NEW ENGLAND POWER POOL

David T. Doot
Secretary

February 23, 2018

VIA ELECTRONIC MAIL

TO: MEMBERS AND ALTERNATES OF THE NEPOOL PARTICIPANTS COMMITTEE

RE: Supplemental Notice of March 2, 2018 NEPOOL Participants Committee Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that a meeting of the NEPOOL Participants Committee will be held on **Friday, March 2, 2018 at 10:00 a.m. at Hilton Boston Logan Airport Hotel, 1 Hotel Drive, Boston, MA.** The Participants Committee meeting will be held in the **International Ballroom** for the purposes set forth on the attached agenda and posted with the meeting materials.

For your information, this meeting will be recorded, as are all the NEPOOL Participants Committee meetings. NEPOOL meetings, while not public, are open to all NEPOOL Participants, their authorized representatives and, except as otherwise limited for discussions in executive session, consumer advocates that are not members, federal and state officials and guests whose attendance has been cleared with the Committee Chair. All those in attendance or participating, either in person or by phone, are required to identify themselves and their affiliation at the meeting. Official records and minutes of meetings are posted publicly. No statements made in NEPOOL meetings are to be quoted or published publicly.

Rooms at the Hilton Logan Hotel for the March 2 meeting are available at the rate of $169.00 per night, on a first-come, first-served basis **UNTIL February 25, 2018.** To take advantage of these arrangements, you can make your reservation using the following link: http://www.hilton.com/en/hi/groups/personalized/B/BOSLHHH-DPT-20180301/index.jhtml?WT.mc_id=POG or contact the hotel directly (617-568-6933) 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 Participants Committee meeting held on February 2, 2018. The preliminary minutes of the February 2 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.

3. To consider and take action, as appropriate, on revisions to certain defined terms in Tariff Section I.2.2 and associated clean-up changes to the ISO Financial Assurance Policy related to the FCM Enhancements – Phase II project. Background materials and a draft resolution are included and posted with this supplemental notice.

4. To receive an ISO Chief Executive Officer Report.

5. To receive an ISO Chief Operating Officer Report, including an update on the 2018 Work Plan.

6. To receive a report from and to discuss and provide Participant perspectives to the ISO on its planned response to the FERC's order initiating a proceeding on resilience (AD18-7), to provide initial input for NEPOOL's responsive comments to the ISO's planned response, and to discuss the process for finalizing NEPOOL's responsive comments following review of the ISO's response as filed. A memorandum summarizing feedback your Officers provided to the ISO for its consideration is included with this supplemental notice.

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

8. To receive reports from Committees, Subcommittees and other working groups:

   - Markets Committee
   - Reliability Committee
   - Transmission Committee
   - Budget & Finance Subcommittee
   - Others

9. Administrative matters.

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

PRELIMINARY

A meeting of the NEPOOL Participants Committee was held via teleconference beginning at 10:00 a.m. on Friday, February 2, 2018, pursuant to notice duly given. A quorum determined in accordance with the Second Restated NEPOOL Agreement was present and acting throughout the meeting. Attachment 1 identifies the members, alternates and temporary alternates who participated in the teleconference meeting.

Mr. Thomas Kaslow, Chair, presided and Mr. David Doot, Secretary, recorded.

APPROVAL OF JANUARY 5, 2018 MEETING MINUTES

Mr. Kaslow referred the Committee to the preliminary minutes for the January 5, 2018 meeting as circulated in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of the January 5 meeting were unanimously approved without change.

CONSENT AGENDA

Mr. Kaslow 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 unanimously approved without discussion or comment.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), referred the Committee to the summaries of the ISO Board and Board Committee meetings that had occurred since the January 5 meeting, which had been circulated and posted in advance of the meeting. There were no questions or comments on the summaries.

