainder of the Transmission Sector and CSC.

LITIGATION REPORT

Mr. Doot referred the Committee to the November 3 Litigation Report that had been circulated and posted in advance of the meeting. Mr. Patrick Gerity, NEPOOL Counsel, highlighted developments with respect to pending appeals of the results of FCA8 (dismissed by the DC Circuit), FCA9 (DC Circuit appeal re-energizing following the dismissal of the FCA8 appeal), and FCA10 (rehearing denied by the FERC). He reported that a FERC technical conference was scheduled to take place the following week concerning the integration of energy storage in the RTO markets and encouraged those interested to let FERC know of their planned participation. Mr. Doot reported on an emergency injunction issued by the U.S. Court of Appeals for the Second Circuit a few days earlier (*Allco Finance Ltd. v. Klee et al.*, case no. 16-2946) prohibiting Connecticut (its Department of Energy and Environmental Protection and Public Utilities Regulatory Authority), but not Massachusetts or Rhode Island, from taking further actions in connection with the multi-state clean energy solicitation until the appeal is resolved.

COMMITTEE REPORTS

Markets Committee. Mr. William Fowler reported that the next Markets Committee meeting was scheduled for November 9. He said the agenda included further discussion of Net Cost of New Entry (CONE), requesting that anyone with amendments either submit them soon or at least advise of their intent to submit an amendment for Markets Committee consideration when it votes in December.

NAMS. Mr. Fowler then reported on behalf of the NEPOOL Audit Management Subcommittee (NAMS) that its next meeting was scheduled for November 9, to take place during the lunch break at the Markets Committee meeting.

Reliability Committee. Ms. Winkler reported that the Reliability Committee was scheduled to meet ~~next~~ on November 15 to review the Vermont Greenline Elective Transmission Upgrade Project, to consider changes to Operating Procedures, and to receive a presentation about the Load Power Factor Audit.

Transmission Committee. Mr. Jose Rotger reported that the Transmission Committee was scheduled to meet on November 17, with further discussions and potential consideration of a Participant proposal concerning the ISO transmission planning process, and continued discussions on the ISO cluster study mechanism for the Interconnection Processes and Tariff language to implement those Processes.

Budget & Finance Subcommittee. Mr. Ken Dell Orto reported that the Budget & Finance Subcommittee was scheduled to ~~next~~ meet on November 22 (the last Subcommittee meeting of 2016) to consider the 2017 NEPOOL Budget ~~for 2017~~ and the final version of Tariff changes that implement the ISO's proposed Financial Assurance methodology supporting the incorporation of Balance of Planning Period (BoPP) auctions into the Financial

Transmission Rights (FTR) Market. He expected Participants Committee consideration of those changes at the December annual meeting.

GIS Agreement Working Group. Mr. David Cavanaugh reported that the next meeting of the NEPOOL Generation Information System (GIS) Agreement Working Group was scheduled for November 7. He said the Working Group would review a document for an expression of interest for GIS Administrators. He added that the ISO had been asked to consider whether it might be interested in an expanded role in ~~the~~ GIS ~~A~~administration. APX was working on a quote in connection with a new administration agreement. The Working Group was also planning to send out a request for expressions of interest to see if other parties may be interested in bidding to perform the GIS work, so the Working Group could decide whether to recommend proceeding with a formal request for proposals.

Membership Subcommittee. Mr. Gerity reported that the Subcommittee was scheduled to~~-~~ meet on November 14. The Subcommittee would consider a proposal to change the Supplier Sector arrangements in ways intended to facilitate participation by smaller suppliers providing "provider of last resort" services. He explained that those suppliers find that the current arrangements impede opportunities to pursue those opportunities, particularly in Maine. He encouraged participation in that meeting and said that a straw proposal would be posted for review by the Membership Subcommittee in advance of its meeting.

OTHER BUSINESS

Mr. Doot reported that the next Participants Committee meeting would be the NEPOOL Annual Meeting scheduled for December 2 at the Colonnade Hotel in Boston, MA, with FERC Commissioner Cheryl LaFleur expected to be in attendance and to provide remarks. He reported balloting for 2017 Participants Committee ~~c~~Chair was underway and requested that members forward their completed ballots to Mr. Gerity.

Prior to concluding the meeting, Mr. Herb Healy announced his retirement from EnerNOC. The Committee recognized Mr. Healey with a round of applause.

There being no further business, the meeting adjourned at 2:30 p.m.

Respectfully submitted,

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David T. Doot, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
NOVEMBER 4, 2016 MEETING

Ashburnham Municipal Light Plant	Publicly Owned		Michael Lynch	
AVANGRID (CMP/UI)	Transmission			Alan Trotta
BP Energy Company	Supplier			Nancy Chafetz
Brookfield Energy Marketing	Supplier	Aleksandar Mitreski		
Calpine Energy Services, LP	Supplier	John Flumerfelt	Brett Kruse	Bill Fowler
Chicopee Municipal Lighting Plant	Publicly Owned		Michael Lynch	
CLEAResult Consulting, Inc.	AR	Doug Hurley		
Connecticut Municipal Electric Energy Coop.	Publicly Owned	Brian Forshaw		
Connecticut Office of Consumer Counsel (CT OCC)	End User		Joseph Rosenthal	
Conservation Law Foundation	End User	Jerry Elmer		
Consolidated Edison Energy, Inc. (ConEd)	Supplier	Jeff Dannels		
Cross-Sound Cable Company, LLC (CSC)	Supplier	Brian Reinhart (tel)		
DC Energy, LLC	Supplier	Bruce Bleiweis		
Direct Energy Business, LLC	Supplier	Ron Carrier		Nancy Chafetz
Dominion Energy Marketing, Inc.	Generation	Jim Davis		
DTE Energy Trading, Inc.	Supplier			Nancy Chafetz
Dynegy Marketing and Trade, LLC	Supplier			Bill Fowler
Elektrisola, Inc.	End User		Gus Fromuth	
Emera Maine	Transmission	Robert Belliveau	Jose Rotger	Stacy Dimou Sandi Hennequin
Entergy Nuclear Power Marketing, LLC	Generation		Ken Dell Orto	
EnerNOC, Inc.	AR	Herb Healy	Sarah Griffiths	
Essential Power, LLC	Generation	M.Q. Riding	Bill Fowler	
Eversource Energy	Transmission	James Daly	Cal Bowie	
Exelon Generation Company	Supplier	Steve Kirk	Bill Fowler	
Fairchild Semiconductor Corporation	End User	Gus Fromuth		
FirstLight Power Resources Management, LLC	Generation	Thomas Kaslow		
Galt Power, Inc.	Supplier	Nancy Chafetz		
Generation Group Member	Generation		Abby Krich	
Groton Electric Light Department	Publicly Owned		Michael Lynch	
H.Q. Energy Services (U.S.) Inc.	Supplier			Abby Krich
Harvard Dedicated Energy Limited	End User			Paul Peterson Doug Hurley
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Holden Municipal Light Department	Publicly Owned		Michael Lynch	
Holyoke Gas & Electric Department	Publicly Owned			Michael Lynch
Hull Municipal Lighting Plant	Publicly Owned		Michael Lynch	
Industrial Energy Consumer Group	End User	Donald Sipe		
Ipswich Municipal Light Department	Publicly Owned		Michael Lynch	
Jeffrey A. Jones, P.E.	End User	Jeff Jones (tel)		
Long Island Lighting Company (LIPA)	Supplier		Bill Killgoar	
Littleton (NH) Water & Light Department	Publicly Owned		Craig Kieny	
Maine Skiing, Inc.	End User	Donald Sipe		
Mansfield Municipal Electric Department	Publicly Owned		Michael Lynch	
Marblehead Municipal Light Department	Publicly Owned		Michael Lynch	
Massachusetts Attorney General's Office (MA AG)	End User	Fred Plett	Christina Belew	
Mass. Municipal Wholesale Electric Company (MMWEC)	Publicly Owned	Michael Lynch		
Middleborough Gas and Electric Department	Publicly Owned		Michael Lynch	
National Grid	Transmission	Tim Brennan	Timothy Martin	
New Hampshire Electric Cooperative (NHEC)	Publicly Owned			Robert Howland Brian Forshaw Michael Lynch
New Hampshire Office of Consumer Advocate (NH OCA)	End User	Paul Peterson		

ATTACHMENT 1

**PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
NOVEMBER 4, 2016 MEETING**

NextEra Energy Resources, LLC	Generation	Michelle Gardner		
Noble Americas Gas & Power Corp.	Supplier		Becky Merola	
NRG Power Marketing LLC	Generation	Dave Cavanaugh		
Paxton Municipal Light Department	Publicly Owned		Michael Lynch	
Peabody Municipal Light Plant	Publicly Owned		Michael Lynch	
PowerOptions, Inc.	End User	Cynthia Arcate		
Princeton Municipal Light Department	Publicly Owned		Michael Lynch	
PSEG Energy Resources & Trade LLC	Supplier	Joel Gordon		
Reading Municipal Light Department	Publicly Owned		Jane Parenteau	
Repsol Energy North America Company	Supplier		Nancy Chafetz	
Russell Municipal Light Department	Publicly Owned		Michael Lynch	
St. Anselm College	End User	Gus Fromuth		
Shipyard Brewing LLC	End User	Gus Fromuth		
Shrewsbury Electric & Cable Operations	Publicly Owned		Michael Lynch	
Small Load Response Group	AR	Doug Hurley	Brad Swalwell (tel)	
Small Renewable Generation Group	AR	Erik Abend (tel)		
South Hadley Electric Light Department	Publicly Owned		Michael Lynch	
Sterling Municipal Electric Light Department	Publicly Owned		Michael Lynch	
Stowe Electric Department	Publicly Owned		Tim Hebert	
SunEdison (First Wind Energy Marketing, Inc.)	AR	John Keene		Abby Krich
Talen Energy Marketing, LLC	Supplier	Tom Hyzinski		
Taunton Municipal Light Department	Publicly Owned		Tim Hebert	
Templeton Municipal Lighting Plant	Publicly Owned		Michael Lynch	
The Energy Consortium	End User			Paul Peterson Doug Hurley
Union of Concerned Scientists	End User		Francis Pullaro	
Utility Services, Inc.	End User			Paul Peterson
Vermont Electric Cooperative (VEC)	Publicly Owned	Craig Kieny		
Vermont Electric Power Company	Transmission	Frank Ettori		
Vermont Energy Investment Corporation	AR		Doug Hurley	
Vermont Public Power Supply Authority (VPPSA)	Publicly Owned		Brian Callnan	
Vitol Inc.	Supplier	Joseph Wadsworth		
Wakefield Municipal Gas and Light Department	Publicly Owned		Michael Lynch	
West Boylston Municipal Lighting Plant	Publicly Owned		Michael Lynch	
Wheelabrator North Andover Inc.	AR	Bill Fowler		
Z-TECH, LLC	End User		Gus Fromuth	

CONSENT AGENDA

From the notice of actions of the November 15, 2016 ***Reliability Committee***[1] meeting, dated November 16, 2016, which has been previously circulated:

1. **Revisions to OP-3 (Clarifications and Updates)**

   Support revisions to ISO New England Operating Procedure (OP) No. 3 (Transmission Outage Scheduling) (OP-3), including clarifications to provisions for posting Long-Term Transmission Outages Reports and to the definitions of Long Term Transmission Outage, Opportunity Outage, and Unplanned Outage, and the removal of Opportunity Outage from Opportunity Outage from the Unplanned Outages Section (Section VII), as recommended by the Reliability Committee at its November 15, 2016 meeting, with such further non-material changes as the Chair and Vice-Chair of the Reliability Committee may approve.

   The motion to recommend Participants Committee support was approved unanimously.

2. **Revisions to OP-7, Appendix A (Annual Review Updates)**

   Support updates to OP-7 (Action in an Emergency) Appendix A (Instructions for Implementation of Manual Load Shedding), including the replacement of "directive" and "directed" with "operation instruction", as recommended by the Reliability Committee at its November 15, 2016 meeting, with such further non-material changes as the Chair and Vice-Chair of the Reliability Committee may approve.

   The motion to recommend Participants Committee support was approved unanimously.

From the notice of actions of the November 9, 2016 ***Markets Committee***[2] meeting, dated November 9, 2016, which has been previously circulated:

3. **Revisions to Tariff and MR1 Appendix F (NCPC Modifications)**

   Support revisions to Tariff Section I.2.2 and Market Rule 1 Appendix F to update the NCPC provisions to support the Sub-hourly Real-Time Settlement design, as recommended by the Markets Committee at its November 9, 2016 meeting, with such further non-material changes as the Chair and Vice-Chair of the Markets Committee may approve.

   The motion to recommend Participants Committee support was approved with 1 opposition and 4 abstentions in the Supplier Sector and 1 abstention in the Generation Sector.

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

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

Summary of ISO New England Board and Committee Meetings

December 2, 2016 Participants Committee Meeting

Since the last update, the System Planning and Reliability Committee met in Windsor Locks, Connecticut, on November 2. The Audit and Finance Committee, the Compensation and Human Resources Committee, the Markets Committee, and the Board of Directors each met on November 3 in Windsor Locks, Connecticut.

The System Planning and Reliability Committee received an update on transmission planning and ongoing activities with regard to implementation of FERC Order 1000 in New England. The Committee reviewed standards being applied in the regional transmission planning process in light of the continued evolution of NERC planning standards at the federal level. The Committee also discussed the Company's launch of its first public policy planning cycle in January of 2017. Next, the Committee reviewed the capacity and energy impacts associated with the potential retirement of the region's remaining coal and oil units. The Committee noted that fuel adequacy constraints continue to be the biggest risk to the reliability of the New England power system. The Committee then considered its annual calendar for 2017.

The Audit and Finance Committee received a report on internal audit activities including follow-up items related to internal reviews and the oversight of external audits. The Committee then met with representatives of KPMG, the Company's external auditors, to discuss the scope and preliminary results of the 2016 Service Organization Controls Report review and resulting unqualified opinion. KPMG also provided an overview of work plans and timing for the financial statements audit. The Committee met with the auditors in executive session. Next, the Committee reviewed compliance issues, including the results of the annual process pursuant to which employees certify that they are in compliance with the Code of Conduct. The Committee was provided with a report on current budget performance along with an update on interest rates. The Committee also approved the unaudited financial statements for the third quarter after receiving a report on the related disclosure control process. Finally, the Committee considered its annual calendar for 2017.

The Compensation and Human Resources Committee convened and reviewed the goal setting, assessment and compensation schedule for 2017. The Committee also considered its annual calendar for 2017, and discussed recent trends and legislation with human resources implications, including the Massachusetts Pay Equity Law.

The Markets Committee was provided with a summary of key market issues for the 2016 summer season, and discussed wholesale market costs, opportunity costs for postured resources, and the impact of pipeline delivery constraints on natural gas prices in both the New York and New England regions. Next, the Committee discussed the results of a recent legal decision concerning the competitiveness of the 2013-2014 winter reliability program, and discussed the filing that must be made with FERC providing information and recommendations regarding the program. The Committee then received a report on recent developments concerning the Integrating Markets and Public Policy stakeholder process, and discussed the challenge of developing solutions that are consistent with both market and reliability principles given the limitations placed on potential solutions. Finally, the Committee considered its annual calendar for 2017.

The Board of Directors received reports from the standing committees, including the committees' risk assessments for the key risks that fall within the scope of each committee's oversight. Next, the Board conducted its annual risk management review and discussed the various topics related to potential risks, including the primary risks that the New England wholesale electricity market faces. Finally, the Board prepared for the upcoming sector meetings with NEPOOL and reviewed topics proposed by stakeholders for discussion.

NEPOOL Participants Committee Report

December 2016

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

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Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Energy Market Value over the period was $157M, down $72M from October and down $135M from November 2015
  - November natural gas prices over the period were 4.0% higher than October 2016 average values
  - Average RT Hub Locational Marginal Prices ($20.19/MWh) over the period were 11.2% lower than October 2016 averages
  - Average November 2016 natural gas prices and RT Hub LMPs over the period were down 30% and down 23%, respectively, from November 2015 averages
- Average DA cleared physical energy during the peak hours as percent of forecasted load was 97.9% during November, down from 98.6% during October

Data are through November 21, 2016, except where otherwise noted.

***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)
  - November NCPC payments totaled $9.9M over the period, down $3.8M from October and down $1.6M from November 2015
    - First Contingency payments totaled $1.1M, down $2.0M from October
      - $1.0M paid to internal resources, down $1.8M from October*
        - » $233K charged to DALO, $469K to RT Deviations
      - $68K paid to resources at external locations, down $179K from October, and charged to RT Deviations
    - Second Contingency payments totaled $8.8M, down $1.6M from October
    - October Voltage payments totaled $20K, down $140K from October
  - NCPC payments over the period as percent of Energy Market value were 6.3%

*** Generator Performance Auditing (GPA) costs are included in the First Contingency amount and totaled $304K**

2016/17 Winter Reliability Program – Based on Initial Submissions

SAME AS LAST MONTH – December 1 Inventory Levels will be reported at the next meeting

- **Oil Program**
  - By the Oct. 1 deadline, 85 Units submitted intent to provide 4.340 million barrels
  - Based upon assets participating in program total eligible oil is anticipated to be 3.057 million barrels
  - Total oil program cost exposure is anticipated to be $31.21M (@$10.21/barrel)
- **LNG Program**
  - By the Oct. 1 deadline, 4 Units submitted intent to provide at least 532 thousand MMBTU
  - Based upon asset submissions, and capping submissions to permissible asset thresholds total eligible LNG is 527.7 thousand MMBTU
  - Total LNG program cost exposure is anticipated to be $897K (@$1.70/MMBTU)
- **DR Program**
  - By the Oct. 1 deadline, 6 Assets accepted by ISO submitted intent to provide at least 23.0 MW of interruption capability
  - Total DR program cost exposure is anticipated to be $70.5K

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 additional winter seasonal claimed capability represented: 1,774 MW
  - DFC Activity and related NCPC:
    - Units commissioned (as of Nov. 29): **All 6 units are successfully commissioned**
    - Total NCPC Commissioning Cap: $5.7M
      - 2014/15: $3.56M
      - 2015/16: $2.19M
    - NCPC incurred (as of Nov. 21): $1.54M
    - Remaining Commissioning Cap for 2016: $40K

Highlights, cont.

- 2016 Economic Study - NEPOOL Scenario Analysis November 29 Planning Advisory Committee Meeting (PAC) meeting discussions included updates on high-level Phase I observations and key messages and study updates
- Keene Road Market Efficiency Transmission Upgrade needs assessment draft results were presented at the November 29 PAC meeting

Forward Capacity Market (FCM) Highlights

- CCP #7 (2016-2017)
  - Approximately 30 MW of new resources that were to be commercial on June 1 are non-commercial
- CCP #8 (2017-2018)
  - ICR and related values were filed with the FERC on December 1
  - Third and final bilateral window is December 1-7
    - Results to be posted no later than January 11, 2017
- CCP #9 (2018-2019)
  - Second bilateral window will be May 2017
  - Second reconfiguration auction will be August 2017

CCP – Capacity Commitment Period
RTEG – Real-Time Emergency Generation
ICR – Installed Capacity Requirement

FCM Highlights, cont.

- CCP #10 (2019-2020)
  - First bilateral transaction window will be April 2017
  - First reconfiguration auction will be June 2017
- CCP #11 (2020-2021)
  - Next installment of financial assurance for new capacity resources is due January 23, 2017
  - ICR and related values were filed with the FERC on November 8
  - Qualification information was filed with the FERC on November 8
  - Auction to commence on February 6, 2017

FCM Highlights, cont.

- CCP #12 (2021-2022)
  - Preparations for qualification have begun and training dates are set
  - On February 24, 2017, the ISO will notify existing resource qualifications of their values
  - Retirement de-list bids and permanent de-list bids are due March 24, 2017
  - Show of interest window will be open April 14-28, 2017

Highlights, cont.

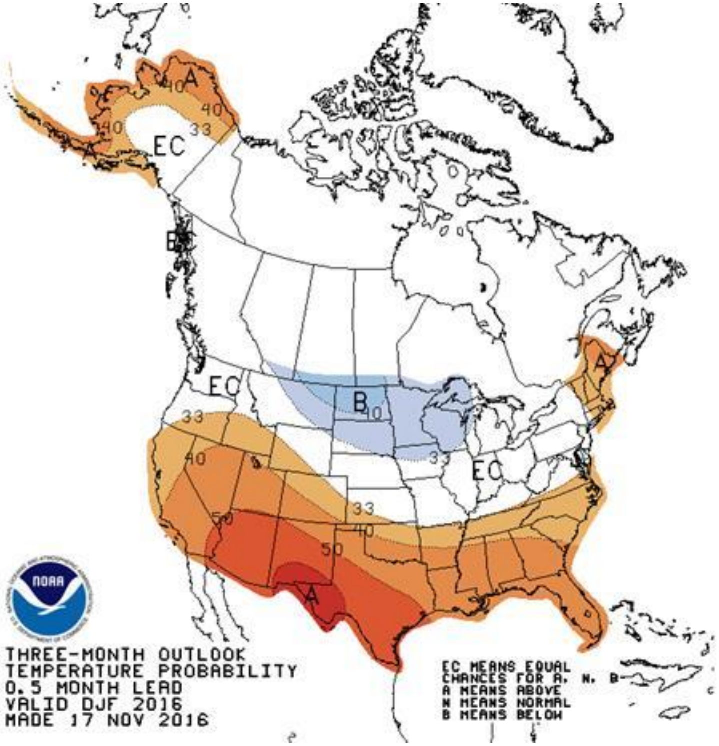
- ISO-NE is forecasting a 50/50 winter peak demand of 21,340 MW and a 90/10 winter peak demand of 22,028 MW for three consecutive weeks starting week beginning January 7, 2017.

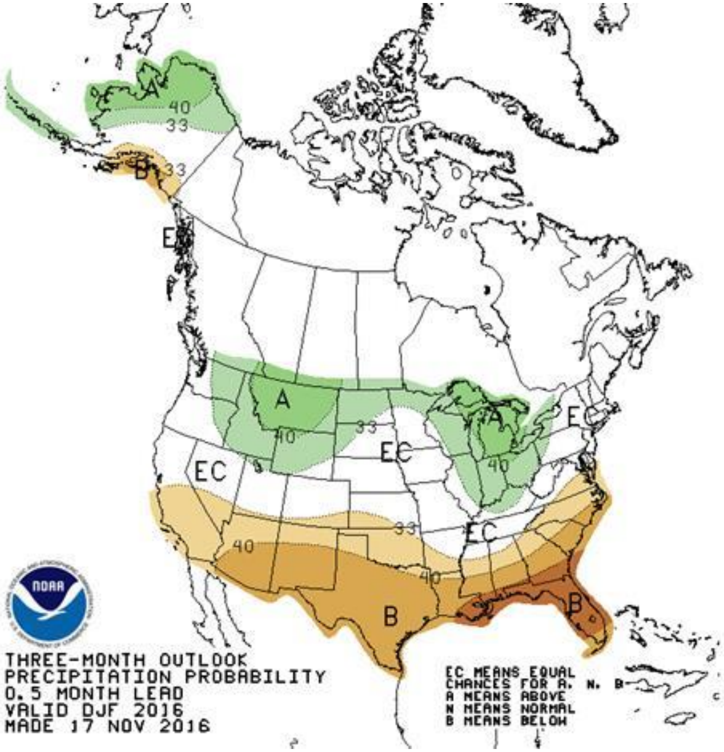
- The lowest 50/50 and 90/10 Winter Operable Capacity Margin Week is projected for week beginning January 14, 2017.

2016/17 WINTER CAPACITY OUTLOOK

2016/17 Winter Capacity Outlook – Weather Forecast

- Forecast calls for El Niño-Southern Oscillation to continue through early winter
- Above normal temperatures; Equal chances on precipitation



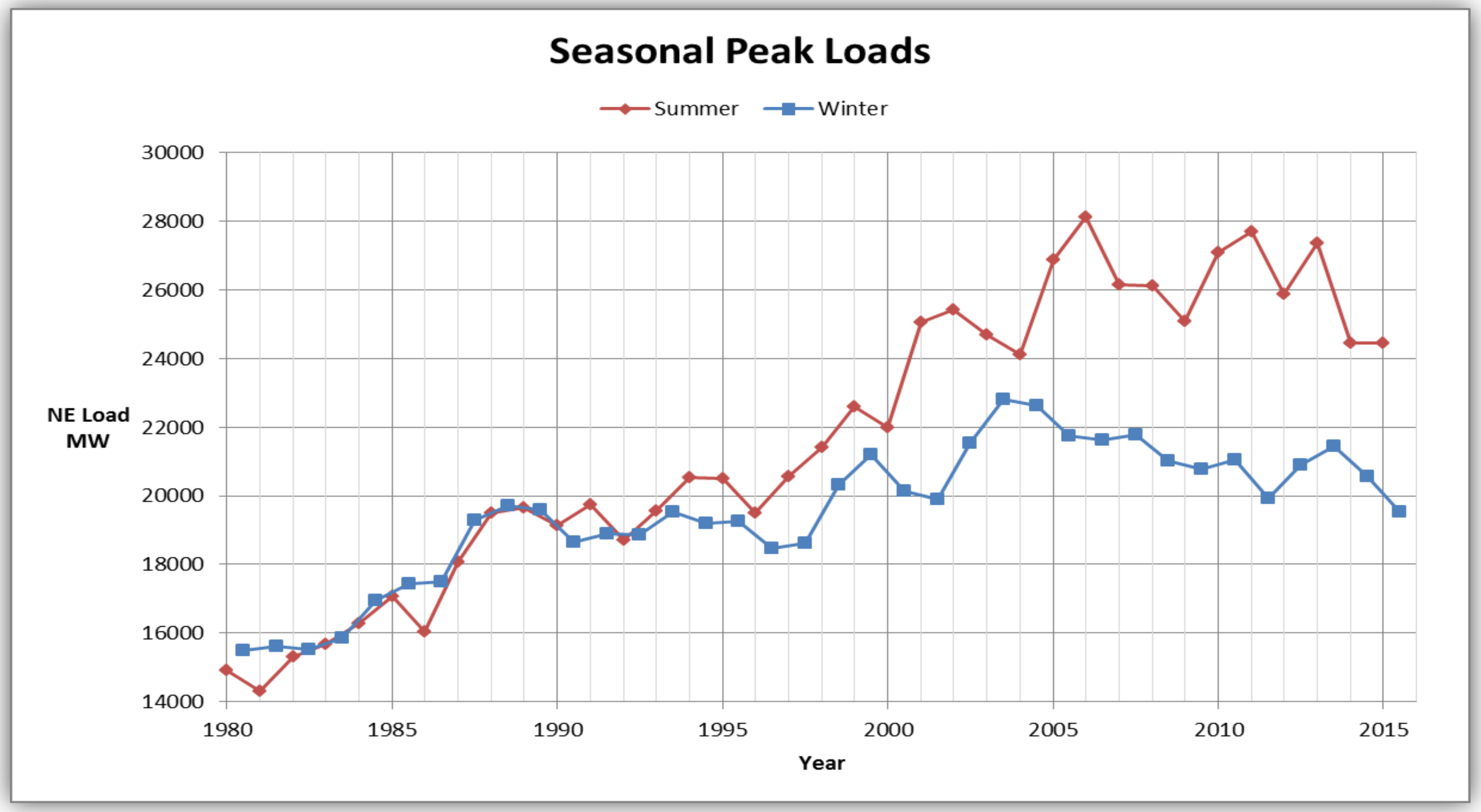


Winter Capacity Outlook – Natural Gas Infrastructure Expansion Projects

- Algonquin Incremental Market (AIM)
  - 342,000 MMBtu/d expansion of the Algonquin pipeline
    - New and upgraded pipeline in the ground
    - New high-capacity compressors
    - Upgraded existing compressor stations
    - Partially In-Service in November 2016 (last ~100,000 MMBtu/d delayed)
- Tennessee Pipeline – Connecticut Expansion
  - Approximately 72,000 MMBtu/d
  - Expected In service by November 2017

Winter Capacity Outlook – Load Forecast

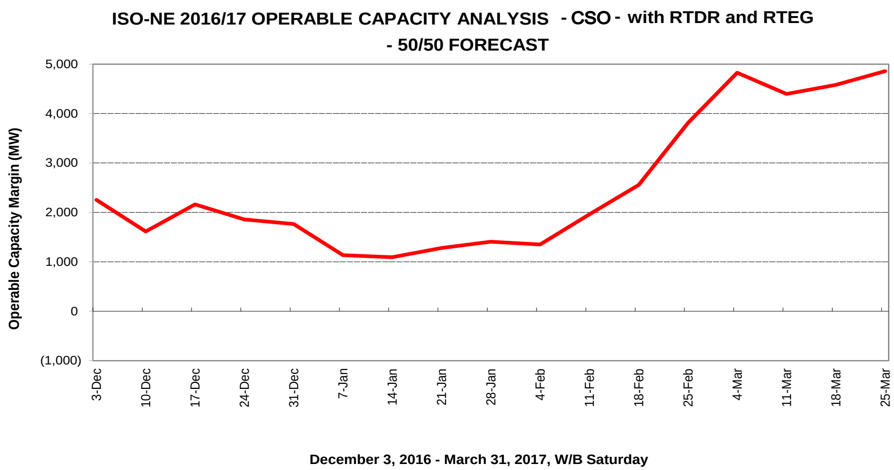
- ISO-NE is forecasting a 50/50 winter peak demand of 21,340 MW and a 90/10 winter peak demand of 22,028 MW

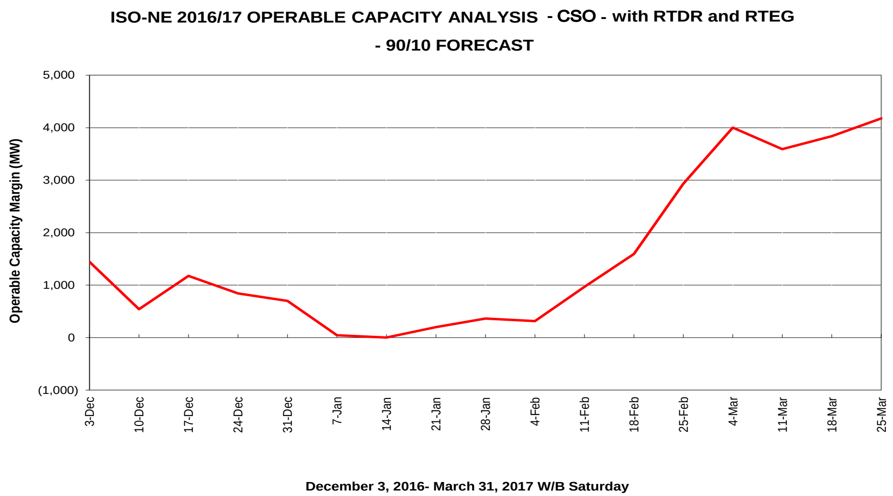


Winter Capacity Outlook – Operational Capacity Analysis

- 50/50 Forecast (CSO Only)
  - **Surplus 1,092 MW**
- 90/10 Forecast (CSO Only)
  - **Surplus 1 MW**
- Note that:
  - Typically, EcoMax offers exceed CSO values
- Weeks in January have lowest capacity margin values

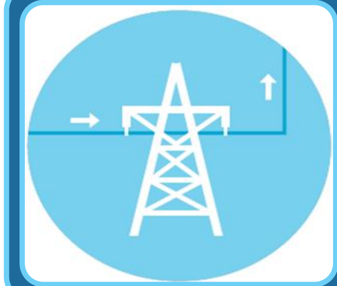
analysis as of 11/21/16





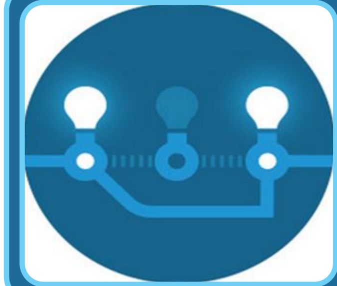
2016/17 WINTER PREPARATIONS

Winter Preparations – Tests & Audits



Load Shed Tests

- Performed every month
-System Operators can order the shedding of 50% of New England load in 10 minutes



Voltage Reduction Tests

-Performed twice annually
-Can provide load relief of approx. 267MW in < 10 min, 124MW in >10 min

Generator audits and DF testing

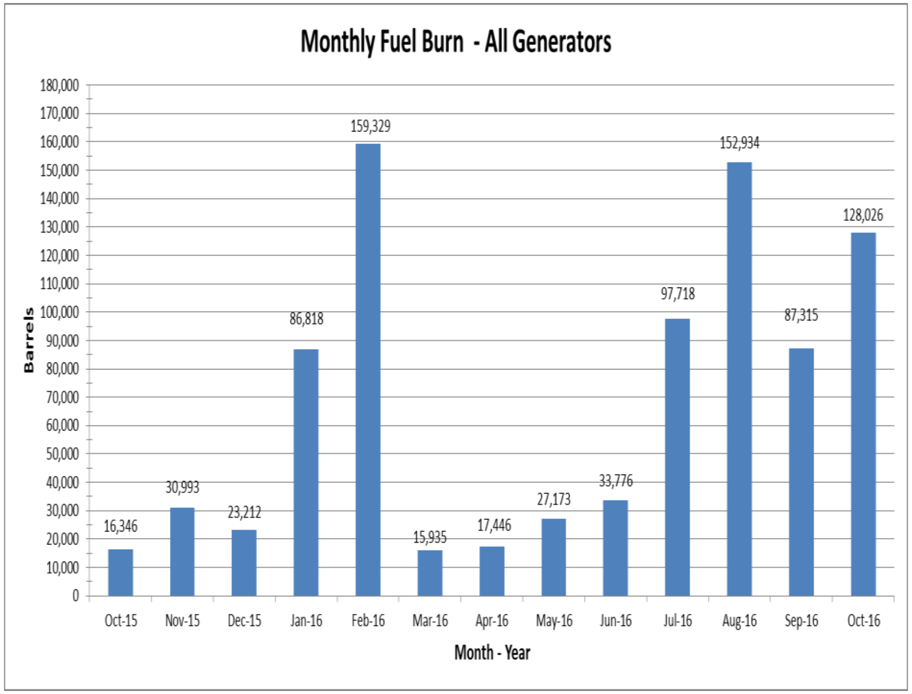
-30 units will audit DF switching capability

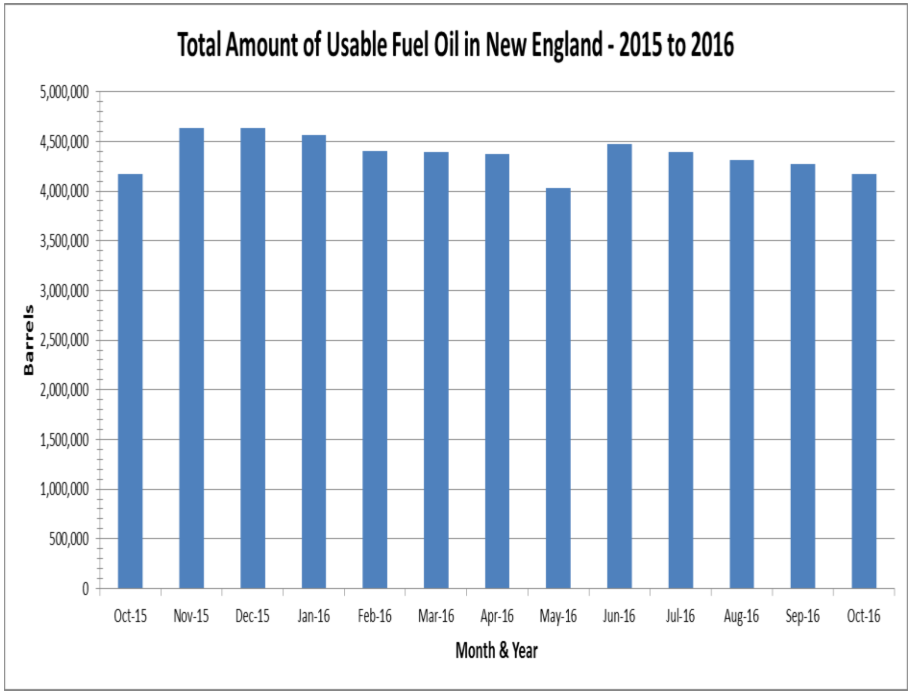
Winter Preparations – Natural Gas Facility Surveys

- Annual Critical Natural Gas Facility Surveys
  - Identify critical NG pipeline and LNG facility loads as well as power sources
  - Verify load shed plans don’t result in shedding of NG compressor stations and NG processing plants

Winter Preparations – Generator Fuel Surveys

- Fuel surveys
  - Performed monthly, but can increase to weekly/daily if needed
  - Provides situational awareness of actual oil/coal inventories, status of fuel that has been ordered and potential environmental constraints





Winter Preparations – Routine Communications

Daily conference calls with NPCC Reliability Coordinators

Daily calls to dual-fuel generators to verify expected fuel type

Direct communications with gas pipeline operators

Coordination of generator planned outages with pipelines on a 6 month forward looking basis

ISO shares daily fuel burn expectations with individual pipelines

Collection of gas pipeline bulletin board data

Winter Preparations – Industry Coordination

- Pre-Winter conference calls with the Northeast Gas Association
  - Emphasized importance of maintaining close coordination regarding outages
- NERC Guideline under development to enhance Gas and Electric Industry Coordination and Operations
- ISO Operations hosted 4th Annual Winter Generator Readiness Seminar for Market Participants, DDEs, and LCC personnel

Abnormal/Emergency Energy Conditions Procedures & Processes

- In order of severity implement the following:
  - Dispatch additional resources in economic order to replace any generation curtailed or expected to be curtailed as a result of the loss

MLCC-2 Abnormal Conditions Alert → **OP-4** Action During a Capacity Deficiency → **OP-7** Action in Emergency → **OP-21** Action During an Energy Emergency

GREATER BOSTON 2016/17 WINTER AND 2017 SPRING ANALYSIS

Winter/Spring 2017 Greater Boston – Transmission Outages

- ISO-NE has met with NGRID and NSTAR regarding the sequencing of transmission outages
- Based on the submitted transmission outages, the following is a high level summary of the outages in Spring 2017
  - 230 kV substation equipment relocation and upgrades
  - 115 kV new substation builds, line reconductoring and equipment installation
- In addition to the outages mentioned above, ISO-NE expects other transmission and generator outages in Winter and Spring 2017
  - For example, unrelated to the Greater Boston project, a 345 kV cable in the NEMA/Boston zone requires immediate repair

Winter/Spring 2017 Greater Boston – Uplift Assessment

- Outages submitted as of November 2016 were analyzed in accordance with ISO-NE Operating Procedures
- The analysis is based on forecasted generation dispatch, New England loads and scheduled/planned generation and transmission outages
  - Actual system conditions (unplanned transmission outages, load level, available generation, etc.) will vary in real-time

Winter/Spring 2017 Greater Boston – Uplift Assessment

- In this analysis, ISO-NE assumes a 50/50 load forecast
- The ISO-NE expects at least one unit is required to provide second contingency protection for NEMA/Boston
- Out-of-merit commitments are a function of real-time load levels, transmission and generation outages and cleared day-ahead market generation

Winter/Spring 2017 Greater Boston – Uplift Assessment

- NEMA/Boston Spring 2017 commitment needs are expected to be comparable to October & November 2016 commitments
- Winter transmission outages are not expected to have a significant impact on NEMA/Boston uplift, uplift would be driven primarily by load levels
- If some area generation clears in merit during the Spring 2017 outage periods, there will be fewer out-of-merit commitments
  - Actual commitment costs will depend on fuel costs and the duration of commitments

Summer 2017 Greater Boston – New Resource Addition

- The addition of a new resource within the Greater Boston area, assuming it clears in merit, will increase the load levels at which second contingency commitments are necessary
  - Assuming transmission outages are on the outer boundaries of the NEMA/Boston zone, the new resource running in merit is likely to offset the need for out-of-merit commitments
  - Assuming certain transmission outages within Boston, second contingency commitments might still be necessary

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Near Normal (0.3°F) Max: 70°F, Min: 30°F Precipitation: 1.39" – Above Normal Normal: 3.72" Snow: 0.20"	Hartford	Temperature: Near Normal (0.1°F) Max: 72°F, Min: 22°F Precipitation: 1.38" - Below Normal Normal: 3.80"

Peak Load:	17,464 MW	November 21, 2016	18:00 (Hour ending)

MLCC2: None	**Reason**	**Declared** **Cancelled**
OP-4 : None	**N/A**	**N/A**

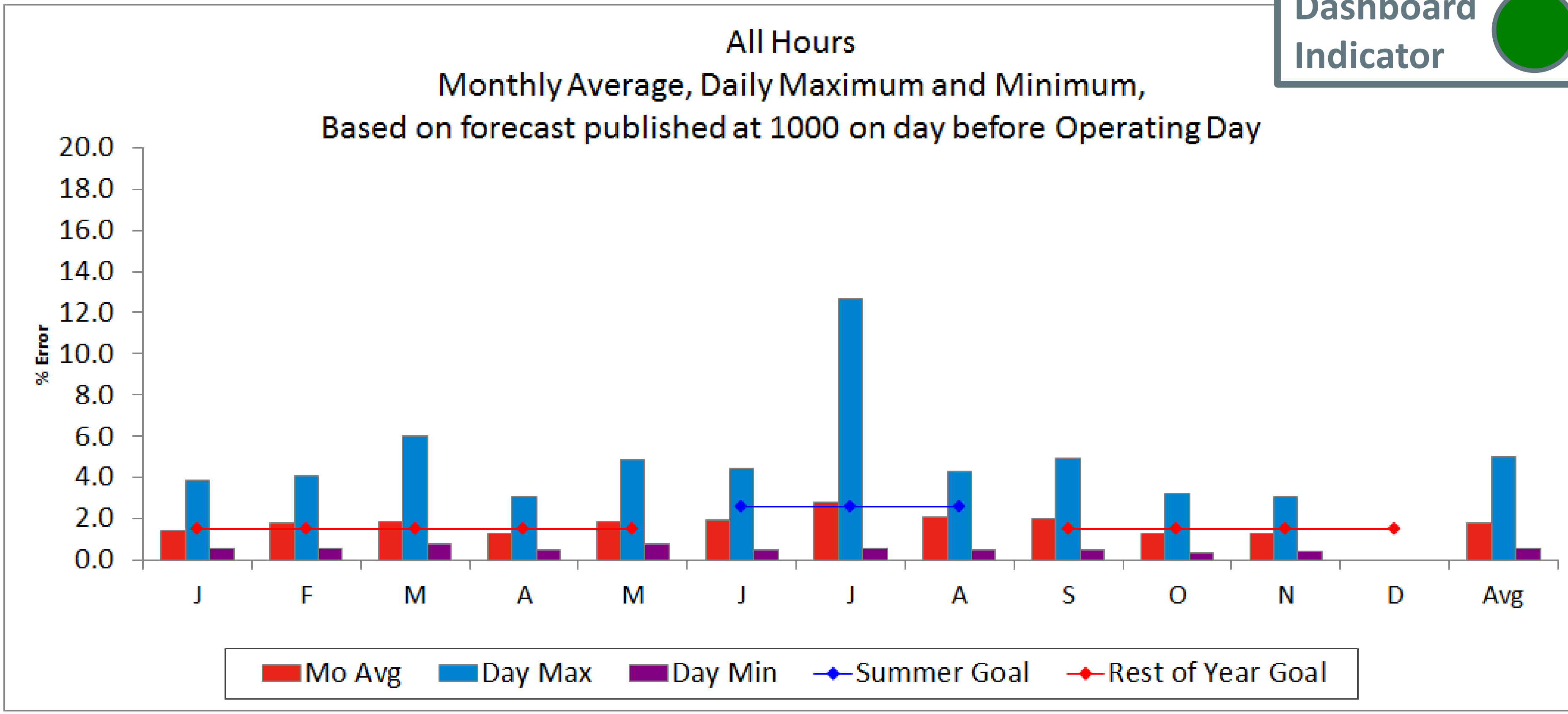
Minimum Generation Warnings & Events: None		
N/A	N/A	N/A

System Operations

NPCC Simultaneous Activation of Reserve Events:		
Date	Area	MW
11/11/16	ISONE	988
11/12/16	IESO	945
11/17/16	ISONE	988

2016 System Operations - Load Forecast Accuracy

Dashboard Indicator

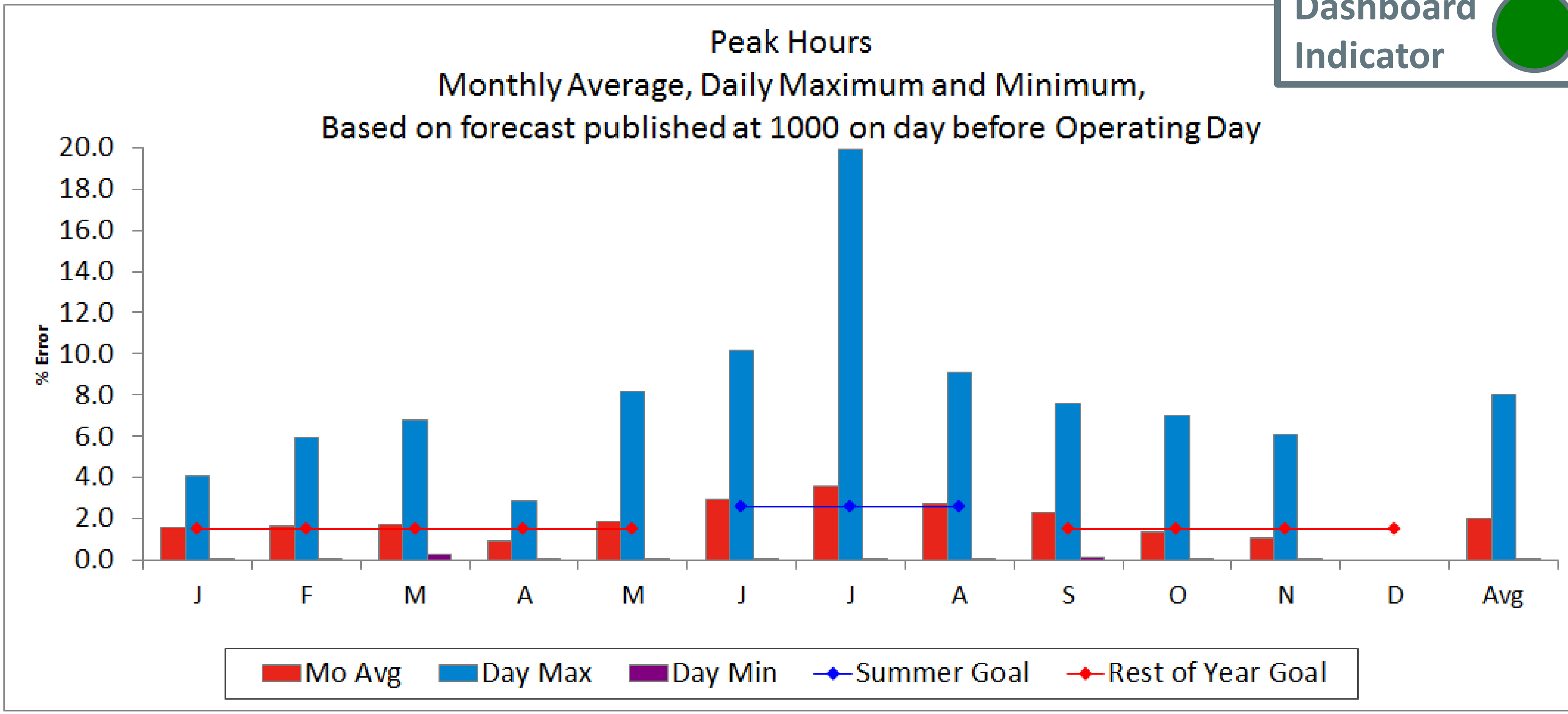


Month	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Mo Avg	1.44	1.78	1.89	1.32	1.86	1.95	2.76	2.05	2.04	1.31	1.31		1.79
Day Max	3.88	4.12	6.05	3.08	4.90	4.45	12.71	4.30	4.92	3.20	3.05		4.99
Day Min	0.54	0.58	0.82	0.50	0.75	0.50	0.61	0.52	0.53	0.37	0.43		0.56
Summer Goal						2.60	2.60	2.60					
Rest of Year Goal	1.50	1.50	1.50	1.50	1.50				1.50	1.50	1.50	1.50	
Rest of Year Actual	1.44	1.78	1.89	1.32	1.86				2.04	1.31	1.31		1.62
Summer Actual						1.95	2.76	2.05					2.26

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

2016 System Operations - Load Forecast Accuracy cont.

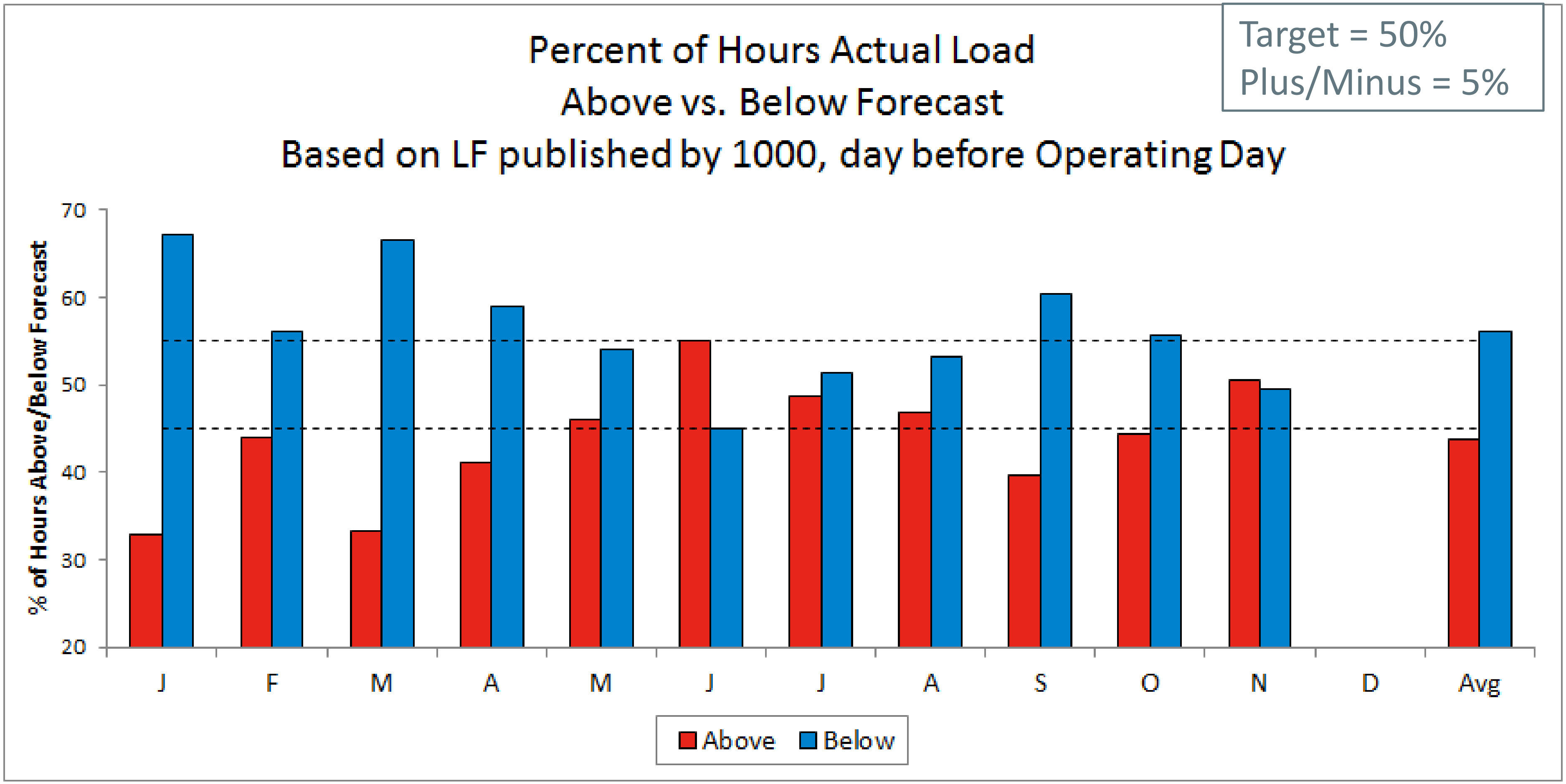
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Mo Avg	1.55	1.67	1.72	0.96	1.87	2.93	3.59	2.73	2.31	1.36	1.07		1.98
Day Max	4.10	5.95	6.80	2.85	8.19	10.17	19.94	9.12	7.61	7.00	6.08		8.01
Day Min	0.09	0.03	0.32	0.01	0.03	0.01	0.01	0.03	0.12	0.06	0.01		0.07
Summer Goal						2.60	2.60	2.60					
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	1.55	1.67	1.72	0.96	1.87				2.31	1.36	1.07		1.56
Summer Actual						2.93	3.59	2.73					3.09

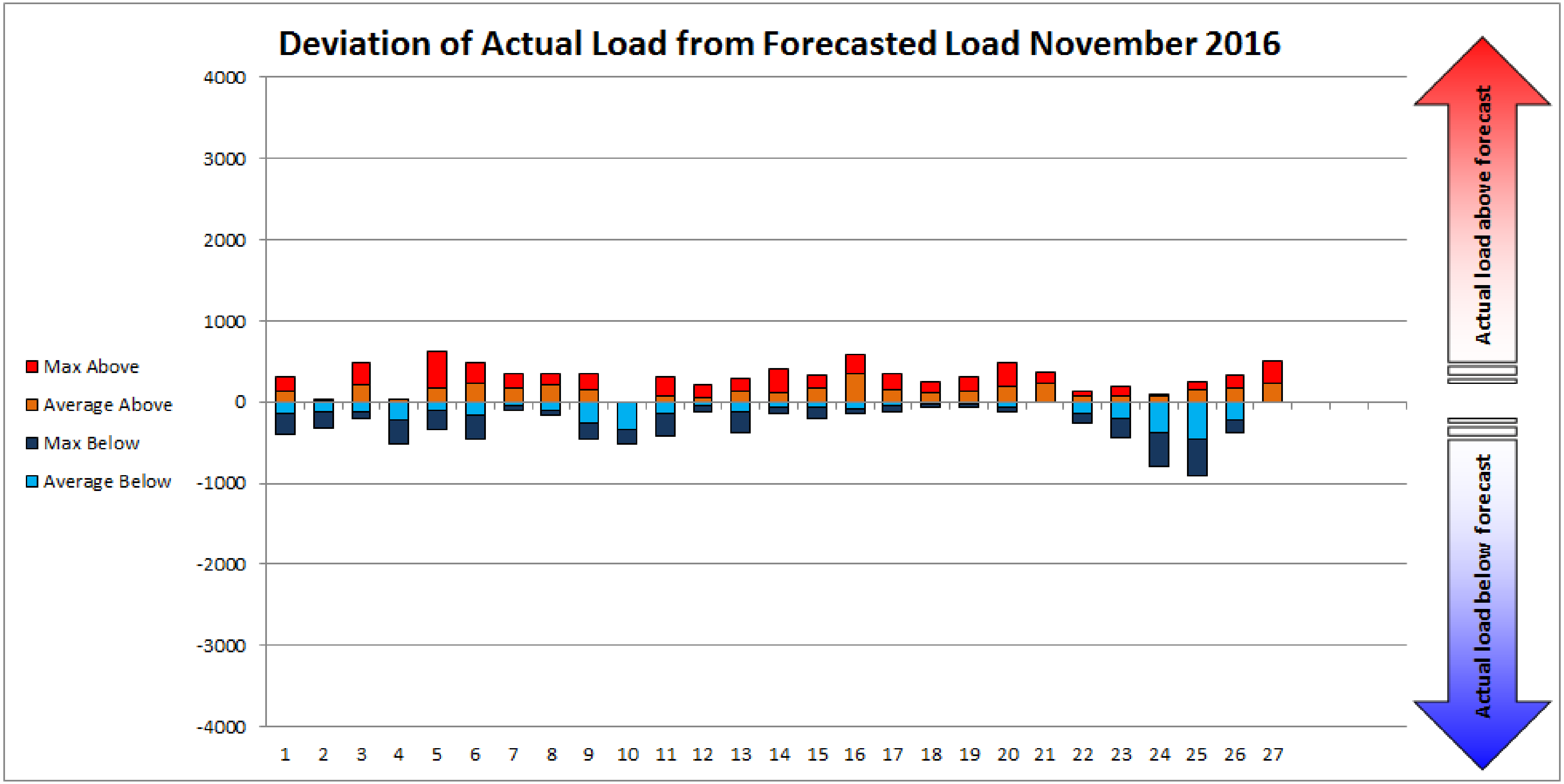
Rest of Year Goal < 1.5%
Summer Goal < 2.6%