Mr. van Welie then provided an update on the ISO's lessons learned during the recent cold weather period, the fuel security study and planned stakeholder process, and the ISO's planned response to the FERC order seeking comments on grid resilience. He summarized the ISO's

concerns with the resilience of the system during recent cold weather (i.e., the ability to withstand major contingencies), which he said the ISO would reinforce in its response to FERC. He said the ISO planned to raise and discuss with its stakeholders a number of questions and concerns with the region's fuel security risks. He expressed concern that the ISO was faced with managing system constraints not otherwise visible to the marketplace, reflected in pricing or for which there were appropriate communication structures, highlighted by the ISO's efforts to maintain a 3-day fuel reserve on the system during the recent cold weather period. He expressed concern also that, as oil reserves dropped during that second week of cold weather, the scarcity value of that oil was not reflected in generator offers and prices for oil-fired generation did not trend up, as they should have, towards the prices for gas-fired generation. He said the experiences during this last cold snap reinforced challenges with the fuel supply chain. He opined that, if the region had in fact concluded to live with the constraints on the gas pipelines, it must have more robust incentives for advanced arrangements to resupply fuel tanks during the winter, especially during adverse weather conditions when the risk of disrupted fuel supply is most acute.

Turning to the Fuel Security Analysis, Mr. van Welie made the following points:

- Risks associated with operations during cold weather are increasing;
- As non-natural gas fired resource retirements continue, the region is becoming more reliant on liquefied natural gas (LNG) and dual-fuel resources;
- Retirements can be accommodated with more replacement energy from resources that do not require fossil fuel and from demand reduction;
- The region's policymakers are encouraging reduction in fossil ~~-fuel-~~fuel-fired generation resources, but there is concern that retirements of such resources will occur more quickly than suitable replacement resources are added to the system; and
- Certain key energy resources are critical to fuel security.

He reviewed two parallel tracks for addressing ~~the~~ fuel security issues: (1) market design changes (to better reflect fuel constraints in pricing and to incent market participants to make forward fuel arrangements and to invest in infrastructure when appropriate); and (2) infrastructure investments

to relieve fuel constraints. As to the latter, he said the ISO did not have jurisdiction over fuel infrastructure and could not direct investments to relieve fuel constraints. As to the market design track, he flagged the following ISO questions:

- Is the pay-for-performance (PFP) payment rate and stop-loss provision properly calibrated, particularly if the region must depend on large quantities of imported LNG?
- How can the markets design enhance incentives for forward fuel supply and re-supply arrangements?
- How can market design be improved to ensure that generators can reflect in their offers the opportunity costs associated with scarce fuels and scarce emission allowances?

He said the ISO planned to begin discussing with stakeholders possible market design improvements in the second quarter of 2018 and expected those efforts would take approximately a year to conclude.

Mr. van Welie discussed the ISO's plans for responding to the FERC's January 8 grid resilience order. He said the ISO's responses would focus on the fuel security issues as the region's largest resilience issue. The ISO also would raise its longer-term operations concerns in the face of increasing reliance on intermittent resources. He noted the increasing reliance especially during very cold conditions, to have available fuel ~~or peaking resources~~, with little relief in sight until there are storage technologies that can carry the region through a season. While New England had electric storage technologies that could sustain operations during hours or even a day, the region needed storage that could help satisfy loads for longer-term, sustained periods of time to ride through extended cold-weather or other events. The market design challenges (to ensure fuel security) were complicated and, to his knowledge, had not yet been solved anywhere in the world. He explained the ISO would make these points with the FERC and he urged NEPOOL and the States to support the ISO's request for adequate time to work through these issues.

Mr. van Welie then concluded his remarks with a summary of the January 23, 2018 hearings of the U.S. Senate Committee on Energy & Natural Resources on the performance of the electric power systems during cold weather. He identified who testified with him on the panel and reported that his introductory remarks had been circulated by the ISO in advance of the hearings. In response to senators' questions, he explained that New England could not get natural gas pipelines built because (1) there was no customer willing and able to commit to pay for that pipeline, and (2) there was considerable resistance in New England and New York to new pipeline infrastructure. Also responding to senators' questions, he noted that New England must import LNG from Russia and elsewhere because the Jones Act prohibits transfer of LNG from one U.S. port to another U.S. port. He said he reinforced that the Mmarket Participant and the states, and not the ISO, must decide what infrastructureresource investments it will be madke to einsure fuel supply. He noted the comments of Senator King of Maine that New England would need to rely on multiple solutionspaths to ensure continued reliable, cost-effective energy supply. He reported that Committee Chair Lisa Murkowski underscored with FERC Chairman McIntyre Congress's sense of urgency. Mr. van Welie's worry was that timing pressures might encourage the FERC to act ahead of New England proposing responsive improvements to its markets, or limit the time available to submit proposals to the FERC. He again urged members and the States to support the ISO's request that the FERC allow the region the sufficient opportunity and time to address its resilience concerns.