2016 System Operations - Load Forecast Accuracy cont.

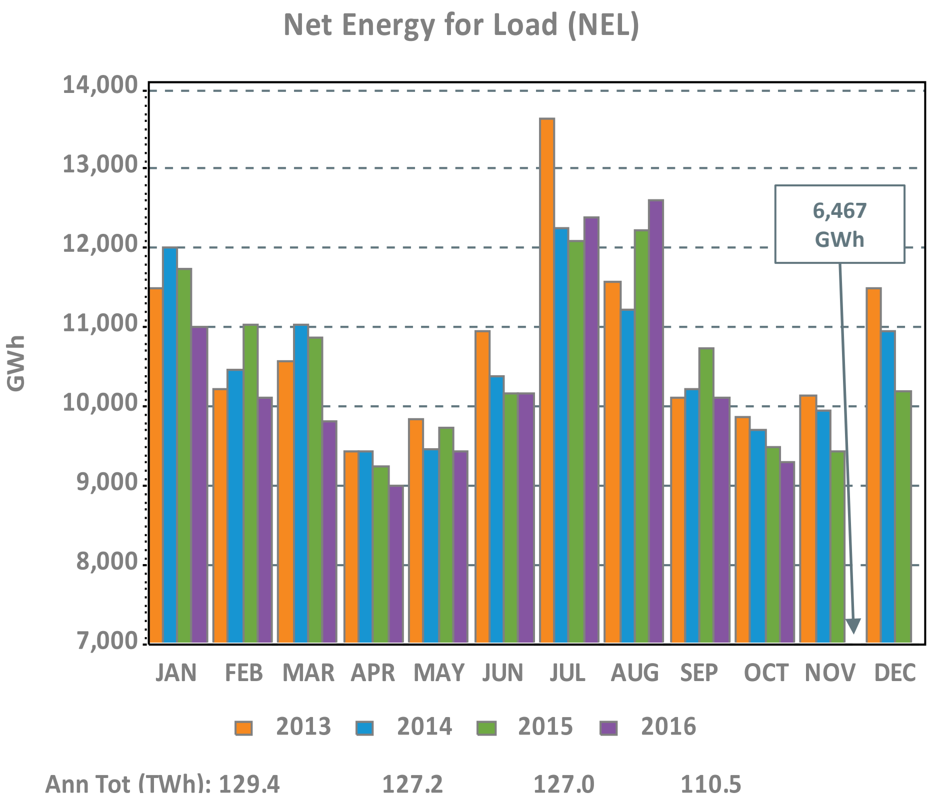


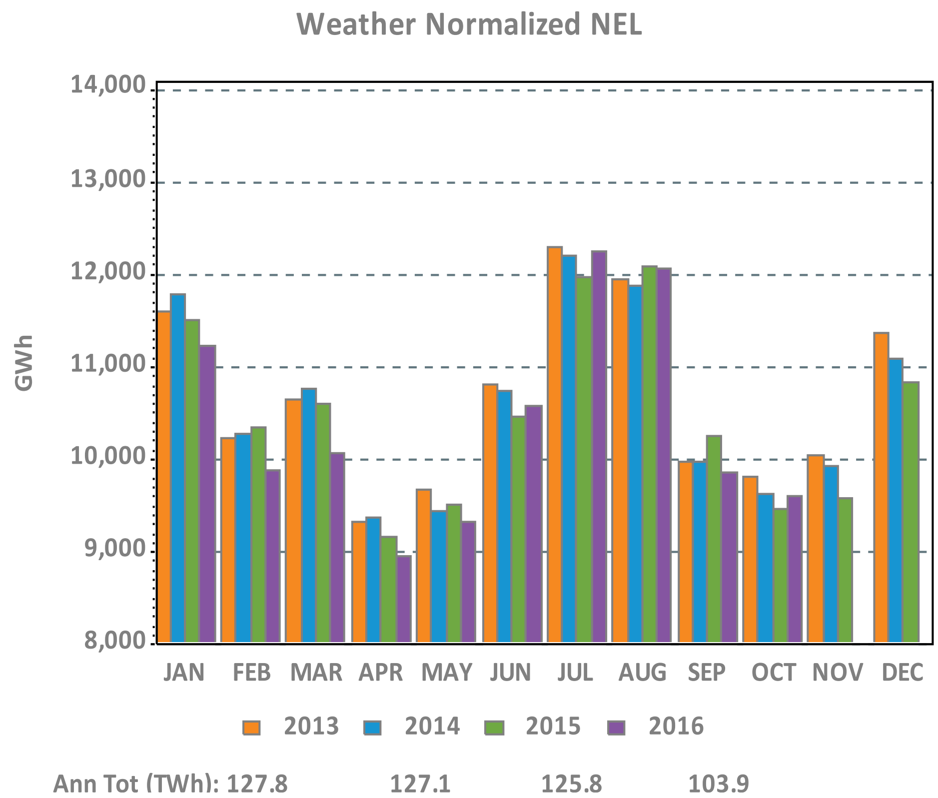
	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	32.9	44	33.4	41.1	46	55	48.7	46.8	39.7	44.4	50.5		44
Below %	67.1	56	66.6	58.9	54	45	51.3	53.2	60.3	55.6	49.5		56
Avg Above	109.8	199.7	172.5	134.6	203.9	218.8	265.1	225.1	175.7	104.4	126.6		176
Avg Below	-200.6	-185.0	-201.1	-141.0	-159.7	-182.8	-369.3	-305.3	-244.8	-143.7	-123.4		-206
Avg All	-100	-7	-59	-12	13	46	-86	-64	-76	-40	-8		-36

2016 System Operations - Load Forecast Accuracy cont.



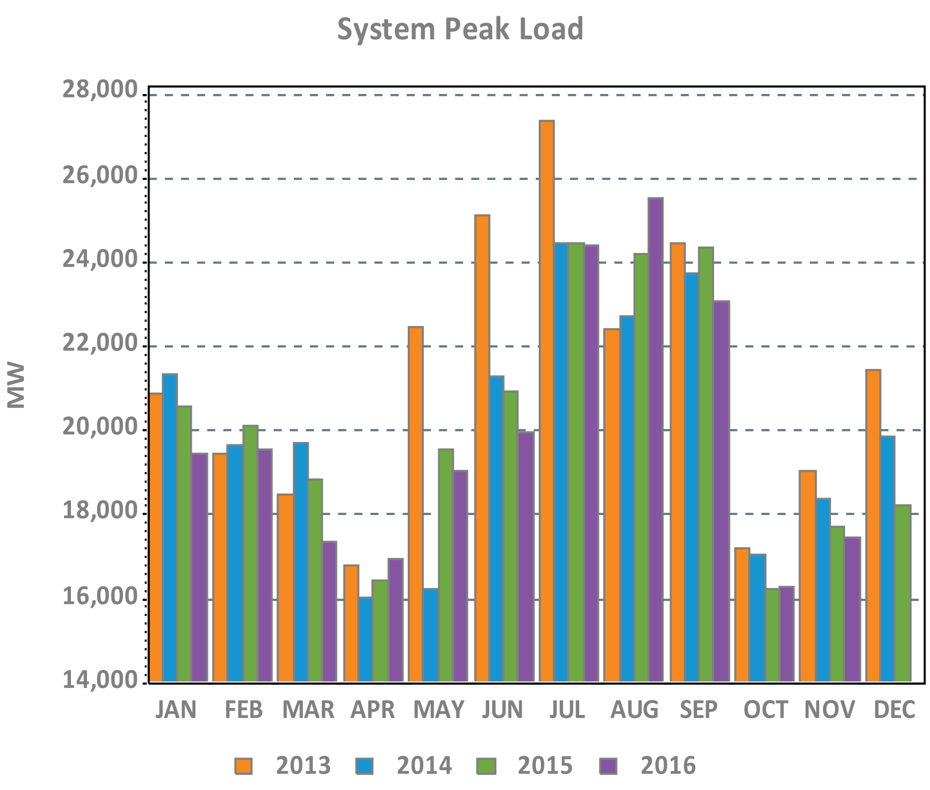
Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL



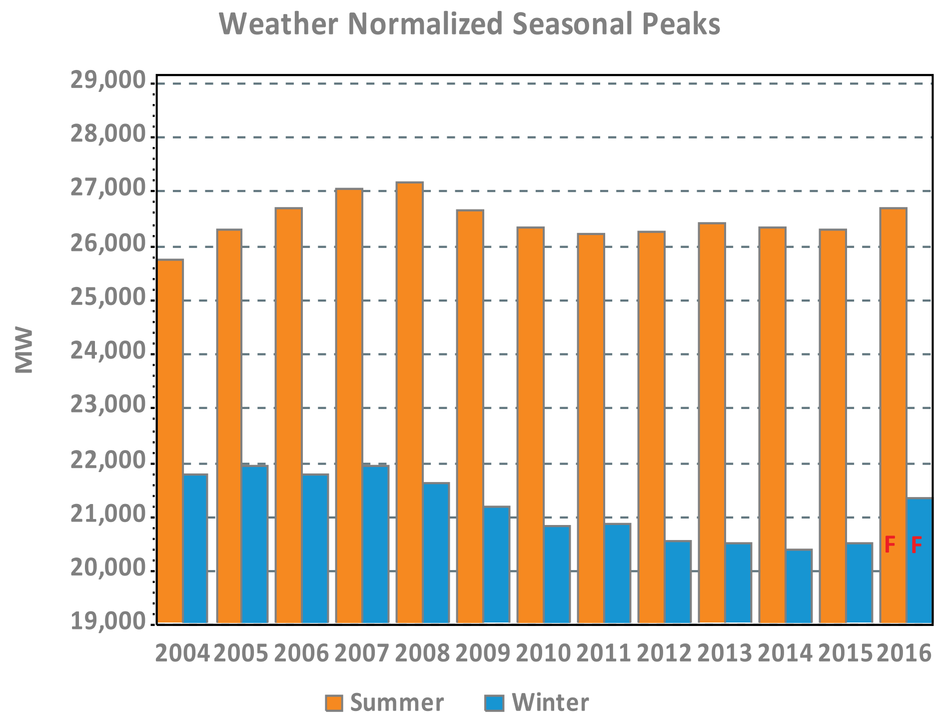


NEPOOL NEL is the total net energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation – pumping load + net interchange where imports are positively signed.
Current month's data may be preliminary. Weather normalized NEL may be reported on a one-month lag.

Monthly Peak Loads and Weather Normalized Seasonal Peak History



*Revenue quality metered value

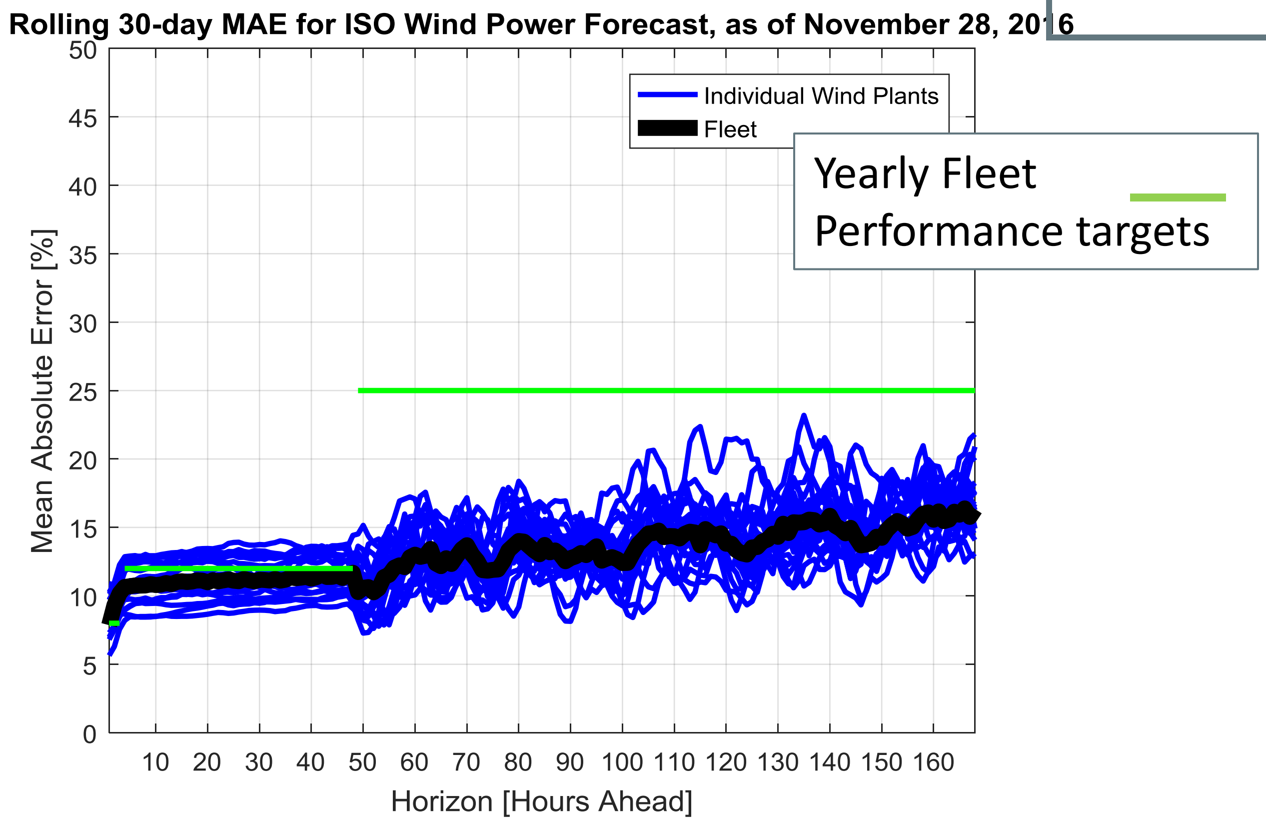


Winter beginning in year displayed

F – designates forecasted values, which are updated in April/May of the following year; represents "net forecast" (i.e., the gross forecast net of passive demand response and behind-the-meter solar demand)

Wind Power Forecast Error Statistics: Medium and Long Term Forecasts MAE

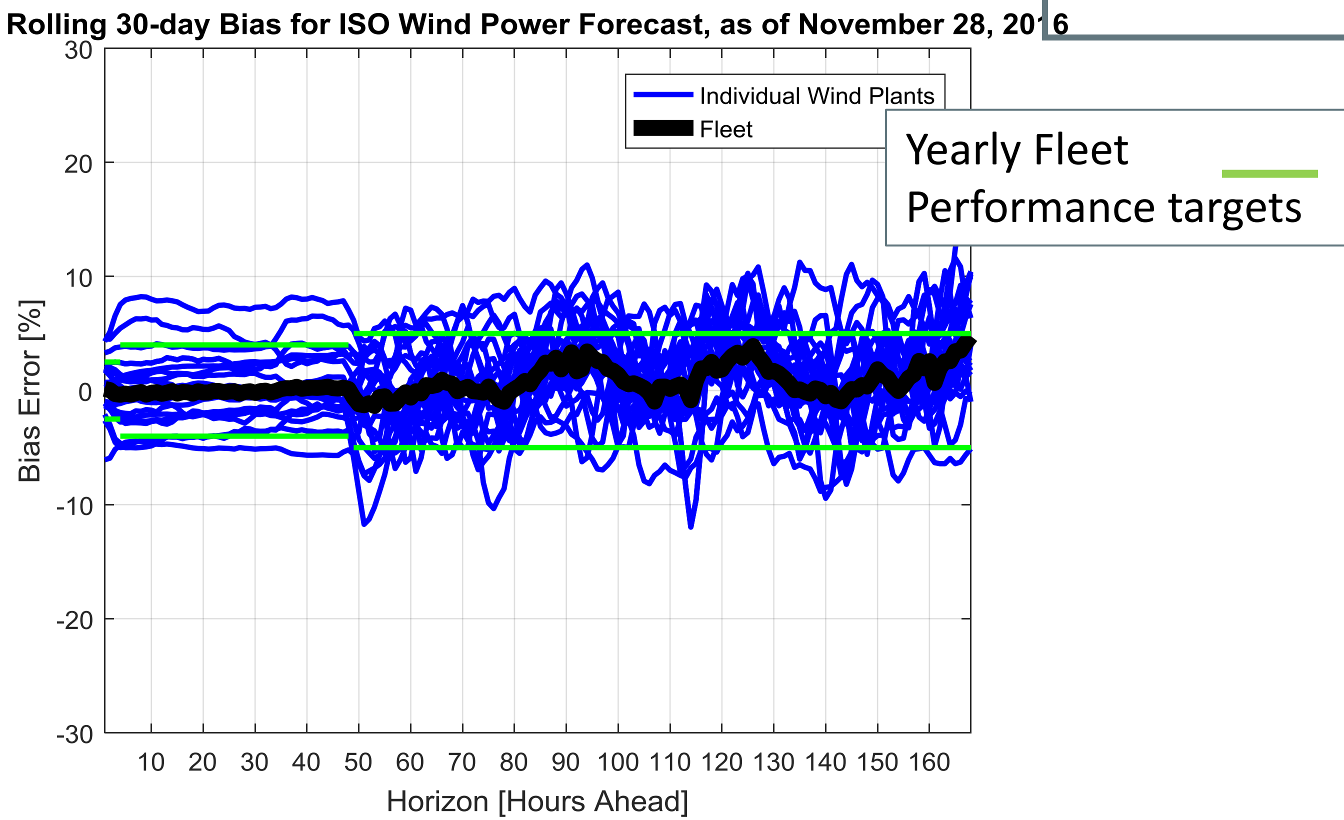
Dashboard Indicator



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/DNV-GL forecast is very good compared to industry standards, and monthly MAE is within the yearly performance targets.

Wind Power Forecast Error Statistics: Medium and Long Term Forecasts Bias

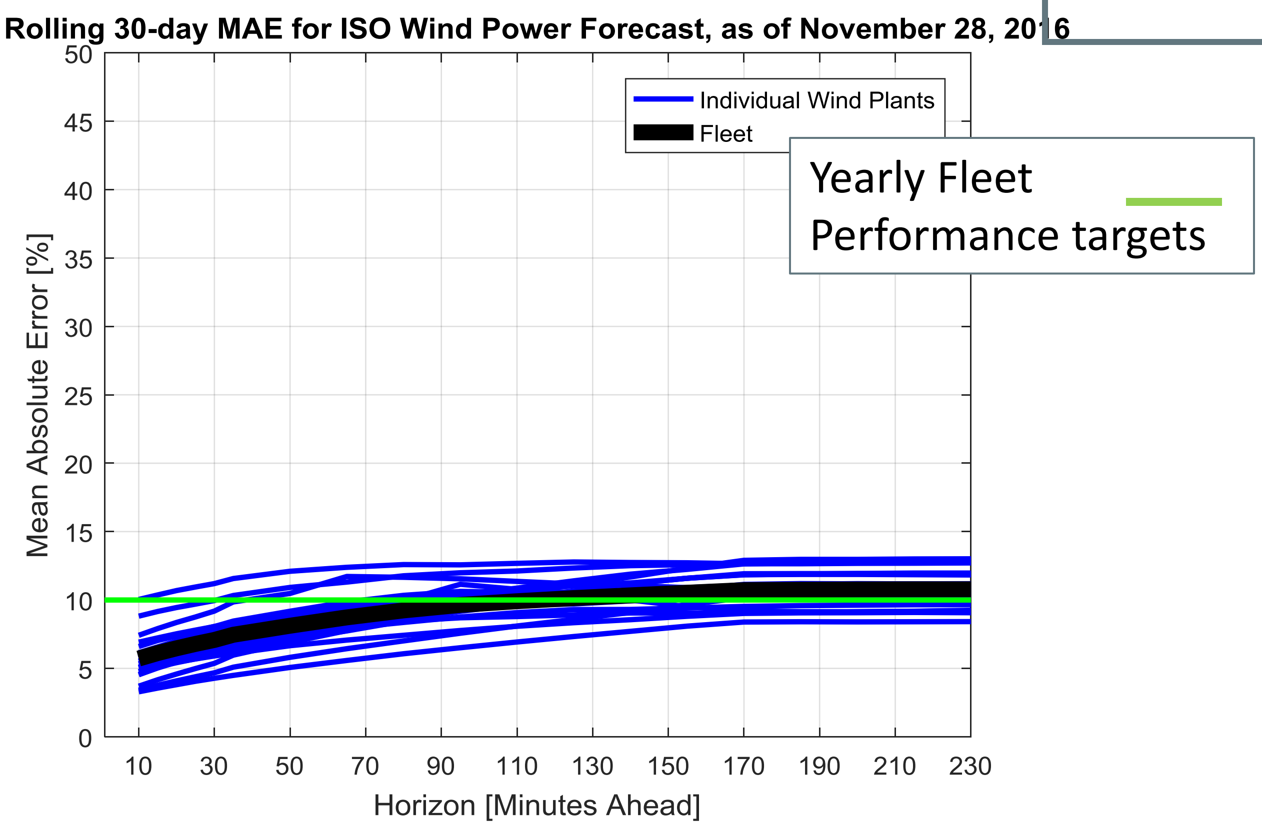
Dashboard Indicator



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/DNV-GL forecast compares well with industry standards, and monthly Bias is within yearly performance targets.

Wind Power Forecast Error Statistics: Short Term Forecast MAE

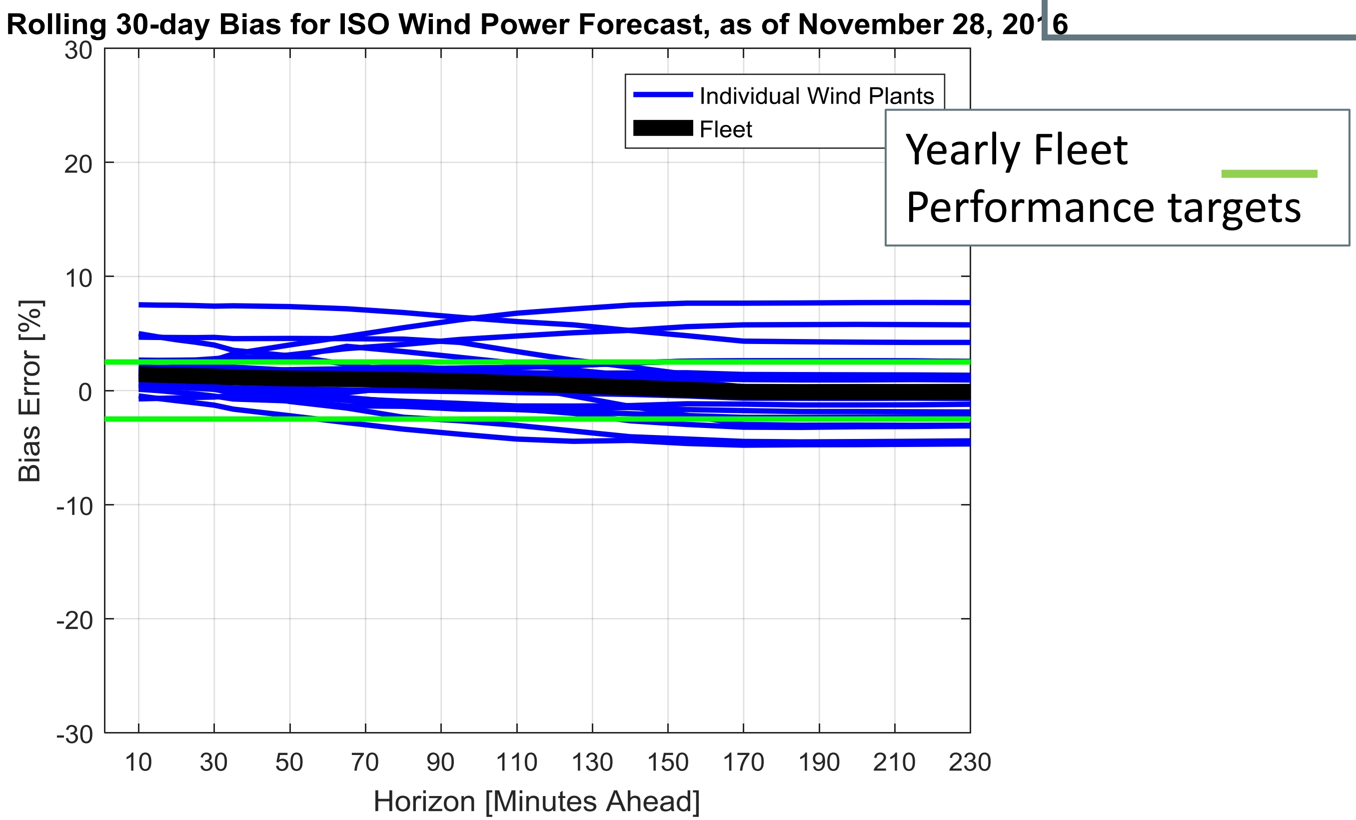
Dashboard Indicator



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/DNV-GL forecast is very good compared to industry standards, and monthly MAE is mostly within the yearly performance targets.

Wind Power Forecast Error Statistics: Short Term Forecast Bias

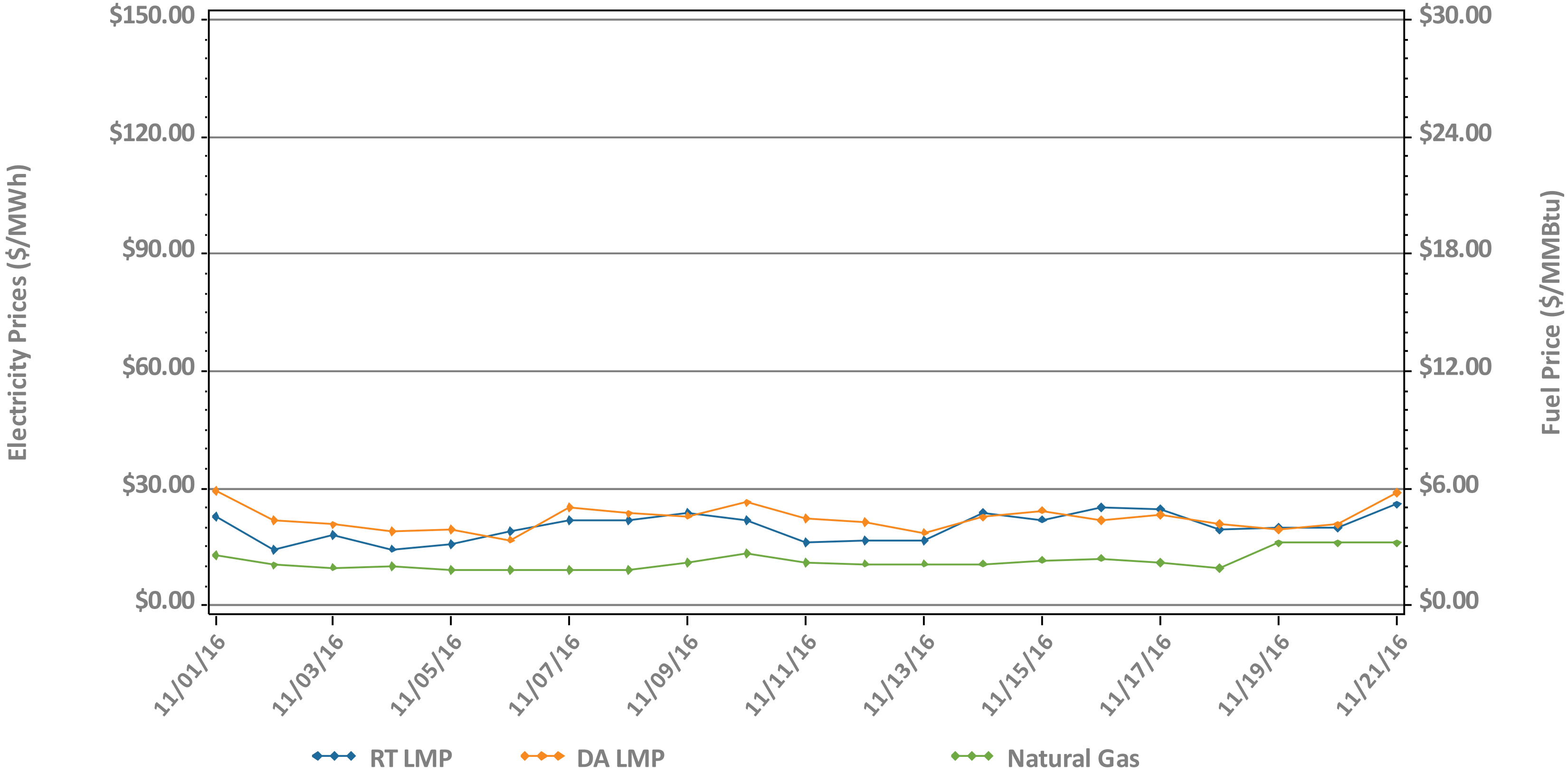
Dashboard Indicator



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/DNV-GL forecast compares well with industry standards, and monthly Bias is within yearly performance targets.

MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: November 1-21, 2016



Underlying natural gas data furnished by:

ICE Global markets in clear view

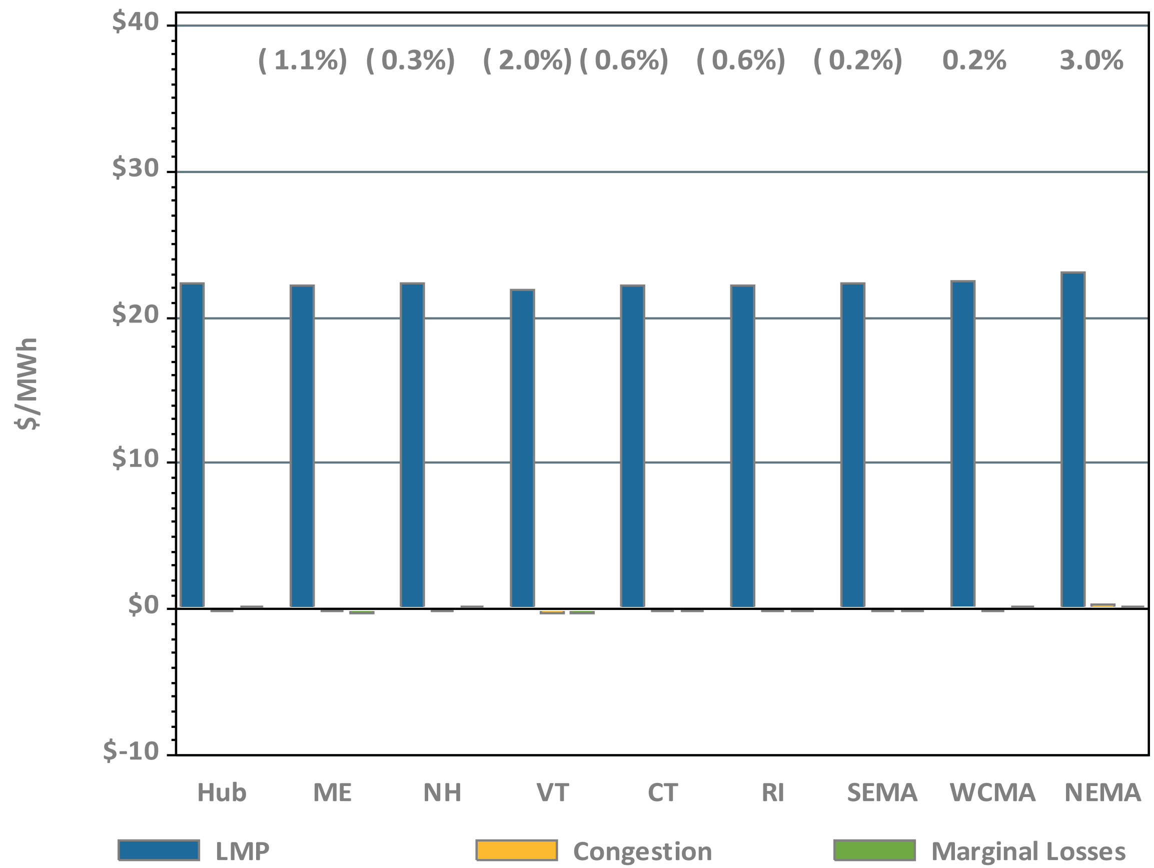
Average price difference over this period (DA-RT): $2.19

Average price difference over this period ABS(DA-RT): $3.08

Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 15%

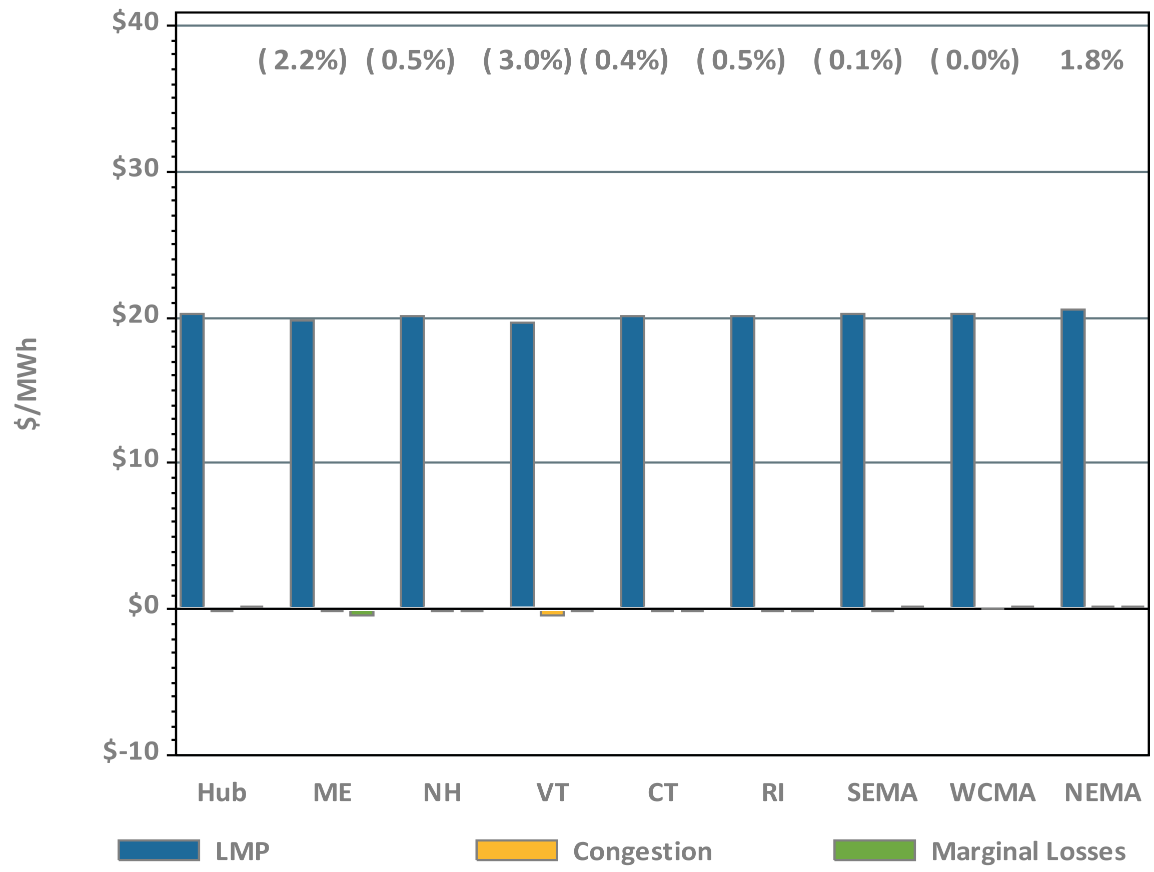
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, November 2016



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, November 2016

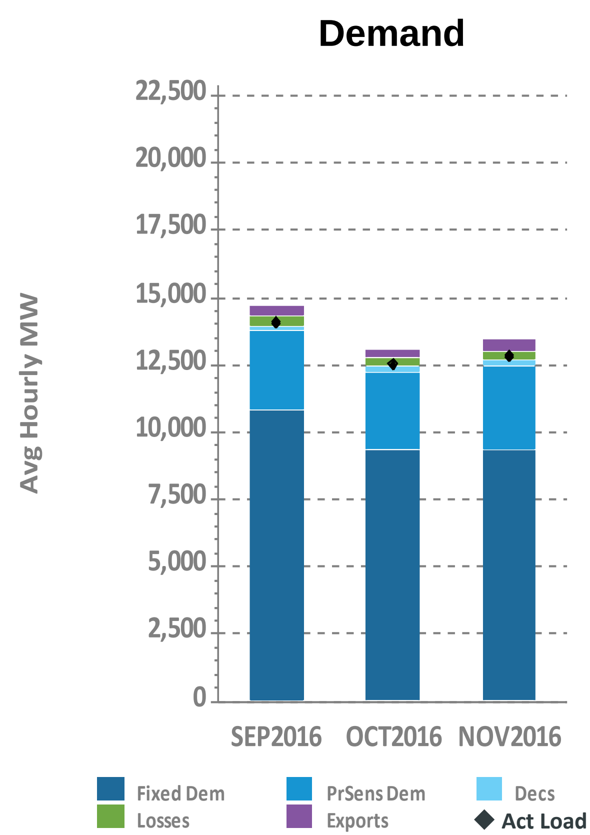


Definitions

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

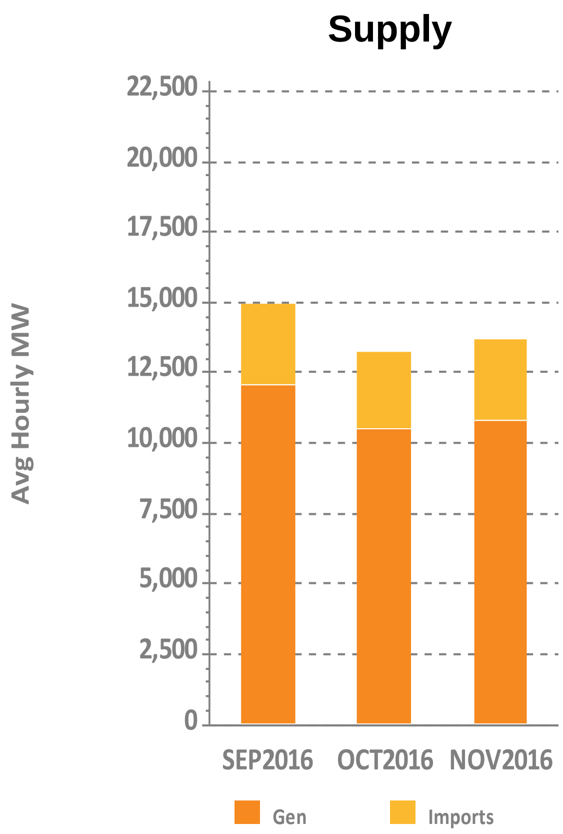
Components of Cleared DA Supply and Demand – Last Three Months

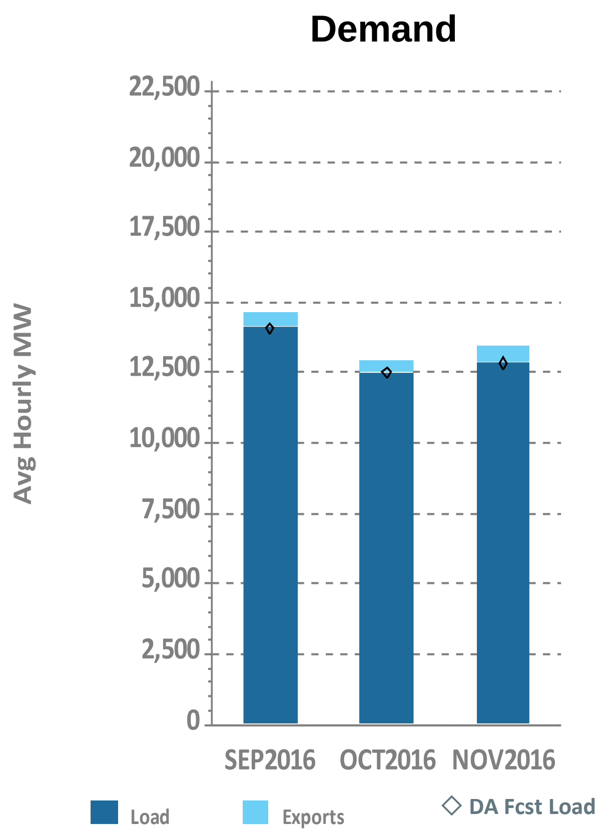
Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load



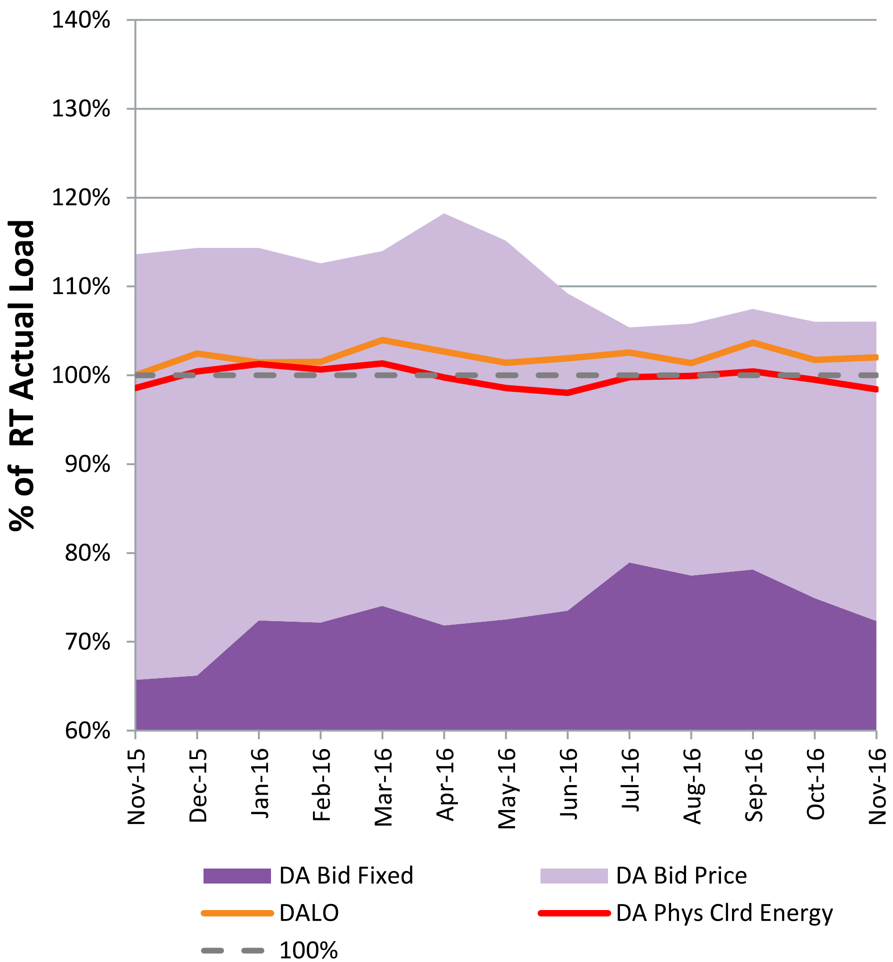
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

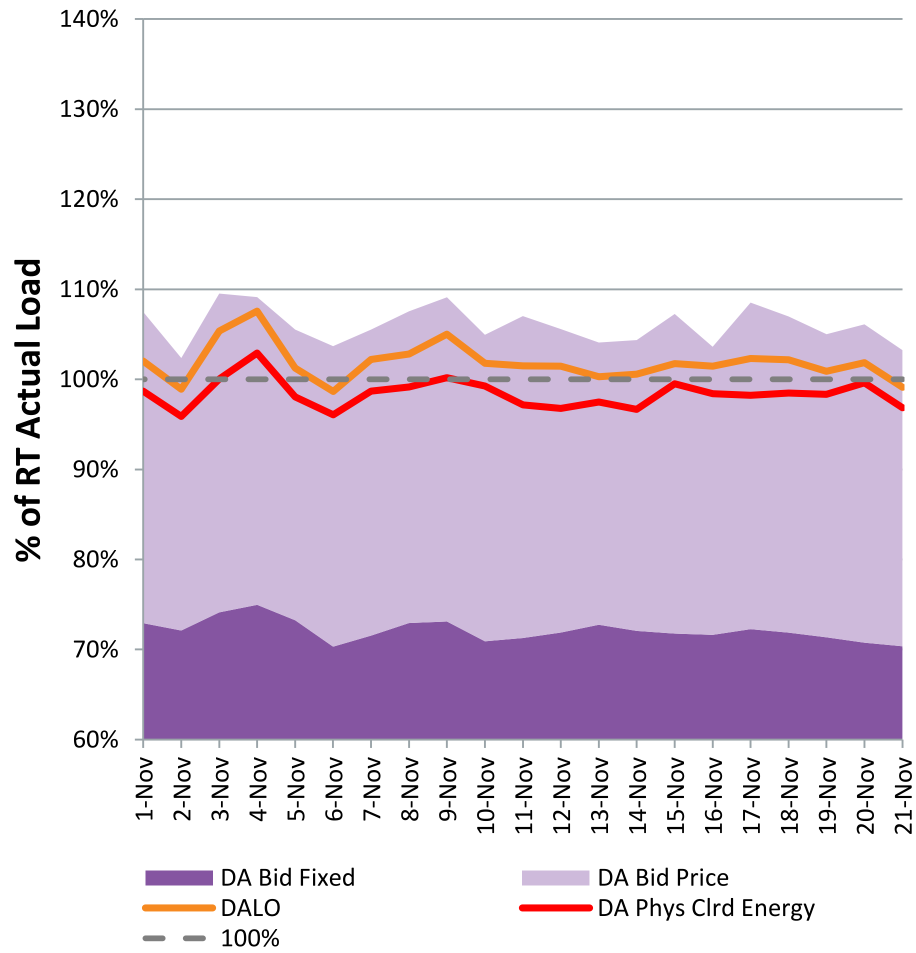
Components of RT Supply and Demand – Last Three Months





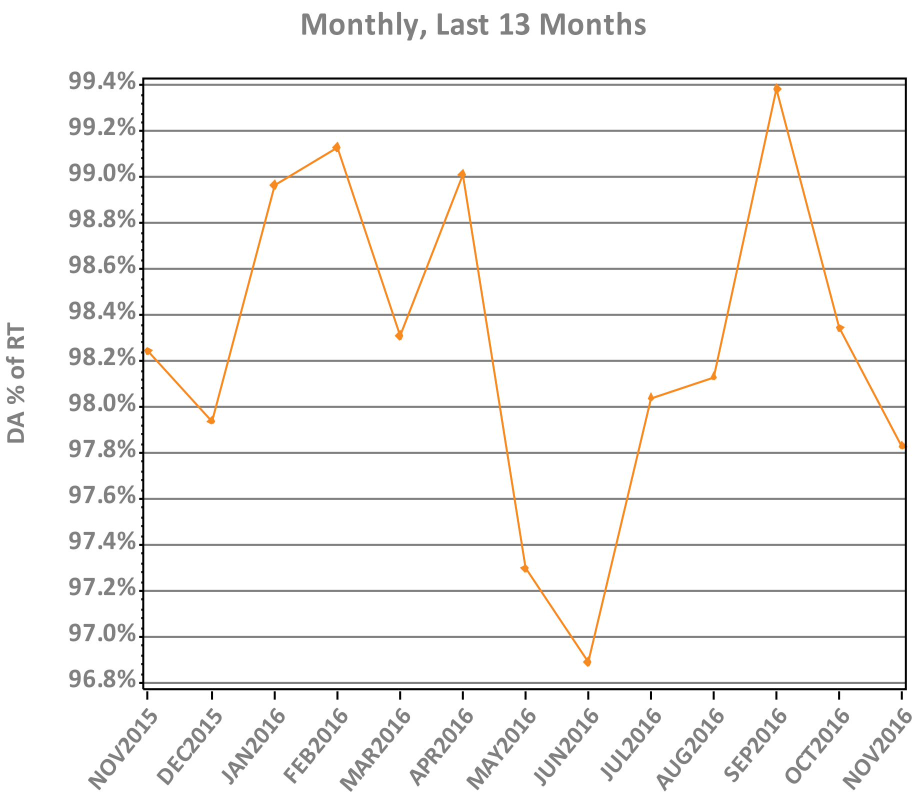
DAM Volumes as % of RT Actual Load (Peak Hour)

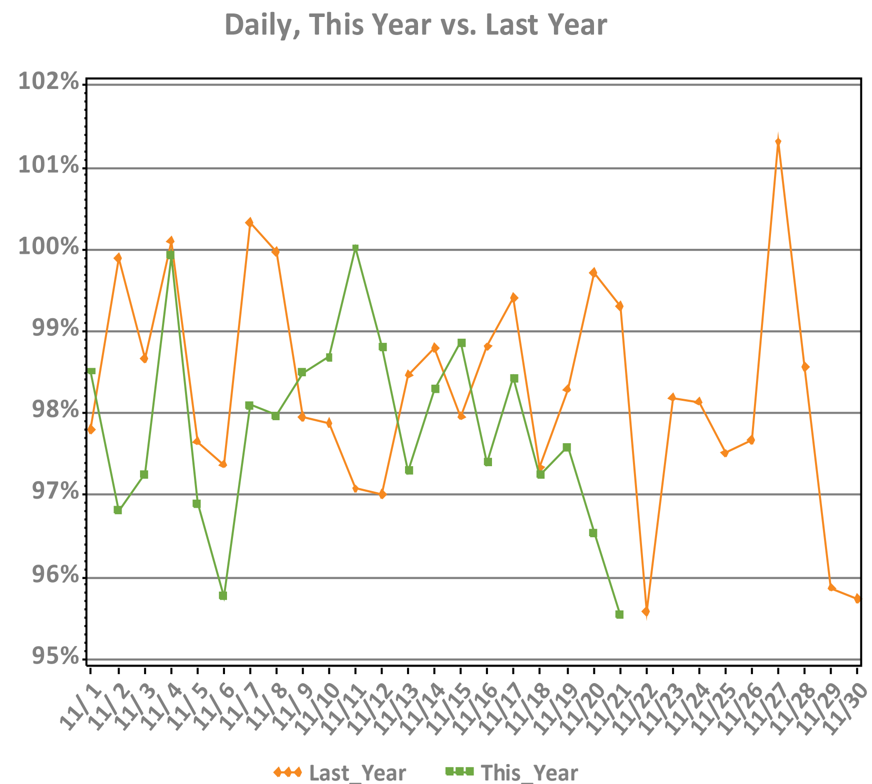




Note: Percentages were derived for the peak hour of each day (shown on right), then averaged over the month (shown on left). Values at hour of forecasted peak load.

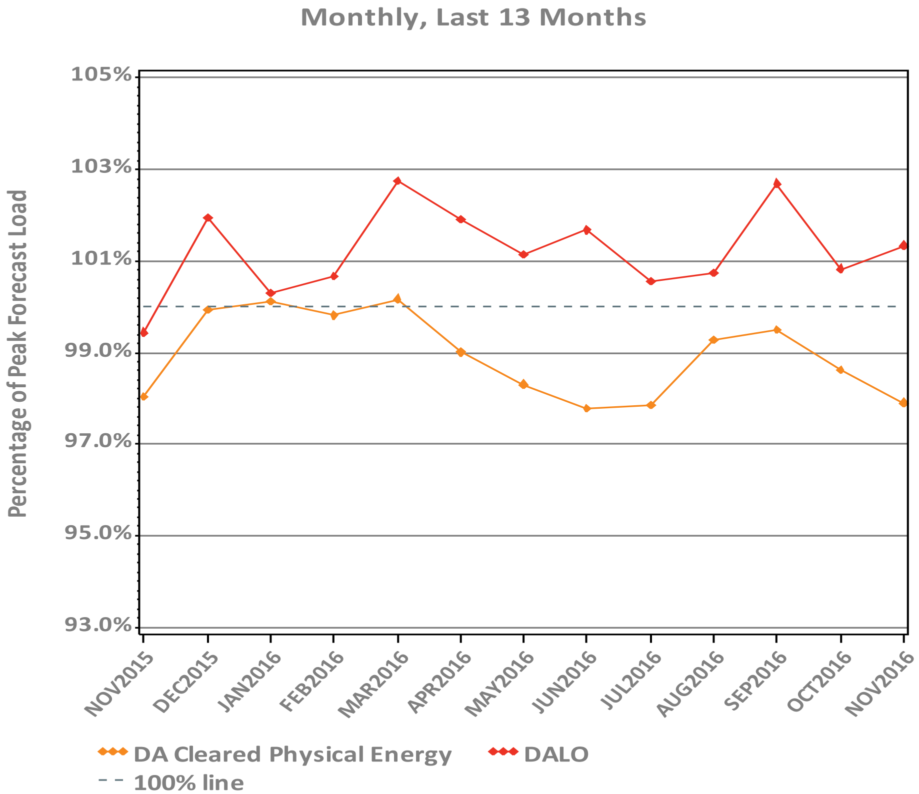
DA vs. RT Load Obligation: November, This Year vs. Last Year

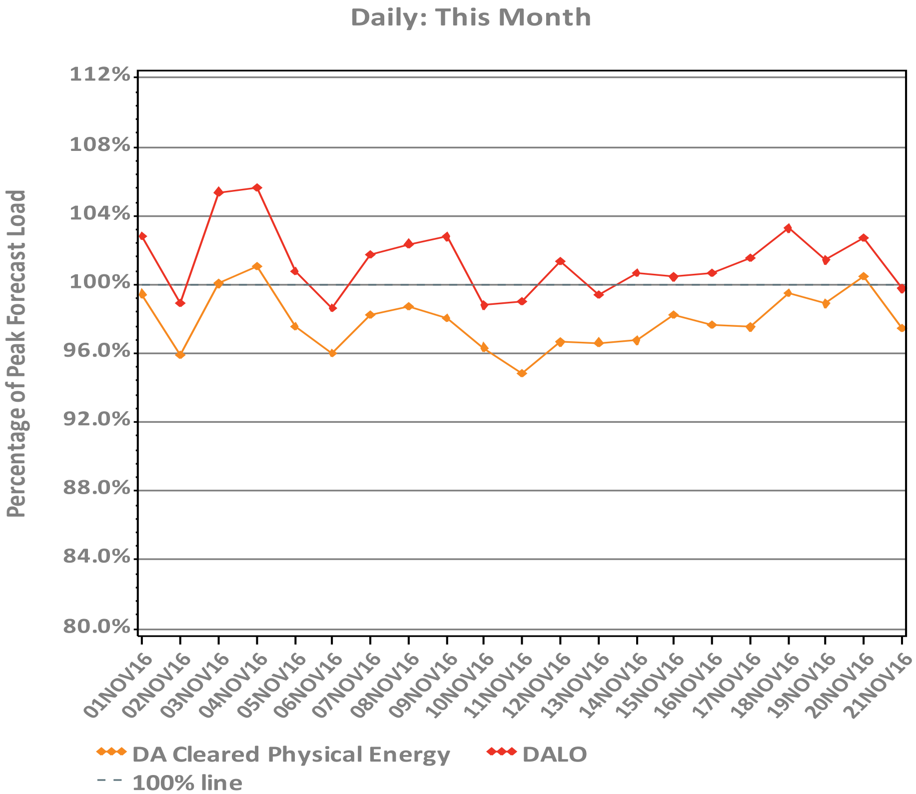




*Hourly average values

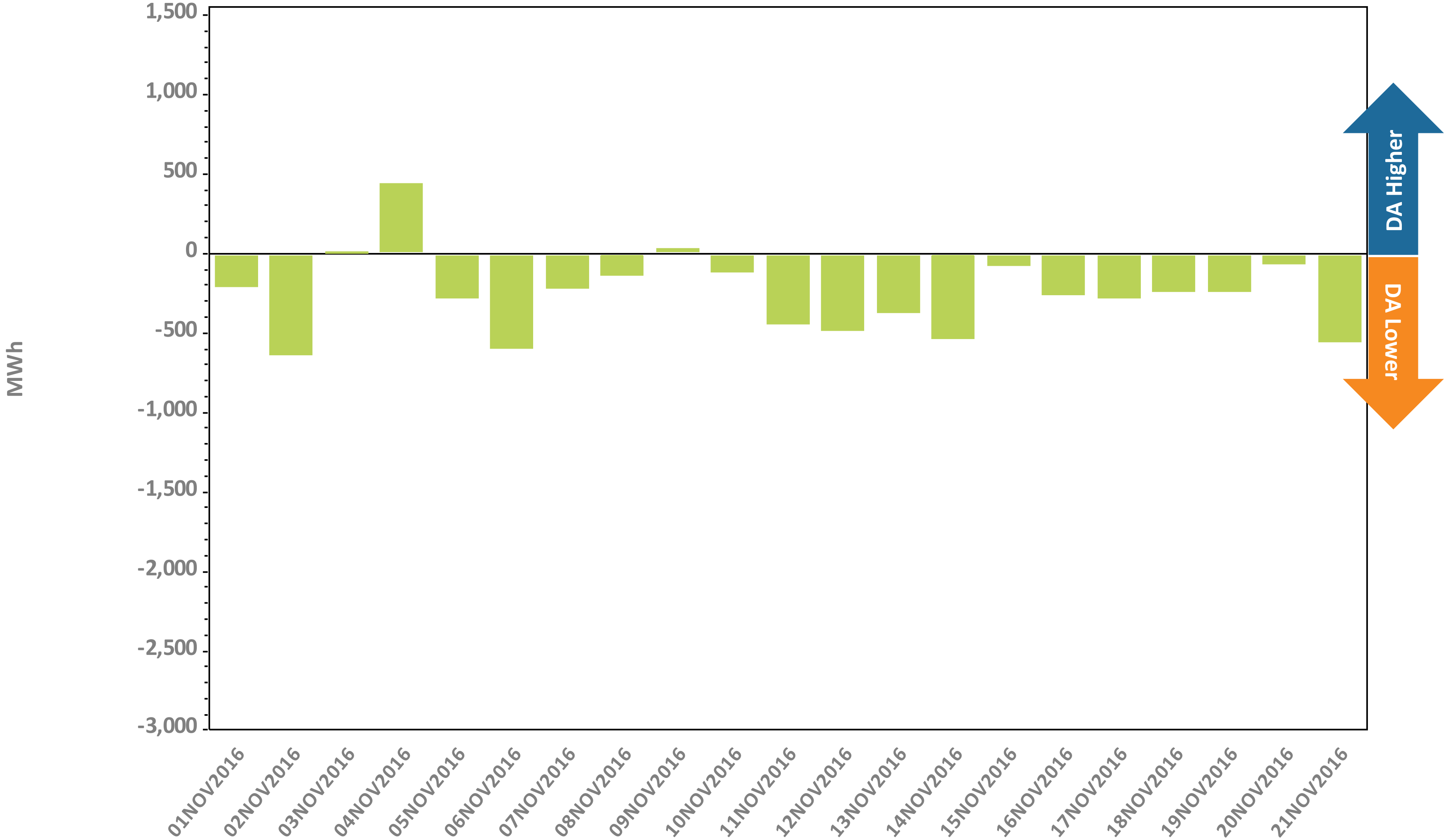
DA Volumes as % of Forecast (Peak Hour)





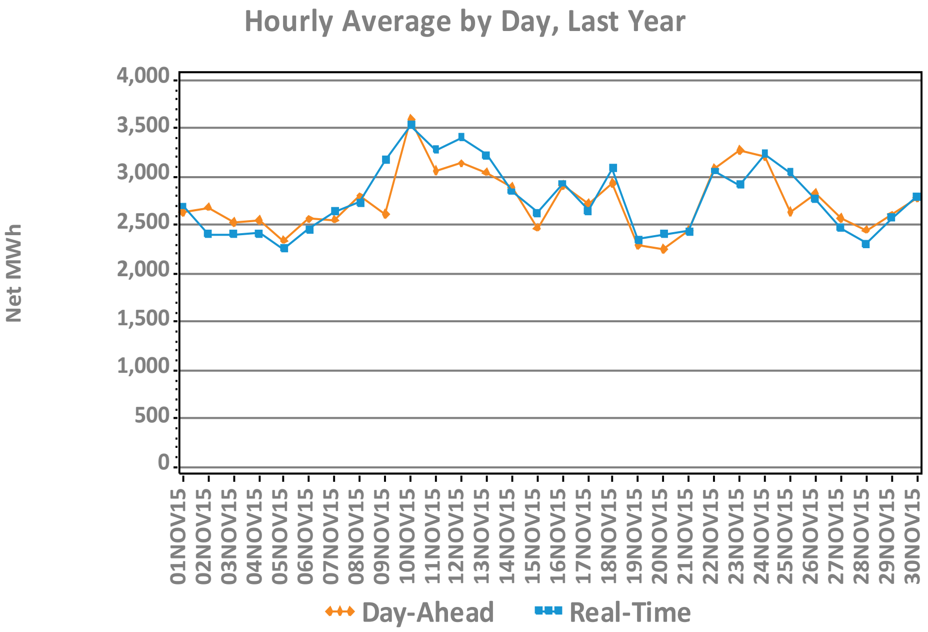
*Forecasted peak hour is reflected.

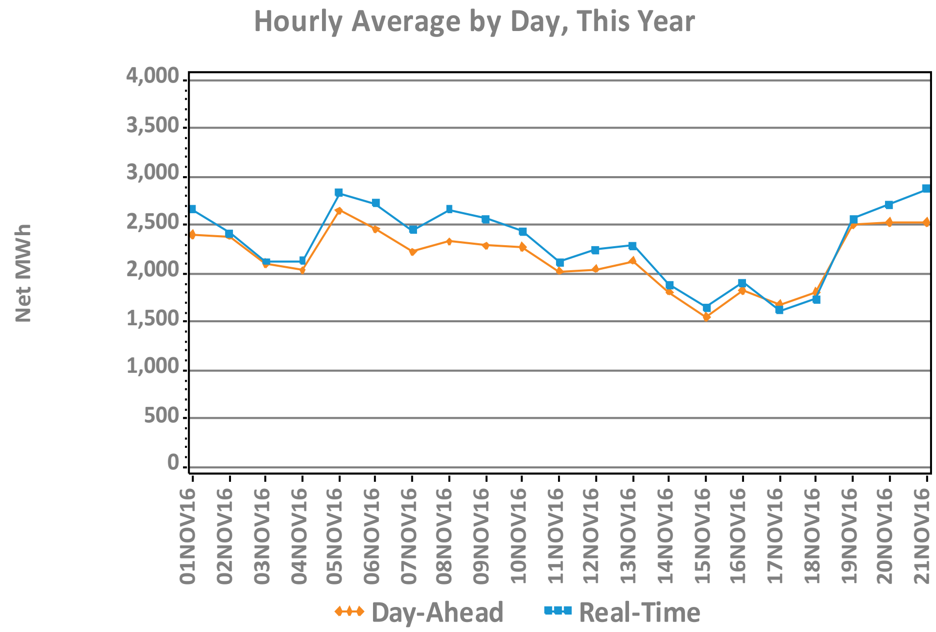
DA Cleared Physical Energy Difference from RT System Load at Peak Hour*



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

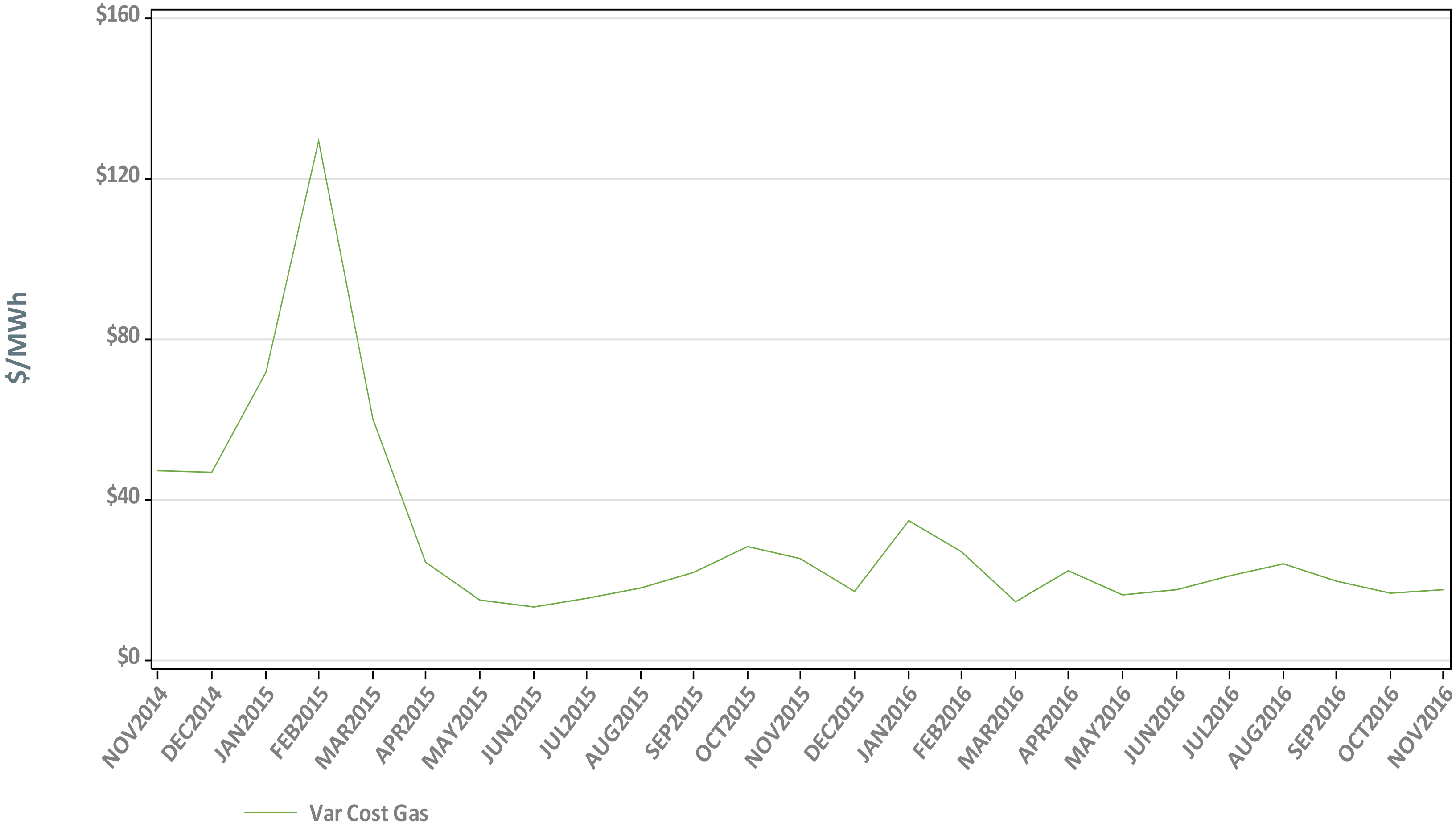
DA vs. RT Net Interchange November 2016 vs. November 2015





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

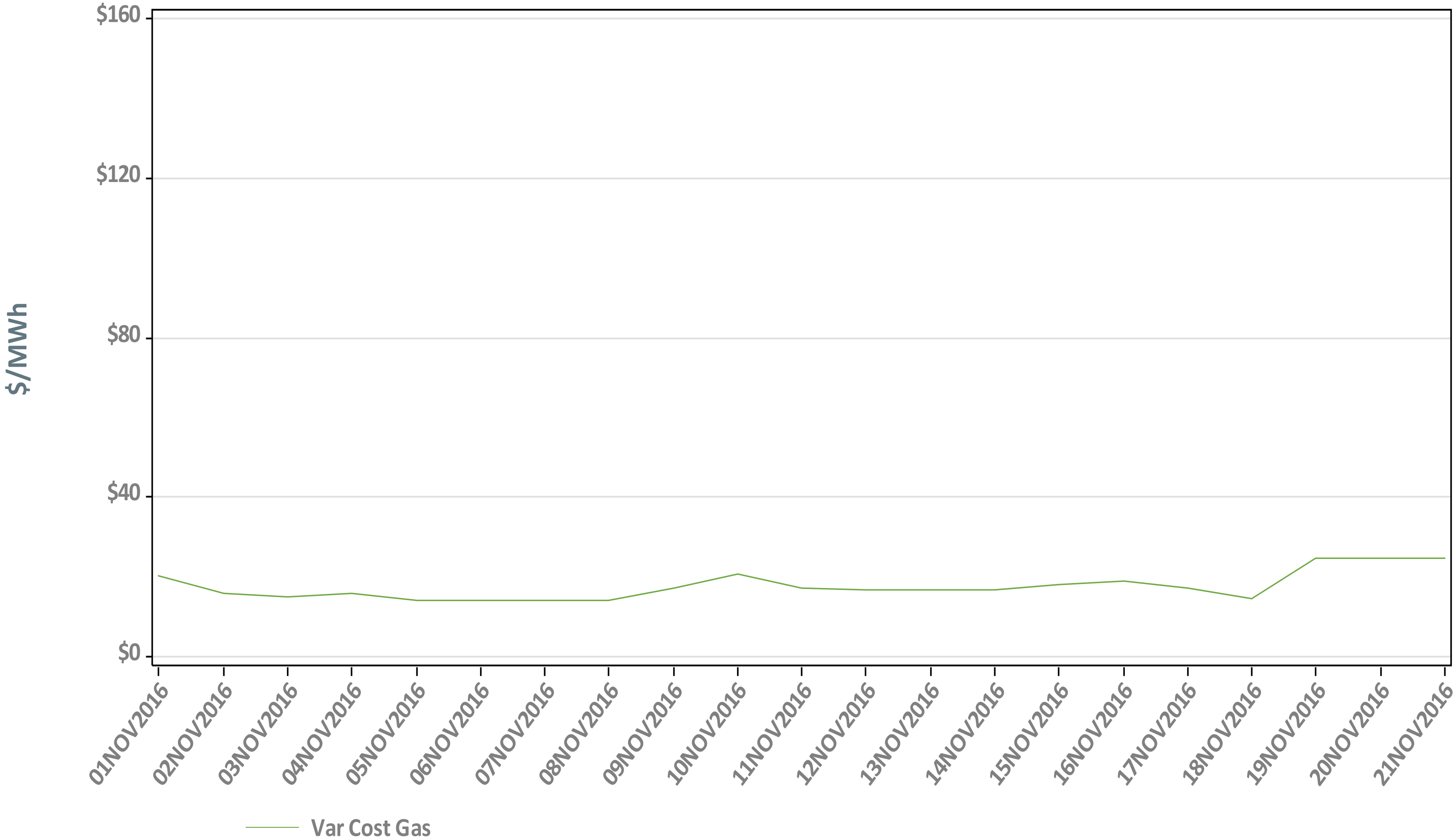


Underlying natural gas data furnished by:

ICE Global markets in clear view

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

Variable Production Cost of Natural Gas: Daily

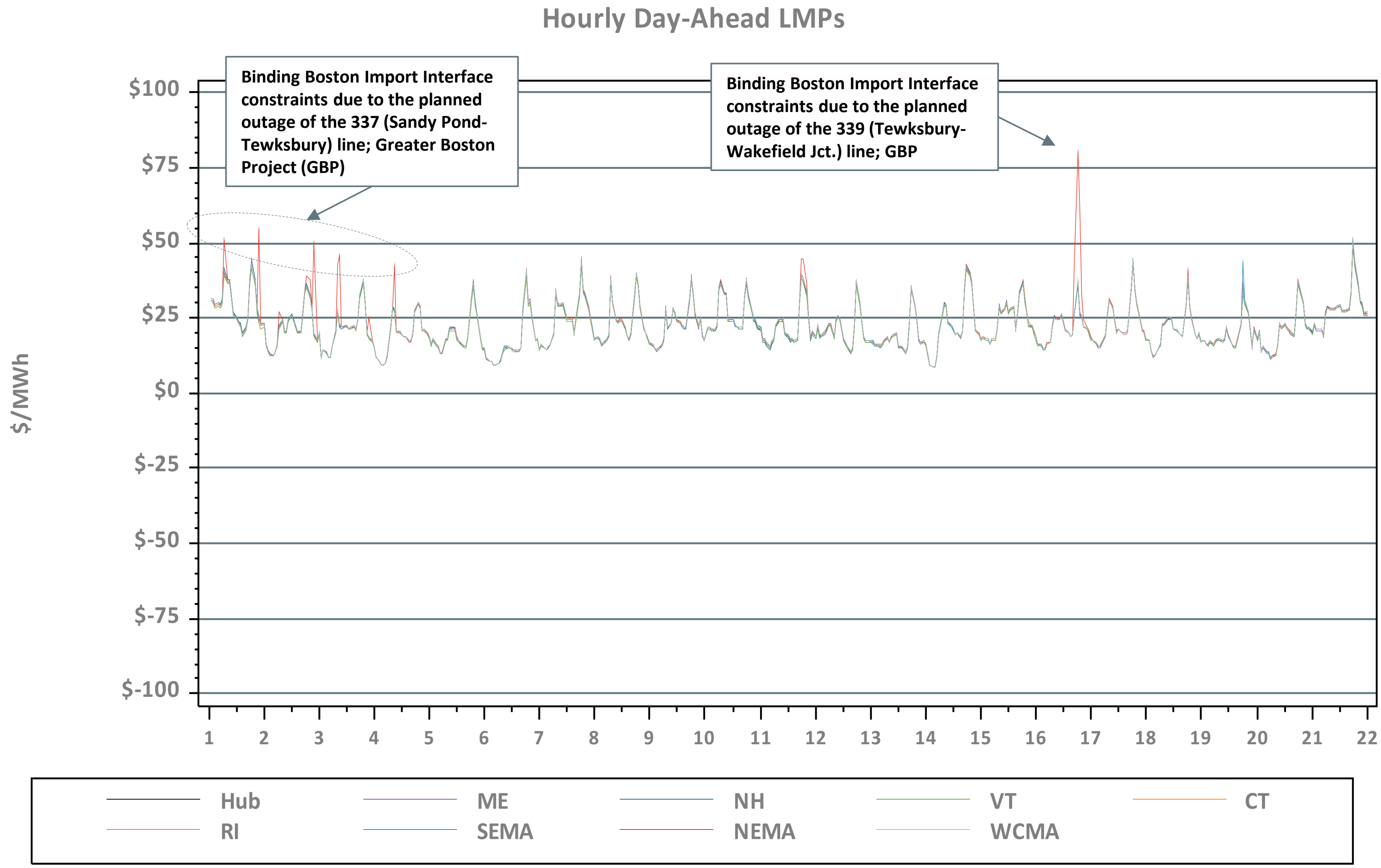


Underlying natural gas data furnished by:

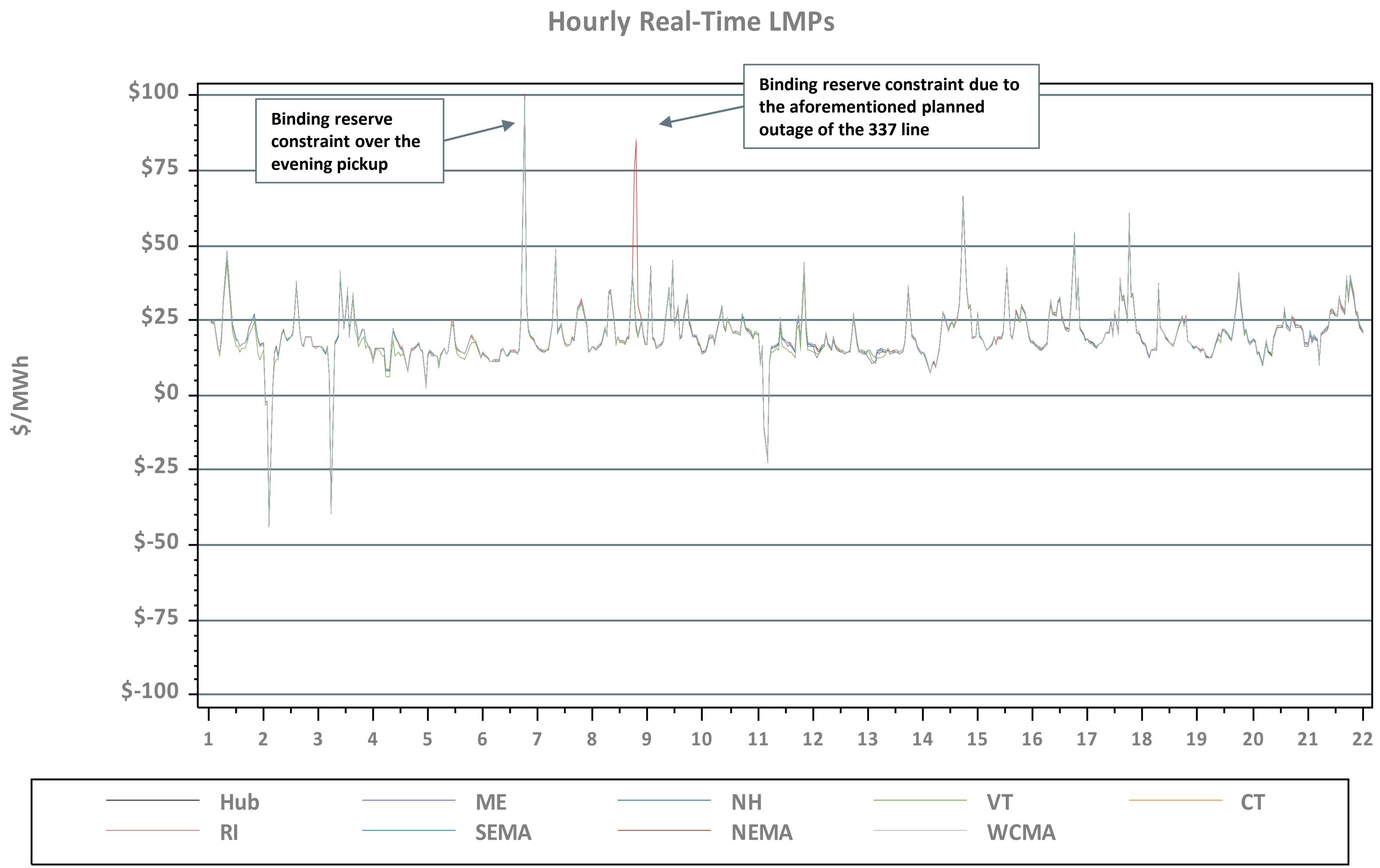
ICE Global markets in clear view

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

Hourly DA LMPs, November 1-21, 2016

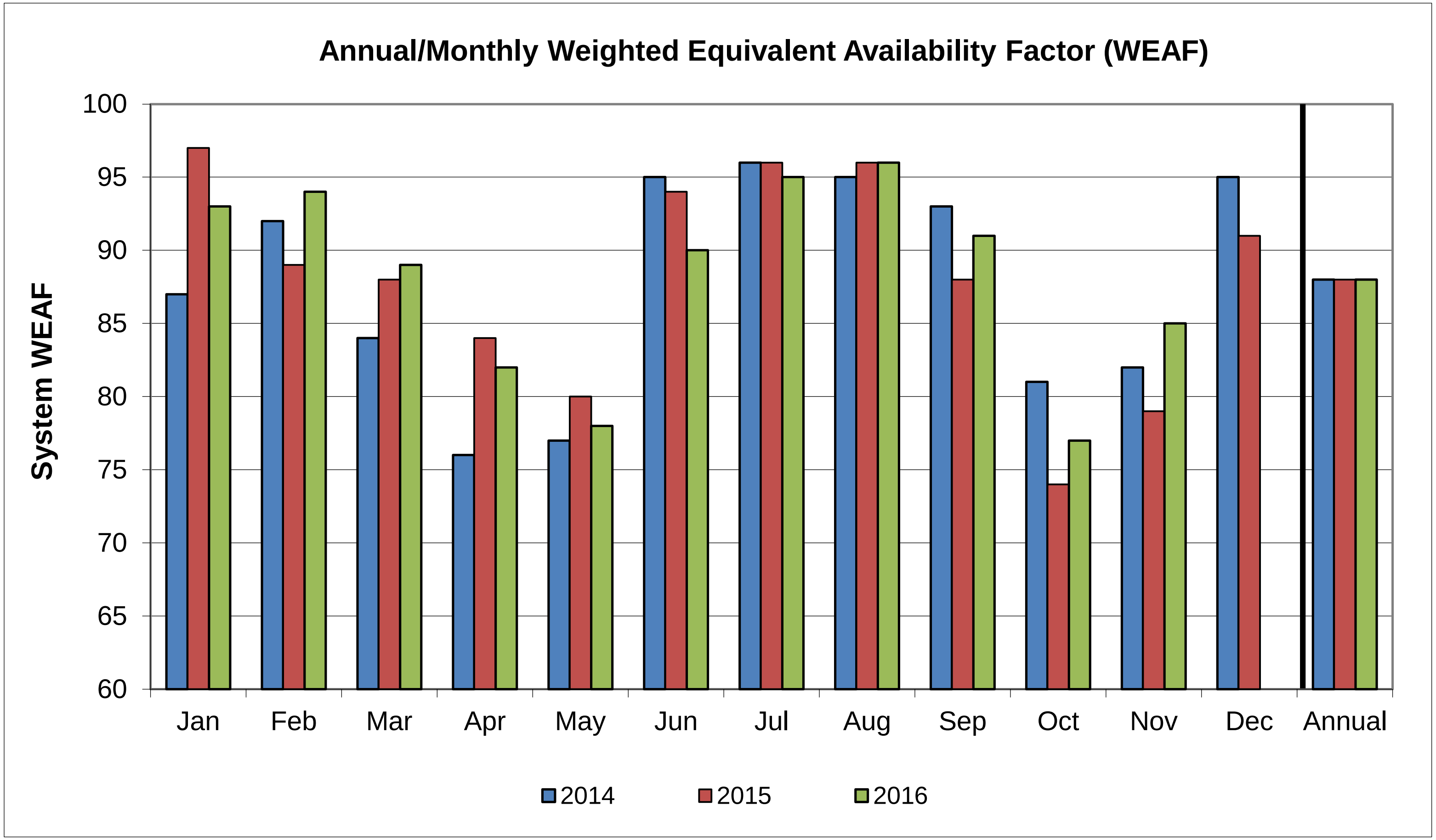


Hourly RT LMPs, November 1-21, 2016



* No Minimum Generation Emergencies were declared in November.

System Unit Availability



Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2016	93	94	89	82	78	90	95	96	91	77	85		88
2015	97	89	88	84	79	94	96	96	88	74	79	91	88
2014	87	92	84	76	77	95	96	95	93	81	82	95	88

Data as of 11/28/16

BACK-UP DETAIL

LOAD RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for December 2016

Load Zone	RTDR*	RTEG**	On Peak	Seasonal Peak	Total
ME	88.6	0.0	129.7	0.0	218.2
NH	10.7	0.0	70.7	0.0	81.3
VT	31.9	0.0	106.6	0.0	138.5
CT	53.6	1.5	59.7	355.4	470.2
RI	7.7	0.0	178.0	0.0	185.6
SEMA	11.4	0.0	246.5	0.0	258.0
WCMA	22.2	0.0	230.8	51.4	304.4
NEMA	24.4	0.0	495.5	0.0	519.9
Total	**250.4**	**1.5**	**1,517.5**	**406.9**	**2,176.2**

*** Real Time Demand Response**

**** Real Time Emergency Generation**

NOTE: CSO values include T&D loss factor (8%).

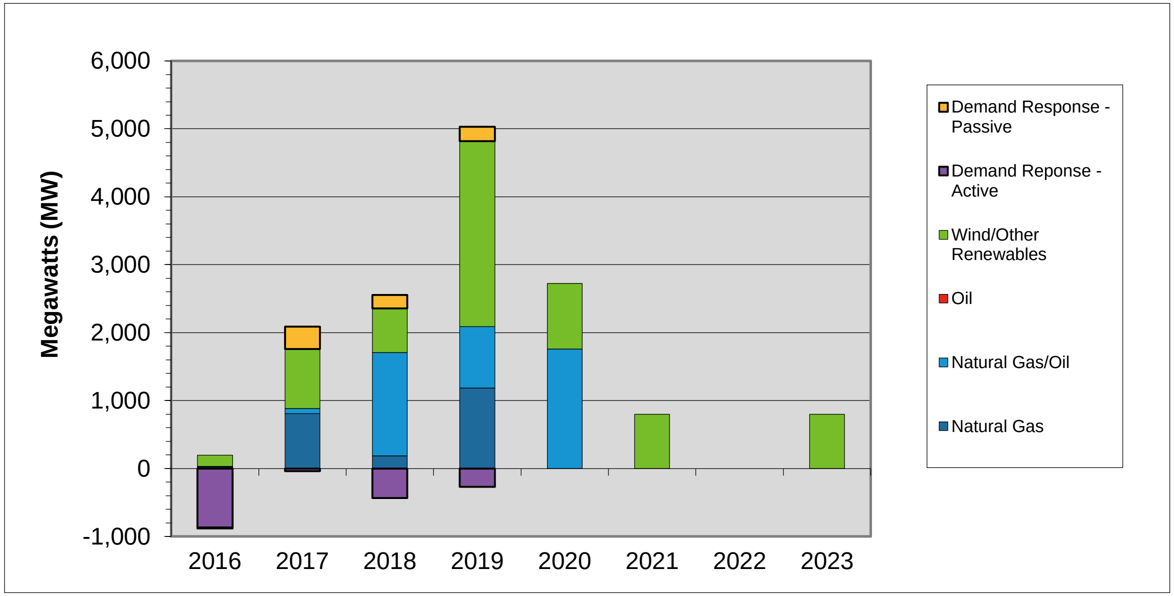
NEW GENERATION

New Generation Update
Based on Queue as of 11/28/16

- Two new projects, with a total rating of 1,000 MW, have applied for interconnection study since the last update
  - The projects consist of a photovoltaic plant and a wind facility, with expected in-service dates in 2020 and 2021
- No projects withdrew from the queue and one project went commercial, resulting in a net increase in new generation projects of 978 MW
- In total, 82 generation projects are currently being tracked by the ISO, totaling approximately 13,300 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



	2016	2017	2018	2019	2020	2021	2022	2023	Total MW	% of Total[1]
Demand Response - Passive	-12	330	196	212	0	0	0	0	726	5.8
Demand Response - Active	-868	-37	-433	-270	0	0	0	0	-1,607	-12.8
Wind & Other Renewables	166	877	650	2,731	966	800	0	800	6,990	55.6
Oil	0	0	0	0	0	0	0	0	0	0.0
Natural Gas/Oil[2]	10	74	1,519	904	1,757	0	0	0	4,264	33.9
Natural Gas	22	808	189	1,183	0	0	0	0	2,202	17.5
Totals	**-682**	**2,052**	**2,121**	**4,761**	**2,723**	**800**	**0**	**800**	**12,574**	**100.0**

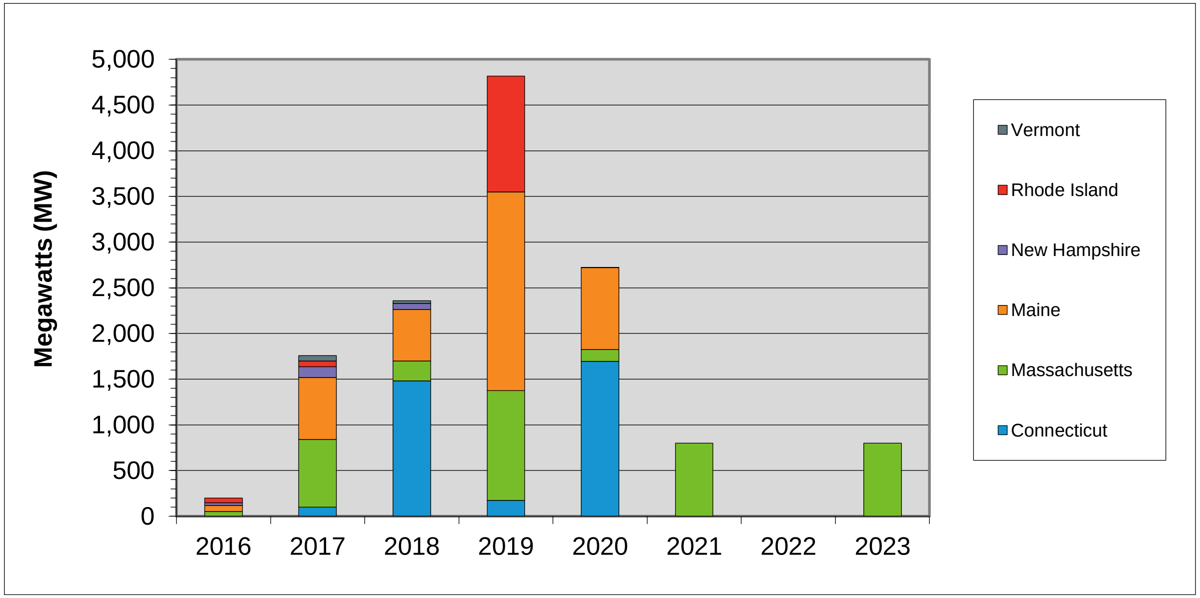
[1] Sum may not equal 100% due to rounding

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

- 2016 values include the 120 MW of generation that has gone commercial in 2016
- DR reflects changes from the initial FCM Capacity Supply Obligations in 2010-11

Actual and Projected Annual Generator Capacity Additions

By State



	2016	2017	2018	2019	2020	2021	2022	2023	Total MW	% of Total[1]
Vermont	0	62	30	0	0	0	0	0	92	0.7
Rhode Island	51	60	0	1,268	0	0	0	0	1,379	10.2
New Hampshire	30	120	65	0	5	0	0	0	220	1.6
Maine	67	676	563	2,177	895	0	0	0	4,378	32.5
Massachusetts	50	741	219	1,200	128	800	0	800	3,938	29.3
Connecticut	0	100	1,481	173	1,695	0	0	0	3,449	25.6
Totals	**198**	**1,759**	**2,358**	**4,818**	**2,723**	**800**	**0**	**800**	**13,456**	**100.0**

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

- 2016 values reflect the 120 MW of generation that has gone commercial in 2016

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	112	0	0	2	112
Hydro	4	103	0	0	4	103
Landfill Gas	1	2	0	0	1	2
Natural Gas	13	2,243	0	0	13	2,243
Natural Gas/Oil	12	4,254	0	0	12	4,254
Oil	0	0	0	0	0	0
Solar	15	780	1	10	14	770
Wind	32	5,749	4	274	28	5,475
Battery Storage	3	93	1	16	2	77
Total	82	13,336	6	300	76	13,036

- 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	5	182	0	0	5	182
Intermediate	18	5,422	0	0	18	5,422
Peaker	27	1,983	2	26	25	1,957
Wind Turbine	32	5,749	4	274	28	5,475
Total	82	13,336	6	300	76	13,036

- 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

	Total		Baseload		Intermediate		Peaker		Wind Turbine	
Fuel Type	**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	112	2	112	0	0	0	0	0	0
Hydro	4	103	1	5	2	32	1	66	0	0
Landfill Gas	1	2	1	2	0	0	0	0	0	0
Natural Gas	13	2,243	1	63	9	1,991	3	189	0	0
Natural Gas/Oil	12	4,254	0	0	7	3,399	5	855	0	0
Oil	0	0	0	0	0	0	0	0	0	0
Solar	15	780	0	0	0	0	15	780	0	0
Wind	32	5,749	0	0	0	0	0	0	32	5,749
Battery Storage	3	93	0	0	0	0	3	93	0	0
Total	82	13,336	5	182	18	5,422	27	1,983	32	5,749

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

FORWARD CAPACITY MARKET

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	638.393	-150.973
	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	1,687.458	-7.308
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**	**2,325.851**	-158.281
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	**28,971.511**	90.492
	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	**754.101**	-23.823
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**	**29,725.612**	66.669
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**	**1,337.037**	0
***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**	**33,388.5**	-91.612
Net ICR (NICR)		**33,456**	**33,456**	**0**	**33,456**	**0**	**33,456**	**0**	33,114	**-342**	**33,114**	**0.00**	**33,391**	**277**	**33,391**	**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 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	781.206	-151.52	671.28	-109.926	575.63	-95.65	556.453	-19.177
	Passive Demand	1,631.335	1,519.740	-111.595	1,519.311	-0.43	1,543.793	24.482	1,544.276	0.48	1,544.119	-0.157	1,607.705	63.586	1,884.902	277.197
Demand Total		**2,748.033**	**2,563.459**	**-184.574**	**2,463.581**	**-99.88**	**2,476.514**	**12.933**	2,325.482	-151.03	2,215.399	-110.083	2,183.335	-32.064	2,441.355	258.02
Generator	*Non-Intermittent*	30,704.578	28,146.837	-2,557.741	28,127.044	-19.79	28,523.002	395.958	28,307.339	-215.66	28,791.131	483.792	28,948.677	157.546	29,152.793	204.116
	Intermittent	936.913	893.710	-43.203	903.244	9.53	913.083	9.839	838.626	-74.46	824.833	-13.793	800.286	-24.547	735.174	-65.112
Generator Total		**31,641.491**	**29,040.547**	**-2,600.944**	**29,030.288**	**-10.26**	**29,436.085**	**405.797**	29,145.965	-290.12	29,615.964	469.999	29,748.963	132.999	29,887.967	139.004
Import Total		**1,830.000**	**1,606.862**	**-223.138**	**1,606.862**	**0.00**	**1,616.401**	**9.539**	1,576.401	-40.00	1,576.401	0	1,440.401	-136	1,162.202	-278.199
***Grand Total**		**36,219.524**	**33,210.868**	**-3,008.656**	**33,100.731**	**-110.14**	**33,529.000**	**428.269**	33,047.848	-481.15	33,407.764	359.916	33,372.699	-35.065	33,491.524	118.825
Net ICR (NICR)		**32,968**	**32,968**	**0**	33,529	561	33,529	0	33,529	0.00	33,529	0	33,152	-377	33,152	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	887.493	-192.59	891.604	4.111	772.352	-119.252						
	Passive Demand	1,960.517	1,958.874	-1.64	1,956.663	-2.211	2025.383	68.72						
Demand Total		**3,040.596**	**2,846.367**	**-194.23**	**2,848.267**	**1.9**	**2,797.735**	-50.532						
Generator	*Non-Intermittent*	28,547.813	28,523.796	-24.02	28,666.87	143.074	28,658.35	-8.52						
	Intermittent	876.925	898.955	22.03	922.173	23.218	918.782	-3.391						
Generator Total		**29,424.738**	**29,422.751**	**-1.99**	**29,589.043**	**166.292**	**29,577.132**	**-11.911**						
Import Total		**1,237.034**	**1,237.034**	**0.00**	**1,375.53**	**138.496**	**1,375.53**	**0**						
*****Grand Total**		**33,702.368**	**33,506.152**	**-196.22**	**33,812.84**	**306.688**	**33,750.397**	**-62.443**						
Net ICR (NICR)		**33,855**	**34,061**	**206.00**	**34,061**	**0**	**34,061**	**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 9

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*	647.26	596.701	-50.559	553.857	-42.844								
	Passive Demand	2,156.151	2153.94	-2.211	2150.196	-3.744								
Demand Total		**2,803.411**	**2,750.641**	**-52.77**	**2,704.053**	**-46.588**								
Generator	*Non-Intermittent*	29,550.564	29,558.181	7.617	29,783.831	225.65								
	Intermittent	891.616	864.924	-26.692	872.425	7.501								
Generator Total		**30,442.18**	**30,423.105**	**-19.075**	**30,656.256**	**233.151**								
Import Total		**1,449**	**1449**	**0**	**1449**	**0**								
*****Grand Total**		**34,694.591**	**34622.746**	**-71.845**	**34,809.309**	**186.563**								
Net ICR (NICR)		**34,189**	**33,883**	**-306**	**33,883**	**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 10

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*	377.525												
	Passive Demand	2,368.631												
Demand Total		**2,746.156**												
Generator	*Non-Intermittent*	30,387.588												
	Intermittent	982.988												
Generator Total		**31,370.576**												
Import Total		**1,449.8**												
*****Grand Total**		**35,566.532**												
Net ICR (NICR)		**34,151**												

* 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.

Active/Passive Demand Response

CSO Totals by Commitment Period

Commitment Period	Active/ Passive	Existing	New	Grand Total
2010-11	Active	1246.399	603.675	1850.074
	Passive	119.211	584.277	703.488
	Grand Total	1365.61	1187.952	2553.562
2011-12	Active	1768.392	184.99	1953.382
	Passive	719.98	263.25	983.23
	Grand Total	2488.372	448.24	2936.612
2012-13	Active	1726.548	98.227	1824.775
	Passive	861.602	211.261	1072.863
	Grand Total	2588.15	309.488	2897.638
2013-14	Active	1794.195	257.341	2051.536
	Passive	1040.113	257.793	1297.906
	Grand Total	2834.308	515.134	3349.442
2014-15	Active	2062.196	41.945	2104.141
	Passive	1264.641	221.072	1485.713
	Grand Total	3326.837	263.017	3589.854
2015-16	Active	1935.406	66.104	2001.51
	Passive	1395.885	247.449	1643.334
	Grand Total	3331.291	313.553	3644.844
2016-17	Active	1116.468	0.23	1116.698
	Passive	1386.56	244.775	1631.335
	Grand Total	2503.028	245.005	2748.033
2017-18	Active	1066.593	13.486	1080.079
	Passive	1619.147	341.37	1960.517
	Grand Total	2685.74	354.856	3040.596
2018-19	Active	565.866	81.394	647.26
	Passive	1870.549	285.602	2156.151
	Grand Total	2436.415	366.996	2803.411
2019-20	Active	357.221	20.304	377.525
	Passive	2018.201	350.43	2368.631
	Grand Total	2375.422	370.734	2746.156

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

What are Daily NCPC Payments?

- Payments made to resources whose 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 during 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
- NCPC payments are intended to make a resource that follows the ISO's operating instructions "no worse off" financially than the best alternative generation schedule

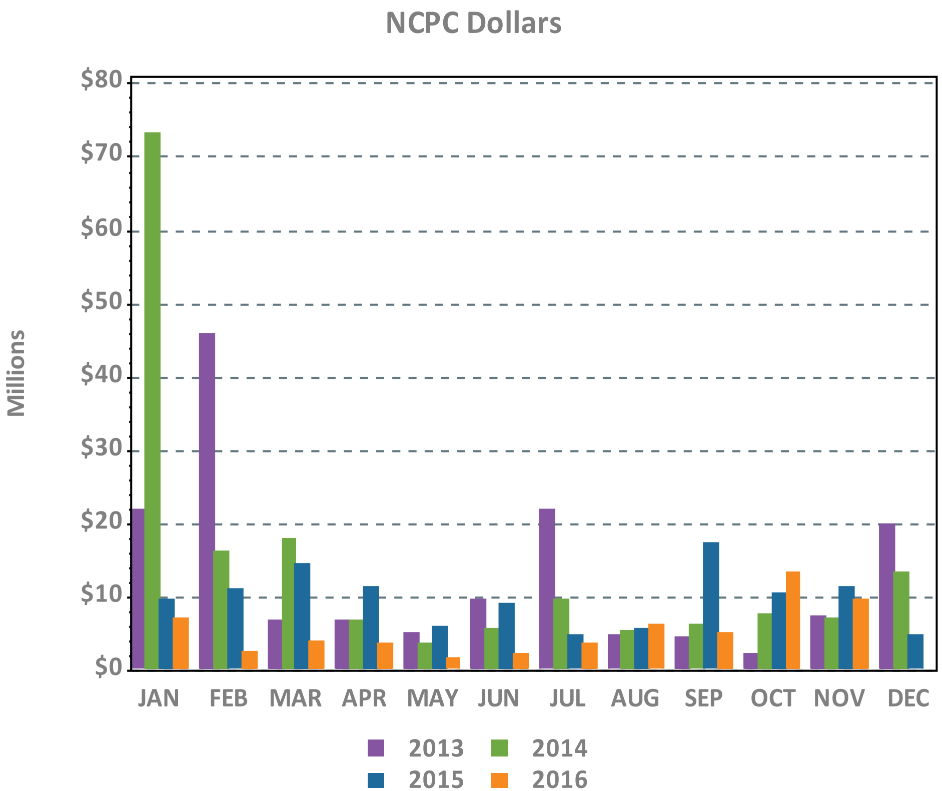
Definitions

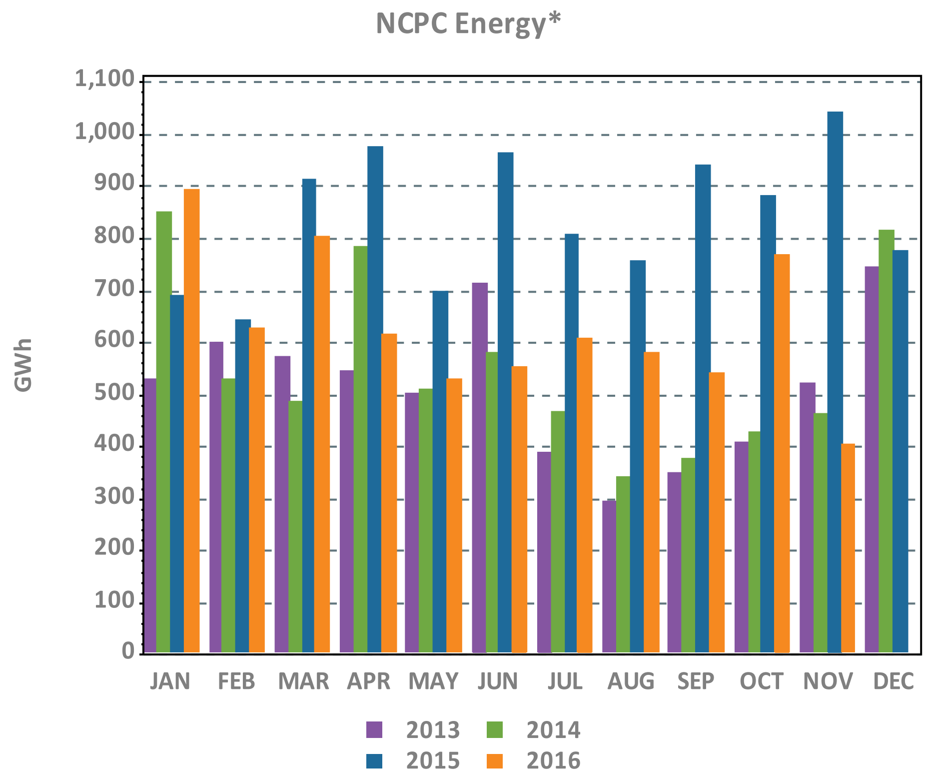
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing 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
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 and Generator/DARD Posturing NCPC (allocated to RTLO) and Min Generation Emergency NCPC (allocated to RTGO).

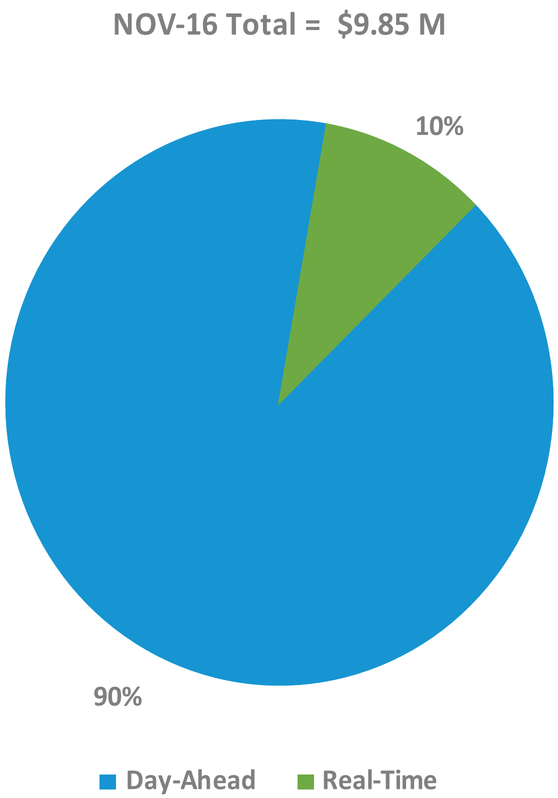
Year-Over-Year Total NCPC Dollars and Energy

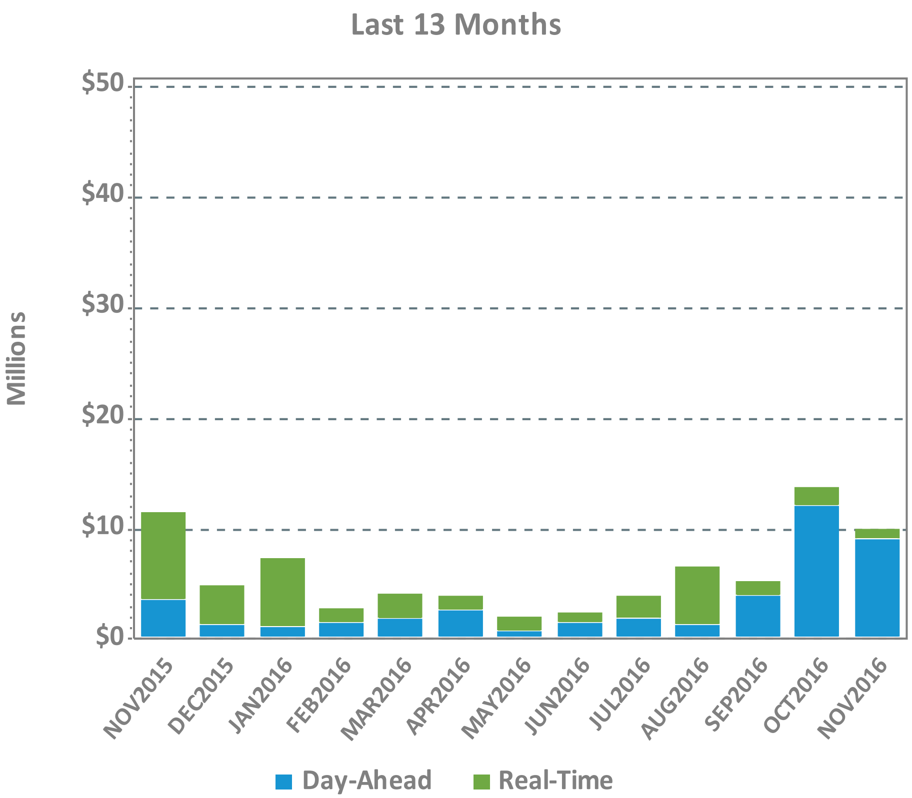




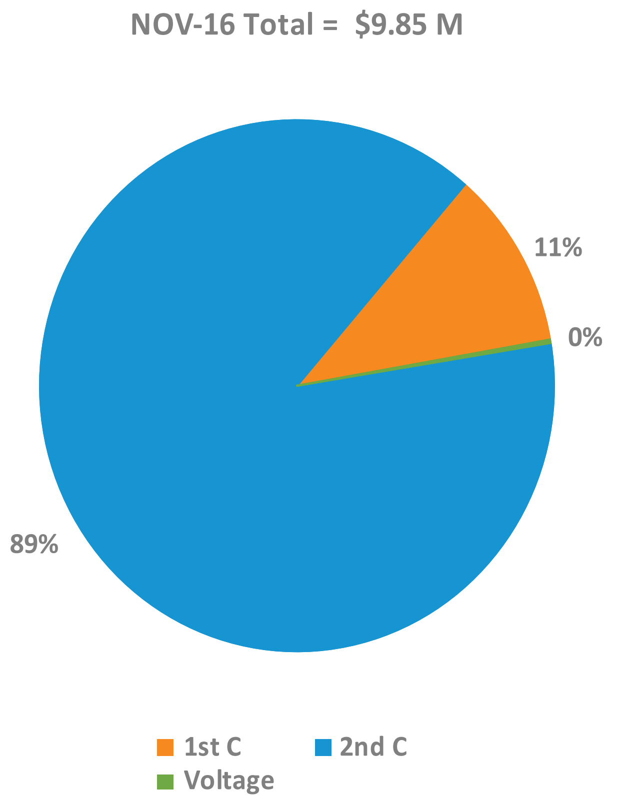
*** NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits, assessed during hours in which they are NCPC-eligible. All NCPC components (1st Contingency, 2nd Contingency, Voltage, and RT Distribution) are reflected.**