The ISO then noted Chair Murkowski's opinion that New England was a potential harbinger for other parts of the country. Based on her read of the Fuel Security Analysis, she noted that New England was confronted with a choice to use load shedding or infrastructure investment to manage reliability. Also reported was the FERC Chairman's observation that the system performed reasonably well under stressed conditions with high wholesale prices and better

coordination between electric and gas system operators than in the past. He also reportedly cited New England's Winter Reliability Program and talked of the need more broadly for capacity market reforms, enhanced performance incentives, and a common understanding of resilience.

In response to Participants Committee members' questions on his remarks, Mr. van Welie clarified that two forms of seasonal storage were fossil fuel (LNG or oil) in a tank and large hydro impoundments such as the Hydro-Québec (HQ) dams. He affirmed that the ISO would not have a Winter Reliability Program in place for Winter 2018-19, but the region did need to discuss whether other market improvements beyond PFP might be needed to provide assurance of continued, adequate fuel supply. He stated the ISO did not plan to change PFP for Winter 2018-19, but would watch market reactions closely, and as needed discuss, for example, whether the payment rate was sufficient to encourage necessary investment and behavior. He noted that, in 2013 when designing PFP, the ISO saw dual-fuel as the most cost effective way to offset the pipeline constraints. The ISO needed to reassess that conclusion given experiences this past winter, when gas was very expensive, the local distribution companies ~~LDCs~~ and not the generators were buying market gas and were not using their own local LNG storage, and most of the energy coming from generators was coming from oil-fueled units or gas-fired units switching to oil. Clarifying his remarks on market design concerns, he explained the ISO wanted to ensure pricing that encourages the use of available gas on the system and furthermore, to provide incentives to make adequate resupply arrangements~~restock fuel~~. The ISO also wanted to reconsider whether the PFP stop-loss provisions would be adequate if the outcome were rolling blackouts due to inadequate fuel supply arrangements~~ to ride through extended cold weather~~.

Mr. van Welie clarified that the ISO ~~was~~ maintained~~ing~~ a reliable power system during the cold snap, but not one that could have handled any additional major contingencies, particularly after Pilgrim was forced down. Dr. Vamsi Chadalavada further clarified the region did not lose

energy from Pilgrim until the night of January 4, closer to the end of the cold snap. Mr. van Welie added by way of example (and reference to one of the contingencies studied in the Operational Fuel Security Analysis) that the energy output of ~~a loss of~~ Everett to the electric system during the two-week cold period was ~~would have added~~ the energy equivalent of burning 600,000 barrels of ~~additional~~ oil and the loss of Everett ~~need to the system, and~~ could have put New England in an untenable position during this period.

ISO COO REPORT

Dr. Chadalavada, ISO Chief Operating Officer (COO), referred to the February COO report, the previous report on the cold weather period and accompanying questions and answers, and an update on the oil inventory levels in New England, each of which ~~that~~ were circulated in advance of the meeting and posted on the NEPOOL and ISO websites. He said the February COO report reflected data through January 24, 2018. During that time: (i) Energy Market value was $1.1 billion, up $285 million from December 2017 and $684 million from January 2017; (ii) average natural gas prices were 77% higher than average prices in December 2017; (iii) average Real-Time Hub LMPs ($119.14/MWh) were 49% higher than December 2017 LMPs; (iv) average daily (peak hour) Day-Ahead cleared physical Energy, as a percent of forecasted load, was 98.9% in January, down from 99.2% in December 2017; and (v) daily Net Commitment Period Compensation (NCPC) for January (based on data through January 24, 2018) totaled $19.6 million, up $12.6 million from December 2017 and up $15.2 million from January 2017. January NCPC, which was 1.7% of total Energy Market value, was comprised of (a) $17.9 million in first contingency payments, which were up $12.5 million from December, and (b) $1.6 million in second contingency payments, which were up $1.1 million from December.

He then referred to a chart showing that the amount of usable oil in New England, which began the winter at 68% of maximum inventory, was down to almost 19% by January 9. He said replenishments since then had increased inventory back up to 35% of maximum storage.

In response to a member's question, Dr. Chadalavada agreed that reporting on average physical load that cleared the Day-Ahead Energy Market did mask peaks and valleys, and the ISO would consider ways to highlight that in future reports. He opined that, given current 10-day forecasts of moderate temperatures, the ISO considered fuel inventory to be sufficient, and that the energy consumption generally decreases as days grow longer.