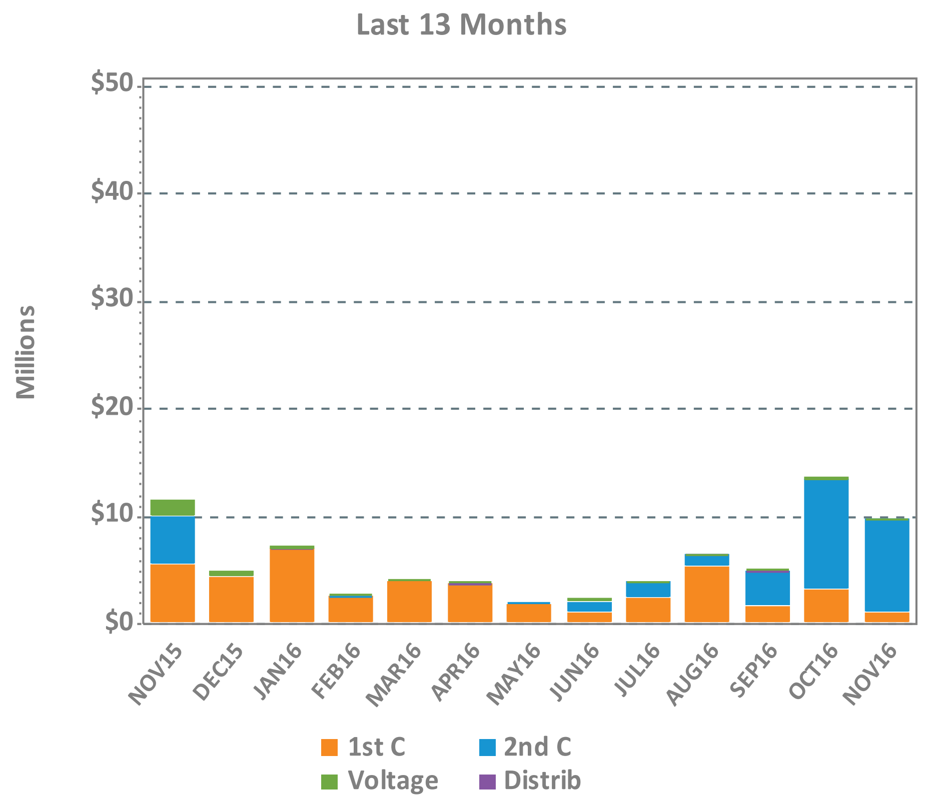
DA and RT NCPC Charges





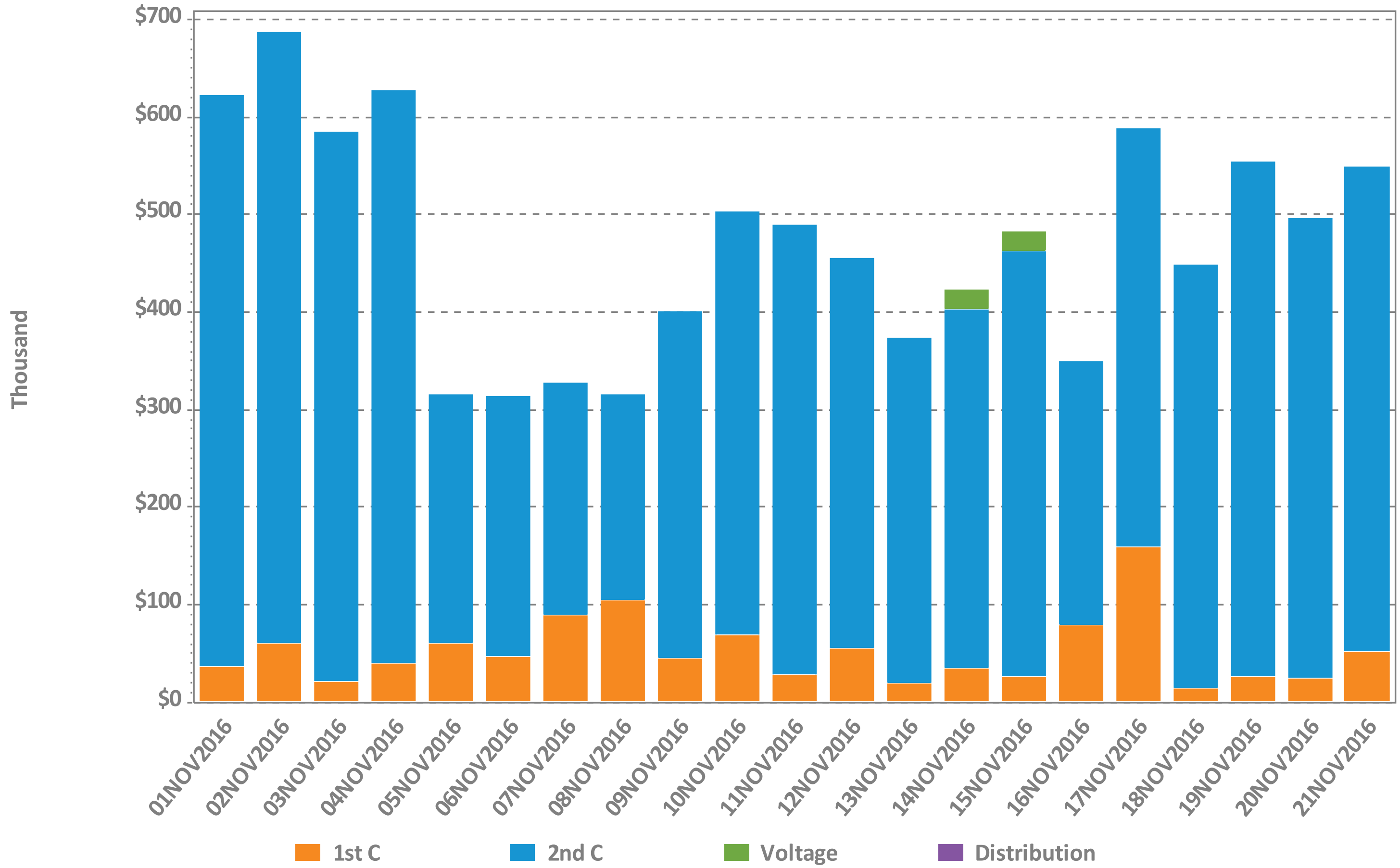
NCPC Charges by Type



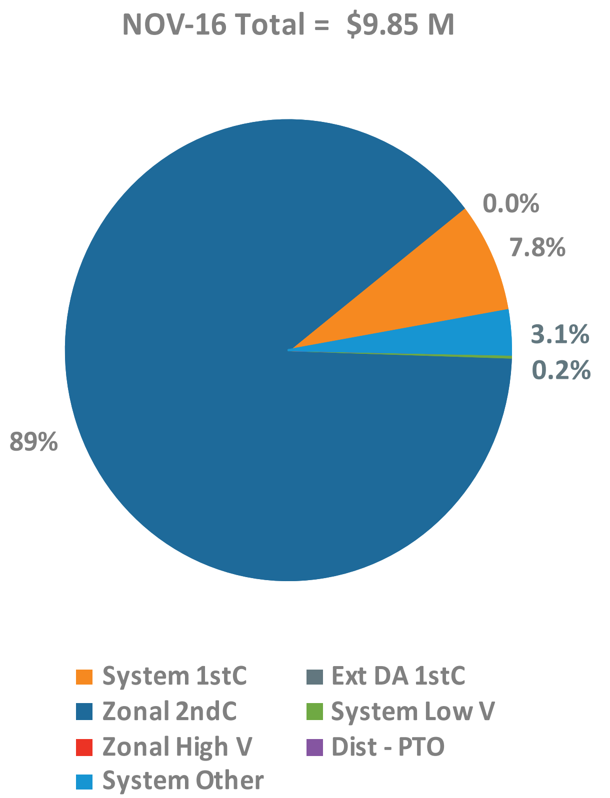


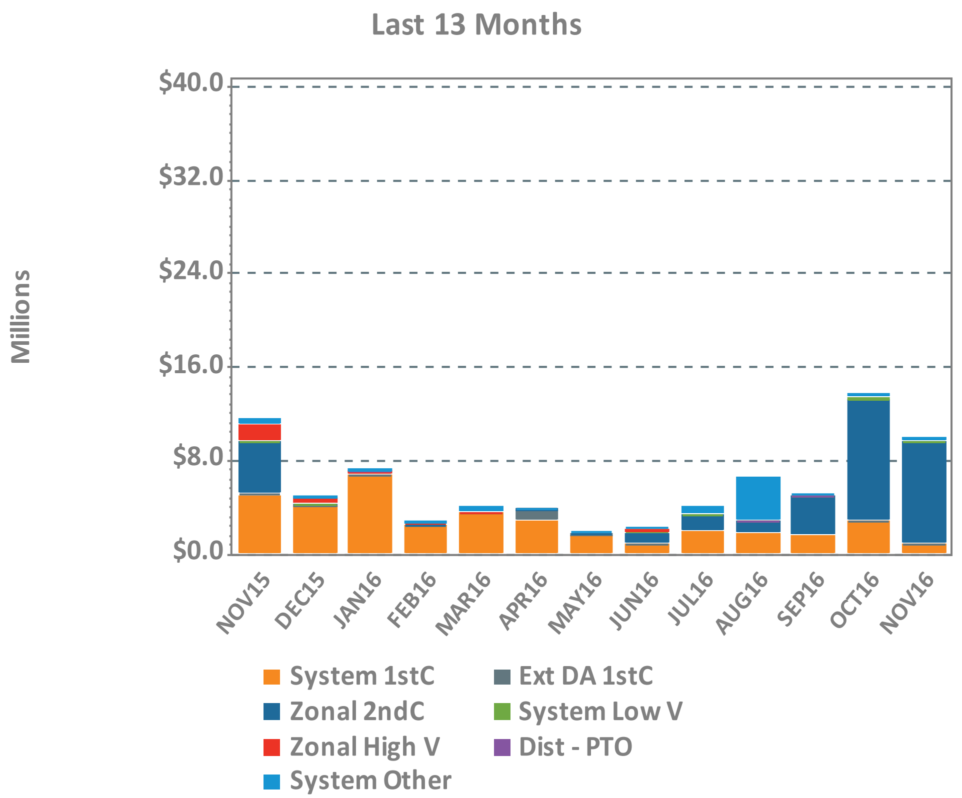
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



NCPC Charges by Allocation

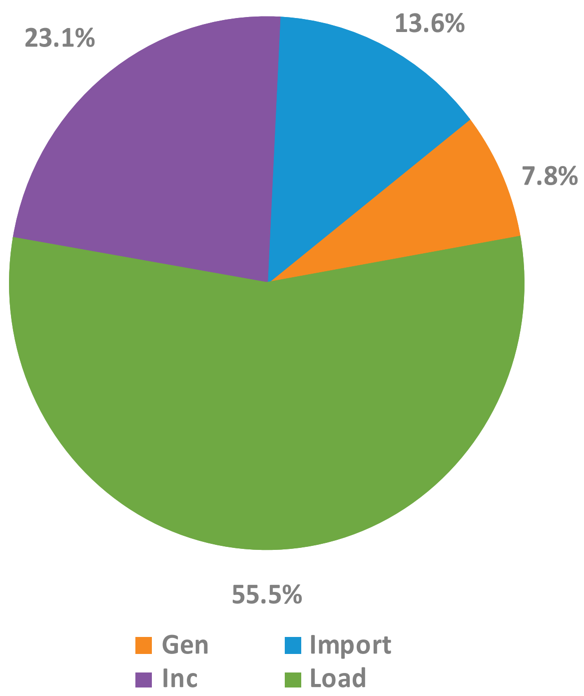




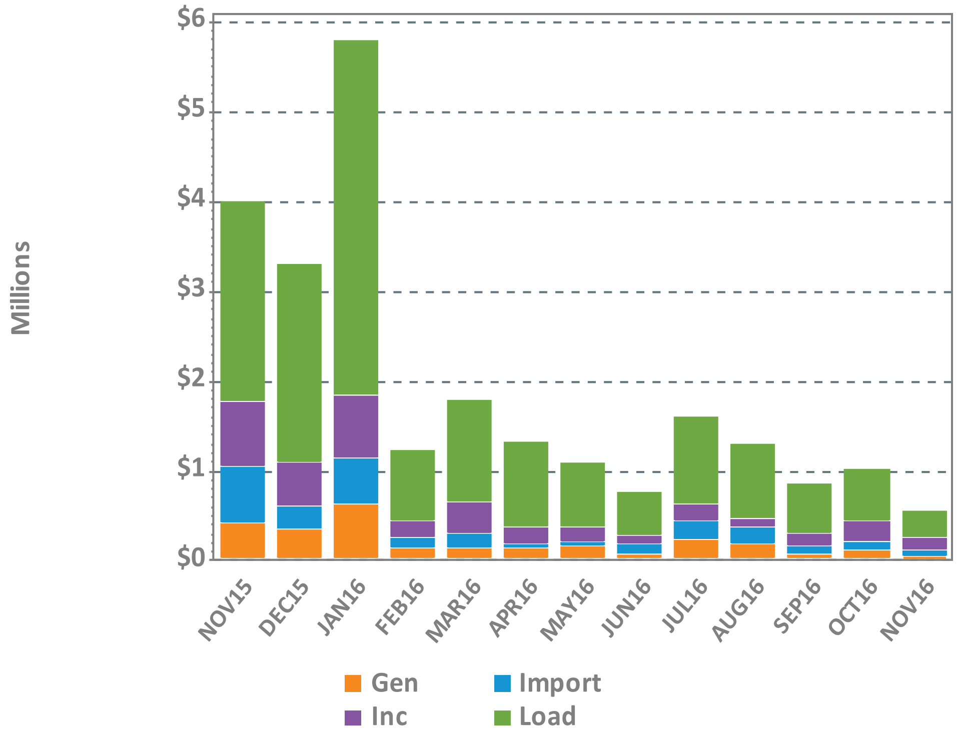
Note: 'System Other' includes, as applicable: Resource Posturing, GPA, and Min Gen Emergency

RT First Contingency Charges by Deviation Type

NOV-16 Total = $0.54 M

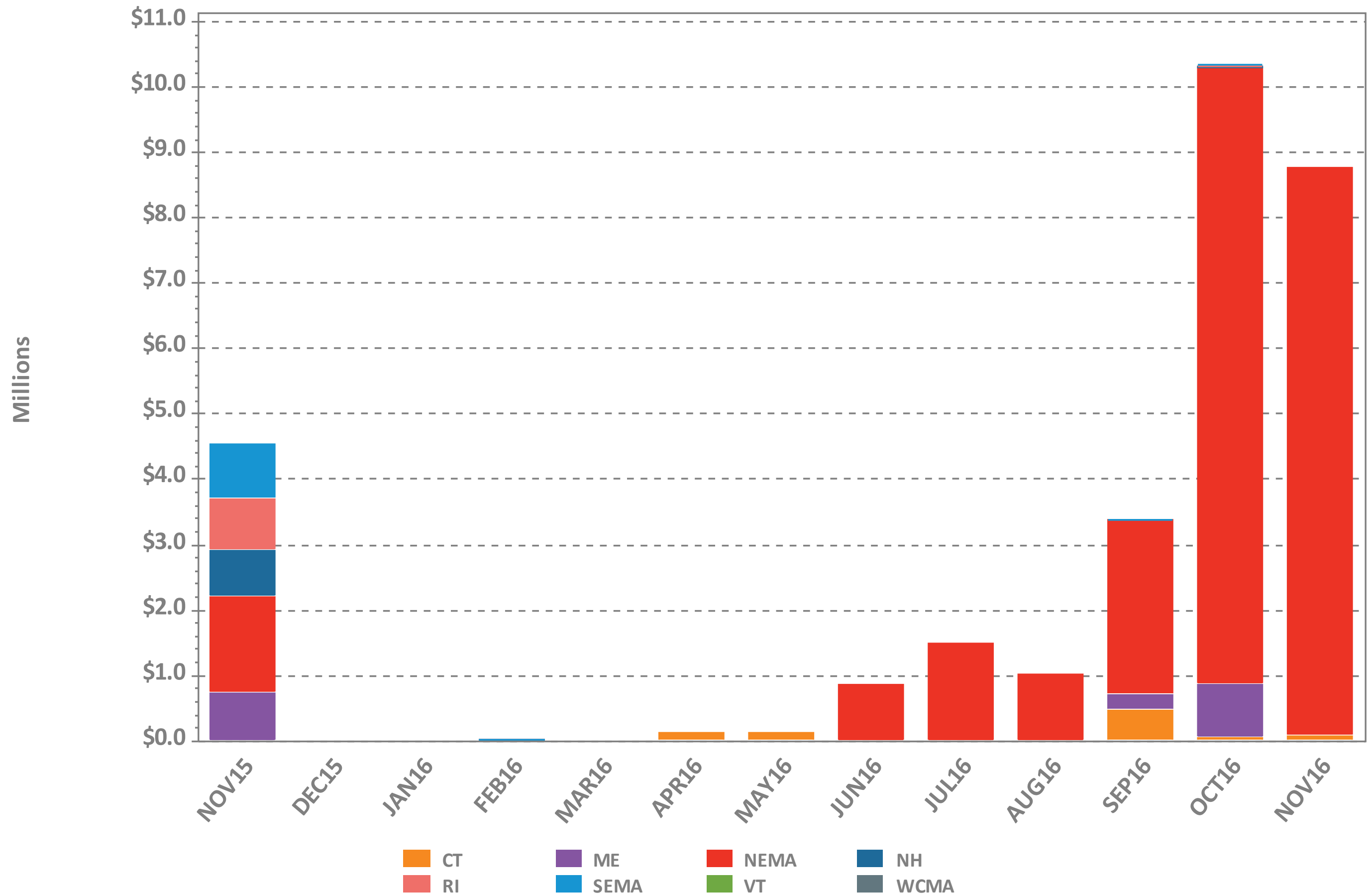


Last 13 Months



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

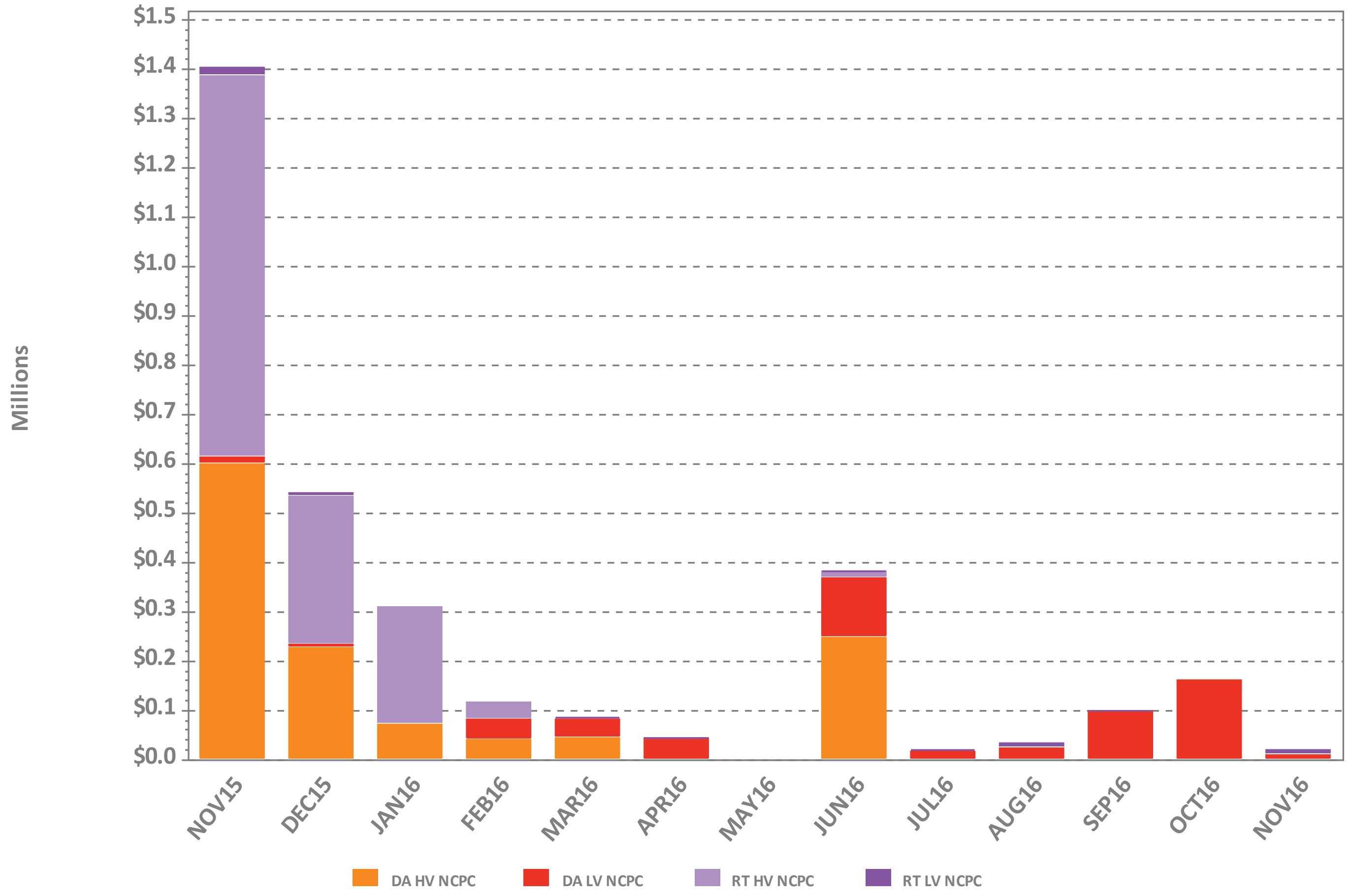
LSCPR Charges by Zone



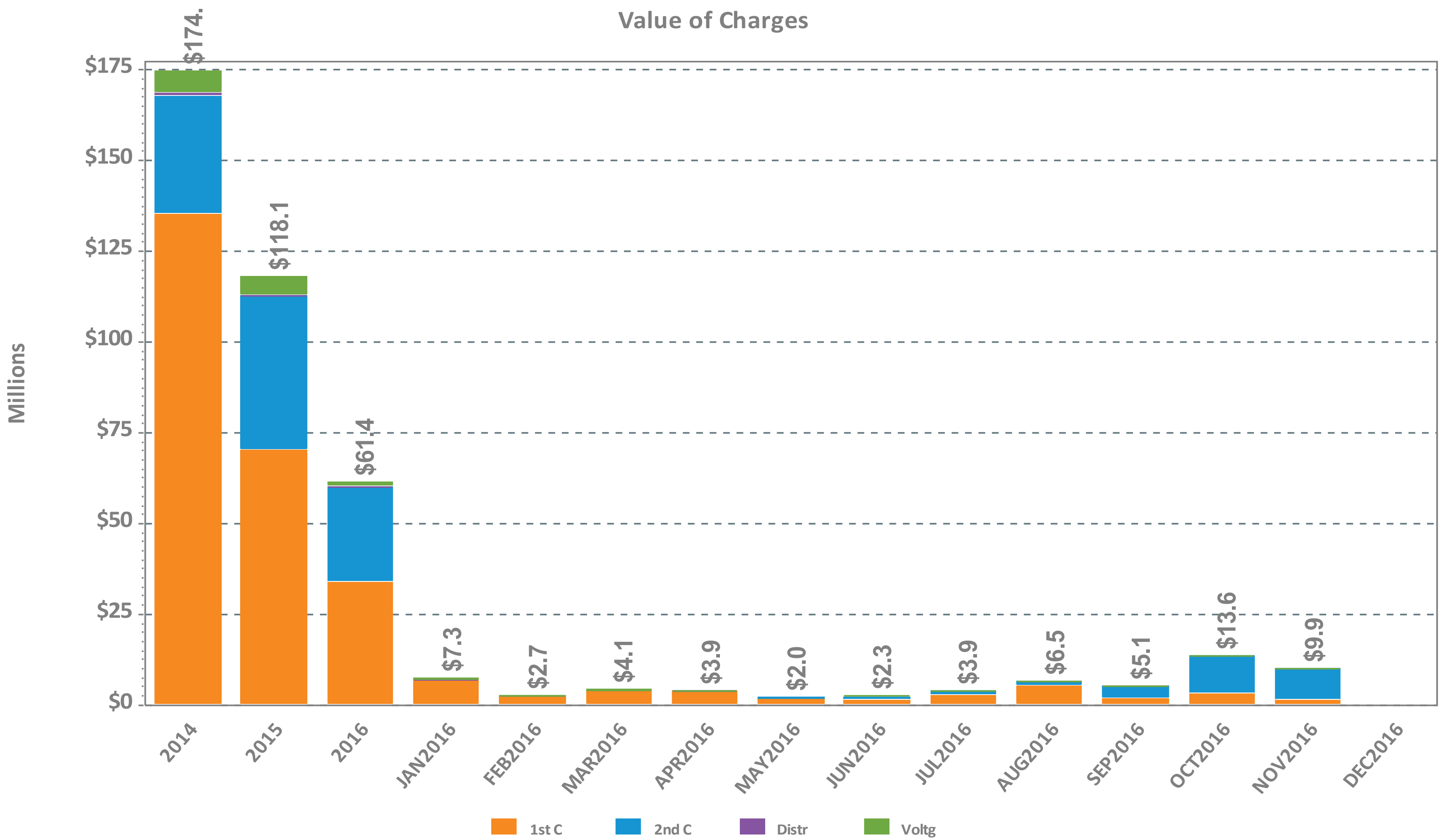
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

SEMA – Southeast Massachusetts Region
WCMA – Western/Central Massachusetts Region
NEMA – Northeast Massachusetts Region
EXT – External Locations

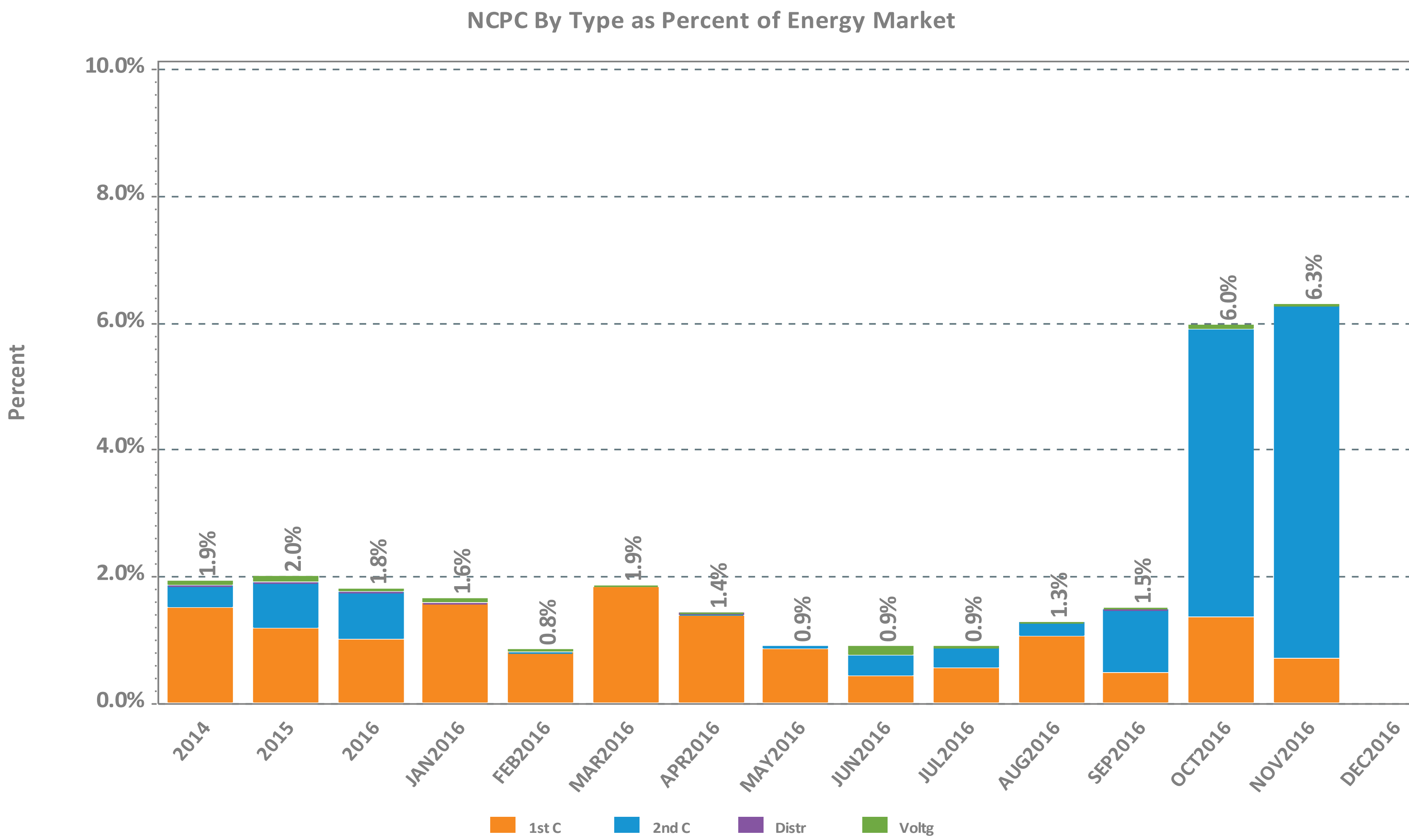
NCPC Charges for Voltage Support and High Voltage Control



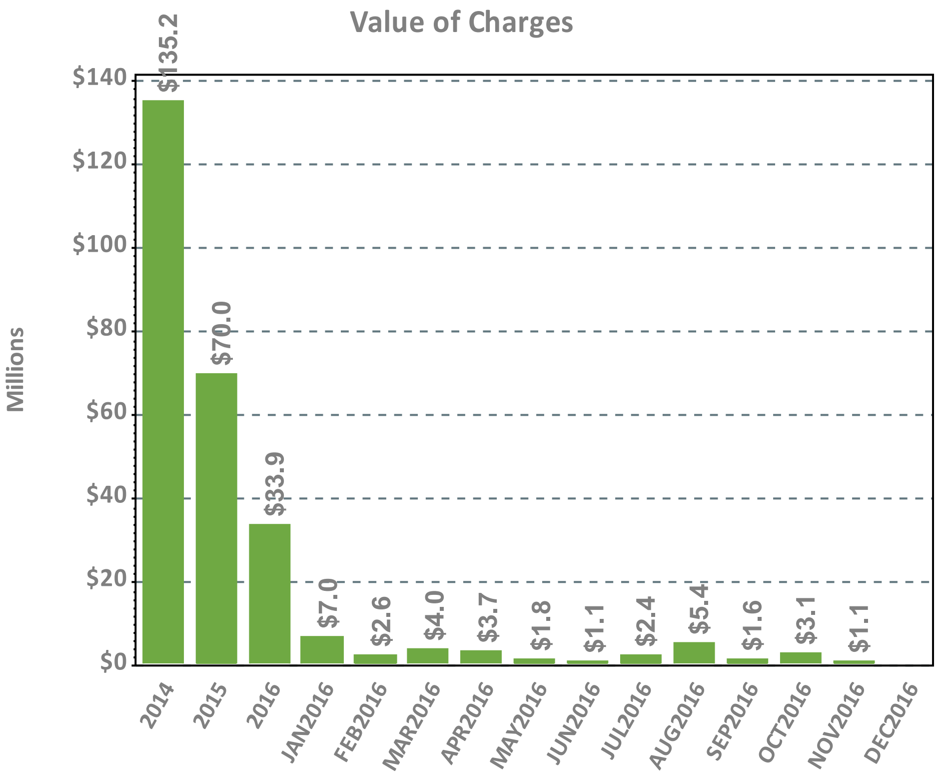
NCPC Charges by Type

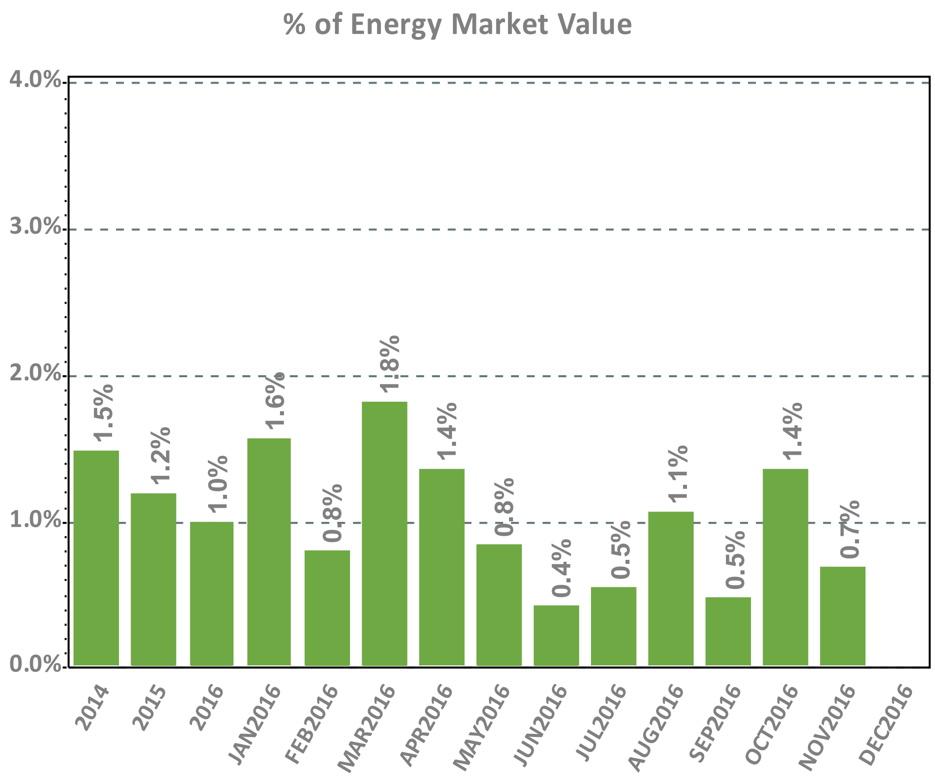


NCPC Charges as Percent of Energy Market



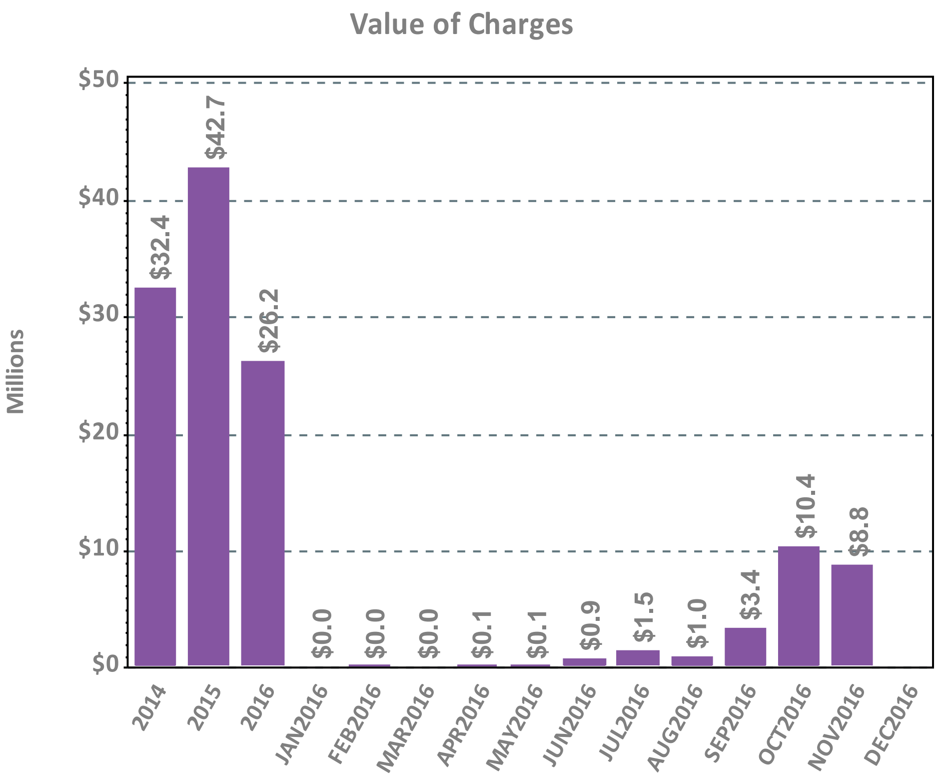
First Contingency NCPC Charges

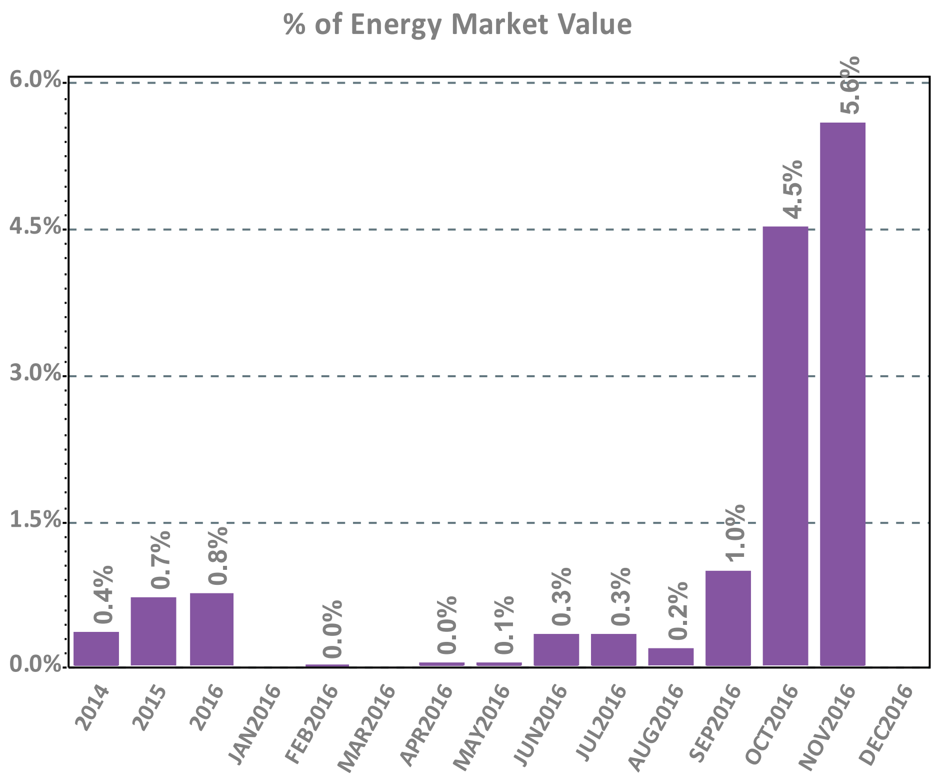




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

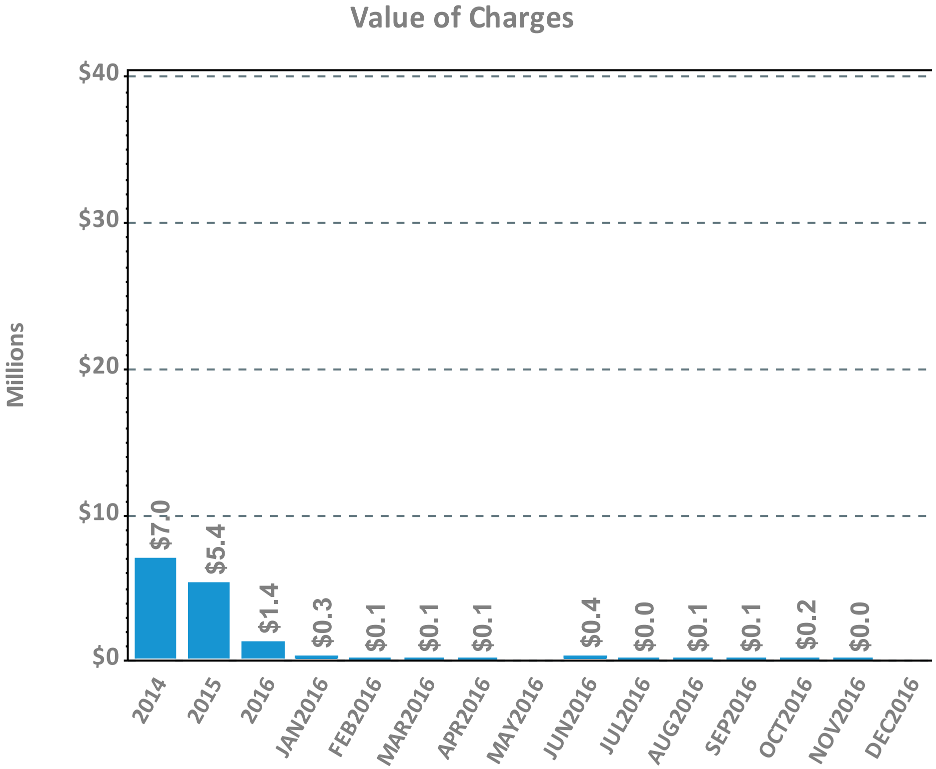
Second Contingency NCPC Charges

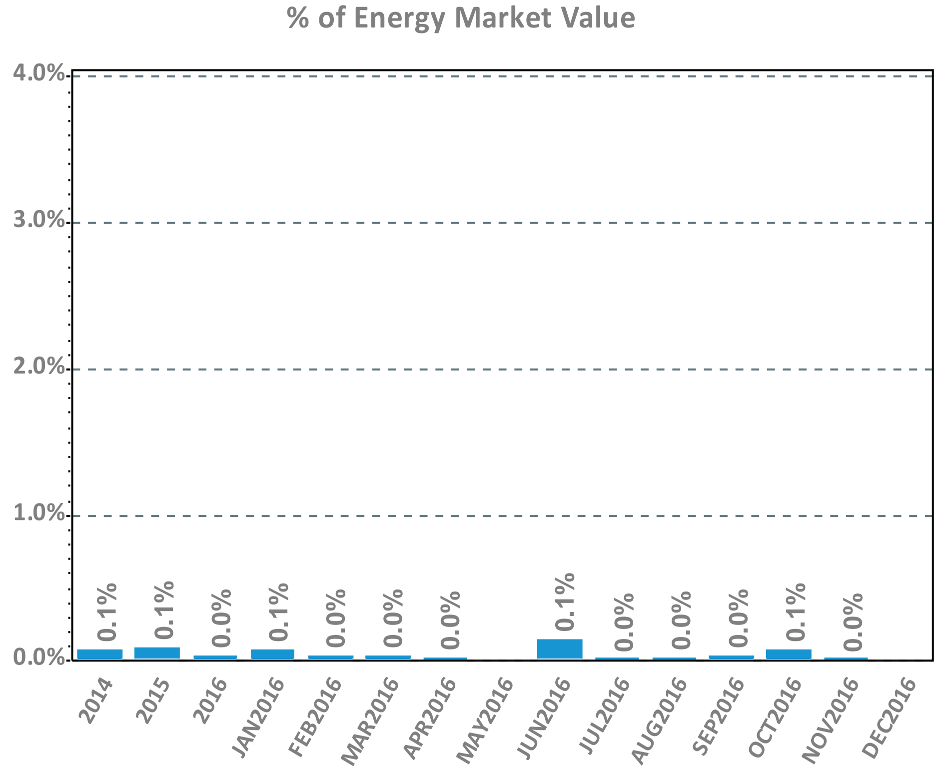




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

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

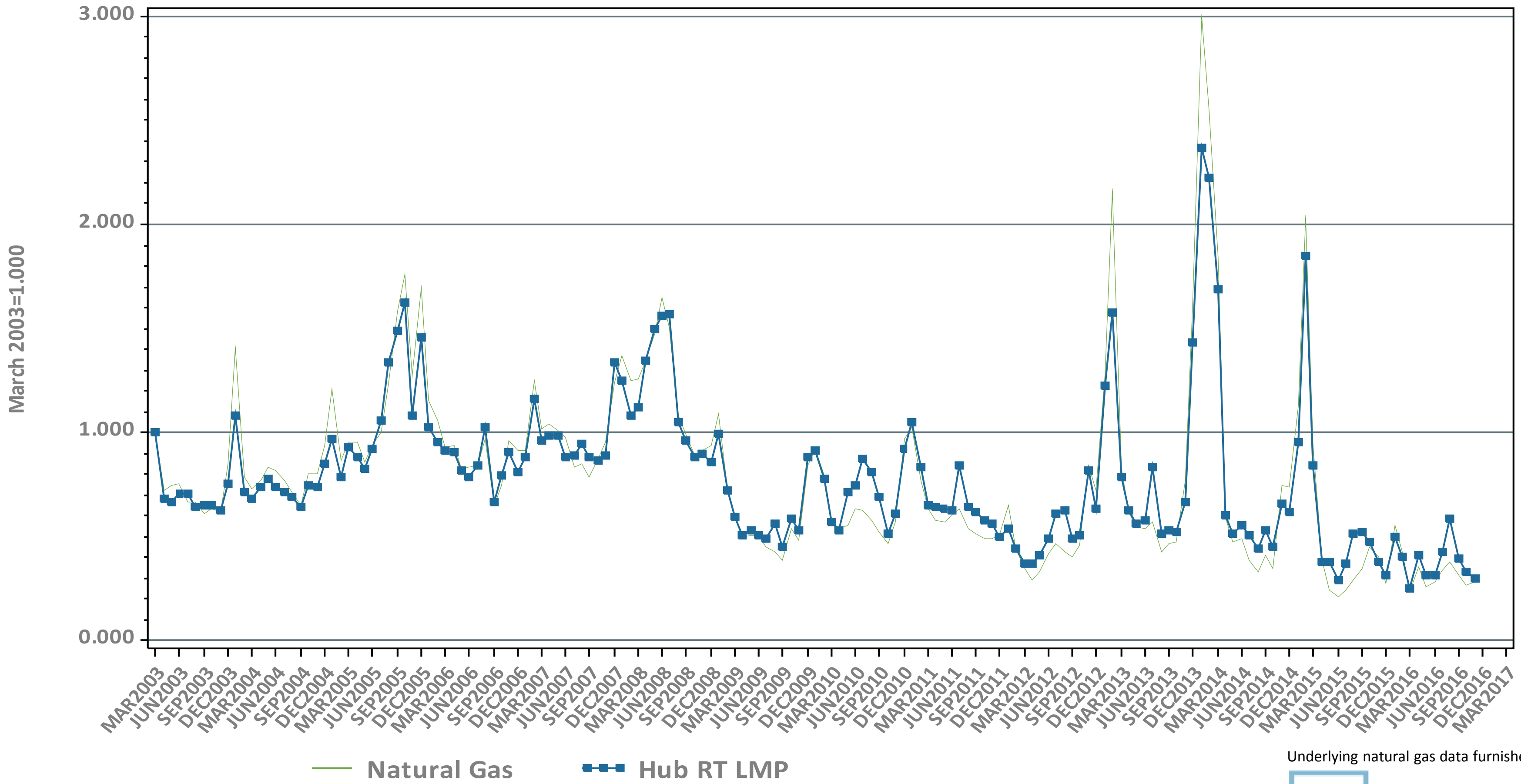
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 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%
Year 2015	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$42.56	$41.23	$40.81	$42.11	$41.58	$42.20	$42.23	$41.93	$41.90
Real-Time	$41.58	$40.58	$39.23	$40.21	$40.22	$41.03	$41.21	$40.96	$41.00
RT Delta %	-2.3%	-1.6%	-3.9%	-4.5%	-3.3%	-2.8%	-2.4%	-2.3%	-2.2%

November-15	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$30.37	$27.80	$29.38	$29.75	$28.25	$30.98	$30.32	$29.30	$29.42
Real-Time	$26.53	$25.56	$25.51	$26.07	$25.48	$26.44	$26.33	$26.07	$26.12
RT Delta %	-12.7%	-8.0%	-13.2%	-12.4%	-9.8%	-14.7%	-13.2%	-11.0%	-11.2%
November-16	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$23.05	$22.26	$22.13	$22.32	$21.94	$22.25	$22.34	$22.43	$22.36
Real-Time	$20.56	$20.12	$19.75	$20.09	$19.60	$20.10	$20.17	$20.20	$20.19
RT Delta %	-10.8%	-9.6%	-10.8%	-10.0%	-10.7%	-9.7%	-9.7%	-9.9%	-9.8%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	-24.1%	-19.9%	-24.7%	-25.0%	-22.3%	-28.2%	-26.3%	-23.4%	-24.0%
Yr over Yr RT	-22.5%	-21.3%	-22.6%	-22.9%	-23.0%	-24.0%	-23.4%	-22.5%	-22.7%

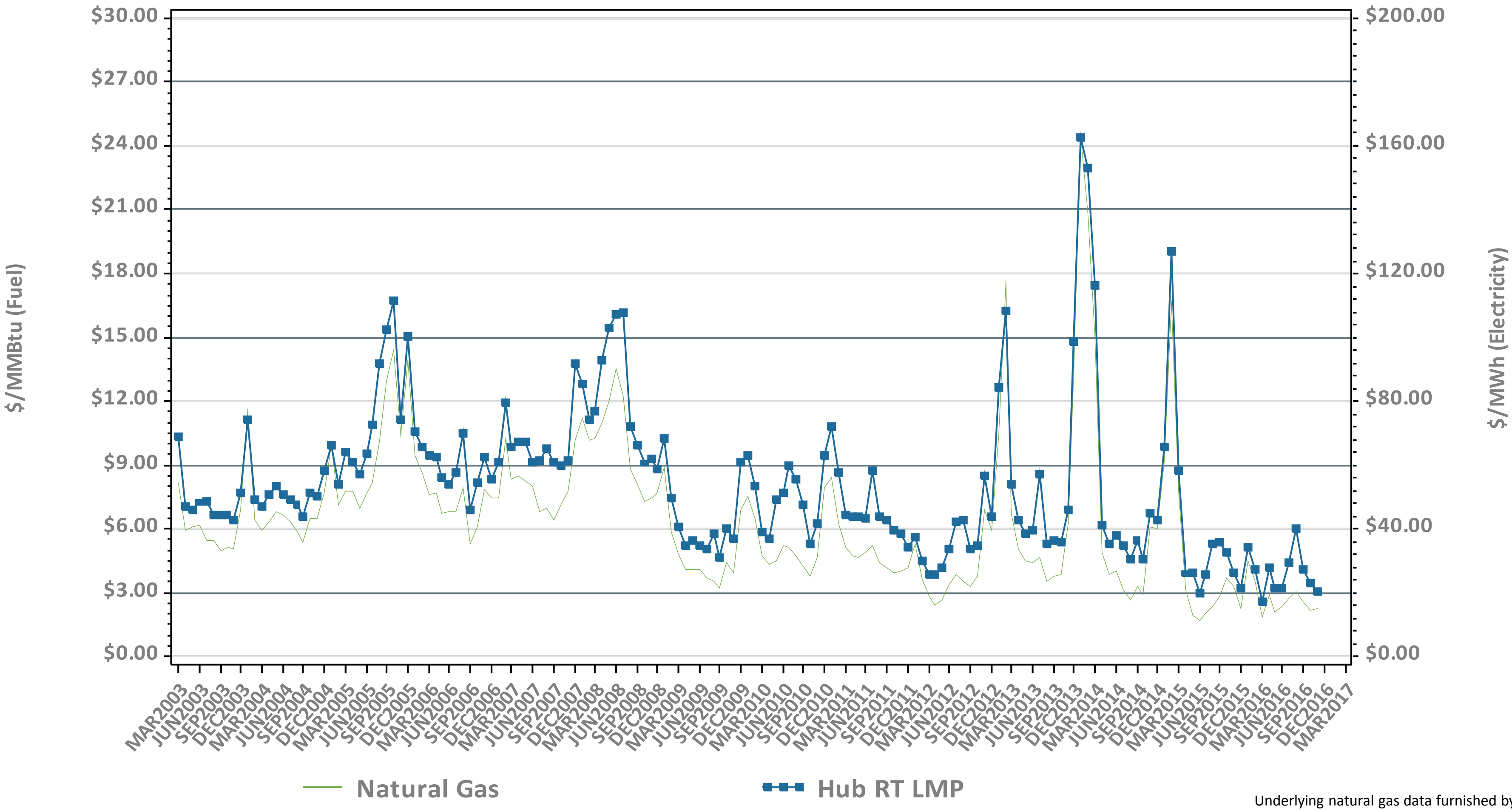
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ICE Global markets in clear view

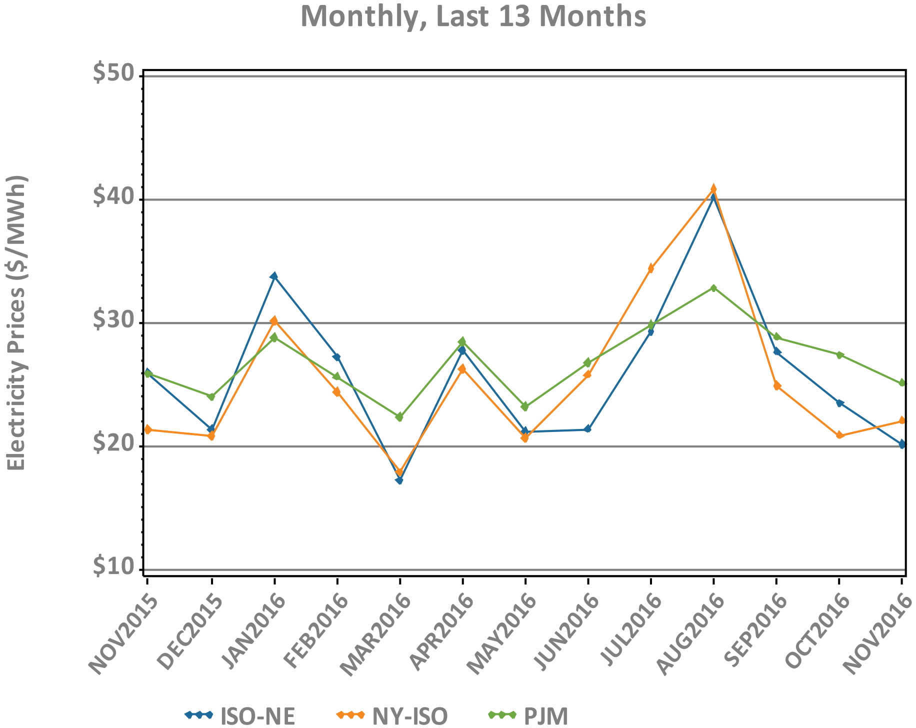
Monthly Average Fuel Price and RT Hub LMP



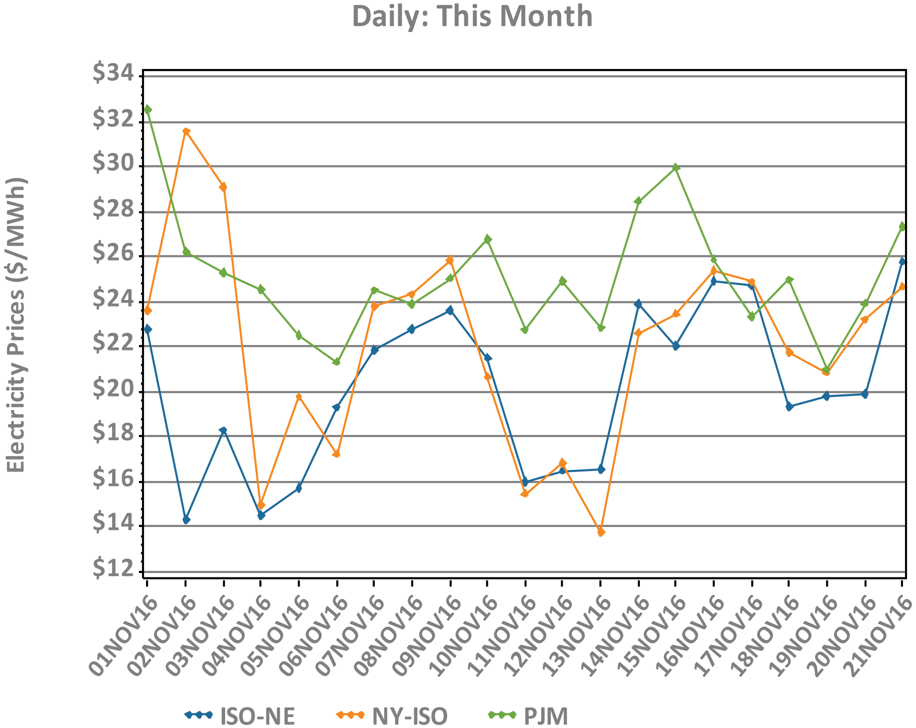
Underlying natural gas data furnished by:

ICE Global markets in clear view

New England, NY, and PJM Hourly Average Real Time Prices by Month

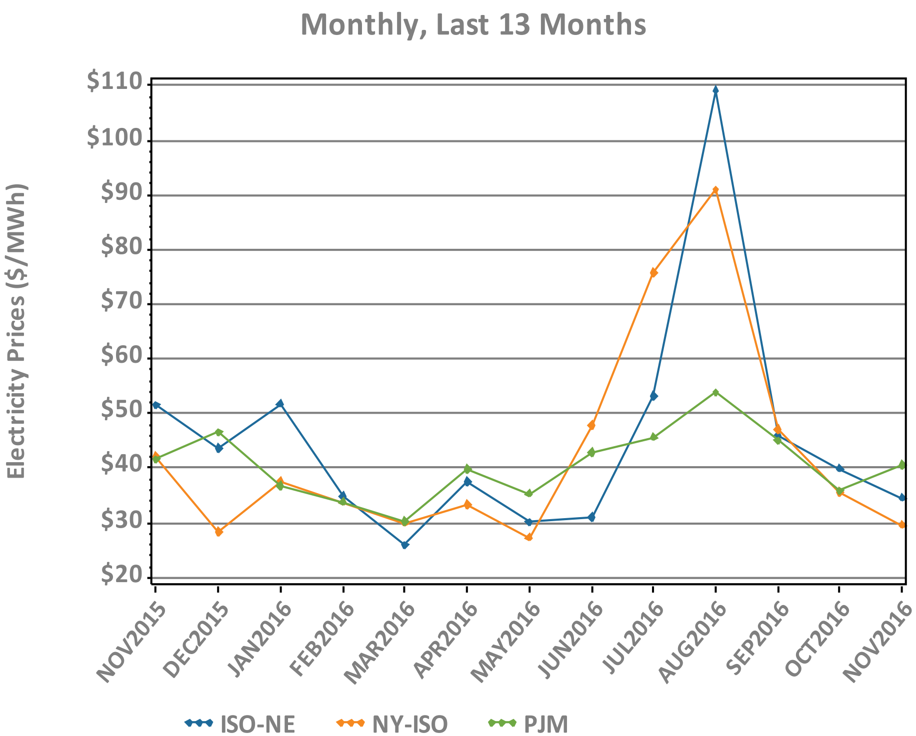


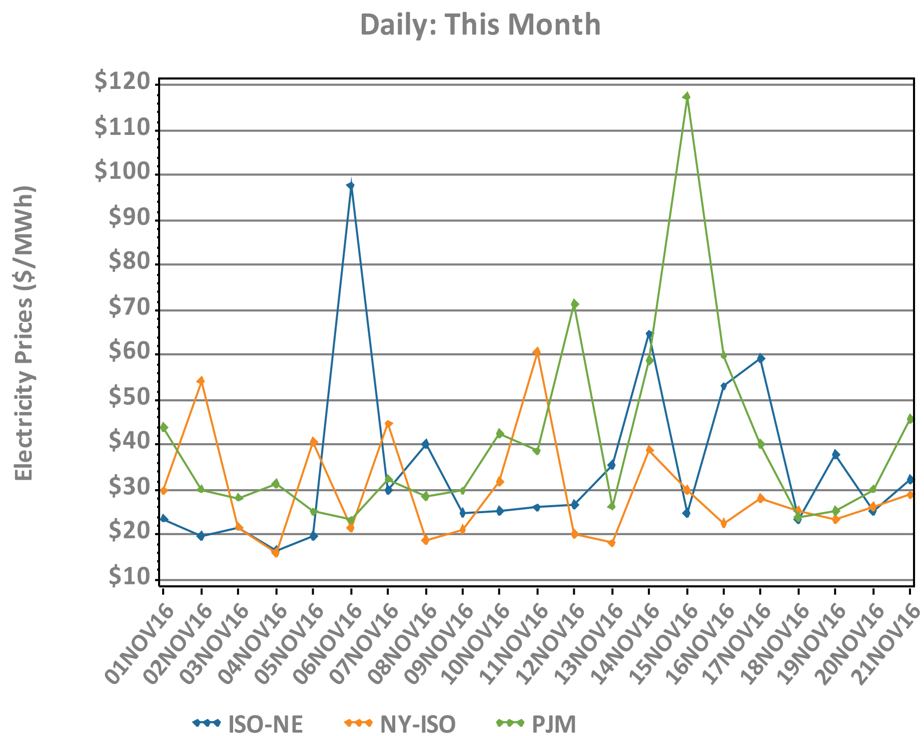
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