Comparing the Winter 2017-18 cold snap ~~this winter with~~ to the 2013~~-/20~~14 cold snap, Dr. Chadalavada said the system performed better because of market enhancements, Day-Ahead replacement reserves, and strong performance from many older oil units. He explained that, had the ISO not postured units during the last three~~3~~ days of the cold snap, there was a good chance that the region would have run out of oil that Saturday and potentially through Tuesday when warmer weather arrived. Mr. van Welie noted as an aside that the ISO's experiences during the two-week cold snap were very close to the conditions assumed in the reference case for the fuel security study, reinforcing the usefulness of that study in identifying future challenges for the region.

Noting earlier comments on the availability of gas on the system for the right price, Dr. Chadalavada observed that the ISO had committed close to 2,000 MW of supplemental gas units on the final Saturday of the cold snap and all those units were able to procure gas. He expressed, at least as a question whether more gas might have been consumed instead of oil had prices reflected oil scarcity ~~of oil~~. He explained that the ISO did not have a reliable means to identify actual gas consumption versus gas availability, whereas it did have that type of data for oil usage. He explained that the ISO would be researching data to better understand the gas supply issues

during the cold snap. Mr. van Welie observed that the Fuel Security Study reference case assumed one billion cubic feet (Bcf) of LNG injection used for gas generation, when the actual experience was that very little of the LNG was used for that purpose. He noted also that energy from HQ was not capacity-backed for the most part and HQ warned Day-Ahead of the possibility of reductions in imports. That reduction was modeled Day-Ahead but did not materialize in Real-Time, which raised an inference that the ISO was overcommitting the system. He explained the ISO needed to operate a system with margins to maintain reliability.

Mr. Kaslow thanked Dr. Chadalavada for his report and for his response to all the questions, which reinforced the need for further discussion of the Fuel Security Analysis with stakeholders.

LITIGATION REPORT

Mr. Doot referred the Committee to the January 31 Litigation Report and to the summary of the filings submitted in January in the Competitive Auctions with Sponsored Policy Resources (CASPR) proceeding (ER18-619) which accompanied that Report, that had been circulated and posted in advance of the meeting. ~~He referred to the summary of the CASPR filings submitted in January~~. Referring to the Clear River Energy complaint seeking changes to Schedule 11 of the Open Access Transmission Tariff and related Tariff provisions that address cost recovery for operating and maintenance associated with large generator interconnection-related network upgrades, he reported that Clear River withdrew its complaint following the pleadings and some developments in its Rhode Island case. He reported on a pending complaint filed by Calpine and LS Power regarding the market structure implications of having a delayed resource continue to be treated as an existing resource in subsequent years, and the fact that the FERC had still not acted on that complaint. He also referenced the contested ISO filing to terminate a capacity

supply obligation (CSO). He reported that the FERC was asked to rule on that quickly so that the ISO could settle the upcoming forward capacity auction with the right MWs of existing resources. He reported that, just prior to the meeting, the DC Circuit Court of Appeals remanded the FERC's decisions to allow the 7-year price lock-in and capacity-carry-forward rules, finding that the FERC did not justify changing its conclusions about appropriate treatment~~s~~ for such resources.

COMMITTEE REPORTS

Mr. William Fowler reported that the Markets Committee meeting originally scheduled for February 6-7 was cancelled for lack of business items.

Mr. Robert Stein reported that the Reliability Committee was scheduled to meet on February 13 and would start a process for reviewing what assumptions for determining Installed Capacity Requirements (ICR) should be evaluated and possibly changed for FCA13 and hopefully for FCA14.

Mr. Jose Rotger reported that the Transmission Committee meeting scheduled for February 27 was cancelled. He stated the Transmission Committee would likely schedule extra meetings in April/May to review Tariff changes arising out of the ongoing RNS/LNS formula rate settlement proceeding.

Mr. Kenneth Dell Orto reported that the Budget & Finance Subcommittee was scheduled to meet on February 9 to review the ISO's quarterly c~~C~~apital projects report ~~Funding Tariff~~ filing, to receive a summary of NEPOOL year-end financial results, and review proposed FCM-related clean up changes to definitions used in the Financial Assurance Policy.