New England, NY, and PJM Average Peak Hour Real Time Prices





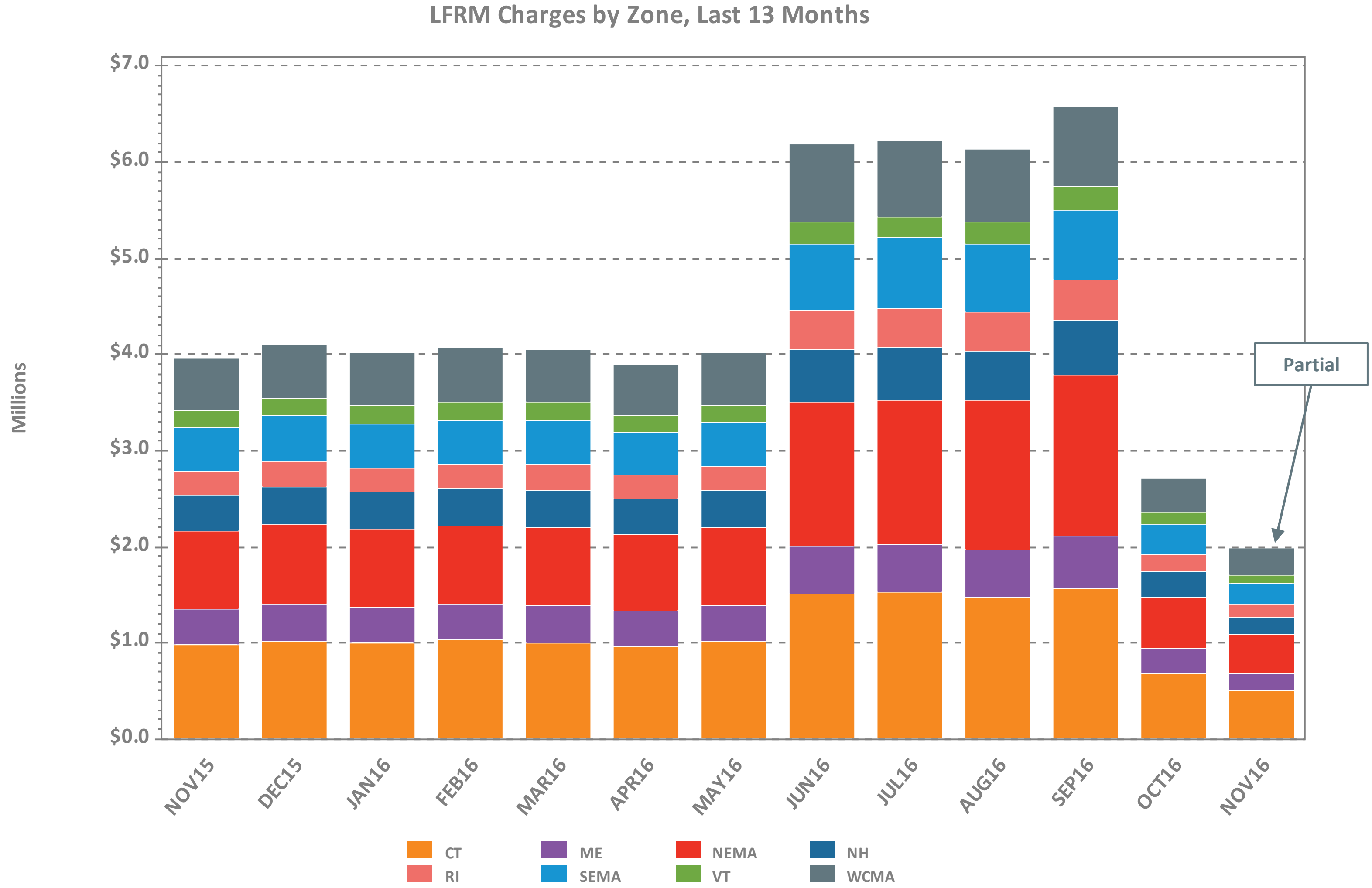
*Forecasted New England daily peak hours reflected

Reserve Market Results – November 2016

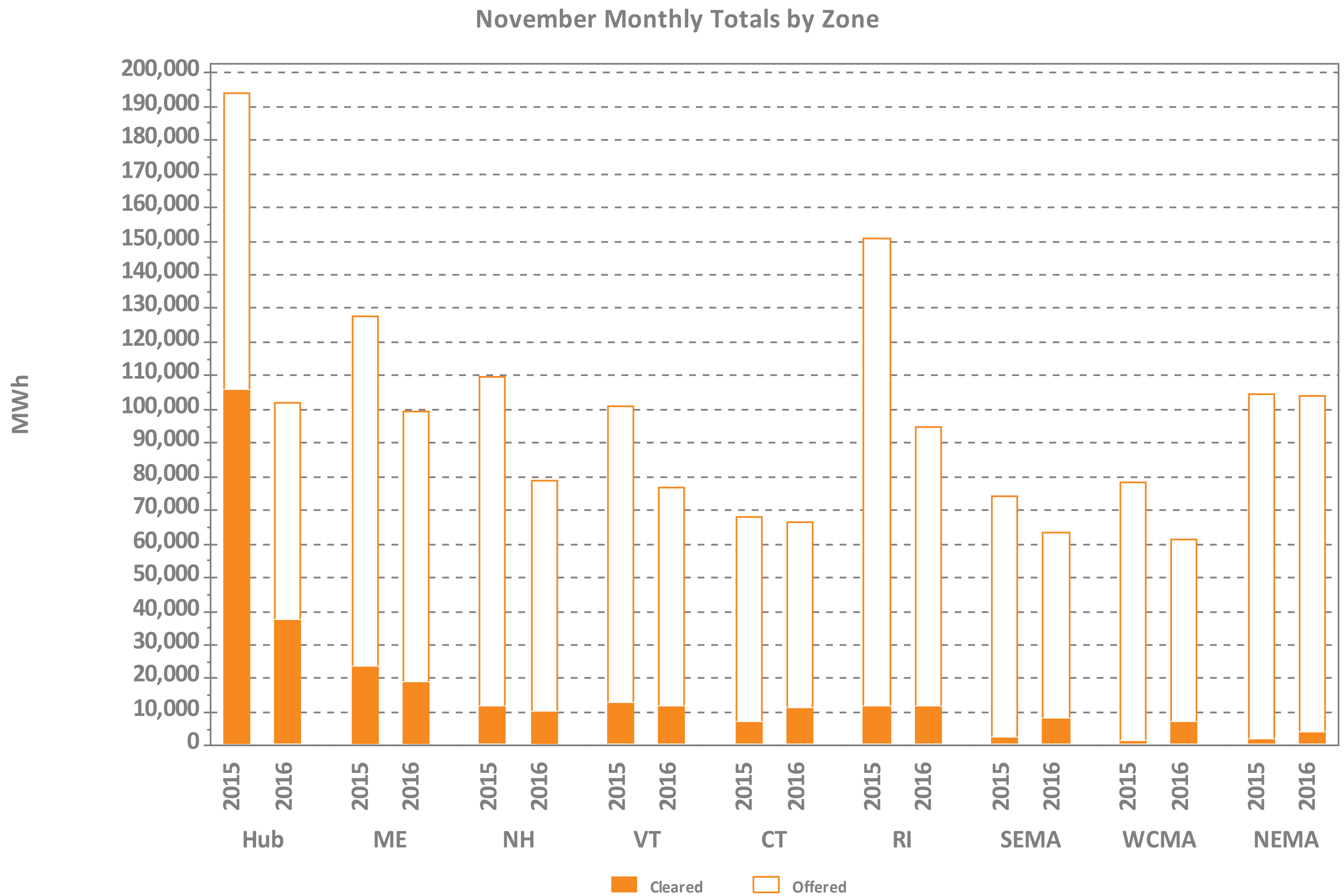
- Maximum potential Forward Reserve Market payments of $2M were reduced by credit reductions of $19K, failure-to-reserve penalties of $28K, and no failure-to-activate penalties, resulting in a net payout of $2M or 98% of maximum
  - Rest of System: $1.15M/1.17M (98)%
  - Southwest Connecticut: $0.19M/0.2M (98)%
  - Connecticut: $0.63M/0.65M (97)%
- $167K total Real-Time credits experienced no reductions for Forward Reserve Energy Obligation Charges, resulting in a net payout of $167K in Real-Time Reserve payments
  - Rest of System: 57 hours, $109K
  - Southwest Connecticut: 57 hours, $4K
  - Connecticut: 57 hours, $4K
  - NEMA: 57 hours, $50K

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

LFRM Charges to Load by Load Zone ($)

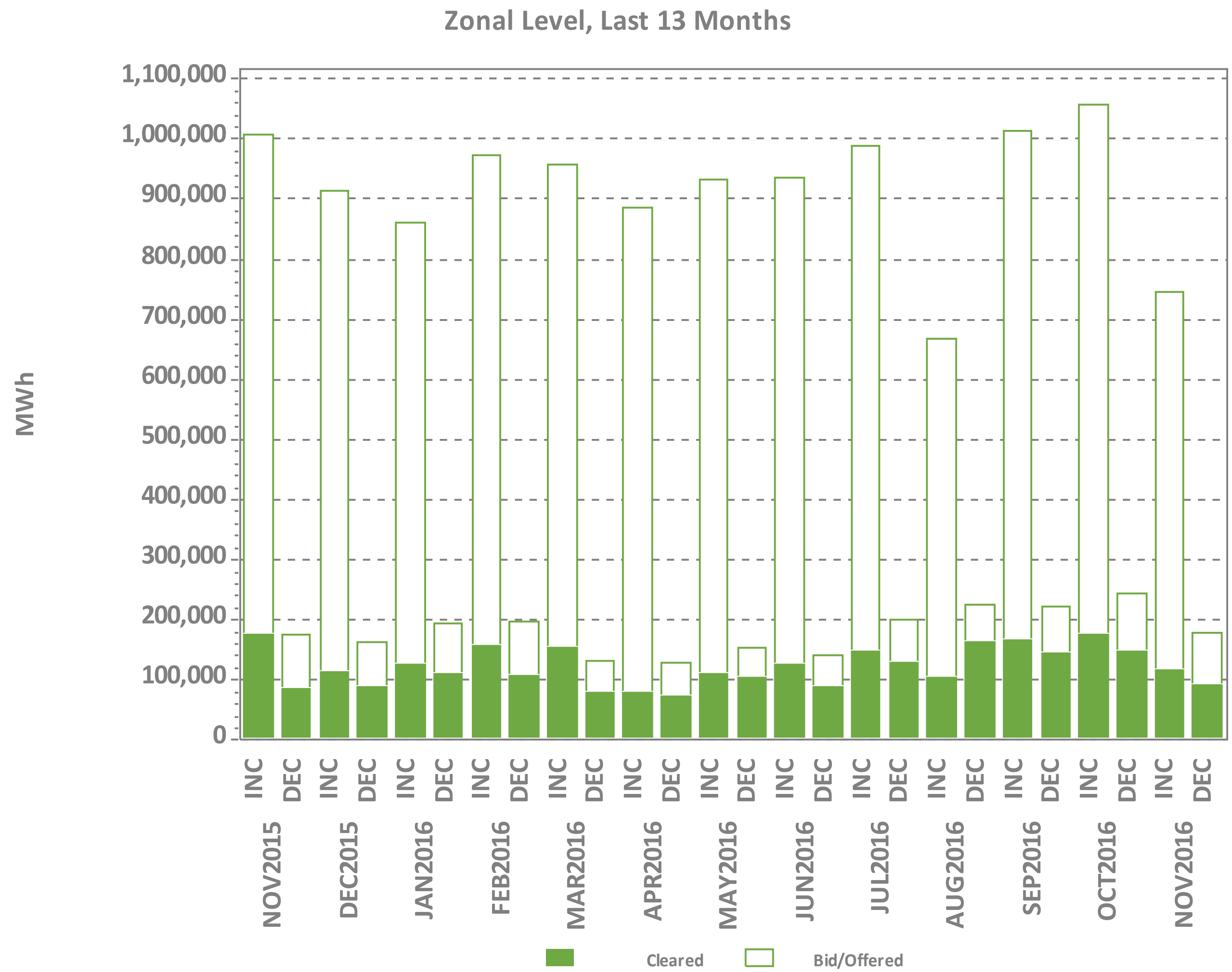


Zonal Increment Offers and Cleared Amounts



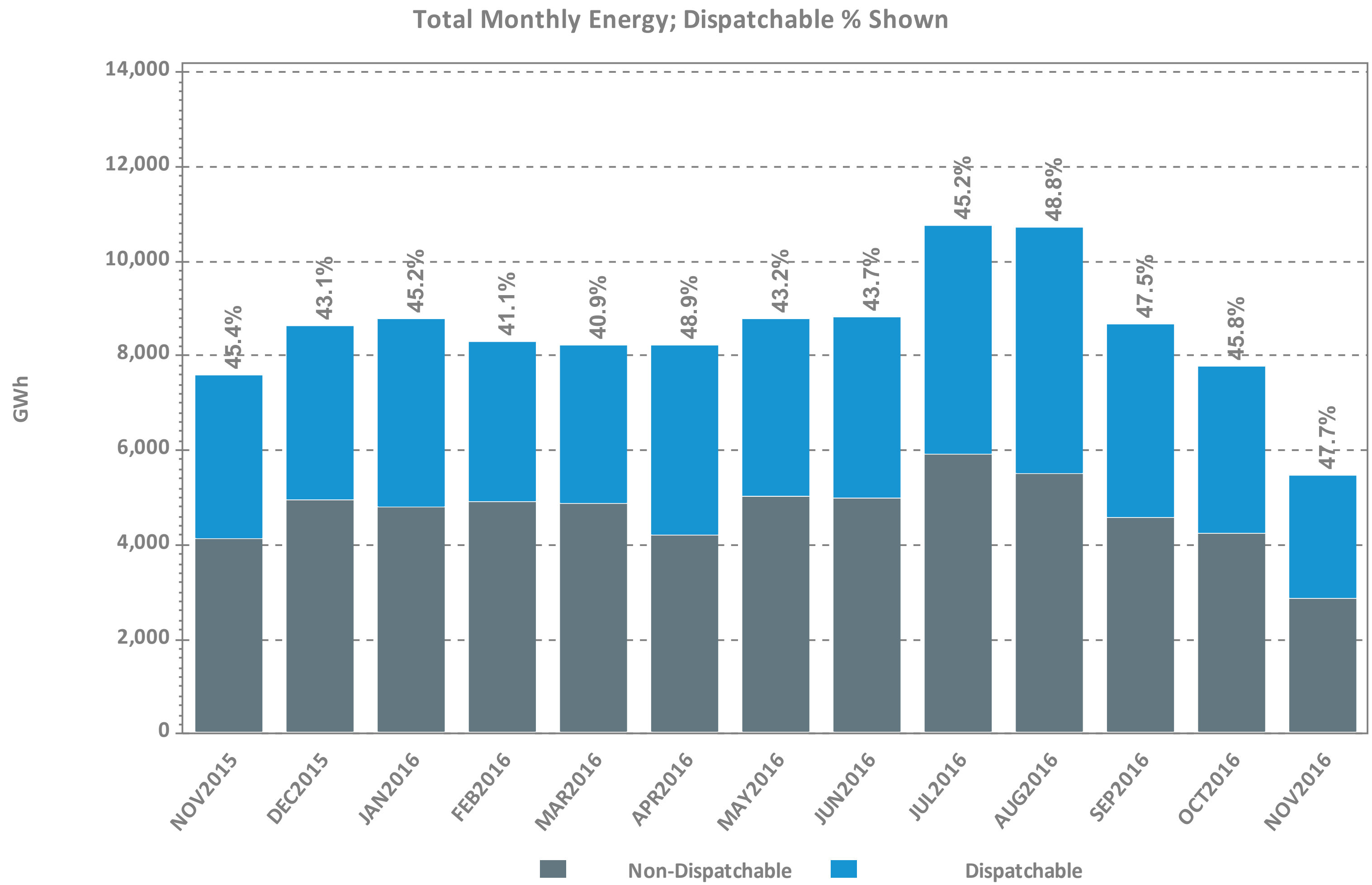
Zonal Decrement Bids and Cleared Amounts

Total Increment Offers and Decrement Bids



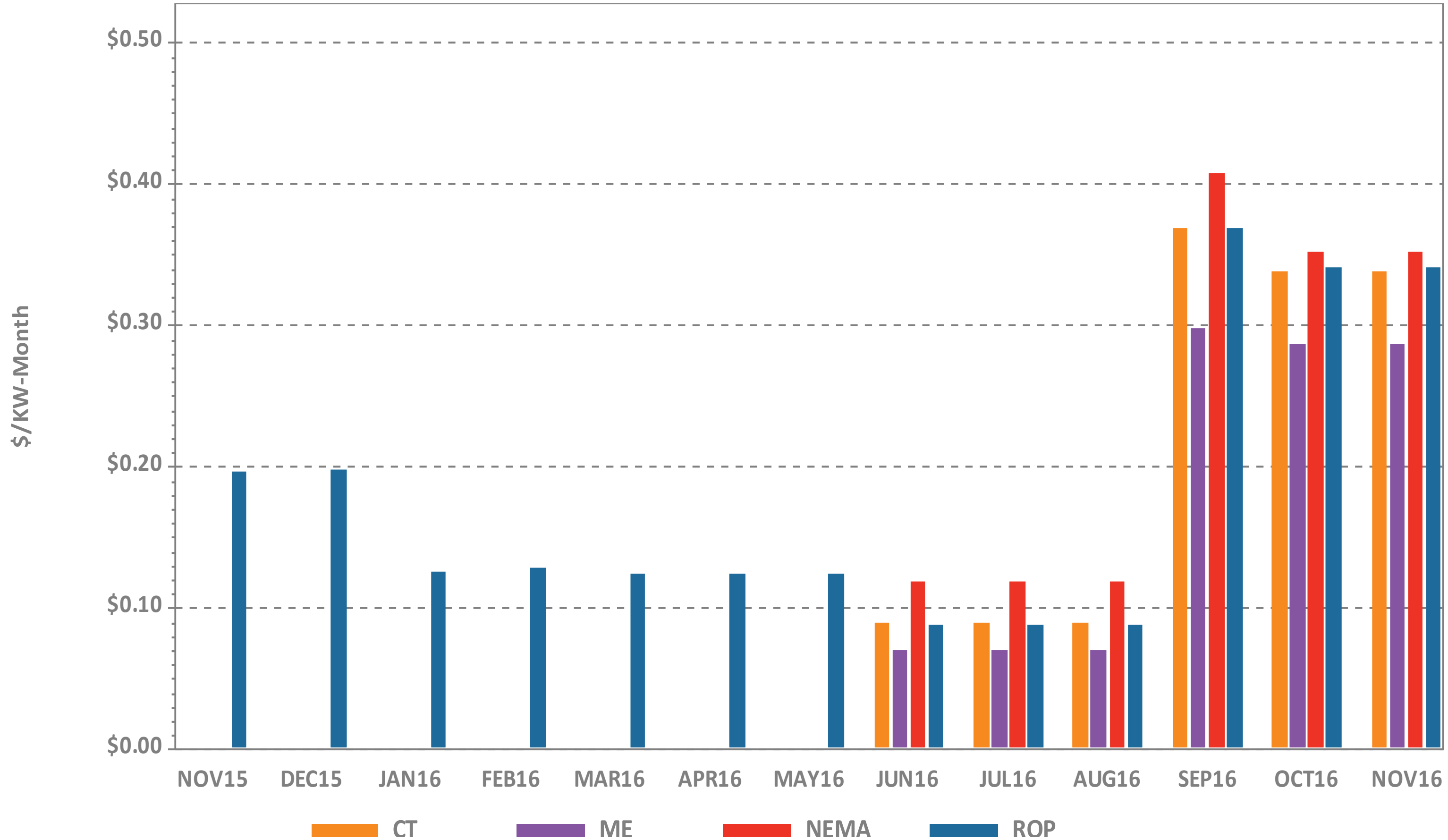
Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



*** Dispatchable MWh here are defined to be generation output that is not self-scheduled (i.e, not self-committed or 'must run' by the customer).**

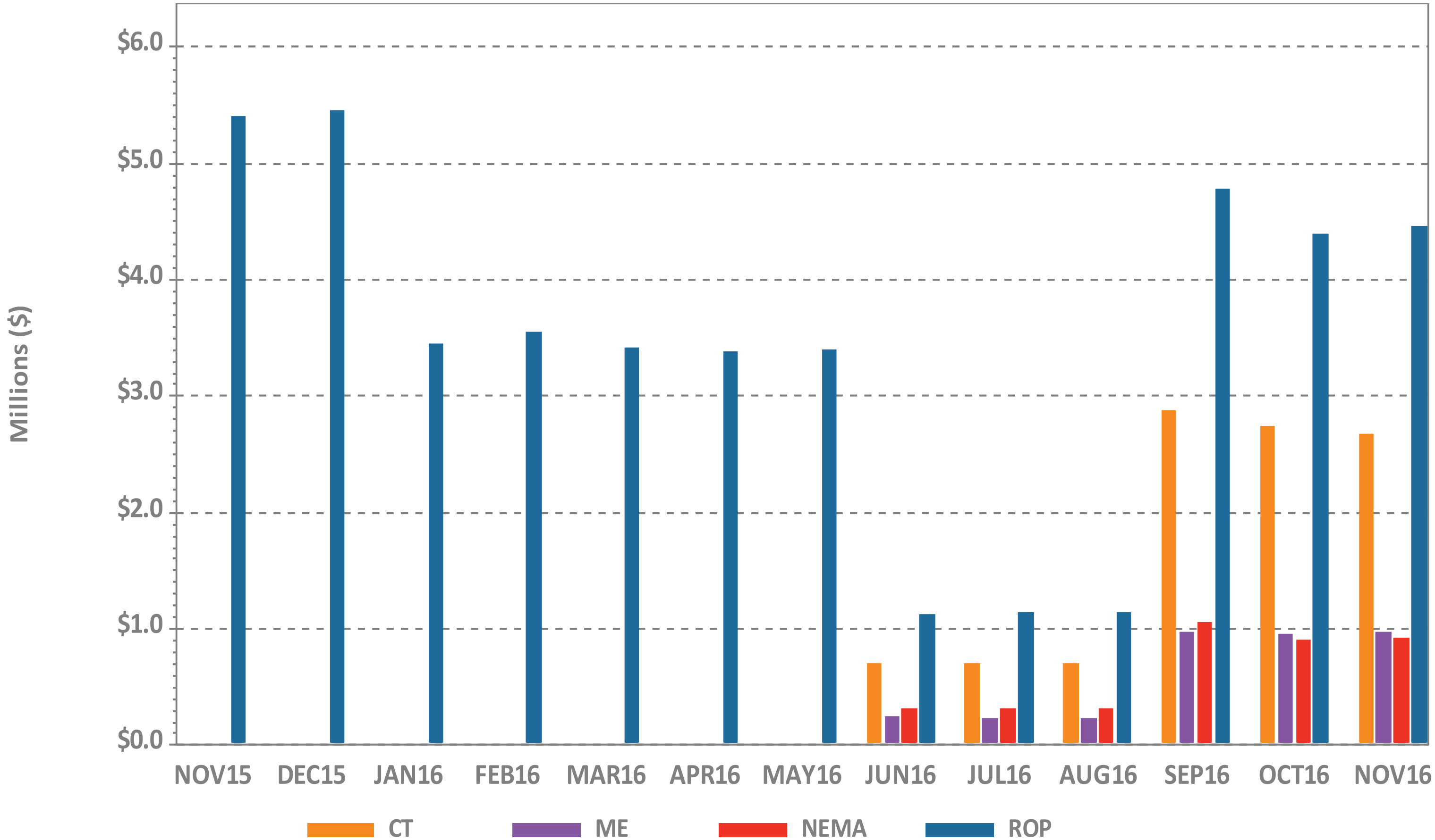
Rolling Average Peak Energy Rent (PER)



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)

Planning Advisory Committee (PAC)

- December 14 PAC Meeting Agenda*
  - 2016 Economic Study – Phase 2 FCA Scope of Work
  - Southeastern Massachusetts and Rhode Island (SEMA/RI) 2026 Preliminary Preferred Solution
  - Scenario Analysis Natural Gas Pipeline Analysis
  - Review of Transmission Planning Assumptions
  - Maine 2023 Solutions Study Update
  - 2016 Economic Study Phase 2 Scope of Work for Regulation, Ramping, and Reserves

* Agenda items are subject to change. Visit https://www.iso-ne.com/committees/planning/planning-advisory for the latest PAC agendas.

Load, Energy Efficiency, and Photovoltaic Forecast

- Load Forecast
  - Development of the ten-year load forecast has begun
    - To be published in the CELT report on or about May 1, 2017
  - Next Load Forecast Committee meeting will be held in Q1 2017
- Energy Efficiency Forecast
  - Data collection process is complete and analysis is in process to prepare the 2017 forecast
  - Next working group meeting will be held on December 16 (morning)
- Photovoltaic Forecast
  - Next Distributed Generation Forecast Working Group meeting will be held on December 16 (afternoon)

Environmental Matters

- Environmental Advisory Group met on November 1 to discuss the following environmental regulatory updates:
  - Preliminary 2015 Emissions Report Results
  - 2016 Regional Greenhouse Gas Initiative Program Review
  - Clean Power Plan Technical Updates and Litigation
  - Other environmental regulatory updates

Economic Studies and Keene Road Market Efficiency Transmission Upgrade Needs Assessment

- 2016 Economic Study - NEPOOL Scenario Analysis results remain ahead of schedule, but the report is scheduled for 1st quarter 2017
  - Phase I observations and key messages and response to PAC requests for additional metrics to be discussed at the November 29 PAC
  - PAC will be updated on sensitivity analysis results as they become available, which will likely continue through Phase II
  - Phase II items will be discussed at the December 14 PAC meeting
    - Natural gas pipeline results
    - Scope of work for FCA auction results
    - Scope of work for regulation, ramping, and reserves
- Keene Road Market Efficiency Transmission Upgrade needs assessment draft results were presented at the November 29 PAC meeting

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

Connecticut River Valley

Status as of 11/28/16

Project Benefit: Addresses system needs in the Connecticut River Corridor in Vermont

Upgrade	Expected In-Service	Present Stage
Rebuild 115 kV line K31, Coolidge-Ascutney	May-18	3
Ascutney Substation - Add a +50/-25 MVAR dynamic reactive device	May-18	3
Hartford Substation - Split 25 MVAR capacitor bank into two 12.5 MVAR banks	April-17	3
Chelsea Station - Rebuild to a three-breaker ring bus	Oct-17	3

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

New Hampshire/Vermont 10-Year Upgrades

Status as of 11/28/16

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected In-Service	Present Stage
Eagle Substation Add: 345/115 kV autotransformer	Dec-16	4*
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	Dec-16	3
New 115 kV overhead line, Scobie Pond-Huse Road	Nov-15	4*
New 115 kV overhead/submarine line, Madbury-Portsmouth	Dec-18	2
New 115 kV overhead line, Scobie Pond-Chester	Dec-15	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 11/28/16

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	Aug-16	4
Rebuild 115 kV line K165, W157 tap Eagle-Power Street	May-15	4
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	Mar-15	4
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 11/28/16

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 11/28/16

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	Jun-17	3
Terminal equipment upgrades on the 345 kV line between Haddam Neck and Beseck (362)	Dec-17	2
Redesign the Green Hill 115 kV substation from a straight bus to a ring bus and add two 115 kV 25.2 MVAR capacitor banks	Dec-17	2
Add a 37.8 MVAR capacitor bank at the Hopewell 115 kV substation	Dec-16	4**
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	2
Increase the size of the existing 115 kV capacitor bank at Branford Substation from 37.8 to 50.4 MVAR	Dec-17	2
Separation of 115 kV double circuit towers corresponding to the Middletown – Pratt and Whitney line (1572) and the Middletown to Haddam (1620) line	Dec-16	3

*Replaces the NEEWS Central Connecticut Reliability Project

**Placed in-service ahead of schedule

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 11/28/16

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)	Jun-15	4
Terminal equipment upgrades on the 115 kV line from Middletown to Portland (1443)	Jun-15	4
Add a new 115 kV underground cable from Newington to Southwest Hartford and associated terminal equipment including a 2% series reactor	Dec-18	2
Add a 115 kV 25.2 MVAR capacitor at Westside 115 kV substation	Dec-18	2
Loop the 1779 line between South Meadow and Bloomfield into the Rood Avenue substation and reconfigure the Rood Avenue substation	Dec-17	3
Reconfigure the Berlin 115 kV substation including two new 115 kV breakers and the relocation of a capacitor bank	Dec-17	2
Reconductor the 115 kV line between Newington and Newington Tap (1783)	Dec-18	2

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 11/28/16

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	3
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	3
Install a 115 kV 3% reactor on the 115 kV line between South Meadow and Southwest Hartford (1704)	Dec-18	2
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	2
Replace the normally open 19T breaker at Southington 115 kV with a normally closed 3% series reactor	Dec-17	2
Add a 345 kV breaker in series with breaker 5T at Southington	Dec-17	2

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 11/28/16

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	2
Add a new 115 kV line from Frost Bridge to Campville	Jun-18	3
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-18	3
Upgrade the 115 kV line between Southington and Lake Avenue Junction (1810-1)	Dec-16	3
Add a new 345/115 kV autotransformer at Barbour Hill substation	Dec-16	4**
Add a 345 kV breaker in series with breaker 24T at the Manchester 345 kV substation	Dec-16	4**
Reconductor the 115 kV line between Manchester and Barbour Hill (1763)	Dec-16	4**

* Replaces the NEEWS Central Connecticut Reliability Project

** Placed in-service ahead of schedule

Southwest Connecticut (SWCT) Projects

Status as of 11/28/16

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-16	4*
Add 2 x 25 MVAR capacitor banks at the Ansonia substation	Dec-17	2
Close the normally open 115 kV 2T circuit breaker at Baldwin substation	Dec-17	2
Rebuild Bunker Hill to a 9-breaker substation in breaker-and-a-half configuration	Dec-18	1
Reconductor the 115 kV line between Bunker Hill and Baldwin Junction (1575)	Dec-16	3
Loop the 1990 line in and out the Bunker Hill substation	Dec-18	1
Expand Pootatuck (formerly known as Shelton) substation to 4-breaker ring bus configuration and add a 30 MVAR capacitor bank at Pootatuck	Dec-18	2
Loop the 1570 line in and out the Pootatuck substation	Dec-18	2
Replace two 115 kV circuit breakers at the Freight substation	Dec-15	4

* Placed in-service ahead of schedule

Southwest Connecticut Projects, cont.

Status as of 11/28/16

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-18	1
Reconductor the 115 kV line between West Brookfield and Brookfield Junction (1887)	Dec-18	2
Reduce the existing 25.2 MVAR capacitor bank at the Rocky River substation to 14.4 MVAR	Dec-18	1
Reconfigure the 1887 line into a three-terminal line (Plumtree - W. Brookfield - Shepaug)	Dec-18	1
Reconfigure the 1770 line into 2 two-terminal lines (Plumtree - Stony Hill and Stony Hill - Bates Rock)	Dec-18	1
Install a synchronous condenser (+25/-12.5 MVAR) at Stony Hill	Dec-18	2
Relocate an existing 37.8 MVAR capacitor bank at Stony Hill to the 25.2 MVAR capacitor bank side	Dec-18	2

Southwest Connecticut Projects, cont.

Status as of 11/28/16

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-17	3
Add a 115 kV circuit breaker in series with the existing 29T breaker at the Plumtree substation	Dec-16	4*
Terminal equipment upgrade at the Newtown substation (1876)	Dec-15	4*
Rebuild the 115 kV line from Wilton to Norwalk (1682) and upgrade Wilton substation terminal equipment	Dec-16	4*
Reconductor the 115 kV line from Wilton to Ridgefield Junction (1470-1)	Dec-17	2
Reconductor the 115 kV line from Ridgefield Junction to Peaceable (1470-3)	Dec-17	2

* Placed in-service ahead of schedule

Southwest Connecticut Projects, cont.

Status as of 11/28/16

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	Mar-16	4*
Upgrade the 115 kV bus at the Baird substation	May-18	2
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-15	4
Rebuild the 115 kV lines from Baird to Congress (8809A / 8909B)	Apr-19	2
Rebuild the 115 kV lines from Housatonic River Crossing (HRX) to Barnum to Baird (88006A / 89006B)	Dec-20	1

* Placed in-service ahead of schedule

Southwest Connecticut Projects, cont.

Status as of 11/28/16

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	Mar-17	2
Install a 7.5 ohm series reactor on 1610 line at the Mix Avenue substation	Dec-16	3
Add 2 x 20 MVAR capacitor banks at the Mix Avenue substation	Dec-16	3
Separate the 3827 (Beseck to East Devon) and 1610 (Southington to June to Mix Avenue) double circuit towers	Dec-18	1
Upgrade the 1630 line relay at North Haven and Wallingford 1630 terminal equipment	Jan-17	2
Rebuild the 115 kV lines from Devon Tie to Milvon (88005A / 89005B)	Nov-16	4
Replace two 115 kV circuit breakers at Mill River	Dec-14	4

Greater Boston Projects

Status as of 11/28/16

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

Upgrade	Expected In-Service	Present Stage
Install new 345 kV line from Scobie to Tewksbury	Dec-17	3
Reconductor the Y-151 115 kV line from Dracut Junction to Power Street	Dec-17	4*
Reconductor the M-139 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	Jun-17	3
Reconductor the N-140 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	Jun-17	3
Reconductor the F-158N 115 kV line from Wakefield Junction to Maplewood and associated work at Maplewood	Dec-15	4
Reconductor the F-158S 115 kV line from Maplewood to Everett	Jun-17	2
Install new 345 kV cable from Woburn to Wakefield Junction, install two new 160 MVAR variable shunt reactors and associated work at Wakefield Junction and Woburn	Dec-18	2
Refurbish X-24 69 kV line from Millbury to Northboro Road	Dec-15	4
Reconductor W-23W 69 kV line from Woodside to Northboro Road	Dec-17	2

* Placed in-service ahead of schedule

Greater Boston Projects, cont.

Status as of 11/28/16

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

Upgrade	Expected In-Service	Present Stage
Separate X-24 and E-157W DCT	Sep-17	2
Separate Q-169 and F-158N DCT	Dec-15	4
Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap	May-17	3
Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook	Sep-19	2
Install third 115 kV line from West Walpole to Holbrook	Sep-19	2
Install new 345 kV breaker in series with the 104 breaker at Stoughton	May-16	4
Install new 230/115 kV autotransformer at Sudbury and loop the 282-602 230 kV line in and out of the new 230 kV switchyard at Sudbury	Dec-17	3
Install a new 115 kV line from Sudbury to Hudson	May-19	1

Greater Boston Projects, cont.

Status as of 11/28/16

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

Upgrade	Expected In-Service	Present Stage
Replace 345/115 kV autotransformer, 345 kV breakers, and 115 kV switchgear at Woburn	Dec-17	3
Install a 345 kV breaker in series with breaker 104 at Woburn	Dec-17	3
Reconfigure Waltham by relocating PARs, 282-507 line, and a breaker	Dec-17	3
Upgrade 533-508 115 kV line from Lexington to Hartwell and associated work at the stations	Aug-16	4
Install a new 115 kV 54 MVAR capacitor bank at Newton	Dec-16	3
Install a new 115 kV 36.7 MVAR capacitor bank at Sudbury	May-17	3
Install a second Mystic 345/115 kV autotransformer and reconfigure the bus	Jun-18	3
Install a 115 kV breaker on the East bus at K Street	Jun-16	4
Install 115 kV cable from Mystic to Chelsea and upgrade Chelsea 115 kV station to BPS standards	Jun-19	2
Split 110-522 and 240-510 DCT from Baker Street to Needham for a portion of the way and install a 115 kV cable for the rest of the way	Dec-18	2

Greater Boston Projects, cont.

Status as of 11/28/16

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

Upgrade	Expected In-Service	Present Stage
Install a second 115 kV cable from Mystic to Woburn to create a bifurcated 211-514 line	Dec-18	2
Open lines 329-510/511 and 250-516/517 at Mystic and Chatham, respectively. Operate K Street as a normally closed station.	Jun-18	1
Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard	Jun-18	2
Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-16	3

Greater Boston Projects, cont.

Status as of 11/28/16

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

Upgrade	Expected In-Service	Present Stage
Upgrade North Cambridge to mitigate 115 kV 5 and 10 stuck breaker contingencies	May-17	3
Install a 200 MVAR STATCOM at Coopers Mills	Sep-18	1
Install a 115 kV 36.7 MVAR capacitor bank at Hartwell	May-17	2
Install a 345 kV 160 MVAR shunt reactor at K Street	May-18	1
Install a 115 kV breaker in series with the 5 breaker at Framingham	Jun-17	3
Install a 115 kV breaker in series with the 29 breaker at K Street	Mar-17	3

Pittsfield/Greenfield Projects

Status as of 11/28/16

Project Benefit: Addresses system needs in the Pittsfield/Greenfield area in Western Massachusetts

Upgrade	Expected In-Service	Present Stage
Separate and reconductor the Cabot Taps (A-127 and Y-177 115 kV lines)	Mar-17	3
Install a 115 kV tie breaker at the Harriman Station, with associated buswork, reconductor of buswork and new control house	Nov-17	3
Modify Northfield Mountain 16R Substation and install a 345/115 kV autotransformer	May-17	3
Build a new 115 kV three-breaker switching station (Erving) ring bus	Mar-17	3
Build a new 115 kV line from Northfield Mountain to the new Erving Switching Station	May-17	3
Install 115 kV 14.4 MVAR capacitor banks at Cumberland, Podick and Amherst Substations	Dec-15	4

Pittsfield/Greenfield Projects, cont.

Status as of 11/28/16

Project Benefit: Addresses system needs in the Pittsfield/Greenfield area in Western Massachusetts

Upgrade	Expected In-Service	Present Stage
Rebuild the Cumberland to Montague 1361 115 kV line and terminal work at Cumberland and Montague. At Montague Substation, reconnect Y177 115 kV line into 3T/4T position and perform other associated substation work	Dec-16	3
Remove the sag limitation on the 1512 115 kV line from Blandford Substation to Granville Junction and remove the limitation on the 1421 115 kV line from Pleasant to Blandford Substation	Dec-14	4
Loop the A127W line between Cabot Tap and French King into the new Erving Substation	Mar-17	3
Reconductor A127 between Erving and Cabot Tap and replace switches at Wendell Depot	Apr-15	4

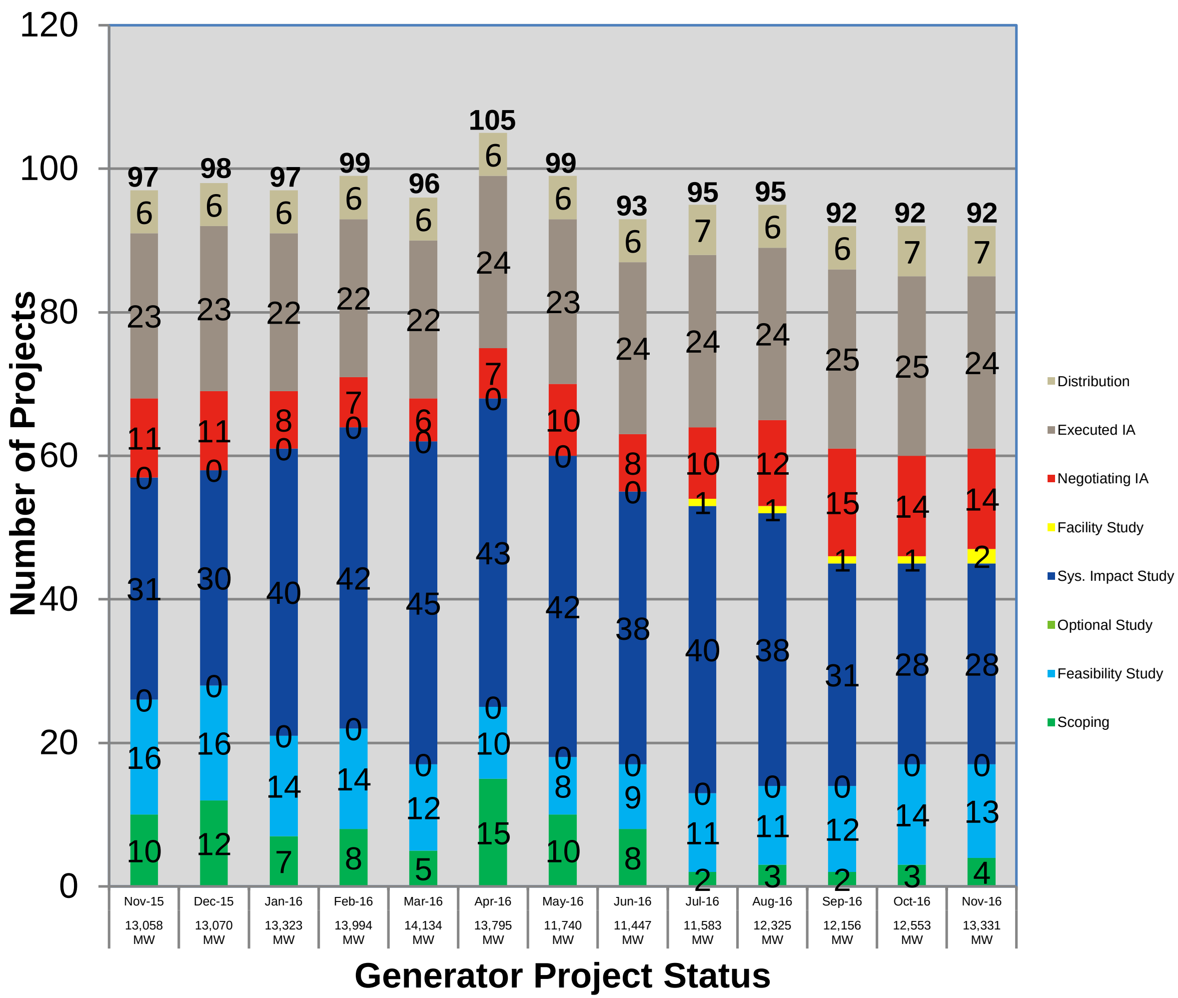
Pittsfield/Greenfield Projects, cont.

Status as of 11/28/16

Project Benefit: Addresses system needs in the Pittsfield/Greenfield area in Western Massachusetts

Upgrade	Expected In-Service	Present Stage
Install a 115 kV 20.6 MVAR capacitor at the Doreen substation and operate the 115 kV 13T breaker N.O.	Dec-17	1
Install a 75-150 MVAR variable reactor at Northfield substation	Dec-17	1
Install a 75-150 MVAR variable reactor at Ludlow substation	Dec-17	1
Construct a 115 kV three-breaker ring bus at or adjacent to Pochassic 37R Substation, loop line 1512-1 into the new three-breaker ring bus, construct a new line connecting the new three-breaker ring bus to the Buck Pond 115 kV Substation on the vacant side of the double-circuit towers that carry line 1302-2, add a new breaker to the Buck Pond 115 kV straight bus and reconnect lines 1302-2, 1657-2 and transformer 2X into new positions	Dec-19	1

Status of Tariff Studies



Note: November 2016 based on partial data

Note: As of November 2016, there are 9 ETU's in SIS, 1 in OSIS, 2 in FS, 2 in Scoping, and 2 in Neg. IA

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

OPERABLE CAPACITY ANALYSIS

Winter 2016/17

Winter 2016/17 Operable Capacity Analysis

50/50 Load Forecast (Reference)	January - 2017[2] CSO	January - 2017[2] SCC
Generator Operable Capacity MW [1]	29,982	32,829
OP CAP From OP-4 RTDR (+)	362	362
OP CAP From OP-4 RTEG (+)	177	177
Operable Capacity Generator with OP-4 DR and RTEG	30,521	33,368
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,037	1,037
Non Commercial Capacity (+)	50	50
Non Gas-fired Planned Outage MW (-)	439	510
Gas Generator Outages MW (-)	489	562
Allowance for Unplanned Outages (-) [5]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [4]	3,143	3,451
Net Capacity (NET OPCAP SUPPLY MW) [3]	24,737	27,132
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	21,340	21,340
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,645	23,645
Operable Capacity Margin [3]	1,092	3,487

[1] Generator Operable Capacity is based on data as of **November 11, 2016** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, Photo Voltaic, and external capacity. SCC value is based on data as of **November 11, 2016**

[2] Load based on 2016 CELT report and week with lowest Operable Capacity Margin, week beginning **January 14, 2017**.

[3] Includes OP4 actions associated with RTEG and RTDR

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

[5] Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.

Winter 2016/17 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	January - 2017[2] CSO	January - 2017[2] SCC
Generator Operable Capacity MW [1]	29,982	32,829
OP CAP From OP-4 RTDR (+)	362	362
OP CAP From OP-4 RTEG (+)	177	177
Operable Capacity Generator with OP-4 DR and RTEG	30,521	33,368
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,037	1,037
Non Commercial Capacity (+)	50	50
Non Gas-fired Planned Outage MW (-)	439	510
Gas Generator Outages MW (-)	489	562
Allowance for Unplanned Outages (-) [5]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [4]	3,546	3,897
Net Capacity (NET OPCAP SUPPLY MW) [3]	24,334	26,686
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	22,028	22,028
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	24,333	24,333
Operable Capacity Margin [3]	1	2,353

[1] Generator Operable Capacity is based on data as of **November 11, 2016** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, Photo Voltaic, and external capacity. SCC value is based on data as of **November 11, 2016.**

[2] Load based on 2016 CELT report and week with lowest Operable Capacity Margin, week beginning **January 14, 2017**.

[3] Includes OP4 actions associated with RTEG and RTDR

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

[5] Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.

Winter 2016/17 Operable Capacity Analysis (MW)
50/50 Forecast (Reference)

ISO-NE 2016/17 OPERABLE CAPACITY ANALYSIS

December 2, 2016 - 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]
12/3/2016	30,238	1,021	16	1,266	1,248	3,200	1,052	24,509	20,202	2,305	22,507	2,002	250	2,252	2	2,254
12/10/2016	30,238	1,021	16	1,223	528	3,200	2,256	24,068	20,501	2,305	22,806	1,262	250	1,512	2	1,514
12/17/2016	30,238	1,021	16	443	454	3,200	2,451	24,727	20,512	2,305	22,817	1,910	250	2,160	2	2,162
12/24/2016	30,238	1,021	16	441	229	3,200	2,918	24,487	20,577	2,305	22,882	1,605	250	1,855	2	1,857
12/31/2016	29,982	1,037	50	369	470	2,800	3,040	24,390	20,859	2,305	23,164	1,226	362	1,588	177	1,765
1/7/2017	29,982	1,037	50	396	718	2,800	2,914	24,241	21,340	2,305	23,645	596	362	958	177	1,135
1/14/2017	**29,982**	**1,037**	**50**	**439**	**489**	**2,800**	**3,143**	**24,198**	**21,340**	**2,305**	**23,645**	**553**	**362**	**915**	**177**	**1,092**
1/21/2017	29,982	1,037	50	374	489	2,800	3,021	24,385	21,340	2,305	23,645	740	362	1,102	177	1,279
1/28/2017	29,982	1,037	57	423	489	3,100	2,780	24,284	21,110	2,305	23,415	869	362	1,231	177	1,408
2/4/2017	29,982	1,037	57	755	489	3,100	2,780	23,952	20,834	2,305	23,139	813	362	1,175	177	1,352
2/11/2017	29,982	1,037	57	540	489	3,100	2,416	24,531	20,804	2,305	23,109	1,422	362	1,784	177	1,961
2/18/2017	29,982	1,037	57	459	489	3,100	2,174	24,854	20,533	2,305	22,838	2,016	362	2,378	177	2,555
2/25/2017	29,982	1,037	57	712	1,234	3,100	945	25,085	19,512	2,305	21,817	3,268	362	3,630	177	3,807
3/4/2017	29,982	1,037	57	1,316	992	2,200	824	25,744	19,151	2,305	21,456	4,288	362	4,650	177	4,827
3/11/2017	29,982	1,037	57	2,069	482	2,200	1,213	25,112	18,949	2,305	21,254	3,858	362	4,220	177	4,397
3/18/2017	29,982	1,037	57	2,752	482	2,200	725	24,917	18,572	2,305	20,877	4,040	362	4,402	177	4,579
3/25/2017	29,982	1,037	57	3,417	482	2,200	365	24,612	17,988	2,305	20,293	4,319	362	4,681	177	4,858

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 and generator improvements 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 2016 CELT Report and adjusted for Passive Demand Resources. http://www.iso-ne.com/system-planning/system-plans-studies/celt
10. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of 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 2016/17 Operable Capacity Analysis (MW)

90/10 Forecast (Extreme)

ISO-NE 2016/17 OPERABLE CAPACITY ANALYSIS

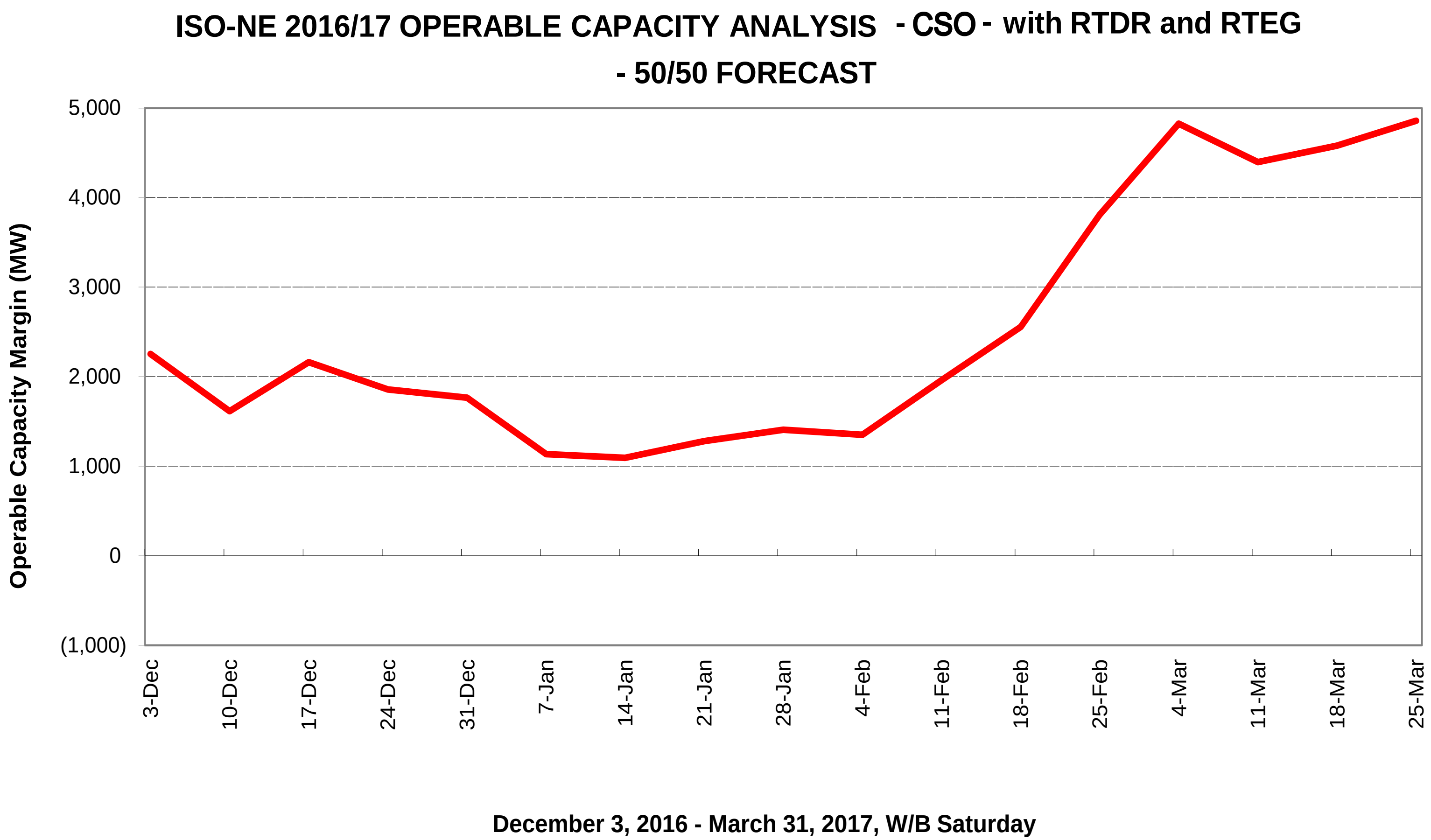
December 2, 2016 - 90/10 FORECAST using CSO values with RTDR and RTEG

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.