OTHER BUSINESS

Mr. Kaslow reported that the March 2 Participants Committee meeting was scheduled to be held in-person at the Hilton Logan Airport Hotel in Boston, MA. He stated that the ISO would be reviewing at the meeting, for NEPOOL's comment and reaction, more details on its intended filing in the FERC grid resilience docket.

There being no further business, the meeting adjourned at 11:17 a.m.

Respectfully submitted,

David T. Doot, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
FEBRUARY 2, 2018 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
AR Small Load Response (LR) Group Member	AR-LR	Doug Hurley	Brad Swalwell	
AR Small Renewable Generation (RG) Group Member	AR-RG	Erik Abend		
Ashburnham Municipal Light Plant	Publicly Owned		Brian Thomson	
Associated Industries of Massachusetts	End User			Roger Borghesani
AVANGRID: CMP/UI	Transmission	Eric Stinneford	Alan Trotta	
Belmont Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Block Island Power Company	Supplier	Dave Cavanaugh		
Boylston Municipal Light Department	Publicly Owned		Brian Thomson	
BP Energy Company	Supplier			Nancy Chafetz
Braintree Electric Light Department	Publicly Owned			Dave Cavanaugh
Calpine Energy Services, LP	Supplier	John Flumerfelt	Brett Kruse	Bill Fowler
Chester Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned		Brian Thomson	
CLEAResult Consulting, Inc.	AR-DG	Doug Hurley		
Competitive Energy Services, LLC	Supplier			Glenn Poole
Concord Municipal Light Plant	Publicly Owned		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop. (CMEEC)	Publicly Owned	Brian Forshaw		
Conservation Law Foundation	End User	David Ismay		
Consolidated Edison Energy, Inc. (ConEd)	Supplier	Jeff Dannels		
CPV Towantic, LLC	Generation	Dan Pierpont		
Cross-Sound Cable Company (CSC)	Supplier		Jose Rotger	
Danvers Electric Division	Publicly Owned		Dave Cavanaugh	
Direct Energy Business, LLC	Supplier			Nancy Chafetz
Dominion Energy Generation Marketing, Inc.	Generation	Michael Purdie	Jim Davis	
DTE Energy Trading, Inc.	Supplier			Nancy Chafetz
Dynegy Marketing and Trade, LLC	Supplier			Bill Fowler
Emera Maine	Transmission	Lisa Martin		
Emera Energy Services	Transmission	Sandi Hennequin		Bill Fowler
ENGIE Energy Marketing NA, Inc.	Generation	Joe Dalton		
Entergy Nuclear Power Marketing, LLC	Generation	Ken Dell Orto		Bill Fowler
Environmental Defense Fund	End User	Liz Delaney		
Eversource Energy	Transmission		Cal Bowie	
Exelon Generation Company	Supplier	Steve Kirk	Bill Fowler	
FirstLight Power Resources Management	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	Nancy Chafetz		
Generation Group Member	Generation		Abby Krich	Bob Stein
Georgetown Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Great River Hydro, LLC	AR-RG			Bill Fowler
Groton Electric Light Department	Publicly Owned		Brian Thomson	
Groveland Electric Light Department	Publicly Owned		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc.	Supplier		Bob Stein	Abby Krich
Harvard Dedicated Energy Limited	End User		Mike Macrae	Roger Borghesani; Paul Peterson; Doug Hurley
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned		Brian Thomson	
Holyoke Gas & Electric Department	Publicly Owned		Brian Thomson	
Hull Municipal Lighting Plant	Publicly Owned		Brian Thomson	
Ipswich Municipal Light Department	Publicly Owned		Brian Thomson	