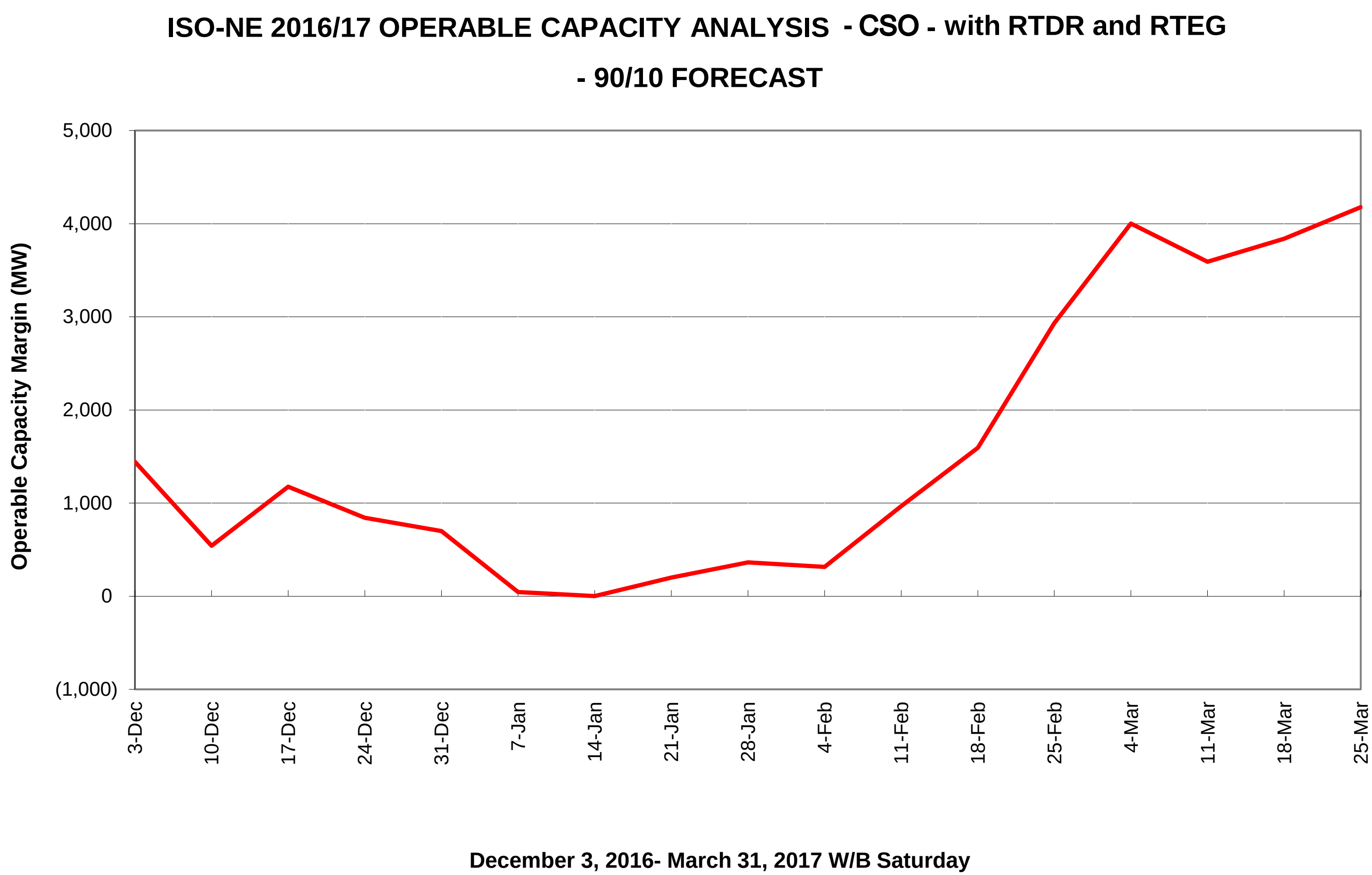
STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERAT OR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET 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]
11/26/2016	30,237	993	16	1,002	714	3,600	1,303	24,627	20,456	2,305	22,761	1,866	259	2,125	2	2,127
12/3/2016	30,238	1,121	16	1,266	1,248	3,200	1,308	24,353	20,856	2,305	23,161	1,192	250	1,442	2	1,444
12/10/2016	30,238	1,021	16	1,223	528	3,200	2,565	23,759	21,164	2,305	23,469	290	250	540	2	542
12/17/2016	30,238	1,021	16	443	454	3,200	2,774	24,404	21,176	2,305	23,481	923	250	1,173	2	1,175
12/24/2016	30,238	1,021	16	441	229	3,200	3,268	24,137	21,242	2,305	23,547	590	250	840	2	842
12/31/2016	29,982	1,037	50	369	470	2,800	3,431	23,999	21,533	2,305	23,838	161	362	523	177	700
1/7/2017	29,982	1,037	50	396	718	2,800	3,317	23,838	22,028	2,305	24,333	(495)	362	(133)	177	44
1/14/2017	**29,982**	**1,037**	**50**	**439**	**489**	**2,800**	**3,546**	**23,795**	**22,028**	**2,305**	**24,333**	**(538)**	**362**	**(176)**	**177**	**1**
1/21/2017	29,982	1,037	50	374	489	2,800	3,412	23,994	22,028	2,305	24,333	(339)	362	23	177	200
1/28/2017	29,982	1,037	57	423	489	3,100	3,143	23,921	21,791	2,305	24,096	(175)	362	187	177	364
2/4/2017	29,982	1,037	57	755	489	3,100	3,143	23,589	21,507	2,305	23,812	(223)	362	139	177	316
2/11/2017	29,982	1,037	57	540	489	3,100	2,739	24,208	21,476	2,305	23,781	427	362	789	177	966
2/18/2017	29,982	1,037	57	459	489	3,100	2,470	24,558	21,197	2,305	23,502	1,056	362	1,418	177	1,595
2/25/2017	29,982	1,037	57	712	1,234	3,100	1,187	24,843	20,145	2,305	22,450	2,393	362	2,755	177	2,932
3/4/2017	29,982	1,037	57	1,316	992	2,200	1,025	25,543	19,774	2,305	22,079	3,464	362	3,826	177	4,003
3/11/2017	29,982	1,037	57	2,069	482	2,200	1,401	24,924	19,565	2,305	21,870	3,054	362	3,416	177	3,593
3/18/2017	29,982	1,037	57	2,752	482	2,200	859	24,783	19,177	2,305	21,482	3,301	362	3,663	177	3,840
3/25/2017	29,982	1,037	57	3,417	482	2,200	459	24,518	18,575	2,305	20,880	3,638	362	4,000	177	4,177

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 and generator improvements 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 2016 CELT Report and adjusted for Passive Demand Resources. http://www.iso-ne.com/system-planning/system-plans-studies/celt
10. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of 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 2016/17 Operable Capacity Analysis (MW)
50/50 Forecast (Reference)



Winter 2016/17 Operable Capacity Analysis (MW)
90/10 Forecast (Extreme)



OPERABLE CAPACITY ANALYSIS

Appendix

Possible Relief Under 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.	**December 250** [3] **January - March 362** [3]
3	Voluntary Load Curtailment of Market Participants' facilities.	40 [2]
4	Implement Power Watch	0
5	Schedule Emergency Energy Transactions and arrange to purchase Control Area-to-Control Area Emergency	1,000
6	Voltage Reduction requiring > 10 minutes Dispatch real time Emergency Generation	134 [4] **December 2** [3] **January – March 177** [3]

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 November 11, 2016.
4. The MW values are based on a 26,930 MW system load and the most recent voltage reduction test % achieved.

Possible Relief Under OP4: Appendix A

OP 4 Action Number	Page 2 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
7	Request generating resources not subject to a Capacity Supply Obligation to voluntary provide energy for reliability purposes	0
8	Voltage Reduction requiring 10 minutes or less	267 [4]
9	Transmission Customer Generation Not Contractually Available to Market Participants during a Capacity Deficiency. Voluntary Load Curtailment by Large Industrial and Commercial Customers.	5 200 [2]
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		**December 2,798 [3]** **January – March 3,085 [3]**

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 November 11, 2016.
4. The MW values are based on a 26,930 MW system load and the most recent voltage reduction test % achieved.

NEW ENGLAND POWER POOL
PARTICIPANTS COMMITTEE MEETING

December 2, 2016

RESOLUTION REGARDING ELECTION OF OFFICERS FOR 2017

WHEREAS, Section 4.6 of the Participants Committee Bylaws sets forth procedures for the nomination and election of a Chair and Vice-Chairs of the Participants Committee; and

WHEREAS, pursuant to those procedures the individuals indentified in the following resolution were nominated and elected for 2017 to the offices of Chair and Vice-Chair, as set forth opposite their names; and

WHEREAS Section 7.1 of the Second Restated NEPOOL Agreement provides that officers be elected at the annual meeting of the Participants Committee.

NOW, THEREFORE, IT IS

RESOLVED, that the Participants Committee hereby adopts and ratifies the results of the election held in accordance with Section 4.6 of the Bylaws and elects the following individuals for 2017 to the offices set forth opposite their names to serve until their successors are elected and qualified:

Chair	Thomas W. Kaslow
Vice-Chair	Calvin A. Bowie
Vice-Chair	Nancy P. Chafetz
Vice-Chair	Brian E. Forshaw
Vice-Chair	John J. Keene Jr.
Vice-Chair	Frederick R. Plett
Secretary	David T. Doot
Assistant Secretary	Paul N. Belval

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Kenneth Dell Orto, Chairman, NEPOOL Budget and Finance Subcommittee
Paul Belval, NEPOOL Counsel

DATE: November 23, 2016

RE: Estimated Budget for 2017 Participant Expenses

The Participants Committee will be asked at its December 2 meeting to approve the estimated NEPOOL expense budget for 2017, which is attached to this memorandum (the "2017 Budget"). As we did in prior years, we have prepared the 2017 Budget to compare the estimated expenses for 2017 to both the estimated 2016 expenses approved by the Participants Committee in December 2015 and the current forecast for actual expenses for 2016 (Attachment A).

The 2017 Budget reflects an increase in NEPOOL expenses from the 2016 budget, due primarily to the increased meetings and counsel efforts associated with the IMAPP initiative. We have also attached an estimated calculation of the per-Participant share of the 2016 Budget expenses, comparing that amount to the same figures from five years ago, which generally shows a slight increase in NEPOOL expenses over that five-year period. (Attachment B).

Consistent with the practice in previous years, the NEPOOL Budget and Finance Subcommittee (the "Subcommittee") has worked with NEPOOL Counsel, the ISO and NEPOOL's Independent Financial Advisor to develop the 2017 Budget. At its November 22 teleconference, the Subcommittee discussed the proposed 2017 Budget and recommended its adoption without objection.

The following form of resolution may be used in acting on the 2017 Budget:

> RESOLVED, that the Participants Committee adopts the estimated NEPOOL expense budget for 2017 as presented at this meeting.

ATTACHMENT A

ESTIMATED 2017 NEPOOL BUDGET COMPARED TO 2016 NEPOOL BUDGET AND 2016 PROJECTED ACTUAL EXPENSES

Line Items	**2017 Proposed Budget**	**2016 Approved Budget**	**2016 Current Forecast**
NEPOOL Counsel Fees (1)	$3,850,000	$3,700,000	$4,000,000
NEPOOL Counsel Disbursements (1)	$ 45,000	$ 55,000	$ 35,000
Independent Financial Advisor Fees and Disbursements (2)	$ 40,000	$ 45,000	$ 38,500
Committee Meeting Expenses (3)	$ 675,000	$ 625,000	$ 660,000
Generation Information System (3)	$1,100,000	$1,095,000	$1,150,000
Credit Insurance Premium (3)	$ 350,000	$ 400,000	$ 300,000
NEPOOL Audit Management Subcommittee (“NAMS”) Consultant (4)	$ 0	$ 64,000	$ 64,000
SUBTOTAL EXPENSES	$6,060,000	$5,984,000	$6,247,500
Revenue			
NEPOOL Membership Fees (3) (5)	($1,900,000)	($1,856,000)	($1,983,000)
Generation Information System (3) (6)	($1,100,000)	($1,095,000)	($1,150,000)
Credit Insurance Premium (3) (7)	($ 350,000)	($ 400,000)	($ 300,000)
TOTAL REVENUE	($3,350,000)	($3,351,000)	($3,433,000)
TOTAL NEPOOL EXPENSES	**$2,710,000**	**$2,633,000**	**$2,814,500**

Notes

(1) 2017 proposed estimate provided by Day Pitney LLP, NEPOOL counsel, presuming continuation of the IMAPP process initiated in 2016.

(2) 2017 proposed estimate provided by Michael M. Mackles, NEPOOL's Independent Financial Advisor.

(3) 2017 proposed estimate provided by ISO New England Inc. ("ISO").

(4) The NEPOOL Participants Committee approved a total budget of $75,000 for the NAMS Consultant at its June 5, 2015 meeting. William Dunn was retained as the NAMS Consultant to participate in the ongoing ISO operational audit process in 2015 and 2016.

(5) The 2017 proposed estimate is based on the 2016 actual receipts through October 2016, plus a forecast (a) for new members, of 5 members at $5,000 each, 1 member at $1,000 each, 1 member at $500 each, and (b) for terminated members, of 5 at $5,000 each, and 2 at $500 each.

(6) Generation Information System ("GIS") costs, other than those associated with accessing the GIS through the application programming interface ("API") are paid by "GIS Participants" under Allocation of Costs Related to Generation Information System, which was approved by the NEPOOL Participants Committee on June 21, 2002. GIS costs associated with accessing the GIS through the API are paid by the GIS account holders using that API.

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

ATTACHMENT B

ESTIMATED BREAKDOWN OF PROJECTED 2017 NEPOOL EXPENSE BUDGET AMONG SECTOR MEMBERS

(2017 figures assume no change in current NEPOOL membership)
(2012 figures as projected and budgeted at 2011 Annual Meeting)

CALCULATION OF COSTS TO BE ALLOCATED TO NEPOOL SECTORS			
		2017	**2012**
A.	Total Projected NEPOOL Expenses (not including costs associated with GIS, credit insurance premium, which are funded separately)	**4,619,000**	**4,332,000**
B.	Projected NEPOOL Membership Fees	**1,900,000**	**1,900,000**
C.	Total Projected NEPOOL Expenses to be Funded Through Non-Hourly Charges (A – B)	**2,710,000**	**2,432,000**
D.	Projected Amount to be paid by all Market Participant End Users (based on highest hourly load in any month in preceding calendar year) (figure used here for 2017 is based on 2015 peak loads of MPEU members)	**45,262**	**75,919**
E.	Total Amount paid by all Load Response, Distributed Generation, and Small Renewable Generation Resource Providers in AR Sector (figure used here for 2017 is estimated amount based on 2016 membership data)	**70,717**	**138,500**
F.	[Reserved]	**0**	**0**
G.	Large Renewable Generation Sub-Sector Share (C x 2% x lrg_y)	**271,900**	**194,560**
H.	Total Amount to be Allocated among Transmission, Generation, Supplier and Publicly Owned Entity Sectors (“Remaining Sectors”) (C – (D + E + F+ G))	**2,331,121**	**2,023,021**
CALCULATION OF SECTOR ALLOCATIONS			
		2017	**2012**
I.	Amount to be allocated to each of the Remaining Sectors (H ÷ 4)	**582,780**	**505,755**
J.	Total Amount paid by Related Person Suppliers (2 voting members) (I ÷ s_y) x rps_y	**9,106**	**9,366**
K.	Aggregate Share to be paid by Generation Sector/Supplier Sector/ Large Renewable Generation Resource Providers ((I x 2) + G – J)	**1,428,355**	**1,196,705**

ATTACHMENT B

L.	Total Amount of Provisional Generation Share shared equally by Generation Sector Provisional Members $(0.02 \div gprov_y \times K) \times (g_y \div (g_y + (s_y - rps_y) + lrg_y))$	**n/a**	**1,265**
M.	Remainder of Aggregate Share to be paid, on a per member basis, by voting members in the Generation Sector (excluding provisional group voting member), Supplier Sector (excluding Related Person Suppliers), and Large Renewable Generation Resource Providers $((K - L) \div (g_y + (s_y - rps_y) + lrg_y))$	**9,783**	**9,719**
N.	Transmission Sector Share per full voting member $((N-O) \div t_y)$	**116,556**	**71,889**
O.	Provisional Transmission Sector member share $(I \times (tprov_y \times 0.005))$	**n/a**	**2,529**
P.	Publicly Owned Entity Sector Member Share (assuming equal sharing of Publicly Owned Entity Sector Share Participant Expense among voting Sector members)[i] $(I \div poe_y)$	**10,224**[i]	**9,543**[i]

ANNUAL VARIABLES			
		2017	**2012**
s_y	# Supplier Sector voting members	128	108
rps_y	# Supplier Sector Related Person Suppliers	2	2
g_y	# Generation Sector voting members	14	13
$gprov_y$	# Generation Sector provisional group members	0	2
lrg_y	# AR Sector Large Renewable Generation Resource Providers	6	4
t_y	# Transmission Sector voting members	5	6
$tprov_y$	# Transmission Sector provisional group members	0	1
poe_y	# Publicly Owned Entity members	57	53

[i] A number of Publicly Owned Entity Sector members share Participant Expenses pursuant to an agreed-upon allocation percentage. The member share noted in the table is indicative of the share a Publicly Owned Entity, which does not participate in the group arrangement, would pay.

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Paul N. Belval, NEPOOL Counsel

DATE: November 23, 2016

RE: ISO New England Financial Assurance Policy – FTR BoPP Financial Assurance

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The Participants Committee will be asked at its December 2 annual meeting to support changes to the ISO Financial Assurance Policy (the "FAP") to implement the financial assurance requirements associated with the Financial Transmission Rights ("FTR") Balance of Planning Period ("BoPP") auctions. The proposed changes are Attachment 1 to this memorandum.

In a 2011 FERC filing, the ISO identified BoPP auctions as a key improvement to the FTR markets. The ISO planned to implement the BoPP auctions after it implemented an arrangement with an exchange to clear all FTR transactions. Due to several regulatory hurdles, the ISO cannot predict when or even if this clearing approach will come to fruition, and the ISO has determined to move forward with the BoPP auctions instead. As part of that process, the ISO has worked with the NEPOOL Budget and Finance Subcommittee (the "Subcommittee") to develop a methodology for incorporating the BoPP auctions into the FTR financial assurance requirements under the FAP.

The primary proposed change to the FAP would allow awarded FTR MWs from different auctions to net for FTR financial assurance calculations if the MWs are from the same or opposite path, same class type (on peak or off peak) and contract month. In order to have a proper netting mechanism, the ISO introduced a new variable called "Unsettled FTR Financial Assurance," which would reflect the net present value of an FTR portfolio for each Market Participant. The netting would also be applied to the requirement that each Market Participant with more than 1,000 MW per month of FTR transactions provide the ISO an annual certification regarding its risk management policies. In addition, the ISO proposed changes to how the proxy value for FTR financial assurance is calculated, with those calculations to be reviewed and approved by the Subcommittee and posted on the ISO website. Finally, FTR financial assurance requirements would be updated after each FTR auction is cleared (i.e. on a monthly basis).

As the ISO does today, during the review process for FTR auctions, if a Market Participant does not provide adequate financial assurance to support all its FTR bid/offer stacks, under the ISO's proposed changes all of that Participant's FTR bids/offers would be rejected from clearing, which would include both monthly auctions and BoPP auctions. After all the auctions clear, there is a chance that a Market Participant with FTR positions could be in default due to the mark-to-market change of the existing portfolio. In such a scenario the Market Participant would go through the normal financial assurance default process and would be allowed to cure the default within 24 hours.

The changes to the FAP were discussed by the Budget & Finance Subcommittee during its October 7 and November 22 teleconferences, and no one objected to the changes.

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

> RESOLVED, that the Participants Committee supports the changes to the ISO Financial Assurance Policy relating to the financial assurance requirements for Financial Transmission Rights Balance of Planning Period auctions, 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 & Finance Subcommittee may approve.

I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

(a) words denoting the singular include the plural and vice versa;

(b) words denoting a gender include all genders;

(c) references to a particular part, clause, section, paragraph, article, exhibit, schedule, appendix or other attachment shall be a reference to a part, clause, section, paragraph, or article of, or an exhibit, schedule, appendix or other attachment to, this Tariff;

(d) the exhibits, schedules and appendices attached hereto are incorporated herein by reference and shall be construed with an as an integral part of this Tariff to the same extent as if they were set forth verbatim herein;

(e) a reference to any statute, regulation, proclamation, ordinance or law includes all statutes, regulations, proclamations, amendments, ordinances or laws varying, consolidating or replacing the same from time to time, and a reference to a statute includes all regulations, policies, protocols, codes, proclamations and ordinances issued or otherwise applicable under that statute unless, in any such case, otherwise expressly provided in any such statute or in this Tariff;

(f) a reference to a particular section, paragraph or other part of a particular statute shall be deemed to be a reference to any other section, paragraph or other part substituted therefor from time to time;

(g) a definition of or reference to any document, instrument or agreement includes any amendment or supplement to, or restatement, replacement, modification or novation of, any such document, instrument or agreement unless otherwise specified in such definition or in the context in which such reference is used;

(h) a reference to any person (as hereinafter defined) includes such person's successors and permitted assigns in that designated capacity;

(i) any reference to "days" shall mean calendar days unless "Business Days" (as hereinafter defined) are expressly specified;

(j) if the date as of which any right, option or election is exercisable, or the date upon which any amount is due and payable, is stated to be on a date or day that is not a Business Day, such right, option or election may be exercised, and such amount shall be deemed due and payable, on the next succeeding Business Day with the same effect as if the same was exercised or made on such date or day (without, in the case of any such payment, the payment or accrual of any interest or

FTR Auction is the periodic auction of FTRs conducted by the ISO in accordance with Section III.7 of Market Rule 1.

FTR Auction Revenue is the revenue collected from the sale of FTRs in FTR Auctions. FTR Auction Revenue is payable to FTR Holders who submit their FTRs for sale in the FTR Auction in accordance with Section III.7 of Market Rule 1 and to ARR Holders and Incremental ARR Holders in accordance with Appendix C of Market Rule 1.

~~**FTR Award Financial Assurance** is a required amount of financial assurance that must be maintained at all times from a Designated FTR Participant for each FTR awarded to the participant in any FTR Auctions. This amount is calculated pursuant to Section VI.C of the ISO New England Financial Assurance Policy.~~

~~**FTR Bid Financial Assurance** is an amount of financial assurance required from a Designated FTR Participant for each bid submission into an FTR auction. This amount is calculated pursuant to Section VI.B of the ISO New England Financial Assurance Policy.~~

FTR Credit Test Percentage is calculated in accordance with Section III.B.1(b) of the ISO New England Financial Assurance Policy.

FTR Financial Assurance Requirements are described in Section VI of the ISO New England Financial Assurance Policy.

FTR Holder is an entity that acquires an FTR through the FTR Auction to Section III.7 of Market Rule 1 and registers with the ISO as the holder of the FTR in accordance with Section III.7 of Market Rule 1 and applicable ISO New England Manuals.

FTR-Only Customer is a Market Participant that transacts in the FTR Auction and that does not participate in other markets or programs of the New England Markets. References in this Tariff to a "Non-Market Participant FTR Customers" and similar phrases shall be deemed references to an FTR-Only Customer.

ISO operating agreements, to facilitate the restoration of the New England Transmission System following a partial or complete shutdown of the New England Transmission System.

New England Transmission System is the system of transmission facilities, including PTF, Non-PTF, OTF and MTF, within the New England Control Area under the ISO's operational jurisdiction.

New Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as described in Section III.13.1.1.1 of Market Rule 1.

New Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.4 of Market Rule 1.

New Resource Offer Floor Price is defined in Section III.A.21.2.

NMPTC means Non-Market Participant Transmission Customer.

NMPTC Credit Threshold is described in Section V.A.2 of the ISO New England Financial Assurance Policy.

NMPTC Financial Assurance Requirement is an amount of additional financial assurance for Non-Market Participant Transmission Customers described in Section V.D of the ISO New England Financial Assurance Policy.

~~**Nodal Amount** is node(s)-specific on-peak and off-peak proxy value to which an FTR bid or awarded FTR bid relates.~~

Node is a point on the New England Transmission System at which LMPs are calculated.

No-Load Fee is the amount, in dollars per hour, for a generating unit that must be paid to Market Participants with an Ownership Share in the unit for being scheduled in the New England Markets, in addition to the Start-Up Fee and price offered to supply energy, for each hour that the generating unit is scheduled in the New England Markets.

Service Commencement Date is the date service is to begin pursuant to the terms of an executed Service Agreement, or the date service begins in accordance with the sections of the OATT addressing the filing of unexecuted Service Agreements.

Services means, collectively, the Scheduling Service, EAS and RAS; individually, a Service.

Settlement Financial Assurance is an amount of financial assurance required from a Designated FTR Participant awarded a bid in an FTR Auction. This amount is calculated pursuant to Section VI.C~~D~~ of the ISO New England Financial Assurance Policy.

Settlement Only Resources are generators of less than 5 MW or otherwise eligible for Settlement Only Resource treatment as described in ISO New England Operating Procedure No. 14 and that have elected Settlement Only Resource treatment as described in the ISO New England Manual for Registration and Performance Auditing.

Shortage Event is defined in Section III.13.7.1.1.1 of Market Rule 1.

Shortage Event Availability Score is the average of the hourly availability scores for each hour or portion of an hour during a Shortage Event, as described in Section III.13.7.1.1.1.A of Market Rule 1.

Shortfall Funding Arrangement, as specified in Section 5.1 of the ISO New England Billing Policy, is a separate financing arrangement that can be used to make up any non-congestion related differences between amounts received on Invoices and amounts due for ISO Charges in any bill issued.

Short-Term is a period of less than one year.

Significantly Reduced Congestion Costs are defined in Section III.G.2.2 of Appendix G to Market Rule 1.

SMD Effective Date is March 1, 2003.

Solutions Study is described in Section 4.2(b) of Attachment K to the OATT.

Uncovered Transmission Default Amounts are defined in Section 3.4.f of the ISO New England Billing Policy.

Unrated means a Market Participant that is not a Rated Market Participant.

Unsecured Covered Entity is, collectively, an Unsecured Municipal Market Participant and an Unsecured Non-Municipal Covered Entity.

Unsecured Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Municipal Market Participant is defined in Section 3.3(h) of the ISO New England Billing Policy.

Unsecured Municipal Transmission Default Amount is defined in Section 3.4.f of the ISO New England Billing Policy.

Unsecured Non-Municipal Covered Entity is a Covered Entity that is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and has a Market Credit Limit or Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy.

Unsecured Non-Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Non-Municipal Transmission Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Transmission Default Amounts are, collectively, the Unsecured Municipal Transmission Default Amount and the Unsecured Non-Municipal Transmission Default Amount.

Unsettled FTR Financial Assurance is an amount of financial assurance required from a Designated FTR Participant as calculated pursuant to Section VI.B of the ISO New England Financial Assurance Policy.

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EXHIBIT IA

ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY

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then the ISO shall be required to make an informational filing with the Commission as soon as reasonably practicable after taking such action. If the ISO chooses to prohibit (in the case of an applicant) or terminate (in the case of a customer) participation in the New England Markets, then the ISO must file for Commission approval of such action, and the prohibition or termination shall become effective only upon final Commission ruling. No action by the ISO pursuant to this subsection (b) shall limit in any way the ISO's rights or authority under any other provisions of the ISO New England Financial Assurance Policy or the ISO New England Billing Policy.

2. Risk Management

(a) Each customer and applicant shall submit, on an annual basis (by April 30 each year), a certificate in the form of Attachment 3 to the ISO New England Financial Assurance Policy stating that the customer or applicant has: (i) either established or contracted for risk management procedures that are applicable to participation in the New England Markets; and (ii) has established or contracted for appropriate training of relevant personnel that is applicable to its participation in the New England Markets. The certificate must be signed on behalf of the customer or applicant by a Senior Officer of the customer or applicant and must be notarized. An applicant that fails to provide this certificate will be prohibited from participating in the New England Markets until the deficiency is rectified. If a customer fails to provide this certificate by end of business on April 30, then the ISO shall issue a notice of such failure to the customer on the next Business Day and, if the customer does not provide the certificate to the ISO within 5 Business Days after issuance of such notice, then the customer will be suspended as described in Section III.B.3 of the ISO New England Financial Assurance Policy until the deficiency is rectified.

(b) Each applicant prior to commencing activity in the FTR market shall submit to the ISO or its designee the written risk management policies, procedures, and controls applicable to its participation in the FTR market relied upon by the Senior Officer of the applicant signing the certificate provided pursuant to Section II.A.2 (a). On an annual basis (by April 30 each year), each ~~customer~~Designated FTR Participant with FTR transactions in any of the previous twelve months or in any currently open month that exceed 1,000 MW per month (on a net basis, as described in the FTR Financial Assurance Requirements provisions in Section VI) shall submit to the ISO or its designee a certificate in the form of Attachment 5 to the ISO New England Financial Assurance Policy stating that, since the customer's delivery of its risk management policies, procedures, and controls or its last certificate pursuant to this Section II.A.2(b), the customer either: (i) has not made any changes to the previously submitted written risk management policies, procedures, and controls; or (ii) that changes have been made to the previously submitted written risk management policies, procedures, and controls and that all such changes are clearly identified and attached to such certificate. If any such applicant fails to submit the relevant written policies, procedures, and controls, then the applicant will be prohibited from participating in the FTR market. If any such customer fails to provide a certificate in the form of Attachment 5 by end of business on April 30, then the ISO shall issue a notice of such failure to the customer, and if the customer does not provide the certificate to the ISO within two Business Days after issuance of such notice, then the customer will be suspended (as described in Section III.B.3.c of the ISO New England Financial Assurance Policy) from entering into any future transactions in the FTR system.

The ISO, at its sole discretion, may also require any applicant or customer to submit to the ISO or its designee the written risk management policies, procedures, and controls that are applicable to its participation in the New England Markets relied upon by the Senior Officer of the applicant or customer signing the certificate provided pursuant to Section II.A.2(a). The ISO may require such submissions based on identified risk factors that include, but are not limited to, the markets in which the customer is transacting or the applicant seeks to transact, the magnitude of the customer's transactions or the applicant's potential transactions, or the volume of the customer's open positions. Where the ISO notifies an applicant or customer that such a submission is required, the submission shall be due within 5 Business Days of the notice. If an applicant fails to submit the relevant written policies, procedures, and controls as required, then the applicant will be prohibited from participating in the New England Markets. If a customer fails to submit the relevant written policies, procedures, and controls, then the ISO shall issue a notice of such failure to the customer, and if the customer fails to submit the relevant written policies, procedures, and controls to the ISO or its designee within two Business Days after issuance of such notice, then the customer will be suspended (as described in Section III.B of the ISO New England Financial Assurance Policy).

satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy).

(b) Any customer or applicant that fails to meet these capitalization requirements will be suspended (as described in Section III.B.3.c of the ISO New England Financial Assurance Policy) from entering into any future transactions of a duration greater than one month in the FTR system or any future transactions for a duration of one month or less except when FTRs for a month are being auctioned for the final time. Such a customer or applicant may enter into future transaction of a duration of one month or less in the FTR system in the case of FTRs for a month being auctioned for the final time. Any customer or applicant that fails to meet these capitalization requirements shall provide additional financial assurance in one of the forms described in Section X of the ISO New England Financial Assurance Policy equal to 25 percent of the customer's or applicant's FTR Financial Assurance Requirements. Any additional financial assurance provided pursuant to this Section II.A.4(b) shall not be counted toward satisfaction of the total financial assurance requirements as calculated pursuant to the ISO New England Financial Assurance Policy.

(c) For markets other than the FTR market:

(i) Where a customer or applicant fails to meet the capitalization requirements, the customer or applicant will be required to provide an additional amount of financial assurance in one of the forms described in Section X of the ISO New England Financial Assurance Policy in an amount equal to 25 percent of the customer's or applicant's total financial assurance requirement (excluding FTR Financial Assurance Requirements).

(ii) An applicant that fails to provide the full amount of additional financial assurance required as described in subsection (i) above will be prohibited from participating in the New England Markets until the deficiency is rectified. For a customer, failure to provide the full amount of additional financial assurance required as described in subsection (i) above will have the same effect and will trigger the same consequences as exceeding the "100 Percent Test" as described in Section III.B.2.c of the ISO New England Financial Assurance Policy.

(iii) Any additional financial assurance provided pursuant to this Section II.A.4(c) shall not be counted toward satisfaction of the total financial assurance

(i) two and one-half (2.5) times the average monthly Non-Hourly Charges for such Non-Market Participant Transmission Customer over the two most recently invoiced calendar months (which amount shall not in any event be less than $0); plus

(ii) amount of any unresolved Disputed Amounts received by such Non-Market ParticipantTransmission Customer.

2. Financial Assurance for Transmission Charges

Each Non-Market Participant Transmission Customer must provide the ISO with additional financial assurance hereunder such that the sum of (x) its Transmission Credit Limit and (y) the excess of (A) the available amount of the additional financial assurance provided by that Non-Market Participant Transmission Customer over (B) the amount of that additional financial assurance needed to satisfy the requirements of Section V.D.1 above is equal to two and one-half (2.5) times the average monthly Transmission Charges for such Non-Market Participant Transmission Customer over the two most recently invoiced calendar months (which amount shall not in any event be less than $0)

3. Notice of Failure to Satisfy NMPTC Financial Assurance Requirement

A Non-Market Participant Transmission Customer that knows or can reasonably be expected to know that it is not satisfying its NMPTC Financial Assurance Requirement shall notify the ISO immediately of that fact. Without limiting the availability of any other remedy or right hereunder, failure by any Non-Market Participant Transmission Customer to comply with the provisions of the ISO New England Financial Assurance Policy (including failure to satisfy its NMPTC Financial Assurance Requirement) may result in the commencement of termination of service proceedings against that non-complying Non-Market Participant Transmission Customer.

VI. ADDITIONAL PROVISIONS FOR FTR TRANSACTIONS

Market Participants must complete an ISO-prescribed training course prior to participating in the FTR Auction. All Market Participants transacting in the FTR Auction that are otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy, including all FTR-Only Customers ("Designated FTR Participants") are required to provide financial assurance in an amount equal to the sum of the FTR Settlement Risk Financial Assurance, the Unsettled FTR Financial Assurance,~~FTR Bid Financial Assurance, the FTR Award Financial Assurance~~ and the Settlement

Financial Assurance, each as described in this Section VI (such sum being referred to in the ISO New England Financial Assurance Policy as the "FTR Financial Assurance Requirements").

A. FTR Settlement Risk Financial Assurance

A Designated FTR Participant is required to provide "FTR Settlement Risk Financial Assurance" for each bid it submits into an FTR Auction and for each ~~bid~~FTR that is awarded to it in an FTR Auction, as described below.

After bids are finalized for an FTR Auction, but before the auction results are final, a Designated FTR Participant must provide FTR Settlement Risk Financial Assurance based on its bids for each FTR path. The ISO will calculate an FTR Settlement Risk Financial Assurance amount for each direction (prevailing flow and counter flow) of each FTR path on which the Designated FTR Participant has bid, equal to the total number of MW bid for that direction of the FTR path multiplied by the applicable proxy value for the FTR path (as described below) multiplied by the number of hours associated with the bid. For that FTR path, the Designated FTR Participant must provide FTR Settlement Risk Financial Assurance equal to the higher of the amounts calculated for each direction.

Once an FTR Auction's results are final, a Designated FTR Participant must provide FTR Settlement Risk Financial Assurance based on awarded FTRs, equal to the MW value of each awarded FTR multiplied by the applicable proxy value for the FTR path (as described below) multiplied by the number of hours associated with the FTR. For purposes of this calculation, the ISO will net the MW values of a Designated FTR Participant's awarded FTRs having the same or opposite path, same contract month, and same type (on-peak or off-peak). For purposes of this netting, annual FTRs may be converted into monthly positions.

The proxy value for each FTR path, which shall be calculated separately for on-peak and off-peak FTRs, will be based on the standard deviation observed in the difference between the average congestion components of the Locational Marginal Price in the Day-Ahead Energy Market at the path's sink and source for the previous 36 months, with differing multipliers for annual and monthly FTRs and for prevailing flow and counter flow paths. These multipliers will be reviewed and approved by the NEPOOL Budget and

Finance Subcommittee and shall be posted on the ISO's website. Where there is insufficient data to perform these calculations for a node, zonal data will be used instead.

FTR Settlement Risk Financial Assurance will be adjusted as the awarded FTRs are settled.~~The amount of a Designated FTR Participant's FTR Settlement Risk Financial Assurance for each FTR bid or awarded FTR bid shall be based upon the node(s)-specific on-peak and off-peak proxy value to which such FTR bid or awarded FTR bid relates (the "Nodal Amount") multiplied by the number of MW-months included in the Designated FTR Participant's bid or remaining in the awarded FTR bid. The Nodal Amount for each node shall be determined from time to time by the ISO based on historical data for that node according to a methodology approved from time to time by the NEPOOL Budget and Finance Subcommittee and shall be posted on the ISO's website. Such Nodal Amounts may be adjusted from time to time.~~ In no event will the FTR Settlement Risk Financial Assurance be less than $0.

~~**B. FTR Bid Financial Assurance**~~

~~A Designated FTR Participant is required to provide "FTR Bid Financial Assurance" for each bid it submits into an FTR Auction. The amount of a Designated FTR Participant's FTR Bid Financial Assurance for any FTR Auction is the maximum dollar value of the bids submitted by such Designated FTR Participant in such FTR Auction at the time such FTR Auction closes. For purposes of calculating FTR Bid Financial Assurance, negative bids are treated as having a value of $0.~~

B~~C~~. Unsettled FTR Financial Assurance~~FTR Award Financial Assurance~~

A Designated FTR Participant is required to maintain, at all times, "Unsettled FTR ~~Award~~ Financial Assurance" for all~~each~~ FTRs awarded to it in any FTR Auctions. Immediately after FTRs are awarded in an FTR Auction, the Unsettled FTR Financial Assurance for those FTRs shall be zero. After subsequent FTR Auctions, the Unsettled FTR Financial Assurance for each FTR awarded in a previous FTR Auction shall be adjusted to reflect any change in the clearing price for that FTR based on non-zero volume. The adjustment will be equal to the change in the clearing price multiplied by the number of MW of the previously awarded FTR, with increases in the clearing price reducing the Unsettled FTR Financial Assurance amount and decreases in the clearing price increasing the Unsetteled FTR Financial Assurance amount. For purposes of these calculations, the ISO will consider FTRs having the same or opposite path, same contract month, and same type (on-peak or off-peak) together. A Designated FTR Participant's Unsettled FTR Financial Assurance may be a charge or a credit, and in the case of a credit, may offset the Designated FTR Participant's other FTR Financial Assurance Requirements (but not to less than zero). A Designated FTR Participant's Unsettled FTR Financial Assurance will be adjusted as the awarded FTRs are settled.~~The amount of a Designated FTR Participant's FTR Award Financial Assurance shall be the total dollar amount of any FTRs awarded to that Designated FTR Participant in any FTR Auctions. Once an FTR is awarded, the FTR Bid Financial Assurance that relates to the bid for that FTR will be converted to the FTR Award Financial Assurance related to such awarded FTR. The required amount of the FTR Award Financial Assurance will be based on the amount of the awarded FTR, not the FTR Bid Financial Assurance, and will decrease proportionately as the amount due with respect to such awarded FTR decreases in a manner approved by the NEPOOL Budget and Finance Subcommittee from time to time. Unpaid credits due to a Designated FTR Participant for short-term FTR awards, and unpaid credits due to a Designated FTR Participant for long-term FTR awards for the current month only, may offset other FTR obligations for purposes of calculating that Designated FTR Participant's FTR Award Financial Assurance. In the event that, as a result of those offsets, a Designated FTR Participant's FTR Award Financial Assurance is less than $0, those offsets may be used to reduce that Designated FTR Participant's FTR Financial Assurance Requirements or remaining Financial Assurance Requirement.~~

C~~D~~. Settlement Financial Assurance

A Designated FTR Participant that has been awarded a bid in an FTR Auction is required to provide "Settlement Financial Assurance." The amount of a Designated FTR Participant's Settlement Financial Assurance shall be equal to the amount of any settled but uninvoiced Charges incurred by such Designated FTR Participant for FTR transactions less the settled but uninvoiced amounts due to such Market Participant for FTR transactions. These amounts shall include the costs of acquiring FTRs as well as payments and charges associated with FTR settlement.

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D~~E~~. Consequences of Failure to Satisfy FTR Financial Assurance Requirements

If a Designated FTR Participant does not have additional financial assurance equal to its FTR Financial Assurance Requirements (in addition to its other financial assurance

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of December 1, 2016

The following activity, as more fully described in the attached litigation report, has occurred since the report dated November 3, 2016 was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

I. Complaints/Section 206 Proceedings

	1	NEPGA PER Adjustment Complaint (EL16-120)	Nov 4 Nov 15	NEPGA answers NESCOE, RESA, NEPOOL pleadings NESCOE answers NEPGA Nov 4 answer
	1	Base ROE Complaint IV (2016) (EL16-64)	Nov 3 Nov 8 Nov 9 Nov 10 Nov 21	Settlement Judge Long issues status report recommending settlement procedures be continued 1st settlement conf. held Settlement Judge Long issues order scheduling Dec 20 settlement conf. and requiring joint positions statements Chief Judge Cintron issues order continuing settlement procedures FERC issues tolling order affording it additional time to consider requests for rehearing of *Base ROE Complaint IV Order*
	2	206 Proceeding: RNS/LNS Rates and Rate Protocols (EL16-19)	Nov 19	5th settlement conf. held telephonically

II. Rate, ICR, FCA, Cost Recovery Filings

*	4	ICR-Related Values and HQICCs – Annual Reconfiguration Auctions (ER17-[ ])	Dec 1	ISO-NE and NEPOOL jointly file ICR-Related Values and HQICCs for the 2017/18 ARA3, 2018/19 ARA2; and 2019/20 ARA1; comment date Dec 22
*	4	FCA11 Qualification Informational Filing (ER17-321)	Nov 10 Nov 18-28	ISO-NE submits required informational filing for FCA11 NEPOOL, Dominion, Eversource, National Grid, NESCOE intervene
*	5	ICR-Related Values and HQICCs - 2020/21 Capacity Commitment Period (ER17-320)	Nov 8 Nov 18-28	ISO-NE and NEPOOL jointly file ICR-Related Values for the 2020/21 Capacity Commitment Period Dominion, Eversource, Exelon, National Grid, NESCOE, NRG intervene
	5	2017 NESCOE Budget (ER17-140)	Nov 8 Nov 9	NEPOOL files comments supporting NESCOE 2017 budget Eversource intervenes
	5	2017 ISO-NE Administrative Costs and Capital Budgets (ER17-116)	Nov 7	NEPOOL files comments supporting ISO-NE 2017 administrative costs and capital budgets; Eversource, NESCOE intervene
	6	Schedule 2 Base CC Rate (ER12-229)	Nov 2, 7 Nov 18 Dec 1	NRG, Calpine intervene NEPOOL submits comments FERC accepts filing

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

*	7	Natural Gas Index Changes (ER17-327)	Nov 10 Nov 16-Dec 1	ISO-NE and NEPOOL jointly file changes Entergy, Eversource, Exelon, HQ US, National Grid, NRG intervene; Dominion protests the Changes
	7	Effective Date Update: MR1 §§ 2.7(a) & (g) (ER17-96)	Nov 4	Eversource intervenes
	7	Resource Dispatchability Changes (ER17-68)	Nov 17	ISO-NE and NEPOOL answer Eversource protest

	7	FCM Enhancements (ER16-2451)	Nov 17	Indicated NYTOs request rehearing of *FCM Enhancements Order*
	10	2013/14 Winter Reliability Program Remand Proceeding (ER13-2266)	Nov 7 Nov 15	ISO-NE requests 45-day extension of time for compliance filing FERC grants ISO-NE request; compliance filing due Jan 20, 2017

IV. OATT Amendments / TOAs / Coordination Agreements

No Activity to Report

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes

*	11	Schedule 21-CMP: Blue Sky LSA (ER17-407)	Nov 22	ISO-NE and CMP file Blue Sky LSA; comment date Dec 13
	11	Schedule 21-ES: Eversource Recovery of NU/NSTAR Merger-Related Costs (ER16-1023)	Nov 22 Nov 23	Eversource files offer of settlement to resolve all unresolved issues in this proceeding Chief Judge Cintron shortens date for initial comments to Dec 5; reply comments, December 10
	12	Schedule 21-EM: Recovery of Bangor Hydro/Maine Public Service Merger-Related Costs (ER15-1434 et al.)	Nov 10 Nov 16 Dec 1	Settlement Judge Dring issues status report recommending settlement judge procedures be continued Judge Dring cancels Nov 22 settlement conf. and schedules 3rd settlement conf. for Dec 1 3rd settlement conf. held

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

	13	Capital Projects Report - 2016 Q3 (ER17-122)	Nov 7 Nov 18	Eversource intervenes FERC accepts Q3 Report
*	14	IMM Quarterly Markets Reports - 2016 Summer (ZZ16-4)	Nov 15	IMM files 2016 Summer Report
*	14	ISO-NE FERC Form 3Q (2016/Q3) (not docketed)	Nov 22	ISO submits quarterly financial report for 2016 Q3

IX. Membership Filings

*	14	December 2016 Membership Filing (ER17-464)	Dec 1	NEPOOL requests the FERC accept (i) the memberships of Green Power USE, Maine Power, EES9, and EES10; and (ii) the termination of the Participant status of Concord Steam and Advanced Power Services; comment date Dec 22

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

	15	NOPR: Revised Rel. Standards: BAL-005-1 & FAC-001-3 (RM16-13)	Nov 17-28	NERC, EEI, Bonneville, Idaho Power, J. Appelbaum file comments
	16	*Order 830*: New Rel. Standard: TPL-007-1 (RM15-11)	Nov 21	FERC issues tolling order affording it additional time to consider EEI, FRS, JINSA requests for rehearing of *Order 830*

XI. Misc. - of Regional Interest

	18	203 Application: Noble Americas Energy Solutions/Calpine (EC17-8)	Nov 18 Dec 1	FERC authorizes Calpine's acquisition of Noble Americas Energy Solutions Acquisition consummated
	18	203 Application: GDF Suez Energy Resources/Atlas Power (Dynegy/ECP) (EC16-93)	Nov 2	Applicants provide supplemental information that FERC authorization is only remaining approval required
	18	PURPA Complaint: Allco v. MA Agencies (EL17-6 et al.)	Nov 2 Nov 8 Nov 9 Nov 10 Nov 17 Nov 18 Nov 23	Mass. DPU requests extension of time to file comments MA DOER requests extension of time to file comments; FERC partially grants Mass. DPU Nov 2 request Mass. DPU requests additional time to file comments; Eversource intervenes FERC grants extension of time, to Nov 17, for responses to Complaint Mass. Agencies and Nation Grid protest Complaint Allco answers protests Mass. Agencies oppose Allco's Nov 18 answer
	19	PURPA Complaint: Allco Finance Ltd. and Windham Solar v. CT PURA (EL16-115 et al.)	Nov 22	FERC issues "Notice of Intent Not to Act and Declaratory Order"
*	19	IA Cancellation: Superseded PSNH/Springfield Power IA (ER17-376)	Nov 17	PSNH submits notice of cancellation of 2012 IA with Springfield Power (recently superseded by a 3-party SGIA); comment date Dec 8
	20	EMM Contract (ER17-290)	Nov 14-18 Nov 21	National Grid, Eversource intervene NEPOOL files comments supporting new contract for EMM services between ISO-NE and Potomac Economics
	20	*Orders 827/828* Compliance Filing: Maine Public District (ER17-137)	Nov 16	FERC accepts Emera Maine's Maine Public District Order Nos. 827/828 compliance filing
	20	Emera MPD OATT Changes (ER15-1429; EL16-13; ER12-1650) (consol.)	Nov 16 Nov 16 Dec 1	5th settlement conf. re-scheduled for Dec 1 Settlement Judge Dring issues status report recommending Settlement procedures be continued 5th settlement conf. held

XII. Misc. - Administrative & Rulemaking Proceedings

	23	Utilization of Electric Storage Resources IN RTO/ISO Markets (AD16-25)	Nov 9 Nov 14	Technical conf. held FERC invites post-technical conf. comments to be filed on or before Dec 14
	23	Competitive Transmission Development Rates (AD16-18)	Nov 4	NEPOOL files its Status Report on New England's *Order 1000* implementation
	24	PURPA Implementation (AD16-16)	Nov 7-15	Over 40 parties file post-technical conf. comments
	24	Enforcement Annual Report (AD07-13-010)	Nov 17	FERC Office of Enforcement issues 2016 Annual Report
*	24	NOPR: Electric Storage Participation in RTO/ISO Markets (RM16-23; AD16-20)	Nov 17	FERC issues *Storage NOPR*: comment date Jan 30, 2017
	25	*Order 833*: Critical Energy/Electric Infrastructure Information (CEII) Procedures (RM16-15)	Nov 17	FERC issues *Order 833*, eff. [60 days after its publication in the *Federal Register*]

26	*NOPR:* Primary Frequency Response - Essential Rel. Services and the Evolving BPS (RM16-6)	Nov 17	FERC issues NOPR; comment date Jan 24, 2017
26	*Order 831*: Price Formation Fixes - Price Caps in RTO/ISO Markets (RM16-5)	Nov 17	FERC issues *Order 831*, eff. and Tariff filing req'd [75 days after its publication in the *Federal Register*]

XIII. Natural Gas Proceedings

29	New England Pipeline Proceedings Salem Lateral Project (CP14-522)	Nov 1	Salem Lateral Project goes into service

XIV. State Proceedings & Federal Legislative Proceedings

No Activity Reported

XV. Federal Courts

*	32	FCA10 Results (16-1408)	Nov 23	UWUA and Robert Clark petition for review of FCA10 results filing orders
			Nov 30	Clerk orders filing by Dec 30 of Docketing Statement Form, Statement of Issues to be Raised, Petitioners' and Respondents' Appearances, and procedural motions; dispositive motions by Jan 17, 2017
	32	NEPGA PER Complaint and FCM Jump Ball and Compliance Proceedings (16-1023/1024)	Nov 14	NEPGA files Joint Appendix
			Nov 22	NEPGA files Petitioner Final Brief and Reply Brief
			Nov 28	FERC files Respondent Final Brief; NESCOE files Intervenor for Respondent Final Brief
	33	Base ROE Complaints II & III (2012 & 2014) (15-1212)	Nov 14	Parties file 5th status report
	33	Base ROE Complaint I (2011) (15-1118, 15-1119, 15-1121**) (consolidated)	Nov 22	Court allocates oral argument time
			Nov 29	TOs file additional authorities
	34	Allco Finance Limited v. Klee et al. 16-2946 ((2d Cir.)	Nov 7	Court issues order setting oral argument for Dec 8
			Nov 22	Briefs and Amicus Briefs filed
			Nov 29	Allco files reply brief
			Nov 30	State Parties (MA, NY, OR, VT, WA, CA Air Resources) file Amicus Brief
			Dec 1	CL&P files Amicus Brief

M E M O R A N D U M

TO: NEPOOL Participants Committee Member and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: December 1, 2016

RE: Status Report on Current Regional Wholesale Power and Transmission Arrangements Pending Before the Regulators, Legislatures, and Courts

We have summarized below the status of key ongoing proceedings relating to NEPOOL matters before the Federal Energy Regulatory Commission ("FERC"), state regulatory commissions, and the Federal Courts and legislatures through December 1, 2016. If you have questions, please contact us.[1]

I. Complaints/Section 206 Proceedings

- **NEPGA PER Complaint (EL16-120)**

As previously reported, on September 30, NEPGA filed a complaint asking the FERC (i) to find the ISO Tariff's Peak Energy Rent ("PER") Adjustment provisions unjust & unreasonable; (ii) to direct the ISO to file revisions to the PER Adjustment sections of the Tariff that return the PER Adjustment to a just & reasonable level; (iii) to establish a refund effective date of September 30, 2016; and (iv) to issue an order granting the complaint by November 29, 2016. Comments on the PER Complaint were due on or before October 20.

In its answer, the ISO took no position on whether the FERC should grant the relief requested, but suggested that, should the FERC grant relief, the FERC "reject NEPGA's primary remedy in favor of a more appropriate, well-reasoned solution". NEPOOL submitted comments providing the FERC with additional information regarding stakeholder consideration of the remedies sought by NEPGA in its Complaint, including NEPOOL's previous consideration of, and failure to support, increases to the PER strike price consistent with those proposed by NEPGA, and urged the FERC to reject, without prejudice, any Tariff remedy sought by NEPGA that has not first been evaluated and considered fully within the NEPOOL Participant Processes. Comments opposing the Complaint were also filed by NESCOE and the Retail Energy Supply Association ("RESA"). Comments supporting the Complaint were filed by Entergy, NextEra and Verso. Doc-less interventions only were filed by Calpine, ConEd, Dominion, HQ US, Eversource, Exelon, National Grid, NRG, and PSEG. On November 4, NEPGA answered the NESCOE, RESA and NEPOOL comments. On November 15, NESCOE answered NEPGA's November 4 answer. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com), Jamie Blackburn (202-218-3905; jblackburn@daypitney.com), or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Base ROE Complaint IV (2016) (EL16-64)**

On September 20, 2016, the FERC established hearing and settlement judge procedures (and set a refund effective date of April 29, 2016) for the 4th ROE Complaint.[2] As previously reported, EMCOS[3] filed

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[1] Capitalized terms used but not defined in this filing are intended to have the meanings given to such terms in the Second Restated New England Power Pool Agreement (the "Second Restated NEPOOL Agreement"), the Participants Agreement, or the ISO New England Inc. ("ISO" or "ISO-NE") Transmission, Markets and Services Tariff (the "Tariff").

[2] *Belmont Mun. Light Dept. et al. v. Central Me. Power Co. et al.*, 156 FERC ¶ 61,198 (Sep. 20, 2016) ("*Base ROE Complaint IV Order*").

the 4th ROE complaint on April 29, 2016. The Complaint asks the FERC to reduce the TOs' current 10.57% return on equity ("Base ROE") to 8.93% and to determine that the upper end of the zone of reasonableness (which sets the incentives cap) is no higher than 11.24%. EMCOS identified three main considerations requiring submission of this Complaint: (1) the continuing decline of the market cost of equity capital, which makes NETOS' currently authorized ROE "excessive, unjust and unreasonable, and therefore ripe for adjustment under FPA Section 206"; (2) "divergent rulings concerning the persistence of the "anomalous" capital market conditions"; and (3) "the extent to which the Commission's anomalous conditions rationale in Opinion No. 531 is intended to reflect changes in its long-standing reliance on the DCF methodology, and particularly the DCF midpoint, for determining ROE remains unclear."

In setting the complaint for hearing and settlement judge procedures, 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 we order."[4] The FERC also found "unpersuasive the assertions of New England TOs and EEI that the Commission should dismiss the Complaint because the New England TOs' base ROE continues to fall within the zone of reasonableness. The Commission has repeatedly rejected the assertion that every ROE within the zone of reasonableness must be treated as an equally just and reasonable ROE."[5] Further, the FERC rejected arguments as to the propriety of allowing a fourth complaint against the TOs' ROE after three previous complaints have been filed since 2011. As it did when it allowed Complaints II and III to go forward, the FERC found that Complaint IV was properly set for hearing as it is based on newer, more current data than prior Complaints subsequent hearings.[6] The FERC is "initiating an entirely new proceeding, based on an entirely separate factual record, that may or may not reach the same conclusions as those reached in the earlier ROE proceeding."[7] The FERC estimated that, if this case does not settle and goes to hearing, the Commission's ultimate decision would be issued on or before June 30, 2018.[8] Both the TOs and EEI requested rehearing of the *Base ROE Complaint IV Order*. The FERC issued a tolling order on November 21, affording it additional time to consider the requests for rehearing, which remain pending.

Settlement Judge Procedures. On October 4, Chief Judge Cintron designated Judge Jennifer Long, the FERC's newest ALJ, as the Settlement Judge. A first settlement conference was held on November 8, 2016. Judge Long scheduled a second settlement conference for December 20, with joint position statements due on or before December 15. Chief Judge Cintron, following the recommendation of Judge Long, issued on November 10 an order continuing settlement judge procedures. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Jamie Blackburn (202-218-3905; jblackburn@daypitney.com).

- **206 Proceeding: RNS/LNS Rates and Rate Protocols (EL16-19)**

Settlement discussions in this proceeding are on-going. As previously reported, the FERC instituted this Section 206 proceeding on December 28, 2015, finding that the ISO Tariff is unjust, unreasonable, and unduly discriminatory or preferential because the Tariff "lacks adequate transparency and challenge procedures with

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[3] "EMCOS" are: Belmont Municipal Light Department, Braintree Electric Light Department, Concord Municipal Light Plant, Georgetown Municipal Light Department, Groveland Electric Light Department, Hingham Municipal Lighting Plant, Littleton Electric Light & Water Department, Middleborough Gas & Electric Department, Middleton Electric Light Department, Reading Municipal Light Department, Rowley Municipal Lighting Plant, Taunton Municipal Lighting Plant, and Wellesley Municipal Light Plant.

[4] *Base ROE Complaint IV Order* at P 37.

[5] *Id.* at P 38.

[6] Complaint IV was filed 21 months after the July 31, 2014 filing of Complaint III, nearly nine months after the July 2, 2015 close of the Complaint III evidentiary hearing record, and six months after the end of the Complaint III refund period.

[7] *Base ROE Complaint IV Order* at P 40.

[8] *Id.* at P 44.

regard to the formula rates" for Regional Network Service ("RNS") and Local Network Service ("LNS").[9] The FERC also found that the RNS and LNS rates themselves "appear to be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful" because (i) "the formula rates appear to lack sufficient detail in order to determine how certain costs are derived and recovered in the formula rates" and "could result in an over-recovery of costs" due to the "the timing and synchronization of the RNS and LNS rates".[10] Accordingly, the FERC established hearing and settlement judge procedures to develop just and reasonable formula rate protocols to be included in the ISO-NE Tariff and to examine the justness and reasonableness of the RNS and LNS rates. The FERC encouraged the parties to make every effort to settle this matter before hearing procedures are commenced.[11] Hearings are being held in abeyance pending the outcome of settlement judge procedures underway.[12] The FERC-established refund date is January 4, 2016.[13] Interventions were due February 3, 2016 and were filed by NEPOOL, the ISO, Braintree, Chicopee, Champlain VT, CT AG, CT DEEP, CT OCC, CT PURA, CMEEC, Fitchburg, Green Mountain, Liberty Utilities, MA AG, MA DPU, MOPA, Middleborough, MMWEC, Maine Public Utilities Commission ("MPUC"), Nat'l Grid, NESCOE, NHEC, NH OCA, Norwood, Public Citizen, Reading, RI PUC, Taunton VEC, VELCO, VPSA, VT DPS, Wallingford, and American Public Power Association ("APPA").

Settlement Judge Procedures. As previously reported, John P. Dring was designated the Settlement Judge in these proceedings. Four settlement conferences have thus far been held: January 19, March 24, April 28, and August 30. Judge Dring issued his latest status report on August 30 indicating that the parties are making progress toward settlement and recommending that the settlement procedures be continued. A 5th (telephonic) settlement conference was held on November 18, 2016. The Transmission Committee is being kept apprised of settlement efforts. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Base ROE Complaints II & III (2012 & 2014) (EL13-33 and EL14-86) (consolidated)**

Judge Sterner's findings and Initial Decision, and pleadings in response thereto, remain pending before the FERC. As previously reported, the FERC, in response to second (EL13-33)[14] and third (EL14-86)[15] complaints regarding the TOs' 11.14% Base ROE, issued orders establishing trial-type, evidentiary hearings and separate refund periods. The first, in EL13-33, was issued on June 19, 2014 and established a 15-month refund period of December 27, 2012 through March 27, 2014;[16] the second, in EL14-86, was issued

[9] *ISO New England Inc. Participating Transmission Owners Admin. Comm. et al.*, 153 FERC ¶ 61,343 (Dec. 28, 2015), *reh'g denied*, 154 FERC ¶ 61,230 (Mar. 22, 2016).

[10] *Id.* at P 8.

[11] *Id.* at P 11.

[12] *Id.*

[13] The notice of this proceeding was published in the *Fed. Reg.* on Jan. 4, 2016 (Vol. 81, No. 1) p. 89.

[14] The 2012 Base ROE Complaint, filed by Environment Northeast (now known as Acadia Center), Greater Boston Real Estate Board, National Consumer Law Center, and the NEPOOL Industrial Customer Coalition ("NICC", and together, the "2012 Complainants"), challenged the TOs' 11.14% return on equity, and seeks a reduction of the Base ROE to 8.7%.

[15] The 2014 Base ROE Complaint, filed July 31, 2014 by 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"), seeks 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.

[16] *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 denied,* 151 FERC ¶ 61,125 (May 14, 2015).

on November 24, 2014, established a 15-month refund period beginning July 31, 2014,[17] and, because of "common issues of law and fact", consolidated the two proceedings for purposes of hearing and decision, with the FERC finding it "appropriate for the parties to litigate a separate ROE for each refund period."[18] The TOs requested rehearing of both orders. On May 14, 2015, the FERC denied rehearing of both orders.[19] On July 13, 2015, the TOs appealed those orders to the DC Circuit Court of Appeals (*see* Section XIV below), and that appeal remains pending.

Hearings and Trial Judge Initial Decision. Initial hearings on these matters were completed on July 2, 2015. In mid-December 2015, Judge Sterner reopened the record for the limited purpose of having the discounted cash flow ("DCF") calculations re-run in accordance with the FERC's preferred approach and re-submitted. A limited hearing on that supplemental information was held on February 1, 2016. On March 22, 2016, Judge Sterner issued his 939-paragraph, 371-page Initial Decision, which lowered the base ROEs for the EL13-33 and EL14-86 refund periods from 11.14% to 9.59% and 10.90%, respectively.[20] The Decision also lowered the ROE ceilings. Judge Sterner's decision, if upheld by the FERC, would result in refunds totaling as much as $100 million, largely concentrated in the EL13-33 refund period. Briefs on exceptions were filed by the TOs, Complainant-Aligned Parties ("CAPs"), EMCOS, and FERC Trial Staff on April 21, 2016; briefs opposing exceptions, on May 20, 2016. Judge Sterner's findings and Initial Decision, and pleadings in response thereto, remain pending, and will be subject to challenge, before the FERC. The *2012/14 ROE Initial Decision* and its findings can be approved or rejected, in whole or in part.

If you have any questions concerning this matter, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Eric Runge (617-345-4735; ekrunge@daypitney.com).

II. Rate, ICR, FCA, Cost Recovery Filings

- **ICR-Related Values and HQICCs – Annual Reconfiguration Auctions (ER17-[ ])**

On December 1, 2016, the ISO and NEPOOL jointly filed materials that identify the Installed Capacity Requirement ("ICR"), Local Sourcing Requirements ("LSR"), Maximum Capacity Limits ("MCL"), Hydro Quebec Interconnection Capability Credits ("HQICCs"), and capacity requirement values for the System-Wide Demand Curve (collectively, the "ICR-Related Values") for the third annual reconfiguration auction ("ARA") for the 2017/18 Capability Year to be held March 1, 2017, the second ARA for the 2018/19 Capability Year to be held August 1, 2017, and the first ARA for the 2019/20 Capability Year to be held June 5, 2017. The ICR-Related Values were supported by the Participants Committee at its November 4, 2016 meeting. A January 30, 2017 effective date was requested. Comments on this filing are due December 22, 2016. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **FCA11 Qualification Informational Filing (ER17-321)**

On November 8, 2016, the ISO submitted its informational filing (the "FCA11 Informational Filing") for qualification in FCA11. The ISO is required under Market Rule Section 13.8.1 to submit an informational filing with the FERC containing the determinations made by the ISO for the upcoming Forward Capacity Auction ("FCA") at least 90 days prior to each auction. FCA11 is scheduled to begin February 6, 2017. The

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[17] *Mass. Att'y Gen. et al. -v- Bangor Hydro et al.*, 149 FERC ¶ 61,156 (Nov. 24, 2014), *reh'g denied,* 151 FERC ¶ 61,125 (May 14, 2015).

[18] *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).

[19] *Environment Northeast, et al. v. Bangor Hydro-Elec. Co., et al. and Mass. Att'y Gen. et al. -v- Bangor Hydro et al.*, 151 FERC ¶ 61,125 (May 14, 2015).

[20] *Environment Northeast, et al. v. Bangor Hydro-Elec. Co., et al. and Mass. Att'y Gen. et al. -v- Bangor Hydro et al.*, 154 FERC ¶ 63,024 (Mar. 22, 2016) ("*2012/14 ROE Initial Decision*").

Informational Filing contained the ISO's determinations that three Capacity Zones, Southeastern New England ("SENE"), Northern New England ("NNE"), and Rest of Pool, will be modeled for FCA11. SENE will be modeled as import-constrained Capacity Zones; NNE will be modeled as an export-constrained Capacity Zone. The Informational Filing reported that there will be 34,505 MW of existing capacity in FCA11 competing with 5,958 MW of new capacity under a Net ICR of 34,075 MW (ICR minus HQICCs). The ISO reported also that there were a total of 1,622 MW of Static, Export, and Administrative Export De-list bids. A summary of the De-list bids accepted and those rejected for reliability purposes was included in a privileged Attachment E.

Comments on the FCA11 Informational Filing were due November 29, 2016. No comments or protests were filed. Doc-less interventions were filed by NEPOOL, Dominion, Eversource, National Grid, and NESCOE. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **ICR-Related Values and HQICCs - 2020/21 Capacity Commitment Period (ER17-320)**

Also on November 8, 2016, the ISO filed ICR, LSR for SENE, MCL for NNE, HQICCs, and Marginal Reliability Impact ("MRI") Demand Curves (collectively, the "2020/21 ICR-Related Values") for the 2020/2021 Capacity Commitment Year. The values will be used in FCA11 to be held in February 2017. With a 2020/21 ICR of 35,034 MW (reflecting tie benefits of 1,950 MW) and HQICCs of 959 MW/mo., the net amount of capacity to be purchased in FCA11to meet the ICR will be 34,075 MW. The LSR for the SENE Capacity Zone is 9,810. The Participants Committee support the 202/21 ICR-Related Values at its October 14, 2016 meeting. Comments on this filing were due December 1 and none were filed. Doc-less interventions were filed by Dominion, Eversource, Exelon, National Grid, NESCOE, and NRG. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **2017 NESCOE Budget (ER17-140)**

This proceeding was initiated by the ISO's October 19 filing of the budget for funding NESCOE's 2017 operations. The 2017 Operating Expense Budget for NESCOE is $2,258,001. The amount to be recovered reflects true-ups from 2015 overcollections of $674,276. Accordingly, if accepted, the NESCOE budget will result in a charge of $0.00678 per kilowatt of Monthly Network Load. The 2017 NESCOE budget was supported by the Participants Committee at its October 14, 2016 meeting. On November 8, NEPOOL submitted comments supporting the NESCOE Budget. Doc-less interventions were filed by Eversource and National Grid. This matter is pending before the FERC. If there are any questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **2017 ISO-NE Administrative Costs and Capital Budgets (ER17-116)**

As previously reported, the ISO filed on October 17 for recovery of its 2017 administrative costs (the "2017 Revenue Requirement") and submitted its capital budget and supporting materials for calendar year 2017 ("2017 Capital Budget", and together with the 2017 Revenue Requirement, the "2017 ISO Budgets"). The 2017 ISO Budgets were filed together pursuant to the Settlement Agreement entered into to resolve challenges to the 2013 ISO Budgets. In the October 17 filing, the ISO reported that the 2017 Revenue Requirement (allowing the ISO to maintain the *status quo* and to fund established initiatives), after true-up for 2015, is $192.7 million. Of that total, the ISO's administrative costs (i.e., the 2017 Core Operating Budget) comprise $158.9 million; depreciation and amortization of regulatory assets, $33.7 million; and 2015 true-up, $400,000.

The ISO further reported that the 2017 Capital Budget is $28 million and is comprised of the following (with 2017 projected costs and target completion dates, if available, in parentheses):

- Non-Project Capital Expenditures ($4.1 million)
- Price Responsive Demand (Q2 2018) ($4 million)
- Capitalized Interest ($500,000)
- FCM Tracking System Technical Architecture Upgrade (Q4 2017) ($500,000)

‣ FCM PFP (Jun 2018)	($3 million)	‣ Operations Document Management System (Q4 2017)	($500,000)
‣ FCA12 (May 2018)	($2 million)	‣ Zonal Load Forecast (Mar 2017)	($500,000)
‣ Desktop Segregation Project – Cyber Security (Q4 2017)	($1.5 million)	‣ Storage Device Alternatives (Q3 2018)	($500,000)
‣ IMM Data Needs (Q4 2017)	($1.5 million)	‣ Updated EES Technical Architecture (Jul 2017)	($500,000)
‣ Situational Awareness (Q2 2018)	($1.1 million)	‣ Transmart Technical Architecture Update (Q2 2017)	($400,000)
‣ Other Emerging Work	($1.1 million)	‣ DARD Pumps Market Enhancements (Mar 2017)	($400,000)
‣ Sub-Hourly Settlements (Mar 2017)	($1 million)	‣ Asset Characteristics Database & User Interface Redesign (Q2 2017)	($400,000)
‣ Energy Manag. Platform 3.1 Upgrade and Customs Reduction (Q4 2019)	($1 million)	‣ Real-Time Fast Start Pricing (Mar 2017)	($400,000)
‣ Balance of Planning Period FA Project (Q2 2017)	($1 million)	‣ FCA11 (Feb 2017)	($300,000)
‣ 2017 Issues Resolution Project Phase I (Q2 2017)	($750,000)	‣ Power System Modelling Management (Aug 2017)	($200,000)
‣ 2017 Issues Resolution Project Phase II (Q4 2017)	($750,000)	‣ Case Snapshot Enhancements for Market Operator Interface PRD (Q2 2017)	($200,000)
		‣ EMS Alarm Presentation Enhancements (May 2017)	($100,000)

The 2017 ISO Budgets were supported by the Participants Committee at its October 14, 2016 meeting. On November 7, NEPOOL filed comments supporting the 2017 ISO Budgets. Doc-less interventions were filed by Eversource, NESCOE and National Grid. This matter is pending before the FERC. If there are any questions on this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **Schedule 2 Base CC Rate (ER12-229-001)**

On October 28, 2016, as required by a December 28, 2011 order in ER12-229,[21] the ISO submitted an informational filing presenting its evaluation of the current Base Capacity Cost ("CC") Rate.[22] Based on the results of its analysis, the ISO concluded that an adjustment to the current Base CC Rate of $2.19/kVAR-year was not supported, and the current Base CC remains appropriate and should be continued. The Participants Committee supported the ISO's proposal to leave unchanged the current "Base CC Rate" as part of the October 14 Consent Agenda. NEPOOL filed comments in response to the informational filing supporting the ISO's decision to not change the Base CC Rate at this time, "with the expectation that ISO will monitor changes to the New England bulk power system that might call for an earlier re-examination of the rate than the "no later than" date of July 1, 2021." Doc-less interventions were filed by Calpine and NRG. On December 1, 2016, the FERC accepted this filing. Unless the December 1 order is challenged, activity in this sub-docket will be concluded If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

[21] *ISO New England Inc.*, 137 FERC ¶ 61,237 (Dec. 28, 2011).

[22] The Base CC Rate, a blended proxy rate, is used to calculate VAR Payments under the fixed Capacity Cost paid to Qualified Reactive Resources for the capability to provide reactive supply and voltage support ("VAR Service") to the New England Transmission System under Schedule 2 of the OATT.

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

- **Natural Gas Index Changes (ER17-327)**

On November 10, 2016, the ISO and NEPOOL jointly filed changes to the Tariff to replace the Algonquin Citygates location with a newer hub established by ICE – the AGT-CG (Non-G) hub – as the source for natural gas prices to be used in the calculation of the Peak Energy Rent Strike Price, the Import Capacity Resource offer threshold price, and the Forward Reserve threshold price ("Natural Gas Index Changes"). NEPOOL supplemented the filing with a more detailed description of the stakeholder process undertaken in connection with the Changes. A January 10, 2017 effective date was requested. The Natural Gas Index Changes were supported by the Participants Committee at its October 14, 2016 meeting. Comments on this filing were due on or before December 1, 2016 and Dominion protested the Changes on that day. Doc-less interventions were filed by Entergy, Eversource, Exelon, HQ US, National Grid, NRG. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Effective Date Update: MR1 §§ 2.7(a) & (g) (ER17-96)**

On October 14, 2016, the ISO submitted a filing to update the effective date for the inclusion of "Dispatch Zone" in Market Rule 1 sections 2.7(a) and (g), from June 1, 2017 to June 1, 2018 (aligning these sections with the previously-supported and accepted one-year deferral of PRD full integration implementation to June 1, 2018). Comments on this filing were due on or before November 4, 2016; none were filed. Doc-less interventions were filed by NEPOOL, Eversource, Exelon, National Grid and NRG. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Resource Dispatchability Changes (ER17-68)**

On October 12, 2016, the ISO and NEPOOL jointly filed changes to the Tariff that broaden the range of resources that are subject to economic dispatch in the Real-Time Energy Market and that make other ancillary changes to improve overall Energy Market price formation (the "Resource Dispatchability Changes"). More specifically, the Resource Dispatchability Changes (i) broaden the range of resources that are capable of responding to electronic Dispatch Instructions to increase or decrease output, both in response to price signals and for reliability purposes (to be effective December 12, 2016, with completed installation and dispatchability required by January 15, 2018); (ii) require capacity suppliers with dispatchable Intermittent Power Resources that participate in the FCM to offer the available energy from an intermittent resource into the Day-Ahead Energy Market (to be effective June 1, 2020); and (iii) create a way for alternative technologies that both consume and inject energy to participate as Energy Market dispatchable resources (to be effective December 1, 2018). The Resource Dispatchability Changes were supported unanimously by the Participants Committee by way of the August 5 Consent Agenda (Item #1). Comments on this filing were due on or before November 2, 2016, and were filed by the Eversource companies. In its comments, Eversource protested the Resource Dispatchability Changes asking the FERC to find that they "are not just and reasonable with respect to the QF resources … because there is no accommodation or recognition of the PURPA rights of the QFs affected by the proposed market design changes." Accordingly, Eversource asked the FERC to direct modifications to the Resource Dispatchability Changes to recognize QF resources' PURPA rights. On November 17, the ISO and NEPOOL answered the Eversource protest. Doc-less interventions only were filed by Exelon, Entergy, HQ US, Kimberly-Clark, National Grid, and NRG. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **FCM Enhancements (ER16-2451)**

The FERC's *FCM Enhancements Order*[23] is subject to a request for rehearing by Indicated NYTOs.[24] As previously reported, the FERC accepted on October 18 changes to the Tariff to increase liquidity in the

[23] *ISO New England Inc. and New England Power Pool Participants Comm. and NY Indep. Sys. Op., Inc.*, 157 FERC ¶ 61,025 (Oct. 18, 2016) ("*FCM Enhancements Order*"), *reh'g requested.*

FCM by increasing Market Participant opportunities to enter into reconfiguration auctions and bilateral contracts for the exchange of CSOs ("FCM Enhancements"). Specifically, the FCM Enhancements (i) modify certain FCM qualification rules to facilitate the ability of New Capacity Resources to supply capacity beginning four months after participating in their first FCA; (ii) provide Import Capacity Resources backed by one or more External Resources the opportunity (currently available to generators and demand response) to provide capacity beginning one or two years after participating in their first FCA; and (iii) establish a new form of bilateral contracting in which Market Participants can, as the Capacity Commitment Period approaches, trade CSOs for a seasonal strip of CSOs. The FCM Enhancements include several smaller improvements as well, including the elimination of a requirement that the ISO make a FERC filing in order to terminate the CSO of a resource that has voluntary withdrawn from the FCM resource development process. The FCM Enhancements were accepted, effective as of October 19, 2016, as requested.

In accepting the FCM Enhancements, the FERC noted that "protestors do not challenge the justness and reasonableness of the specific tariff revisions … the concerns raised by NYISO are not the result of ISO-NE's proposed tariff revisions, but result from NYISO's treatment of generators that export capacity from within a constrained locality under its current market rules."[25] Accordingly, the FERC was "not persuaded that the potential behavior of New York suppliers provides a sufficient basis to reject ISO-NE's filing in this case, and deferring the effective date of an otherwise just and reasonable proposal would be inconsistent with the notice provision in section 205 of the FPA."[26] The FERC did acknowledge NYISO's concerns about a potential flaw in its market rules, and encouraged NYISO stakeholders to timely complete discussions underway to address that flaw. The FERC directed NYISO to file, on or before November 4, 2016, an informational report addressing its progress in preparing any tariff filing so that the FERC can assess whether additional FERC action would be appropriate.

As noted above, on November 17, Indicated TOs' requested rehearing of the *FCM Enhancements Order*, which remains pending before the FERC. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **FCM Composite Offers & Price Lock Mechanisms (FERC Compliance) (ER16-2126)**

As previously reported, on August 30, the FERC conditionally accepted the July 1, 2016 compliance filing directed by the *Manchester Street FCA10 Order*.[27] Persuaded by Dominion and NEPGA protests in response to that compliance filing, however, the FERC directed the ISO to submit a further compliance filing with Tariff language (i) requiring the ISO to automatically match new winter incremental capacity with excess existing summer qualified capacity at the same resource, and (ii) allow new incremental capacity and the corresponding matched excess existing capacity at the same resource to elect the price lock-in.[28]

Compliance Filing. On October 25, the ISO and NEPOOL jointly filed the directed compliance changes. Those changes were unanimously supported at the October 14 Participants Committee meeting. Comments on the compliance filing were due on or before November 15; none were filed. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Waiver Request: RTEG Resource Type/De-List (ISO-NE) (ER16-1904)**

CPower's request for rehearing of the *ISO RTEG Waiver Request Order* remains pending. As previously reported, the FERC granted the limited waiver requested by the ISO of Tariff Sections

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[24] "Indicated NYTOs" are Central Hudson Gas & Electric, Consolidated Edison Co. of New York, New York Power Authority, New York State Electric & Gas, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric.

[25] *Id.* at P 31.

[26] *Id.*

[27] *ISO New England Inc.*, 156 FERC ¶ 61,144 (Aug. 30, 2016).

[28] *Id.* at PP 19, 25.

III.13.1.4.2.5.2, III.13.1.4.3.1.2 & III.13.1.2.3.1.1.[29] The waiver allows Real-Time Emergency Generation Resources ("RTEGs") either to change their resource type to Real-Time Demand Response Resources or to de-list ("Waiver Request"), particularly in connection with FCA11, but also, to the extent applicable, for FCA8, FCA9, and FCA10, in light of (i) a May 4, 2016 order of the United States Court of Appeals for the District of Columbia Circuit ("DC Circuit") reversing and remanding United States Environmental Protection Agency ("EPA") rules that provided for a 100-hour exemption for operation of emergency engines for purposes of emergency demand response under National Emissions Standards; and (ii) an April 15, 2016 EPA Guidance Memorandum, which in anticipation of the DC Circuit order, indicated that the EPA will not develop an alternative to the rules reversed by the DC Circuit. In granting the waiver, the FERC rejected CPower's request for limited modifications thereto, finding CPower's proposed modification "beyond the scope of ISO-NE's instant proposal," and that it "would decrease incentives for RTEG market participants to exhaust existing remedies". The FERC also found "speculative CPower's characterization that applying the FCA Starting Price to the Third Annual Reconfiguration Auction, rather than the FCA Payment Rate, would essentially cause a 'penalty'."[30] On September 7, CPower requested rehearing of the *ISO RTEG Waiver Request Order*. On October 7, the FERC issued a tolling order affording it additional time to consider the CPower request, which as noted above remains pending before the FERC. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **FCM Resource Retirement Reforms (ER16-551)**

Rehearing remains pending of the FERC's *Resource Retirement Reforms Order*.[31] As previously reported, the FERC conditionally accepted, effective March 1, 2016, changes to the FCM rules for resource retirements proposed by the ISO and its Internal Market Monitor ("IMM") (the "ISO/IMM Proposal"). The FERC conditioned its acceptance of the ISO/IMM Proposal on the filing of Tariff revisions "establishing a materiality threshold for determining whether or not a particular proxy de-list bid will replace a Retirement Bid in an FCA,"[32] which were filed with and accepted by the FERC.[33] All other protests and comments were rejected. NEPGA, Exelon and NextEra jointly requested rehearing of the *Resource Retirement Reforms Order*. On June 13, the FERC issued a tolling order affording it additional time to consider the joint rehearing request, which remains pending before the FERC. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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

Rehearing remains pending of the FERC's April 8, 2016 *Demand Curve Remand Order*.[34] As previously reported, the FERC conditionally accepted, on May 30, 2014, revisions to the FCM rules that establish a system-

[29] *ISO New England Inc.*, 156 FERC ¶ 61,096 (Aug. 8, 2016) ("*ISO RTEG Waiver Request Order*") , *reh'g requested*.

[30] *Id.* at P 19.

[31] *ISO New England Inc.*, 155 FERC ¶ 61,029 (Apr. 12, 2016), *reh'g requested* ("*Resource Retirement Reforms Order*"). As previously reported, the ISO/IMM Proposal requires (i) that capacity suppliers with existing resources to submit a price for the retirement of a resource (to replace the existing Non-Price Retirement Request process), (ii) the use of a Proxy De-List Bid, and (iii) notice of the potential retirement and proposed retirement price to be submitted prior to the commencement of an FCA's qualification process for new resources. The ISO/IMM Proposal was considered but not supported by the Participants Committee at its Dec. 4, 2015 meeting.

[32] *Id.* at P 62.

[33] *ISO New England Inc.*, 15 FERC ¶ 61,067 (July 27, 2016) ("*Resource Retirement Reforms Compliance Order*").

[34] *ISO New England Inc. and New England Power Pool Participants Comm.*, 155 FERC ¶ 61,023 (Apr. 8, 2016), *reh'g requested* ("*Demand Curve Remand Order*") (affirming its earlier finding that the renewables exemption from the minimum offer price rule is just and reasonable, and not unduly discriminatory or preferential).

wide sloped demand curve ("Demand Curve Changes").[35] The Demand Curve Changes defined the shape of the system-wide sloped demand curve (with key points defined by CONE and the 0.1 days/year LOLE target), extended 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 resource exemption, and eliminated, at the system-wide level, the administrative pricing rules that were necessary in certain market conditions under the vertical demand curve construct. In response to challenges, the FERC denied rehearing of the *Demand Curve Order*,[36] 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).[37] A compliance filing clarifying that a resource may not utilize both the renewable resource exemption and the new resource price lock-in was submitted, accepted, and became effective on May 2, 2015.[38] NextEra, NRG and PSEG petitioned the DC Circuit Court of Appeals for review of the FERC's Demand Curve orders (March 30, 2015). Following submission of Petitioner and Intervenor for Petitioner briefs (October 5 and 20, 2015, respectively), the FERC, on November 20, 2015, requested that the Court remand the case back to the FERC for further proceedings (stating that "review of the opening briefs indicates that further consideration by the Commission is appropriate"). On December 1, 2015, the Court granted FERC's unopposed motion, and remanded the case back to the FERC for further proceedings, which, as noted above, resulted in the *Demand Curve Remand Order*. NextEra, NRG and PSEG jointly requested rehearing of the *Demand Curve Remand Order* on May 9, 2016. On June 3, NESCOE answered the NextEra/PSEG/NRG rehearing request. On June 8, 2016, the FERC issued a tolling order affording it additional time to consider the NextEra/PSEG/NRG request for rehearing, which remains pending before the FERC. If you have any questions concerning these matters, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **2013/14 Winter Reliability Program Remand Proceeding (ER13-2266)**

On August 8, 2016, the FERC issued its long-awaited remand order.[39] As previously reported, the DC Circuit remanded the FERC's decision in ER13-2266, agreeing with TransCanada that the record upon which the FERC relied is devoid of any evidence regarding how much of the 2013/14 Winter Reliability Program cost was attributable to profit and risk mark-up (without which the FERC could not properly assess whether the Program's rates were just and reasonable), and directing the FERC to either offer a reasoned justification for the order in ER13-2266 or revise its disposition to ensure that the Program rates are just and reasonable.[40] In the *2013/14 Winter Reliability Program Remand Order*, the FERC directed the ISO to request from Program participants the basis for their bids, including the process used to formulate the bids, and to file with the FERC, by December 6, 2016, a compilation of that information, an IMM analysis of that information, and the ISO's recommendation as to the reasonableness of the bids, so that the FERC can further consider the question of whether the Bid Results were just and reasonable.[41] On November 7, the ISO requested, and on November 15 the FERC granted, a 45-day extension of time to submit the directed filing. Accordingly, the filing is now due on or before January 20, 2017. If you have any questions concerning these matters, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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[35] *ISO New England Inc. and New England Power Pool Participants Comm.*, 147 FERC ¶ 61,173 (May 30, 2014) ("*Demand Curve Order*").

[36] *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).

[37] *ISO New England Inc. and New England Power Pool Participants Comm.*, 150 FERC ¶ 61,065, at P 27 (Jan. 30, 2015) ("*Demand Curve Clarification Order*").

[38] The changes become effective with FCA-10, and will not apply to the resources in FCA9, totaling 12.96 MW, that utilize both the renewable resource exemption and the price lock-in election.

[39] *ISO New England Inc.*, 156 FERC ¶ 61,097 (Aug. 8, 2016) ("*2013/14 Winter Reliability Program Remand Order*").

[40] *TransCanada Power Mktg. Ltd. v. FERC,* 2015 U.S. App. LEXIS 22304 (D.C. Cir. 2015).

[41] *2013/14 Winter Reliability Program Remand Order* at P 17.

IV. OATT Amendments / TOAs / Coordination Agreements

- ***Orders 827/828* Compliance Filing: New England (ER16-2695)**

The revisions to Schedules 22 and 23 of the ISO OATT filed jointly by the ISO, NEPOOL and PTO AC on September 29, 2016 to comply with the FERC Order Nos. 827[42] and 828[43] are pending before the FERC. As previously reported, Schedules 22 and 23 were revised to incorporate the *pro forma* revisions set forth in *Orders 827* and *828* with variations necessary to recognize New England reactive power requirements and overall structure previously accepted under the "independent entity variation" standard and to make certain enhancements "consistent with or superior to" the *pro forma* revisions. An October 5, 2016 effective date was requested. The compliance filing changes were supported by the Participants Committee at its September 9 meeting. Comments on this filing were due on or before October 20, 2016; none were filed. Doc-less interventions were filed by National Grid and NRG. This matter is pending before the FERC. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes

- **Schedule 21-CMP: Blue Sky LSA (ER17-407)**

On November 22, CMP and the ISO filed a Local Service Agreement ("LSA") by and among CMP, Blue Sky West LLC ("Blue Sky"), and the ISO for Local Non-Firm Point-to-Point Transmission Service under Schedule 21-CMP of the ISO OATT (the "Blue Sky LSA"). An August 8, 2016 effective date was requested. Comments on the LSA are due on or before December 13, 2016. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-ES: Eversource Recovery of NU/NSTAR Merger-Related Costs (ER16-1023)**

Eversource filed on November 22 an offer of settlement to resolve the issues in this proceeding. As previously reported, the FERC accepted but, finding that Eversource "has not shown that the transaction-related costs are just and reasonable and that such costs may be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful", set for hearing and settlement judge procedures Eversource's changes to Schedule ES-21 to recover $38.9 million in FERC-jurisdictional, merger-related transmission costs incurred as the result of the April 10, 2012 NU/NSTAR merger.[44] The FERC accepted Eversource's proposed "Option B" tariff revisions for filing, which would amortize costs over a three-year period, "to minimize the immediate impact on transmission customers while the issues are being resolved at hearing."[45] In accepting the changes, the FERC reiterated the following points with respect to transaction-related cost recovery, as explained in prior FERC orders: (i) "applicant must demonstrate its use of appropriate internal controls and procedures for proper identification, accounting, and rate treatment of all transaction-related costs"; (ii) transaction-related savings must be realized prior to, or concurrent with, any authorized recovery of transaction-related costs; (iii) savings must be shown to have a nexus with the transaction and must directly benefit (i.e., be passed on to) transmission customers; (iv) the filing must be shown to be just and reasonable in light of all the other factors underlying the new rate; and (v) the applicant must demonstrate that the

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[42] *Reactive Power Requirements for Non-Synchronous Generation*, Order No. 827, 155 FERC ¶ 61,277 (June 16, 2016) ("*Order 827*"), *order on clarification and reh'g*, 157 FERC 61,003 (Oct. 3, 2016).

[43] *Requirements for Frequency and Voltage Ride Through Capability of Small Generating Facilities*, Order No. 828, 156 FERC ¶ 61,062 (July 21, 2016) ("*Order 828*").

[44] *ISO New England Inc. et al.*, 155 FERC ¶ 61,136 (May 3, 2016).

[45] *Id.* at P 27.

transaction-related costs are exceeded by the savings produced by the transaction.[46] The FERC also provided guidance on other points with respect to transaction-related cost recovery: (x) "only costs that would have been eligible for inclusion in the then-existing transmission rates, but for the hold harmless commitment, will be eligible for cost recovery"; and (y) "transaction-related savings should not be calculated based on an after-the-fact reconstruction of costs that would have been incurred absent the transaction, but instead should be based on a comparison of costs known prior to consideration of the transaction compared against actual spending."[47] The FERC encouraged participants to make every effort to settle their dispute before hearing procedures commence.

Offer of Settlement. As noted above, Eversource filed an unopposed offer of settlement on November 22. As Eversource requested, comments on the offer of settlement are due on or before December 5. Reply comments, if any, will be due on December 12. If you have any questions concerning these proceedings, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-EM: Recovery of Bangor Hydro/Maine Public Service Merger-Related Costs (ER15-1434 et al.)**

On June 2, 2016, the FERC accepted, but established hearing and settlement judge procedures for,[48] March 31 filings by Emera Maine in which Emera Maine sought authorization to recover certain merger-related costs viewed by the FERC's Office of Enforcement's Division of Audits and Accounting ("DAA") to be subject to the conditions of the orders authorizing Emera Maine's acquisition of, and ultimate merger with, Maine Public Service ("Merger Conditions"). As previously reported, the Merger Conditions imposed a hold harmless requirement, and required a compliance filing demonstrating fulfillment of that requirement, should Emera Maine seek to recover transaction-related costs through any transmission rate. Following its recent audit of Emera Maine, DAA found that Emera Maine "inappropriately included the costs of four merger-related capital initiatives in its formula rate recovery mechanisms" and "did not properly record certain merger-related expenses incurred to consummate the merger transaction to appropriate non-operating expense accounts as required by [FERC] regulations [and] inappropriately included costs of merger-related activities through its formula rate recovery mechanisms" without first making a compliance filing as required by the merger orders.

In the *June 2 Order*, the FERC found that the Compliance Filings raise issues of material fact that could not be resolved based on the record, and are more appropriately addressed in the hearing and settlement judge procedures.[49] The FERC reiterated several points with respect to transaction-related cost recovery explained in prior FERC orders and provided guidance on other transaction-related cost recovery points.[50] The FERC encouraged the parties to make every effort to settle their disputes before hearing procedures are commenced, and will hold the hearing in abeyance pending the outcome of settlement judge procedures.[51] The separate compliance filing dockets were consolidated for the purposes of settlement, hearing and decision.[52]

Settlement Judge Procedures. ALJ John Dring is the settlement judge for these proceedings. A first settlement conference was held on June 29; a second settlement conference, October 25. A third settlement conference, scheduled for November 22, 2016, was cancelled and subsequently held on December 1. Also since the last Report, Judge Dring issued a report recommending that settlement judge procedures be

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[46] *Id.* at P 28.

[47] *Id.* at P 29.

[48] *Emera Maine and BHE Holdings*, 155 FERC ¶ 61,230 (June 2, 2016) ("*June 2 Order*").

[49] *Id.* at P 24.

[50] *Id.* at PP 25-26.

[51] *Id.* at P 27.

[52] *Id.* at P 21; Ordering Paragraph (B).

continued. If you have any questions concerning these matters, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

- **Capital Projects Report - 2016 Q3 (ER17-122)**

On November 18, the FERC accepted the ISO's 2016 second quarter ("Q2") Capital Projects Report and Unamortized Cost Schedule (the "Report"). The ISO filed the Report under Section 205 of the FPA pursuant to Section IV.B.6.2 of the Tariff. Report highlights included the following new projects: (i) 2016 Enterprise corrective action/preventative action ("CAPA") ($185,000); and (ii) Interconnection Request Tracking Tool Elective Transmission Upgrade ($102,644). One projects with a significant changes was the Phasor Measurement Unit External Data Exchange (with a 2016 budget decrease of $91,000). Unless the order accepting the Q3 Report is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- ***Opinion 531-A* Local Refund Report: FG&E (EL11-66)**

On June 29, 2015, FG&E filed its refund report for its customers taking local service during the refund period in accordance with *Opinion 531-A*. Comments, if any, on this filing were due on or before July 20; 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).

- ***Opinions 531-A/531-B* Regional Refund Reports (EL11-66)**

On November 2, 2015, the TOs submitted a refund report documenting resettlements of regional transmission charges by the ISO in compliance with *Opinions No. 531-A*[53] *and 531-B.*[54] As previously reported, refunds resulting from *Opinion No. 531-B* were completed by August 31, 2015. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- ***Opinions 531-A/531-B* Local Refund Reports (EL11-66)**

In accordance with *Opinions 531-A and 531-B*, the following TOs filed their refund reports for their customers taking local service during the refund period (comment date on refund report noted in parentheses):

- ♦ Central Maine Power (Jan 21)
- ♦ Emera Maine (Jan 29)
- ♦ Eversource (CL&P, PSNH, WMECO) (Jan 21)
- ♦ National Grid (Jan 13)
- ♦ NHT (Jan 21)
- ♦ NSTAR (Jan 21)
- ♦ United Illuminating (Jan 21); supplement (Feb 1)
- ♦ VT Transco (Feb 3)

All comments dates have passed. No comments were filed in response to any of the reports and each is pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

[54] *Martha Coakley, Mass. Att'y Gen. et al.*, Opinion No. 531-B, 150 FERC ¶ 61,165 (Mar. 3, 2015) ("*Opinion 531-B*").

- **IMM Quarterly Markets Reports - 2016 Summer (ZZ16-4)**

On November 15, the Internal Market Monitor ("IMM") filed with the FERC its report for the Summer quarter of 2016 of "market data regularly collected by [it] in the course of carrying out its functions under … Appendix A and analysis of such market data," as required pursuant to Section 12.2.2 of Appendix A to Market Rule 1. These filings are not noticed for public comment by the FERC.

- **ISO-NE FERC Form 3Q (2016/Q3) (not docketed)**

On November 17, the ISO submitted its 2016/Q3 FERC Form 3Q (Quarterly financial report of electric utilities, licensees, and natural gas companies). FERC Form 3-Q is a quarterly regulatory requirement which supplements the annual FERC Form 1 financial reporting requirement. These filings are not noticed for comment.

IX. Membership Filings

- **December 2016 Membership Filing (ER17-464)**

On December 1, NEPOOL requested that the FERC accept (i) the memberships of Green Power USA [AR Sector, Renewable Generation Sub-Sector, Small RG Group Seat]; Maine Power LLC [MPEU, Related Person of Jeff Jones]; Emera Energy Services Subsidiary Nos. 9 ("EES9") and 10 ("EES10") [Related Persons of Emera Maine, Transmission Sector]; and (ii) the termination of the Participant status of Concord Steam Corporation (AR Small RG Group Member) and Advanced Power Services [Generation Sector Group Seat]. Comments on this filing are due on or before December 22.

- **November 2016 Membership Filing (ER17-229)**

On October 31, NEPOOL requested that the FERC accept (i) the memberships of Aspirity Energy, LLC [Related Person of Town Square Energy (Supplier Sector)]; King Forest Industries, Inc. (End User Sector, MPEU); and Titan Gas LLC (Supplier Sector); (ii) the termination of the Participant status of CES Retail Energy Supply, LLC (ConEd Energy Related Person); Ameresco DR LLC (Ameresco CT Related Person); and Quantum Utility Generation, LLC (AR Sector).; and (iii) the name changes of Stored Solar J&WE, LLC (f/k/a Covanta Maine, LLC) and EmpireCo Limited Partnership (f/k/a ReEnergy Sterling CT Limited Partnership). This matter is pending before the FERC.

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).

- **Revised Reliability Standards: IRO-018-1 & TOP-010-1 (RD16-6)**

NERC filed on November 7 the revised VRF designations that the FERC directed NERC to submit in its *September 22 Order* approving the Revised IRO-018-1 and TOP-010-1 Standards.[55] The compliance filing modifies the VRF designations for IRO-018-1 Requirement R1 and TOP-010-1 Requirements R1 and R2 to "high."[56] As previously reported, the FERC otherwise conditionally accepted NERC's filing requesting approval of revised Reliability Standards -- IRO-018-1 (Reliability Coordinator Real-Time Reliability Monitoring and Analysis Capabilities) and TOP-010-1 (Real-Time Reliability Monitoring and Analysis Capabilities), and associated implementation plan, VSLs, and VFRs (together, the "Real-Time Situational Awareness Changes"). Comments on the compliance filing are due on or before December 7.

- **New Reliability Standards: PRC-027-1 and PER-006-1 (RM16-22)**

On September 2, 2016, NERC filed for approval (i) two new Reliability Standards -- PRC-027-1 (Coordination of Protection Systems for Performance During Faults) and PER-006-1 (Specific Training for

[55] *N. Amer. Elec. Rel. Corp.*, 156 FERC ¶ 61,207 (Sep. 2, 2016) ("*September 22 Order*").

[56] *September 22 Order* at P 2.

Personnel), (ii) associated Glossary definitions, (iii) an implementation plan, (iv) VRFs and VSLs, and (v) the retirement of PRC-001-1.1(ii) (together, the "Protection System Changes"). NERC stated that the purpose of the Protection System Changes is to: (1) maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System ("BES") Elements, such that those Protection Systems operate in the intended sequence during Faults; and (2) require registered entities to provide training to their relevant personnel on Protection Systems and Remedial Action Schemes ("RAS") to help ensure that the BES is reliably operated. NERC requested that the new Standards and definitions become effective on the first day of the first calendar quarter that is 24 months following the effective date of the FERC's order approving the Standards. As of the date of this Report, the FERC has not noticed a proposed rulemaking proceeding or otherwise invited public comment.

- **NOPR: Revised Reliability Standards: BAL-005-1 & FAC-001-3 (RM16-13)**

On September 22, the FERC issued a NOPR proposing to approve Reliability Standards BAL-005-1 (Balancing Authority Control) and FAC-001-3 (Facility Interconnection Requirements), and associated Glossary definitions, implementation plan, VRFs and VSLs (together, the "Frequency Control Changes").[57] As previously reported, NERC stated that the Frequency Control Changes clarify and refine Requirements for accurate, consistent, and complete reporting of Area Control Error ("ACE") calculations. NERC indicated that the Frequency Control Changes will improve reliability by supporting efforts to maintain Interconnection frequency at 60 Hz in a manner consistent with FERC directives, technological developments, and NERC's current framework of integrated Reliability Standards. NERC requested that the Frequency Control Changes become effective on the first day of the first calendar quarter that is 12 months after the effective date of an order approving the Standard, pursuant to the Implementation Plans included with the Changes. Comments on the *Frequency Control Changes NOPR* were due on or before November 28, 2016,[58] and were filed by NERC, EEI, Bonneville, Idaho Power and J. Appelbaum. The *Frequency Control Changes NOPR* is now pending before the FERC.

- **NOPR: Revised Reliability Standard: BAL-002-2 (RM16-7)**

The *BAL Changes NOPR* remains pending before the FERC. As previously reported, the FERC issued a NOPR. on May 19, 2016, proposing to (i) approve a revised Reliability Standard -- BAL-002-2 (Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event), and associated Glossary definitions, implementation plan, VRFs and VSLs (together, the "BAL Changes"); (ii) direct NERC to modify BAL-002-2 to address concerns related to the possible extension or delay of the periods for ACE recovery and contingency reserve restoration; and (iii) direct NERC to address a reliability gap regarding megawatt losses above the most severe single contingency.[59] NERC stated that the BAL Changes consolidate six requirements in BAL-002-1 into three requirements, supported by several proposed associated NERC Glossary definitions, along with a revised Applicability section that incorporates language from the existing Standard. BAL-002-2 requires responsible entities to maintain and deploy energy reserves and to stabilize system frequency through identification of a Reportable ACE deviation and restoration of Reporting ACE to defined values after a system disturbance. BAL-002-2 will also require the responsible entity to maintain an Operating Process to ensure maintenance of Contingency Reserves to a level at least equal to the responsible entity's Most Severe Single Contingency ("MSSC"), thereby implementing a continent-wide reserve policy to ensure that adequate Contingency Reserves will always be available to be deployed as necessary. NERC requested that responsible entities be required to comply with BAL-002-2 on the first day of the first calendar quarter that is six months after this standard is approved by the FERC. On February 12, 2016, NERC submitted supplemental information that clarified how BAL-002-2 will work in conjunction with the successor provisions to TOP-007-0 (TOP-007-0 is set to expire on April 1, 2017). On March 31, NERC provided further supplemental information to further clarify the

[57] *Balancing Authority Control, Inadvertent Interchange, and Facility Interconnection Rel. Standards*, 156 FERC ¶ 61,210 (Sep. 22, 2016) ("*Frequency Control Changes NOPR*").

[58] The *Frequency Control Changes NOPR* was published in the *Fed. Reg.* on Sep. 28, 2016 (Vol. 81, No. 188) pp. 66,555-66,562.

[59] *Disturbance Control Standard - Contingency Reserve for Recovery from a Balancing Contingency Event Rel. Standard*, 155 FERC ¶ 61,180 (May 19, 2016) ("*BAL Changes NOPR*").

significance of the MSSC as the upper bounds for events that qualify as Reportable Balancing Contingency Events ("RBCE") under Reliability Standard BAL-002-2 and the way in which other Reliability Standards are necessary and appropriate to address events beyond MSSC. Comments on the *BAL Changes NOPR* were due on or before July 25, 2016[60] and were filed by APS, IESO, NaturEner USA, the Canadian Electricity Association, Idaho Power, TVA, NRECA, NERC, Bonneville, EEI, and jointly by the Alberta Electric System Operator ("AESO"), the California Independent System Operator ("CAISO"), Electric Reliability Council of Texas, Inc. ("ERCOT"), the Independent Electricity System Operator of Ontario, Inc. ("IESO"), Midcontinent Independent System Operator, Inc. ("MISO"), PJM Interconnection, L.L.C. ("PJM"), and Southwest Power Pool, Inc. ("SPP"). The *BAL Changes NOPR* is pending before the FERC.

- ***Order 830*: New Reliability Standard: TPL-007-1 (RM15-11)**

As previously reported, the FERC issued, on September 22, 2016, a final rule approving a new Reliability Standard -- TPL-007-1 (Geomagnetic Disturbance ("GMD") Operations) -- and one new definition (Geomagnetic Disturbance Vulnerability Assessment), associated VRFs and VSLs ("*Order 830*").[61] In addition, the FERC directed NERC (i) to develop modifications to the benchmark GMD event definition set forth in TPL-007-1 Attachment 1 so that the definition is not based solely on spatially-averaged data, (ii) to require the collection of necessary geomagnetically-induced current monitoring and magnetometer data and to make such data publicly available; and (iii) to include a one-year deadline for the development of corrective action plans and two and four-year deadlines to complete mitigation actions involving non-hardware and hardware mitigation, respectively. The FERC also directed NERC to submit a work plan and, subsequently, one or more informational filings that address specific GMD-related research areas. *Order 830* will become effective November 29, 2016.[62] Rehearing of Order 830 was requested by EEI, the Foundation for Resilient Societies ("FRS"), and the Jewish Institute for national Security Affairs ("JINSA"). On November 21, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending before the FERC.

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

The *ATC NOPR* remains pending before the FERC. As previously reported, the FERC's June 19, 2014, NOPR[63] proposed to approve changes to MOD-001-2 (Modeling, Data, and Analysis - Available Transmission System Capability) to 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[64] 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 sought 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 sought further elaboration on specific actions NERC could take to assure synchronization of the effective dates.

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[60] The *BAL Changes NOPR* was published in the *Fed. Reg.* on May 26, 2016 (Vol. 81, No. 102) pp. 33,441-33,448.

[61] *Rel. Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events*, 151 FERC ¶ 61,134 (May 14, 2015) ("*TPL-007 NOPR*").

[62] *Order 830* was published in the *Fed. Reg.* on Sep. 30, 2016 (Vol. 81, No. 190) pp. 67,120-67,140.

[63] *Modeling, Data, and Analysis Rel. Standards*, 147 FERC ¶ 61,208 (June 19, 2014) ("*ATC NOPR*").

[64] 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.

Comments on this NOPR were due August 25, 2014,[65] and were filed by NERC, Bonneville, Duke, MISO, and NAESB. On December 19, 2014, NAESB supplemented its comments with a report on its efforts to develop WEQ Business Practice Standards that will support and coordinate with the MOD Standards proposed in this proceeding. NASEB issued a report on September 25, 2015, informing the FERC that the NAESB standards development process has been completed and NAESB will file the new suite of business practice standards as part of Version 003.1 of the NAESB WEQ Business Practice Standards in October 2015. As noted above, the *ATC NOPR* remains pending before the FERC.

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

The *BAL-002-1a Interpretation Remand NOPR*[66] remains pending. As previously explained, this NOPR 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). 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,[67] and were filed by NERC, EEI, ISO/RTO Council, MISO, NC Balancing Area, Northwest Power Pool Balancing Authorities, NRECA, and WECC. As noted, this NOPR remains pending before the FERC.

XI. Misc. - of Regional Interest

- **CFTC RTO/ISO Exemption Amendment (2016-11385)**

On October 24, the Commodity Futures Trading Commission (''CFTC'') issued a final order in response to an application from Southwest Power Pool, Inc. (''SPP'') to exempt specified transactions from certain provisions of the Commodity Exchange Act (''CEA'') and Commission regulations ("*CFTC SPP Order*").[68] Importantly for New England, the *CFTC SPP Order* also amends the CFTC's March 28, 2013 order (which generally exempted specified RTO/ISO transactions from certain provisions of the CEA and CFTC regulations) by specifically exempting the transactions covered under that Order from private actions pursuant to CEA Section 22 (a 180º turn from what the CFTC had signaled in its May 10, 2016 draft order that it was contemplating). Accordingly, private parties are not permitted to bring claims under either the CEA or the FPA for fraud and manipulation involving financial energy products traded in the organized wholesale power markets. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

[66] *Elec. Rel. Org. Interpretation of Specific Requirements of the Disturbance Control Performance Standard*, 143 FERC ¶ 61,138 (2013) ("*BAL-002-1a Interpretation Remand NOPR*").

[67] 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.

[68] *Final Order Regarding Southwest Power Pool, Inc. Application To Exempt Specified Transactions; Amendment to the Final Order Exempting Specified Transactions of Certain Independent System Operators and Regional Transmission Organizations*, published in the *Fed. Reg.* on Oct. 24, 2016 (Vol. 81, No. 205 pp. 73,062-73,087.

- **203 Application: Noble Americas Energy Solutions/Calpine (EC17-8)**

On November 18, the FERC authorized Calpine Energy Services Holdco II LLC's ("Calpine's") acquisition of 100% of the equity interests in Noble Americas Energy Solutions.[69] The parties consummated this transaction on December 1, 2016 and must advise the FERC of that fact on or before December 11, 2016. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **203 Application: Belmont/NSTAR (EC16-145)**

On October 25, the FERC authorized NSTAR's acquisition of limited jurisdictional transmission facilities associated with the Town of Belmont's construction of a new 115 kV/13.8 kV substation in Belmont.[70] Operational control of the transmission facilities will be given to the ISO. The portion of the facility under construction that comprises distribution facilities will remain with Belmont. NSTAR must notify the FERC within 10 days of the date that the acquisition has been consummated. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **203 Application: GDF Suez Energy Resources/Atlas Power (Dynegy/ECP) (EC16-93)**

The March 25, 2016 request by Atlas Power Finance, a subsidiary of Atlas Power (a newly-formed joint venture between Dynegy and ECP III), Dynegy Inc. ("Dynegy"), Energy Capital Partners III, LLC ("ECP") and GDF Suez, for authorization to acquire of GDF Suez Energy Resources remains pending. Also pending, in a separate proceeding (EC16-94), is the Dynegy and ECP III request that the FERC approve the purchase by an ECP affiliate, Terawatt Holdings, LP ("Terawatt"), of newly-issued Dynegy common stock representing approximately 10% of the outstanding shares of Dynegy. Comments on both those filings were due on or before May 24, 2016; none were filed. On June 8, the FERC requested additional data to process the filing, which was filed on July 8. In addition, on June 15, Atlas supplemented the application by informing the FERC that Dynegy would purchase all of ECP's interests in Atlas Power prior to the closing of the Transaction. Comments on the June 15 filing were due on or before June 29; none were filed. Comments on the July 8 response were due on or before July 29. On July 29, Public Citizen filed a protest. Atlas answered Public Citizen's protest on August 4, and Public Citizen answered Atlas' answer on August 9. On November 2, applicants provided supplemental information that, other than FERC authorization, there are no outstanding approvals required before the Applicants would be able to consummate the acquisition. This matter remains pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **PURPA Complaint: Allco v. MA Agencies (EL17-6 et al.)**

On October 19, 2016, Allco Renewable Energy Limited and Allco Finance Limited (together, "Allco") petitioned the FERC to pursue an enforcement action under the Public Utility Regulatory Policies Act of 1978 ("PURPA") against the Massachusetts Department of Public Utilities ("MA DPU") and the Massachusetts Department of Energy Resources ("MA DOER", and together with MA DPU, the "Massachusetts Agencies").[71] Allco states that this petition is the result of Massachusetts' implementation of Massachusetts state law, Section 83A, which it asserts compels wholesale transactions with non-QFs, requires QFs to participate in a bidding process to obtain a contract, unlawfully regulates wholesale sales, violates Massachusetts' ongoing obligation to implement PURPA, and perpetuates Massachusetts Utilities' refusal to enter into long-term contracts. Allco seeks FERC action enforcing PURPA against the Massachusetts Agencies to invalidate and permanently enjoin Section 83A, and to declare void *ab initio* any wholesale power contracts executed under Section 83A. Responses to this Complaint, following two requests for extensions by the MA DPU and partially granted by the FERC, were due and filed on November 17. Allco

[69] *Noble Americas Energy Solutions LLC and Calpine Energy Services Holdco II LLC*, 157 FERC ¶ 62,140 (Nov. 18, 2016).

[70] *NSTAR Elec. Co.*, 157 FERC ¶ 62,059 (Oct. 25, 2016).

[71] Section 210(h)(2) of PURPA permits the FERC to initiate, and for QFs to petition the FERC to initiate, an enforcement action against a State regulatory authority for failure to implement the FERC's PURPA regulations. If the FERC declines to initiate an enforcement action, the petitioning QF then has the right to bring an action in the appropriate U.S. district court to enforce the PURPA regulations.

responded to the Massachusetts Agencies' protest on November 18. The Massachusetts Agencies opposed that answer on November 23. The Allco Petition and the pleadings connected therewith are pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **PURPA Complaint: Allco Finance Ltd. and Windham Solar v. CT PURA (EL16-115 et al.)**

On November 22, in response to the Petition of Windham Solar LLC and Allco Finance Limited (together, "Allco") requesting the FERC pursue an enforcement action under the Public Utility Regulatory Policies Act of 1978 ("PURPA") against the Connecticut Public Utilities Regulatory Authority ("CT PURA"), the FERC issued a "Notice of Intent Not to Act and Declaratory Order".[72] As previously reported, this petition was Allco's ***third*** petition for enforcement filed against Connecticut within the past year. Allco stated that this petition was the result of the final decision by CT PURA, on August 24, 2016, denying Windham's petition for a power purchase agreement ("PPA") for various solar facilities that are 1 to 2 megawatts in size. Allco also sought a FERC order declaring invalid, and enforcing PURPA against CT PURA by invalidating and permanently enjoining, Connecticut's rules, which Allco asserted prevents it from securing the PPAs.

In its November 22 order, the FERC, while declining to initiate an enforcement action, issued a declaratory ruling providing its views on a number of the substantive questions raised by the parties' pleadings. For example, among others, the FERC stated:

- "regardless of whether a QF can provide firm output, that QF has the option to sell its output pursuant to a legally enforceable obligation with a forecasted avoided cost rate."
- Windham has opted to sell its output pursuant to section 292.304(d)(2)(ii) of the Commission's regulations, which it is entitled to do (and at a rate based on avoided costs calculated at the time the legally enforceable obligation is incurred – which it is also entitled to do), and, therefore, the Connecticut Authority must recognize that a legally enforceable obligation exists and calculate the appropriate forecasted avoided cost rate pursuant to section 292.304(d)(2)(ii) of the Commission's regulations.
- to the extent that Eversource's capacity needs can be satisfied by Windham's QFs rather than through the capacity auction, the avoided cost rates available to Windham should include an estimate of Eversource's avoided cost of capacity.
- a legally enforceable obligation should be long enough to allow QFs reasonable opportunities to attract capital from potential investors (though its regulations, do not, however, specify a particular number of years for such legally enforceable obligations.

The FERC's notice means that Allco may themselves bring an enforcement action against the CT PURA in an appropriate court. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **IA Cancellation: Superseded PSNH/Springfield Power IA (ER17-376)**

On November 17, Eversource filed a notice of cancellation of a 2012 Interconnection Agreement ("IA") between PSNH and Springfield Power. Eversource stated that the IA was recently superseded by a three-party SGIA entered into as a result of Springfield Power's request to increase the facility's Capacity Network Resource Capability and Network Resource Capability. An October 26, 2016 effective date (the effective date of the SGIA) was requested. Comments, if any, on this filing are due on or before December 8, 2016. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

[72] *Windham Solar LLC and Allco Finance Limited et al.*, 157 FERC ¶ 61,134 (Nov. 22, 2016).