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
FEBRUARY 2, 2018 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Littleton (MA) Electric Light and Waster Department	Publicly Owned		Dave Cavanaugh	
Long Island Lighting Company (LIPA)	Supplier		William Killgoar	
Maine Power LLC	Provisional Member	Jeff Jones		
Mansfield Municipal Electric Department	Publicly Owned		Brian Thomson	
Marblehead Municipal Light Department	Publicly Owned		Brian Thomson	
Massachusetts Attorney General's Office (MA AG)	End User	Fred Plett	Christina Belew	
Mass. Municipal Wholesale Electric Company	Publicly Owned	Brian Thomson		
Mercuria Energy America, Inc.	Supplier			Nancy Chafetz
Merrimac Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Middleborough Gas & Electric Department	Publicly Owned		Brian Thomson	
Middleton Municipal Electric Department	Publicly Owned		Dave Cavanaugh	
National Grid	Transmission		Tim Martin	
Nautilus Power, LLC	Generation		Bill Fowler	
New Hampshire Electric Cooperative (NHEC)	Publicly Owned			Brian Forshaw
New Hampshire Office of Consumer Advocate (NH OCA)	End User	Paul Peterson		
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
NRG Power Marketing LLC	Generation		Pete Fuller	
Pascoag Utility District	Publicly Owned		Dave Cavanaugh	
Paxton Municipal Light Department	Publicly Owned		Brian Thomson	
Peabody Municipal Light Department	Publicly Owned		Brian Thomson	
PowerOptions, Inc.	End User	Cindy Arcate		
Princeton Municipal Light Department	Publicly Owned		Brian Thomson	
PSEG Energy Resources & Trade LLC	Supplier	Joel Gordon		
Reading Municipal Light Department	Publicly Owned			Brian Forshaw
Repsol Energy North America Company	Gas Industry Part.		Nancy Chafetz	
Rowley Municipal Lighting Plant	Publicly Owned		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned		Brian Thomson	
Shipyard Brewing LLC	End User		Stacy Dimou	
Shrewsbury Electric & Cable Operations	Publicly Owned		Brian Thomson	
South Hadley Electric Light Department	Publicly Owned		Brian Thomson	
Sterling Municipal Electric Light Department	Publicly Owned		Brian Thomson	
Stowe Electric Department	Publicly Owned		Dave Cavanaugh	
Taunton Municipal Lighting Plant	Publicly Owned		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned		Brian Thomson	
The Energy Consortium	End User	Roger Borghesani		Paul Peterson, Fred Plett Doug Hurley
Utility Services Inc.	End User			Paul Peterson
Vermont Electric Power Company	Transmission	Frank Ettori		
Vermont Energy Investment Corporation	AR-LR		Doug Hurley	
Vermont Public Power Supply Authority	Publicly Owned			Brian Forshaw
Verso Energy Services LLC	Generation	Glenn Poole		
Wakefield Municipal Gas & Light Department	Publicly Owned		Brian Thomson	
Wallingford DPU Electric Division	Publicly Owned		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned		Brian Thomson	
Westfield Gas & Electric Department	Publicly Owned		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG	Bill Fowler		

CONSENT AGENDA

Reliability Committee

From the notice of actions of the Reliability Committee's ***February 13, 2018*** meeting,[1] dated February 14, 2018, which has been previously circulated:

1. **Revisions to PP 5-1 and PP 5-6 (Updates, Clarifications, and Practice- and Procedure-Conforming Revisions)**

   Support revisions to Planning Procedure (PP) 5-1 (Procedure for Review of Governance Participant's Proposed Plans) and PP-5-6 (Interconnection Planning Procedure for Generation and Elective Transmission Upgrades), including updates to references, updates regarding wind farm analysis, form updates related to under frequency requirements, revisions related to NERC and NPCC data collection, and other practice-conforming revisions, as recommended by the Reliability Committee at its February 13, 2018 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.

Markets Committee

From the notice of actions of the Markets Committee's ***January 9, 2018*** meeting,[2] dated January 10, 2018, which has been previously circulated:

2. **Revisions to Tariff § I.2.2 and MR1 § III (FCM Enhancements – Phase II)**

   Support revisions to Tariff Section I.2.2 and Section III of Market Rule 1 for the FCM Enhancements – Phase II Project, as recommended by the Markets Committee at its January 9, 2018 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 unanimously with two abstentions in the Supplier Sector.

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

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

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Paul Belval, NEPOOL Counsel

DATE: February 23, 2018

RE: ISO New England Financial Assurance Policy – Defined Terms and Clean-up Changes

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The Participants Committee will be asked at its March 2 meeting to support changes to the ISO Financial Assurance Policy (the "FAP") to conform the FAP to changes in the ISO Tariff and the Market Rules that have been approved by the NEPOOL Markets Committee. The proposed changes are Attachment A to this memorandum.

The Markets Committee approved a change to the definition of "Commercial Capacity" in Section I.2.2. of the ISO Tariff as part of the FCM Enhancements II project, and that change is on the Consent Agenda for the Participants Committee's March 2 meeting. One of the proposed changes to the FAP, in Section VII.B.3, conforms to that change. The other changes, in Section VII.C of the FAP, update cross-references to the Market Rules. The current cross-references in that FAP section will become obsolete on June 1, 2018. The Budget & Finance Subcommittee discussed these changes during its February 9, 2018 teleconference, and there were no objections to these changes.