- **EMM Contract (ER17-290)**

The ISO filed on October 31, pursuant to Section 9.4.5 of the Participants Agreement, a copy of its new 3-year contract with Potomac Economics, Ltd. to continue as the ISO's External Market Monitor ("EMM"). In its filing, the ISO notes that the new agreement is closely modeled on the existing agreement between Potomac and the ISO, including all of the functions laid out for the EMM in Section 9.4.3 of the Participants Agreement. The new EMMU contract term will run from January 1, 2017 through December 31, 2019. On November 21, NEPOOL filed comments supporting the new Contract, requesting that the FERC accept the Contract without modification, condition, or delay to be effective January 1, 2017. Doc-less interventions were filed by Eversource and National Grid. This matter is pending before the FERC. If there are questions on this matter, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com), Jamie Blackburn (202-218-3905; jblackburn@daypitney.com), or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Orders 827/828 Compliance Filing: Maine Public District (ER17-137)**

On November 16, the FERC accepted Emera Maine's changes to the LGIA and SGIA of its Open Access Transmission Tariff for Maine Public District (the "MPD OATT") in response the requirements of *Orders 827* and *828*. The changes were accepted effective as of December 14, 2016, as requested. Unless the November 16 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Emera MPD OATT Changes (ER15-1429; EL16-13, ER12-1650)**

As previously reported, the FERC conditionally accepted, on December 7, 2015, changes to the Maine Public District ("MPD") Open Access Transmission Tariff ("MPD OATT"), including to the rates, terms, and conditions set forth in MPD OATT Attachment J.[73] However, the FERC found, ultimately, that the changes to the MPD OATT had not been shown to be just and reasonable, may be unjust and unreasonable, instituted a Section 206 proceeding (in EL16-13) to examine the provisions, and set the matter for a trial-type evidentiary hearing, to be held in abeyance pending the outcome of settlement judge procedures (*see* below).

Background (ER15-1429). Emera Maine, as successor to Maine Public Service Company ("Maine Public"), provides open access to Emera Maine's transmission facilities in northern Maine (the "MPD Transmission System") pursuant to the MPD OATT. Emera Maine stated that the changes to the MPD OATT were needed to ensure that, in light of the filing by Emera of consolidated FERC Form 1 data (data comprising both the former Bangor Hydro and Maine Public systems), charges for service under the MPD OATT reflect only the costs of service over the MPD Transmission System. Emera Maine also proposed additional, limited changes to the MPD OATT. A June 1, 2015 effective date was requested. The "Maine Customer Group"[74] filed a motion to reject ("Motion to Reject") the April 1 Filing, asserting the April 1 Filing was deficient because, rather than actual rates, it included proxy rates that MPD said would be replaced with 2014 Form 1 numbers when MPD's 2014 Form 1 was available. On April 22, the Maine PUC and the Maine Customer Group protested the filing. The MPUC challenged three aspects of the filing: (i) the proposed increase of ROE from 9.75% to 10.20% based on anomalous economic conditions; (ii) the change from a measured loss factor calculation to a fixed loss factor; and (iii) the use of end-of-year account balances, rather than average 13-month account balances, for determination of facilities that are included in rate base. In addition to those aspects, the Maine Customer Group further challenged: (iv) inclusion of an out-of-period adjustment to rate base for forecasted transmission; (v) the proposed capital structure, which they assert is artificially distorted to accommodate a requirement resulting from the merger of Emera Maine's predecessor companies; and (vi) the proposed new cost allocation scheme. On April 24, Emera Maine answered the Maine Customer Group's Motion to Reject. On April 29, the Maine Customer Group answered

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[73] *Emera Maine*, 153 FERC ¶ 61,283 (Dec. 7, 2015).

[74] The "Maine Customer Group ("MCG") is comprised of: the Maine Office of the Public Advocate ("MOPA"), Houlton Water Company ("Houlton"), Van Buren Light and Power District ("Van Buren"), and Eastern Maine Electric Cooperative, Inc. ("EMEC").

Emera Maine's April 24 answer. On May 1, Emera Maine filed an amendment and errata to its April 1 filing, in part reflecting 2014 FERC Form 1 data rather than estimated data. On May 7, Emera Maine answered the April 22 Maine PUC and MCG protests and the MCG's April 29 answer. On May 8, MCG moved to compel revision to Emera's May 1 filing, asserting that it was not filed in accordance with Emera's OATT, and specifically the Protocols for Implementing and Reviewing Charges Established by the Attachment J Rate Formulas (the "Motion to Compel"). MCG also protested the May 1 filing on May 22. On May 26, Emera Maine answered MCG's May 8 Motion to Compel, which MCG answered the next day.

On June 2, 2016, the FERC granted Maine Customer Group's Motion to Compel, and set the remaining issues with respect to Emera Maine's 2014 and 2015 Annual Updates for hearing and settlement judge procedures.[75] The FERC also consolidated ER12-1650 with this proceeding. In addition, the FERC directed that Emera Maine to make a compliance filing, on or before July 5, that (1) revises its 2014-2015 formula rate charges to correct the errors the Maine Customer Group raised with respect to amortization of long-term debt costs and post-retirement benefits other than pensions, and (2) imputes the retired debt balance for the tax-free Maine Public bonds ($22.6 million) into the capital structure calculation for the 2014-2015 Rate Year. Emera Maine requested rehearing of the June 2 order on July 5. On August 2, the FERC issued a tolling order affording it additional time to consider the Emera Maine request for rehearing, which remains pending before the FERC.

Compliance Filing (ER12-1650). Emera Maine's July 5, 2016, submitted in response to the June 2 Order described above, remains pending before the FERC. The compliance filing was contested by the Maine Customer Group, which asserted that Emera's compliance filing was incorrect as to two of the three refund issues, and Emera should be ordered to pay immediate refunds in accordance with the corrected revised formula rate it proposed. Emera Maine answered the Maine Customer Group's July 18 answer on August 1, contending that the Group's answer should be denied and Emera Maine's compliance filing found to comply fully with the June 2 Order. The compliance filing remains pending before the FERC.

Hearing and Settlement Judge Procedures. The FERC encouraged the parties to make every effort to settle their disputes before hearing procedures are commenced, and is holding the hearing in abeyance pending the outcome of settlement judge procedures. As previously reported, Chief Judge Cintron substituted ALJ Dring in place of ALJ Johnson in mid-September as the settlement judge for these proceedings. Settlement conferences before Judge Johnson were held on January 5, March 3, and April 26, 2016 and on October 25 before Judge Dring. A fifth settlement conference, scheduled for November 22, was held on December 1. On November 22, Judge Dring issued a status report recommending that settlement judge procedures be continued. If you have any questions concerning these matters, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **MISO Methodology to Involuntarily Allocate Costs to Entities Outside Its Control Area (ER11-1844)**

As previously reported, the FERC issued in late September *Opinion 550*[76], which found that the Midcontinent Independent System Operator, Inc. ("MISO") and International Transmission Company ("ITC") had not demonstrated that their proposal to allocate costs of ITC Phase Angle Regulating Transformers ("PARs") to entities outside of MISO, including to entities in NYISO or PJM, was just and reasonable. *Opinion 550* affirmed in part, and reversed in part, certain determinations of the Presiding Administrative Law Judge Sterner,[77] and dismissed Judge Sterner's remaining determinations as moot. Consistent with these actions, the FERC also dismissed as moot requests for rehearing of Judge Sterner's *MISO Hearing Order*. No party ultimately challenged *Opinion 550*, which is now final and unappealable. This proceeding is now

[75] *Emera Maine*, 155 FERC ¶ 61,233 (June 2, 2016), *reh'g requested*.

[76] *Midwest Indep. Trans. Sys. Op., Inc.*, 156 FERC ¶ 61,202 (Sep. 22, 2016) ("*Opinion 550*").

[77] *Midwest Indep. Trans. Sys. Op., Inc.*, 141 FERC ¶ 63,021 (Dec. 18, 2012) ("*MISO Hearing Order*"), *reh'g denied*, 156 FERC ¶ 61,202 (Sep. 22, 2016).

concluded. If there are any questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **FERC Enforcement Action: Order of Non-Public, Formal Investigation (IN15-10)**

MISO Zone 4 Planning Resource Auction Offers. On October 1, 2015, the FERC issued an order authorizing Enforcement to conduct a non-public, formal investigation, with subpoena authority, regarding violations of FERC's regulations, including its prohibition against electric energy market manipulation, that may have occurred in connection with, or related to, MISO's April 2015 Planning Resource Auction for the 2015/16 power year.

Unlike a staff notice of alleged violation, a FERC order converting an informal, non-public investigation to a formal, non-public investigation does not indicate that the FERC has determined that any entity has engaged in market manipulation or otherwise violated any FERC order, rule, or regulation. It does, however, give OE's Director, and employees designated by the Director, the authority to administer oaths and affirmations, subpoena witnesses, compel their attendance and testimony, take evidence, compel the filing of special reports and responses to interrogatories, gather information, and require the production of any books, papers, correspondence, memoranda, contracts, agreements, or other records.

- **FERC Enforcement Action: Maxim Power (IN15-4)**

On September 26, the FERC approved a Stipulation and Consent Agreement[78] that resolves its investigation into (and subsequent litigation in the US District Court for the District of Massachusetts[79] regarding) whether Maxim Power (USA), Inc., Maxim Power (USA) Holding Company Inc., Pawtucket Power Holding Co., LLC, and Pittsfield Generating Company, LP (collectively, "Maxim")[80] violated the FERC's Anti-Manipulation and Market Behavior 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.[81] Under the Settlement, in which Maxim neither admits nor denies the alleged violations, Maxim agreed to ***disgorge $4 million*** to ISO New England and pay a ***$4 million civil penalty*** to the United States Treasury. The disgorgement to ISO New England will be made in two parts. Refunds will be made to current customers based on Real-Time Load Obligation. The amount of the first payment (1/3 of the total penalties, or roughly $2.67 million) will be included in the November Non-Hourly Charges Statement. The second payment will be due and subsequently disbursed as just described

[78] *Maxim Power Corp. et al.*, 156 FERC ¶ 61,223 (Sep. 26, 2016).

[79] *FERC v. Maxim Power Corp. et al.*, No. 3:15-cv-30113-MGM (D. Mass.).

[80] 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).

[81] As previously reported, the FERC found 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, 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, during the ordinary operation of the plants. Based on these findings, the FERC had previously assessed civil penalties to Maxim and its affiliates totaling $5 million (no disgorgement). *Maxim Power Corp. et al.*, 151 FERC ¶ 61,094 (May 1, 2015) ("*Maxim Penalties Order*"). At Maxim's election, the *Maxim Penalties Order* proceeded to a *de novo* review before the federal district court in Massachusetts, which was the first to find that *de novo* review would be conducted according to the same procedures applicable to an ordinary civil action (e.g. permitting defendants to seek discovery from witnesses interviewed by FERC or presenting their own witnesses during the civil trial) rather than be limited, as FERC argued, to a review of the full record developed in the underlying FERC proceeding.

approximately one year from now. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **FERC Audit of ISO-NE (PA16-6)**

The FERC's audit of ISO-NE docketed in this proceeding is on-going. As previously reported, the FERC informed ISO-NE on November 24, 2015 that it would evaluate ISO-NE's compliance with: (1) the transmission provider obligations described in the Tariff, (2) *Order 1000* as it relates to transmission planning and expansion, and interregional coordination, (3) accounting requirements of the Uniform System of Accounts under 18 C.F.R. Part 101, (4) financial reporting requirements under 18 C.F.R. Part 141; and (5) record retention requirements under 18 CFR Part 125. The FERC indicated that the audit will cover the July 10, 2013 period through the present.

XII. Misc. - Administrative & Rulemaking Proceedings

- **Utilization of Electric Storage Resources in RTO/ISO Markets (AD16-25)**

On November 9, the FERC held a technical conference to discuss the utilization of electric storage resources as transmission assets compensated through RTO/ISO transmission rates, for grid support services that are compensated in other ways, and for multiple services. On November 14, the FERC invited all those interested to file, on or before December 14, 2016, post-technical conference comments on the topics discussed in the November 1 Supplemental Notice of Technical Conference.

- **Competitive Transmission Development Rates (AD16-18)**

The FERC held a technical conference on a June 27-28, 2016 to discuss competitive transmission development process-related issues, including use of cost containment provisions, the relationship of competitive transmission development to transmission incentives, and other ratemaking issues. In addition, participants had the opportunity to discuss issues relating to interregional transmission coordination, regional transmission planning and other transmission development issues. Pre-technical conference comments were filed by over 20 parties, including by NESCOE, BHE US Transmission, LSPower, and NextEra Energy Transmission. Technical conference materials are available on the FERC's e-Library. On August 3, the FERC issued a notice inviting post-technical conference comments on questions listed in the attachment to the notice. Following requests by Utility Trade Associations[82] and the New Jersey BPU, the deadline for comments was extended to October 3, 2016. Comments were filed by over 60 parties, including: ISO-NE, Avangrid, AWEA, BHE US Transmission, EDF Renewables, EEI, ELCON, Eversource, Exelon, LSP Transmission Holdings, MMWEC, National Grid, NESCOE, NextEra, and PSEG. Since the last Report, NEPOOL filed its Status Report, which was approved at the November 4 meeting. This matter is pending before the FERC.

- **Reactive Supply Compensation in RTO/ISO Markets (AD16-17)**

A workshop to discuss compensation for Reactive Supply and Voltage Control (Reactive Supply) in RTO/ISO markets was held on June 30, 2016. The workshop explored the types of costs incurred by generators for providing Reactive Supply capability and service; whether those costs are being recovered solely as compensation for Reactive Supply or whether recovery is also through compensation for other services; and different methods by which generators receive compensation for Reactive Supply (e.g., FERC-approved revenue requirements, market-wide rates, etc.). The workshop also explored potential adjustments in compensation based on changes in Reactive Supply capability and potential mechanisms to prevent overcompensation for Reactive Supply. Technical conference materials are available on the FERC's e-Library. Written comments were due on or before July 28, 2016, and were filed by, among others, NYISO, PJM, the PJM IMM, AWEA, EEI, EPSA, EDF Renewables, Talen, Essential Power, and Exelon. EDF Renewables filed reply comments on August 19. Since the last Report, the PJM IMM filed comments answering and objecting to AWAE's July 28 comments suggesting that wind units should receive cost of

[82] The "Utility Trade Associations" are APPA, EEI, Large Public Power Council, National Rural Electric Cooperative Association ("NRECA"), and Transmission Access Policy Study Group ("TAPS").

service compensation for reactive capability apart from how the rules apply to other types of generators. This matter remains pending before the FERC.

- **PURPA Implementation (AD16-16)**

A workshop to discuss issues associated with the FERC's implementation of PURPA was held on June 29, 2016. The conference focused on two issues: the mandatory purchase obligation under PURPA and the determination of avoided costs for those purchases. Panelists' advanced written comments and materials from the technical conference are available on the FERC's e-Library. On September 6, the FERC issued a notice inviting post-technical conference comments to be filed. Such comments may address (1) the use of the "one-mile rule" to determine the size of an entity seeking certification as a small power production qualifying facility ("QF"); and (2) minimum standards for PURPA-purchase contracts. Comments were due on or before November 7, 2016 and were filed by over 40 parties, including AWEA, Covanta, CT PURA/MA AG, Duke, EDP, EEI, ELCON, NARUC, and NRECA.

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

On October 18, 2016, FERC staff issued a report reviewing RTO/ISO performance metrics as well as metrics for non-RTO/ISO utilities for the 2010-14 period. The Report has not been noticed for public comment.

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

As previously reported, the FERC directed each RTO/ISO to publicly provide information related to five price formation issues:[83] (1) pricing of fast-start resources; (2) commitments to manage multiple contingencies; (3) look-ahead modeling; (4) uplift allocation; and (5) transparency. The FERC directed each RTO/ISO to file a report that provides an update on its current practices in the identified topic areas, that provides the status of its efforts (if any) to address each of the five issues, and that fully responds to the questions. The FERC indicated it would use the reports and comments to determine what further action is appropriate. The RTO/ISO reports were filed February 17 by PJM, March 4 by ISO-NE, CAISO, MISO, and NYISO (corrected on March 23), and March 7 by SPP. Comments on the reports were due on or before April 6[84] and were filed by over 25 parties, including Exelon, EEI, and EPSA. This matter is pending before the FERC.

- **Enforcement Annual Report (AD07-13-010)**

On November 17, 2016, the FERC issued its Annual Enforcement Report. The report provides additional transparency and guidance for regulated entities and the public. Highlights include summaries of activities undertaken by the Office of Enforcement's investigations, audits and accounting, market oversight, and analytics and surveillance divisions. In 2017, the Office Enforcement will continue to target fraud and market manipulation, serious violations of Reliability Standards, anticompetitive conduct, and conduct that threatens the transparency of regulated markets. The Report is available at http://ferc.gov/enforcement/enforce-res.asp.

- **NOPR: Electric Storage Participation in RTO/ISO Markets (RM16-23; AD16-20)**

On November 23, the FERC issued a NOPR proposing to require each RTO and ISO to revise its tariff "to (1) establish a participation model consisting of market rules that, recognizing the physical and operational characteristics of electric storage resources, accommodates their participation in the organized wholesale electric markets and (2) define distributed energy resource aggregators as a type of market participant that can participate in the organized wholesale electric markets under the participation model that

[83] *Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators*, 153 FERC ¶ 61,221 (Nov. 20, 2015).

[84] In the order directing the reports, the FERC provided that public comment in response to the RTOs/ISOs' reports may be submitted within 30 days of the filing of the reports. Apr. 6 was 30 days after the filing of the last of the reports, the SPP report, on Mar. 7.

best accommodates the physical and operational characteristics of its distributed energy resource aggregation."[85] Comments on the *Storage NOPR* are due on or before January 30, 2017.[86]

The Storage NOPR follows FERC Staff's data request directing the RTO/ISOs to submit information on rules that affect the participation of electric storage resources in their markets, including, but not limited to, the eligibility of electric storage resources to participate in the markets, the qualification and performance requirements for market participants, required bid parameters, and the treatment of electric storage resources when they are receiving electricity for later injection to the grid. (Information from each of the ISO/RTOs, including ISO-NE's information, was submitted on May 16)..

- **NOPR: Data Collection for Analytics & Surveillance and MBR Purposes (RM16-17)**

As previously reported, the FERC issued a July 21, 2016 NOPR, which supersedes both its *Connected Entity NOPR* (RM15-23) and *Ownership NOPR* (RM16-3), proposing to collect certain data for analytics and surveillance purposes from market-based rate ("MBR") sellers and entities trading virtual products or holding FTRs and to change certain aspects of the substance and format of information submitted for MBR purposes.[87] The *Data Collection NOPR* presents substantial revisions from what the FERC proposed in the *Connected Entity NOPR*, and responds to the comments and concerns submitted by NEPOOL in that proceeding. Among other things, the changes proposed in the *Data NOPR* include: (i) a different set of filers; (ii) a reworked and substantially narrowed definition of Connected Entity; and (iii) a different submission process. With respect to the MBR program, the proposals include: (i) adopting certain changes to reduce and clarify the scope of ownership information that MBR sellers must provide; (ii) reducing the information required in asset appendices; and (iii) collecting currently-required MBR information and certain new information in a consolidated and streamlined manner. The FERC also proposes to eliminate MBR sellers' corporate organizational chart submission requirement adopted in *Order 816*. Comments on the *Data Collection NOPR* were due on or before September 19, 2016[88] and were filed by over 30 parties, including: APPA, Avangrid, Brookfield, EPSA, Macquarie/DC Energy/Emera Energy Services, NextEra, and NRG.

Technical Workshops. On November 2, 2016, the FERC issued a notice that its second technical workshop will be held on December 7, 2016. The first technical workshop was held on August 11 and focused on the *Data Collection NOPR's* draft data dictionary. The second technical workshop that will focus on the submittal process, with case studies serving as a platform for discussion of (i) the steps to submit data; (ii) data review and validation processes; and (iii) the notifications to be provided through the data validation and receipt process. Staff will also provide a high-level update on proposed technical refinements to the data dictionary based on input received during the first workshop and additional outreach. All interested are encourage to participate and register online (whether attending in person or via webcast) at https://www.ferc.gov/whats-new/registration/12-07-16-form.asp.

- ***Order 833*: Critical Energy/Electric Infrastructure Information (CEII) Procedures (RM16-15)**

On June 16, the FERC issued *Order 833* amending its regulations to implement provisions of the Fixing America's Surface Transportation ("FAST") Act that pertain to the designation, protection and sharing of Critical Electric Infrastructure Information ("CEII") and to amend its regulations that pertain to CEII.[89] The amended

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[85] *Electric Storage Participation in Markets Operated by Regional Transmission Orgs. and Indep. Sys. Operators*, 157 FERC ¶ 61,121 (Nov. 17, 2016) ("*Storage NOPR*").

[86] The *Storage NOPR* was published in the *Fed. Reg.* on Nov. 30, 2016 (Vol. 81, No. 230 pp. 86,522-86,550.

[87] *Data Collection for Analytics and Surveillance and Market-Based Rate Purposes*, 156 FERC ¶ 61,045 (July 21, 2016) ("*Data Collection NOPR*").

[88] The *Data Collection NOPR* was published in the *Fed. Reg.* on Aug. 4, 2016 (Vol. 81, No. 150 pp. 51,726-51,772.

[89] *Regulations Implementing FAST Act Section 61003 – Critical Electric Infrastructure Security and Amending Critical Energy Infrastructure Information; Availability of Certain North American Electric Reliability Corporation Databases to the Commission*, Order No. 833, 157 FERC ¶ 61,123 (Nov. 17, 2016) ("*Order 833*").

procedures will be referred to as the Critical Energy/Electric Infrastructure Information (CEII) procedures. *Order 833* will become effective [60 days after its publication in the *Federal Register*].

- **Review of Generator IAs & Procedures / AWEA Petition for LGIA/LGIP Rulemaking (RM16-12; RM15-21)**

On May 13, 2016, the FERC held a technical conference to discuss select issues related to AWEA's petition in RM15-21 and to explore other generator interconnection issues, including interconnection of energy storage. Discussions addressed: the current state of generator interconnection queues, transparency and timing in the generator interconnection study process; certainty in cost estimates and construction time; other interconnection queue coordination and management issues; and interconnection of electric storage resources. Speaker materials are posted on the FERC's eLibrary. Post-technical conference comments were invited and filed by nearly 30 parties, including comments by AWEA, the ISO, Public Power (APPA, LPPC, NRECA), NextEra, EEI, Avangrid, and the Energy Storages Association ("ESA"), and are available on the FERC's eLibrary.

- **NOPR: Primary Frequency Response - Essential Reliability Services and the Evolving Bulk-Power System (RM16-6)**

On November 17, 2016, the FERC issued a NOPR proposing to require all newly interconnecting large and small generating facilities, both synchronous and non-synchronous, to install and enable primary frequency response capability as a condition of interconnection.[90] To implement these requirements, the Commission proposes to revise the *pro forma* Large Generator Interconnection Agreement ("LGIA") and the *pro forma* Small Generator Interconnection Agreement ("SGIA"). The *Primary Frequency Response NOPR* follows the FERC's *Frequency Response NOI*[91] from early 2016. Comments on the *Primary Frequency Response NOPR* are due on or before January 24, 2017.[92]

seeking comment on the need for reforms to its rules and regulations regarding the provision and compensation of primary frequency response. In light of the nation's changing resource mix and other factors, and considering the significance of primary frequency response to the reliable operation of the Bulk-Power System, the FERC seeks comment on (i) whether amendments to the *pro forma* LGIA and SGIA are warranted to require all new generation resources to have frequency response capabilities as a precondition of interconnection; (ii) the performance of existing resources and whether primary frequency response requirements for these resources are warranted; and (iii) the requirement to provide and compensate for primary frequency response.[93] Comments on the *Frequency Response NOI* were due on or before April 25, 2016 and were filed by over 50 parties, including: ISO-NE (with NYISO, PJM, SPP, and IESO), APPA/LPPA/TAPS, EDP Renewables, EEI, ELCON, ESA, EPRI, ESPA/NEPGA/IPPNY/Western Power Trading Forum, NARUC, NEI, and NERC. The *Frequency Response NOI* is pending before the FERC.

- ***Order 831*: Price Formation Fixes - Price Caps in RTO/ISO Markets (RM16-5)**

On November 17, 2016, the FERC issued *Order 831*[94] requiring each RTO/ISO: (i) to cap each resource's incremental energy offer at the higher of $1,000/MWh or that resource's verified cost-based incremental energy offer; and (ii) cap verified cost-based incremental energy offers at $2,000/MWh when calculating locational marginal prices ("LMP"). In addition, the FERC clarified that the verification process

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[90] *Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response*, 157 FERC ¶ 61,122 (Nov. 17, 2016) ("*Primary Frequency Response NOPR*").

[91] *Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response*, 154 FERC ¶ 61,117 (Feb. 18, 2016) ("*Frequency Response NOI*").

[92] The *Primary Frequency Response NOPR* was published in the *Fed. Reg.* on Nov. 25, 2016 (Vol. 81, No. 227) pp. 85,176-85,190.

[93] *Frequency Response NOI* at P 2.

[94] *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 831, 157 FERC ¶ 61,115 (Nov. 17, 2016) ("*Order 831*").

for cost-based incremental offers above $1,000/MWh should ensure that a resource's cost-based incremental energy offer reasonably reflects that resource's actual or expected costs. *Order 831* modified the FERC's *Offer Cap NOPR* by including a $2,000/MWh hard cap for the purposes of calculating LMPs. *Order 831* will become effective, and Market Rule changes implementing *Order 831* will be required to be filed [75 days after its publication in the Federal Register].

- ***Order 825*: Price Formation Fixes - Settlement Intervals/Shortage Pricing (RM15-24)**

Also on June 16, the FERC issued *Order 82*5,[95] which revises FERC regulations to require that each RTO/ISO (i) settle (a) energy transactions in its real-time markets at the same time interval it dispatches energy; (b) operating reserves transactions in its real-time markets at the same time interval it prices operating reserves; and (c) intertie transactions in the same time interval it schedules intertie transactions; and (ii) trigger shortage pricing for any dispatch interval during which a shortage of energy or operating reserves occurs. The FERC stated that adopting these reforms will align prices with resource dispatch instructions and operating needs, providing appropriate incentives for resource performance. *Order 825* will become effective September 13, 2016.[96]

Compliance. Each RTO/ISO is required to submit a compliance filing with the tariff changes needed to implement this Final Rule within 120 days of the Final Rule's September 13, 2016 effective date (on or before January 11, 2017). The FERC will allow a further 12 months from the compliance filing date for the tariff changes implementing reforms to settlement intervals to be effective, and 120 days from that same compliance filing date for the tariff changes implementing shortage pricing reforms to be effective. As previously noted, the ISO's and NEPOOL's jointly filed Sub-Hourly Settlement Changes, which changed to five minutes the settlement interval in the Real-Time Energy and Reserves Markets, was filed and accepted by the FERC.

XIII. Natural Gas Proceedings

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

- **Algonquin EDC Capacity Release Bidding Requirements Exemption Request (RP16-618)**

On March 31, 2016, the FERC conditionally accepted Algonquin tariff modifications and request for waiver that provided an exemption from capacity release bidding requirements for certain types of firm transportation capacity releases by Electric Distribution Companies ("EDCs") that are participating in state-regulated electric reliability programs.[97] As previously reported, Algonquin stated that the modifications were consistent with the FERC's current policy of exempting releases pursuant to state-regulated retail access programs of natural gas local distribution companies ("LDCs") from bidding requirements. Algonquin added that its proposal (i) supports the efforts of EDCs to increase the reliability of supply for natural gas-fired electric generation facilities in New England and to address high electricity prices during peak periods in New England and therefore is in the public interest; and (ii) furthers the FERC's initiatives related to gas-electric coordination. On May 9, 2016, the FERC held a technical conference to examine "concerns raised regarding the basis and need for the waiver." Initial comments were due May 31. Almost two dozen sets of initial comments were filed, raising numerous issues both in support and in opposition to the Algonquin proposal. Reply comments were due June 10, 2016 and were filed by Algonquin Gas Transmission, Sequent Energy Management, L.P. and Tenaska Marketing Ventures, Indicated Shippers, National Grid, Eversource, Repsol, Calpine, Exelon/NextEra, New England LDCs, CT PURA and the MA AG.

On August 31, 2016, the FERC issued an order in which it rejected Algonquin's request for a waiver that would have exempted gas-fired generators from capacity release bidding requirements but accepted Algonquin's

[95] *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 825, 155 FERC ¶ 61,276 (June 16, 2016) ("*Order 825*").

[96] *Order 825* was published in the *Fed. Reg.* on June 30, 2016 (Vol. 81, No. 126) pp. 42,882-42,910.

[97] *Algonquin Gas Transmission, LLC*, 154 FERC ¶ 61,269 (Mar. 31, 2016).

proposal to exempt from bidding an EDC's capacity release to an asset manager who is required to use the released capacity to carry out the EDC's obligations under the state-regulated electric reliability program.[98] The FERC explained that its capacity release regulations seek to balance the interests of the releasing shipper in releasing capacity to a replacement shipper of its choosing while still ensuring that allocative efficiency is enhanced by ensuring the capacity is used for its highest valued use.[99] Algonquin's proposal, whereby any gas-fired generator to whom EDCs release capacity would be a pre-arranged replacement shipper, failed to meet the standard of "improving the competitive structure of the natural gas industry" as formulated by the FERC in granting bidding exemptions for state-regulated retail access programs.[100] Furthermore, the FERC found that exemption proponents had not shown why such a broad exemption was necessary in order for EDCs to have a sufficient ability to direct their capacity releases to natural gas-fired generators in order to accomplish the goal of increasing electric reliability.[101] On September 30, 2016, ConEd and Orange & Rockland Utilities, Inc. ("O&R") requested clarification of the *Algonquin Order Following Technical Conference*, asking the FERC to clarify certain aspects of its approval exempting from bidding an EDC's capacity release to an asset manager. Algonquin Gas Transmission, National Grid Electric Distribution Companies, and Sequent Energy Management and Tenaska Marketing Ventures filed answers to the requests for clarification on October 17. Those requests are pending before the FERC.

On September 23, Algonquin submitted a compliance filing in response to the requirements of the *Algonquin Order Following Technical Conference*. Comments on that compliance were due on or before October 5; none were filed. The compliance filing is pending before the FERC.

- **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:

BP (IN13-15). On July 11, 2016, the FERC issued *Opinion 549*[102] affirming Judge Cintron's August 13, 2015 Initial Decision finding that BP America Inc., BP Corporation North America Inc., BP America Production Company, and BP Energy Company (collectively, "BP") violated Section 1c.1 of the Commission's regulations ("Anti-Manipulation Rule") and section 4A of the Natural Gas Act ("NGA").[103] Specifically, after extensive discovery and hearing procedures, Judge Cintron found that BP's Texas team engaged in market manipulation by changing their trading patterns, between September 18, 2008 through the end of November 2008, in order to suppress next-day natural gas prices at the Houston Ship Channel ("HSC") trading point in order to benefit correspondingly long position at the Henry Hub trading point. The FERC agreed, finding that the "record shows that BP's trading practices during the Investigative Period were fraudulent or deceptive, undertaken with the requisite scienter, and carried out in connection with Commission-jurisdictional transactions."[104] Accordingly, the FERC assessed a ***$20.16 million civil penalty*** and required BP to ***disgorge $207,169*** in "unjust profits it received as a result of its manipulation of the Houston Ship Channel Gas Daily index." The $20.16 million civil penalty was at the top of the FERC's Penalty Guidelines range, reflecting increases for having had a prior adjudication within 5 years of the violation, and for BP's violation of a FERC order within 5 years of the scheme. BP's penalty was mitigated because it cooperated during the investigation, but BP received no deduction for its compliance program, or for self-reporting. The *BP Penalties Order* also denied BP's request for rehearing of the

[98] *Algonquin Gas Transmission, LLC*, 156 FERC ¶ 61,151 (Aug. 31, 2016) ("*Algonquin Order Following Technical Conference*")

[99] *Id.* at P 27.

[100] *Id*. at P 34.

[101] *Id.* at P 35

[102] *BP America Inc., et al.*, Opinion No. 549, 156 FERC ¶ 61,031 (July 11, 2016) ("*BP Penalties Order*").

[103] *BP America Inc., et al.*, 152 FERC ¶ 63,016 (Aug. 13, 2015) ("*BP Initial Decision*").

[104] *BP Penalties Order* at P 3.

order establishing a hearing in this proceeding.[105] BP was directed to pay the civil penalty and disgorgement amount within 60 days of the *BP Penalties Order*. On August 10, BP requested rehearing of the *BP Penalties Order*. On September 8, the FERC issued a tolling order, affording it additional time to consider BP's request for rehearing of the *BP Penalties Order*, which remains pending.

On September 7, BP submitted a motion for modification of the *BP Penalties Order's* disgorgement directive because it cannot comply with the disgorgement directive as ordered. BP explained that the entity to which disgorgement was to be directed, the Texas Low Income Home Energy Assistance Program ("LIHEAP"), is not set up to receive or disburse amounts received from any person other than the Texas Legislature. In response, on September 12, the FERC stayed the disgorgement directive (until an order on BP's pending request for rehearing is issued), but indicated that interest will continue to accrue on unpaid monies during the pendency of the stay.[106]

Total Gas & Power North America, Inc. et al. (IN12-17). On April 28, 2016, the FERC issued a show cause order[107] in which it directed Total Gas & Power North America, Inc. ("TGPNA") and its West Desk traders and supervisors, Therese Tran f/k/a Nguyen ("Tran") and Aaron Hall (collectively, "Respondents") to show cause why Respondents should not be found to have violated NGA Section 4A and the FERC's Anti-Manipulation Rule through a scheme to manipulate the price of natural gas at four locations in the southwest United States between June 2009 and June 2012.[108]

The FERC also directed TGPNA to show cause why it should not be required to disgorge unjust profits of ***$9.18 million***, plus interest; TGPNA, Tran and Hall to show cause why they should not be assessed civil penalties (TGPNA ***- $213.6 million***; Hall ***- $1 million*** (jointly and severally with TGPNA); and Tran ***- $2 million*** (jointly and severally with TGPNA)). In addition, the FERC directed TGPNA's parent company, Total, S.A. ("Total"), and TGPNA's affiliate, Total Gas & Power, Ltd. ("TGPL"), to show cause why they should not be held liable for TGPNA's, Hall's, and Tran's conduct, and be held jointly and severally liable for their disgorgement and civil penalties based on Total's and TGPL's significant control and authority over TGPNA's daily operations. Respondents field their answer on July 12, 2016. OE Staff replied to Respondents' answer on September 23, 2016.

- **New England Pipeline Proceedings**
  The following New England pipeline projects are currently under construction or 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 (Dth/d) of firm capacity to NY, CT, RI and MA.

[105] *BP America Inc. et al.*, 147 FERC ¶ 61,130 (May 15, 2014) ("*BP Hearing Order*"), *reh'g denied,* 156 FERC ¶ 61,031 (July 11, 2016).

[106] *BP America Inc. et al.*, 156 FERC ¶ 61,174 (Sep. 12, 2016) ("*Order Staying BP Disgorgement*")

[107] *Total Gas & Power North America, Inc., et al.*, 155 FERC ¶ 61,105 (Apr. 28, 2016) ("*TGPNA Show Cause Order*").

[108] The allegations giving rise to the Total Show Cause Order were laid out in a September 21, 2015 FERC Staff Notice of Alleged Violations which summarized OE's case against the Respondents. Staff determined that the Respondents violated section 4A of the Natural Gas Act and the Commission's Anti-Manipulation Rule by devising and executing a scheme to manipulate the price of natural gas in the southwest United States between June 2009 and June 2012. Specifically, Staff alleged that the scheme involved making largely uneconomic trades for physical natural gas during bidweek designed to move indexed market prices in a way that benefited the company's related positions. Staff alleged that the West Desk implemented the bidweek scheme on at least 38 occasions during the period of interest, and that Tran and Hall each implemented the scheme and supervised and directed other traders in implementing the scheme.

    - 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 Staff-prepared Environmental Impact Statement (EIS) issued Jan. 23, 2015.
    - Certificate of public convenience and necessity granted Mar. 3, 2015.[109] Order Denying Rehearing and Dismissing Stay Request issued Jan. 28, 2016. FERC orders appealed to DC Circuit. Order Amending Certificate issued October 6, 2016.[110]
    - Construction began May 2015.
    - Partially in-service; expected to be fully in-service in 4th quarter 2016.

- ***Atlantic Bridge Project (CP16-9)***
    - Algonquin Gas Transmission filed for Section 7(b) and 7(c) certificate on Oct. 22, 2015.
    - 132,700 Dth/d of firm transportation to new and existing delivery points on the Algonquin system and 106,276 Dth/d of firm transportation service from Beverly, MA to various existing delivery points on the Maritimes & Northeast system.
    - 6.3 miles of replacement pipeline along Algonquin in NY and CT; new 7,700-horsepower compressor station in Weymouth, MA; more horsepower at existing compressor stations in CT and NY.
    - Seven firm shippers: Heritage Gas Limited, Maine Natural Gas Company, NSTAR Gas Company d/b/a Eversource Energy, Exelon Generation Company, LLC (as assignee and asset manager of Summit Natural Gas of Maine), Irving Oil Terminal Operations, Inc., New England NG Supply Limited, and Norwich Public Utilities.

- ***Connecticut Expansion Project (CP14-529)***
    - Tennessee Gas Pipeline filed for Section 7(c) certificate July 31, 2014.
    - 72,100 Dth/d of firm capacity.
    - 13.26 miles of three looping segments & facility upgrades/modifications in NY, MA & CT.
    - Three firm shippers: Conn. Natural Gas, Southern Conn. Gas, and Yankee Gas.
    - Notice of Schedule issued Sept. 1 with FERC EA to be issued Oct. 23 and 90-day Federal Authorization Decision Deadline set at Jan. 21, 2016.
    - Environmental Assessment (EA) issued on Oct. 23, 2015.
    - Certificate of public convenience and necessity granted Mar. 11, 2016.[111]
    - Construction expected to begin 4th Quarter 2016.

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[109] Order Issuing Certificate and Approving Abandonment, *Algonquin Gas Transmission LLC*, 150 FERC ¶ 61,163 (Mar. 3, 2015), *reh'g denied*, 154 FERC ¶ 61,048 (Jan. 28, 2016).

[110] *Algonquin Gas Transmission LLC*, 157 FERC ¶ 61,011 (Oct. 6, 2016). The order amends Algonquin's certificated initial reservation charges to reflect increases in the estimated construction costs of the AIM Project and West Roxbury Lateral. Specifically, the initial reservation charge for the AIM Project was increased from an estimated $42.5748 per Dth to $48.507 per Dth for Rate Schedule AFT-1 service and the initial reservation charge for the West Roxbury Lateral was increased from an estimated $18.1976 per Dth to $24.378 per Dth for Rate Schedule AFT-CL service. The proposed initial rates reflect a first-year cost of service of $199,074,096 and $29,253,221 for the AIM Project and West Roxbury Lateral, respectively. A commodity charge of $0.0069 per Dth for Rate Schedule AFT-1 to recover $603,667 in variable costs was also added.

[111] *Tennessee Gas Pipeline Co., LLC*, 154 FERC ¶ 61,191 (Mar. 11, 2016) (order issuing certificate); *reh'g requested*. *See also* 154 FERC ¶ 61,263 (Mar. 30, 2016) (order denying stay); 155 FERC ¶ 61,087 (Apr. 22, 2016) (order denying stay).

- In-service: Nov. 2017 (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 Dth/d of firm capacity from Susquehanna County, PA (Marcellus Shale) 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 of public convenience and necessity granted Dec 2, 2014.
  - On April 22, 2016, New York State Department of Environmental Conservation denied Constitution's application for a Section 401 permit under the Clean Water Act. The decision effectively guarantees that the Constitution Pipeline project will, at best, be delayed by several years.
  - On May 16, 2016, the New York Attorney General filed a complaint against Constitution at the FERC (CP13-499) seeking a stay of the December 2014 order granting the original certificates, as well as alleging violations of the order, the Natural Gas Act, and the Commission's own regulations due to acts and omissions associated with clear-cutting and other construction-related activities on the pipeline right of way in New York.
  - Construction was expected to begin Spring 2016 (after final Federal Authorizations), but has been plagued by delays.
    - On October 13, 2016, the FERC approved Constitution's request to proceed to remove the felled trees in Pennsylvania.

- ***Salem Lateral Project (CP14-522)***
  - Algonquin Gas Transmission filed application Jul 10, 2013.
  - 115,000 Dth/d of firm capacity.
  - 1.2 miles of pipeline to 630 MW Salem Harbor Station and other Salem, MA facilities.
  - Footprint Power sole firm customer.
  - FERC Staff-prepared EA issued Dec 2, 2014.
  - Certificate of public convenience and necessity granted May 14, 2015.[112]
  - Construction began in May 2015.
  - ***In-Service: November 1, 2016*** *(reporting is now concluded).*

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).

[112] Order Issuing Certificate, *Algonquin Gas Transmission LLC*, 151 FERC ¶ 61,118 (May 14, 2015).

- **FCA10 Results (16-1408)**
  Underlying FERC Proceeding: ER16-1041[113]
  Petitioner: UWUA Local 464 and Robert Clark

In a new appeal since the last Report, UWUA Local 464 and Robert Clark ("Petitioners") filed a petition for review of the FERC's orders on the FCA10 Results Filing. A Docketing Statement Form, Statement of Issues to be Raised, Petitioners' and Respondents' Appearances, and procedural motions are due December 30, 2016; dispositive motions, January 17, 2017.

- **FCA9 Results (16-1068)**
  Underlying FERC Proceeding: ER15-1137[114]
  Petitioner: UWUA Local 464 and Robert Clark

Robert Clark and UWUA Local 464 ("Petitioners") filed a petition for review of the FERC's orders on the FCA9 Results Filing on February 24, 2016. A Docketing Statement Form, Statement of Issues to be Raised, Petitioners' and Respondents' Appearances, and procedural motions were filed on March 28, 2016. The FERC filed a certified index to the record on April 11. On April 13, the Court granted NEPGA's and CPV Towantic's interventions. On July 25, 2016, Petitioners filed an unopposed motion requesting that the Court stay briefing of this appeal until 45 days after the Court rules on the FCA8 Results appeal (*see* 14-1244, 14-1246 (consolidated) below. The Court's order in the FCA8 Results appeal was issued on October 25, 2016). On July 27, the Court granted Petitioners' motion, ordering that this case be held in abeyance pending further order of the Court and directing the parties to file motions to govern future proceedings in this case within 45 days of the disposition of the FCA8 Results appeal proceeding, or December 9, 2016.

- **NEPGA PER Complaint and FCM Jump Ball and Compliance Proceedings (16-1023/1024)**
  Underlying FERC Proceeding: ER14-1050;[115] **EL14-52;116 EL15-25**[117]
  Petitioner: NEPGA

As previously reported, NEPGA filed, on January 19, 2016, a petition for review of the FERC's orders on NEPGA's first PER Complaint. A Docketing Statement Form, Statement of Issues to be Raised, Petitioners' and Respondents' Appearances, and procedural motions were filed. On February 24, the Court granted NEPGA's February 18 motion to consolidate this proceeding with 16-1024. On July 18, NEPGA submitted its Petitioner Brief. On July 25, Entergy indicated that it would not file an Intervenor for Petitioner Joint Brief. FERC filed Respondent's Brief on September 23; NESCOE filed Intervenor for Respondent Brief on September 30; NEPGA filed its Reply Brief on October 31. Remaining submissions are to be filed as follows: Deferred Appendix, November 14; and Final Briefs, November 28. On October 4, NEPGA informed Court of its latest PER Complaint (*see* EL16-120 in Section I above), which it stated would not resolve the issues in this proceeding even if FERC ruled in its favor in that proceeding. On November 14, NEPGA filed a Joint Appendix. NEPGA filed its Petitioner Final Brief and Reply Brief on November 22. On November 28, the FERC filed its Respondent Final Brief and NESCOE filed its Intervenor for Respondent Final Brief.

[113] 155 FERC ¶ 61,273 (June 16, 2016); 157 FERC ¶ 61,060 (Oct. 27, 2016).

[114] 153 FERC ¶ 61,378 (Dec. 30, 2015); 151 FERC ¶ 61,226 (June 18, 2015).

[115] 153 FERC ¶ 61,224 (Nov. 19, 2015); 153 FERC ¶ 61,223 (Nov. 19, 2015); 147 FERC ¶ 61,172 (May 30, 2014).

[116] 153 FERC ¶ 61,222 (Nov. 19, 2015); 150 FERC ¶ 61,053 (Jan. 30, 2015).

[117] 153 FERC ¶ 61,222 (Nov. 19, 2015); 150 FERC ¶ 61,053 (Jan. 30, 2015).

- **Base ROE Complaints II & III (2012 & 2014) (15-1212)**
Underlying FERC Proceedings: EL13-33; EL14-86[118]
Appellants: New England Transmission Owners

The TOs filed a petition for review of the FERC's orders in the 2012 and 2014 ROE complaint proceedings on July 13, 2015. On July 16, the Court issued a scheduling order directing, among other things, a statement of issues and procedural motions to be filed by August 17 and dispositive motions to be filed by August 31; briefing was deferred until further order of the court. However, on August 14, 2015, NETOs filed an unopposed motion to hold this case in abeyance pending final FERC action on the 2012 and 2014 ROE Complaints (*see* Section I above). On August 20, 2015, the Court granted NETOs' motion to hold the case in abeyance, subject to submission of status reports every 90 days. On November 14, the parties filed their fifth 90-day status report, again indicating, ultimately, that the proceedings upon which the NETOs based their request for abeyance of this appeal remain ongoing.

- **Order 1000 Compliance Filings (15-1139, 15-1141**) (consolidated)**
Underlying FERC Proceedings: ER13-193; ER13-196[119]
Appellants: New England Transmission Owners (NETOs); NESCOE/CT DEEP/CT PURA, *et al*.

As previously reported, NETOs[120] and NESCOE, *et al*., filed a petition for review of the FERC's orders in the *Order 1000* Compliance Filing proceeding on May 15, 2015. Briefing has been completed. However, since the last Report, the FERC filed supplemental authority with respect to *Oklahoma Gas & Electric Co. v. FERC*, No. 14-1281 (D.C. Cir. July 1, 2016). On July 22, Counsel for LS Power and NextEra responded to the FERC's *Oklahoma Gas* authorities submission. On October 4, the Court scheduled the case for oral argument on January 13, 2017, at 9:30 a.m. The composition of the argument panel will usually be revealed 30 days prior to the date of oral argument.

- **Base ROE Complaint I (2011) (15-1118, 15-1119, 15-1121**) (consolidated)**
Underlying FERC Proceeding: EL11-66[121]
Appellants: NETOs

On April 30, 2015, NETOs filed a petition for review of the FERC's orders in the 2011 Base ROE Complaint Proceeding. Motions for leave to intervene have been filed by NEPOOL,EMCOS,[122] NJ Division of Rate Counsel, NHEC, MMWEC, CT PURA, CT OCC, CT AG, NJ BPU, Delaware PSC, and Coalition of MISO Transmission Customers. The Court granted all motions to intervene on June 23, 2015. On August 10, 2015, Petitioners filed an unopposed proposed briefing format and schedule. On October 6, 2015, the court issued an order setting the briefing schedule. On December 7, 2015, (i) "Customers"[123] and the TOs[124]filed their opening briefs. On December 8, the clerk's office sent to counsel a letter noting the use of uncommon acronyms and abbreviations in briefs filed with the court (parties are expected to limit the use of acronyms and to avoid using acronyms that are not widely known), advising counsel that they could submit within a week revised briefs eliminating any uncommon acronyms used in previously filed briefs, which the TOs did on December 15. The

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[118] 147 FERC ¶ 61,235 (June 19, 2014); 149 FERC ¶ 61,156 (Nov. 24, 2014); 151 FERC ¶ 61,125 (May 14, 2015).

[119] 150 FERC ¶ 61,209 (Mar. 19, 2015); 143 FERC ¶ 61,150 (May 17, 2013).

[120] "NETOs" are Emera Maine; Central Maine Power Co., National Grid; New Hampshire Transmission ("NHT"), Eversource (on behalf of its electric utility company affiliates CL&P, WMECO, PSNH, and NSTAR), UI, and Vermont Transco.

[121] 150 FERC ¶ 61,165 (Mar. 3, 2015); 149 FERC ¶ 61,032 (Oct. 16, 2014); 147 FERC ¶ 61,234 (June 19, 2014).

[122] "EMCOS" are Taunton, Reading, Hingham, and Braintree.

[123] "Customers" are: the Commonwealth of Massachusetts, CT AG, CT PURA, NH PUC, RI PUC, CT OCC, MOPA, NH OCA, the "EMCOS" group (Braintree, Hingham, Reading, Taunton), MMWEC, NHEC, AIM, IECG, and Power Options.

[124] In this case, TOs are CMP, Emera Maine, Eversource, National Grid, NHT, UI, and Vermont Transco.

FERC filed its brief on February 12. On March 4, briefs were filed on the issues of the ROE being too low and modification of incentive adders and by NETOs on the issue of the ROE being too high. On March 25, TOs and EMCOs filed their reply briefs. The deferred appendix was filed on April 15. Final briefs were filed April 26, 2016 by the FERC, and April 29 by TOs and Customers. On May 18, CT PURA supplemented the deferred appendix. All briefing is complete. On October 3, the Court scheduled this case for oral argument on December 6, 2016, at 9:30 a.m. The TOs and the MA AG will be allotted 10 minutes each; the FERC, 20 minutes. The argument panel will be composed of Judges Millett, Sentelle and Randolph.

- **FCM Pricing Rules Complaints (15-1071**, 16-1042) (consol.)**
  Underlying FERC Proceeding: EL14-7,[125] EL15-23[126]
  Petitioners: NEPGA, Exelon

On March 31, 2015, NEPGA filed a petition for review of the FERC's orders on NEPGA's FCM Administrative Pricing Rules Complaint. A docketing statement form, statement of issues to be raised, and Petitioners' appearances were filed on April 23, 2015. Also on April 23, 2015, NEPGA requested that the case be held in abeyance pending the FERC's issuance of an order on rehearing of its initial order in Exelon Corporation v. ISO New England Inc. (EL15-23). Motions for leave to intervene were filed by NEPOOL, CT PURA, CT OCC, NESCOE, NECPUC, NHEC, and PSEG. On May 22, the Court granted all motions to intervene and NEPGA's motion to hold the case in abeyance pending a decision in EL15-23. Following the FERC's decision in EL15-23 and Exelon's appeal of that case (16-1042), the Court granted, on March 1, 2016, Exelon's motion to consolidate this proceeding with 16-1042. Accordingly, this proceeding was returned to the court's active docket on a consolidated basis with 16-1042.

On June 16, NEPGA and Exelon filed Petitioners' Briefs. PSEG submitted its Intervenor for Petitioner Brief on July 7. FERC's Respondent Brief was filed on August 15. A Joint Intervenor for Respondent Brief was filed on September 6 by NESCOE, NECPUC, CT PURA, and CT OCC. NEPGA filed its Reply Brief on September 20. On October 7, PSEG advised that it would not be filing a Reply Brief. On October 11, the parties filed a joint appendix. On October 25, Final Briefs for Respondent, Joint Intervenor for Respondent, Petitioner, Intervenor for Petitioner, as well as Joint Petitioners' Final Brief were filed. All briefing is complete as this matter is now before the Court.

- **Allco Finance Limited v. Klee et al. (Commissioners, CT DEEP and CT PURA) (2d Cir. 16-2946)**

In this proceeding, an appeal from an unsuccessful challenge of Connecticut's actions under the 2015 multi-state clean energy RFP ("Clean Energy RFP") in Connecticut District Court, Allco continues its challenges to Connecticut's actions under the Clean Energy RFP. Allco asserts that Connecticut's actions are inconsistent with PURPA and constitutional principles recently addressed by the Supreme Court in *Hughes v Talen Energy Marketing* and summarized in prior Reports. As reported at the November Participants Committee meeting, the Second Circuit Court of Appeals on November 2 granted Allso's motion for an emergency injunction. The emergency injunction enjoins Connecticut (but not Massachusetts or Rhode Island) from "awarding, entering into, executing, or approving any wholesale electricity contracts in connection with the [Clean Energy RFP] during the pendency of this appeal." The injunction does "not apply retroactively to any wholesale electricity contract that has been entered into, executed, and approved" as of November 2, 2016. Since the last Report, Briefs and Amicus Briefs have been filed. Oral argument has been set for December 8, 2016.

- **Entergy Nuclear Fitzpatrick, LLC et al. v. Zibelman et al (NY PSC Commissioners) (NDNY 5:15-cv-00230-DNH-TWD)**

Entergy[127] filed, on February 27, 2015, in the United States District Court for the Northern District of New York ("NDNY"), a Complaint that seeks a declaratory judgment that the NYPSC Commissioners' order ("Order") approving an agreement to keep NRG's 435 MW Dunkirk facility in the NYISO market, "repowered"

[125] 150 FERC ¶ 61,064 (Jan. 30, 2015); 146 FERC ¶ 61,039 (Jan. 24, 2014).

[126] 154 FERC ¶ 61,005 (Jan. 7, 2016); 150 FERC ¶ 61,067 (Jan. 30, 2015).

[127] Plaintiffs are Entergy Nuclear FitzPatrick, LLC ("FitzPatrick"); Entergy Nuclear Power Marketing, LLC ("ENPM"); and Entergy Nuclear Operations, Inc. ("ENOI").

as a natural gas-fired (rather than coal-fired) plant (the "Term Sheet")[128] is preempted by the FPA and invalid under the dormant Commerce Clause of the US Constitution. Entergy also seeks a permanent injunction requiring the NYPSC Commissioners to withdraw the Order and/or preventing the NYPSC Commissioners from continuing to treat the Order as valid and binding. This case is noteworthy given the relationship of the issues raised to the Supreme Court's *Hughes*[129] decision summarized in earlier Reports.

As previously reported, the Court dismissed, on March 7, 2016, a NYPSC motion to dismiss Entergy's claim that its Order is both field- and conflict-preempted by the FPA, finding that "Entergy has timely asserted claims of harm flowing from state action to an interstate market in which it participates". Since the last Report, briefing on how *Hughes* impacts discovery and the issue of a stay in this case was filed on May 6. Also on May 6, the Parties filed updated Civil Case Management Plans. On May 10, the trial judge issued a protective order adopting a confidentiality agreement should discovery proceed. On May 20, 2016, the NYPSC requested that the stay of discovery be continued to afford the NYSPC the opportunity to consider in a separate proceeding the impact of the *Hughes* case and other developments on the NYPSC's prior authorization of the Term Sheet, subject to reporting to this Court, advising the Court that it had contemporaneously solicited comments in in NYPSC Case 12-E-0577.[130]

On June 3, the Court found this case appropriate for referral to and order the case to the Mandatory Mediation Program. The Mediator will encourage and assist the parties in reaching a resolution to their dispute, but may not compel or coerce the parties to settle. Mediation Reports are to be filed within seven days after the close of each mediation session. On September 22, the deadline for completion of mediation was extended to November 1, 2016.

[128] The Term Sheet provides that, in exchange for Dunkirk's commitment to participate in the NYISO energy and capacity markets through 2025, Dunkirk will receive out-of-market payments of $20.4 million per year from National Grid and a $15 million one-time subsidy from a New York State agency. Entergy asserts that the contract structure will lead Dunkirk to bid below its actual costs in the capacity auction, causing the auction market to "clear" at a lower price than otherwise would have resulted, and resulting in all generators receiving lower capacity revenues than they otherwise would have received.

[129] *Hughes v. Talen Energy Marketing LLC*, 136 S. Ct. 993 (2016) ("*Hughes*").

[130] The NYPSC asked for comments on whether "National Grid should still be authorized to recover costs under the Term Sheet given various intervening events subsequent to the Commission's approval. In particular, NRG/Dunkirk mothballed the Dunkirk facility in January 2016, and has not taken the actions necessary to add natural gas firing capability at the Dunkirk facility by September 1, 2015, or otherwise. Meanwhile, National Grid has completed certain transmission upgrades that it previously could defer and avoid, in contemplation of the refueled Dunkirk facility being available. Moreover, on April 19, 2016, the United States Supreme Court issued a decision with respect to preemption of a State-ordered contract for the sale of electric generation capacity, which may implicate the Dunkirk/National Grid Term Sheet. *Hughes v. Talen Energy Marketing, LLC*, 136 S. Ct. 1288 (2016) ("*Hughes*"). For instance, would *Hughes* require modification of the Term Sheet? Similarly, would *Hughes* be considered a "Change of Law" under the provisions of the Term Sheet providing for termination?

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