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

> RESOLVED, that the Participants Committee supports the clean-up changes to the ISO Financial Assurance Policy, 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.

Commercial Capacity~~, for the purposes of the ISO New England Financial Assurance Policy,~~ is ~~defined in Section VII.A of that policy~~capacity that has achieved FCM Commercial Operation.

Commission is the Federal Energy Regulatory Commission.

Commitment Period is (i) for a Day-Ahead Energy Market commitment, a period of one or more contiguous hours for which a Resource is cleared in the Day-Ahead Energy Market, and (ii) for a Real-Time Energy Market commitment, the period of time for which the ISO indicates the Resource is being committed when it issues the Dispatch Instruction. If the ISO does not indicate the period of time for which the Resource is being committed in the Real-Time Energy Market, then the Commitment Period is the Minimum Run Time for an offline Resource and one hour for an online Resource.

Common Costs are those costs associated with a Station that are avoided only by the clearing of the Static De-List Bids, the Permanent De-List Bids, or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

Completed Application is an Application that satisfies all of the information and other requirements of the OATT, including any required deposit.

Compliance Effective Date is the date upon which the changes in the predecessor NEPOOL Open Access Transmission Tariff which have been reflected herein to comply with the Commission's Order of April 20, 1998 became effective.

Composite FCM Transaction is a transaction for separate resources seeking to participate as a single composite resource in a Forward Capacity Auction in which multiple Designated FCM Participants provide capacity, as described in Section III.13.1.5 of Market Rule 1.

Conditional Qualified New Resource is defined in Section III.13.1.1.2.3(f) of Market Rule 1.

Confidential Information is defined in Section 2.1 of the ISO New England Information Policy, which is Attachment D to the Tariff.

Nominated Consumption Limit is the consumption level specified by the Market Participant for a Dispatchable Asset Related Demand as adjusted in accordance with the provisions of Section III.13.7.5.1.3.

Non-Commercial Capacity is the capacity of a New Capacity Resource or an ~~increment of an~~ Existing Capacity Resource, or portion thereof, ~~that is treated as a New Capacity Resource in the Forward Capacity Auction and~~ that has not achieved FCM Commercial Operation ~~been declared commercial and has not had its capacity rating verified by the ISO~~.

Non-Commercial Capacity Cure Period is the time period described in Section VII.D of the ISO New England Financial Assurance Policy.

Non-Commercial Capacity Financial Assurance Amount (Non-Commercial Capacity FA Amount) is the financial assurance amount held on Non-Commercial Capacity cleared in a Forward Capacity Auction as calculated in accordance with Section VII.B.2 of the ISO New England Financial Assurance Policy.

Non-Designated Blackstart Resource Study Cost Payments are the study costs reimbursed under Section 5.3 of Schedule 16 of the OATT.

Non-Dispatchable Resource is any Resource that does not meet the requirements to be a Dispatchable Resource .

Non-Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Non-Hourly Requirements are determined in accordance with Section III.A(ii) of the ISO New England Financial Assurance Policy, which is Exhibit 1A of Section I of the Tariff.

Non-Incumbent Transmission Developer is a Qualified Transmission Project Sponsor that: (i) is not currently a PTO; (ii) has a transmission project listed in the RSP Project List; and (iii) has executed a Non-Incumbent Transmission Developer Operating Agreement. "Non-Incumbent Transmission Developer" also includes a PTO that proposes the development of a transmission facility not located

New England Financial Assurance Policy, beginning at 8 a.m. (Eastern Time) 30 days after Commission approval of the request to defer, an amount equal to the amount that would apply to a resource that has not achieved commercial operation one year after the start of a Capacity Commitment Period in which it has a Capacity Supply Obligation, as calculated pursuant to Section VII.B.2.a or Section VII.B.2.b, as applicable.

3. Return of Non-Commercial Capacity Financial Assurance

Non-Commercial Capacity cleared in a Forward Capacity Auction up to and including the eighth Forward Capacity Auction that is declared commercial and has had its capacity rating verified by the ISO or otherwise becomes a Resource meeting the definition of ~~"~~Commercial Capacity~~" above~~, or that is declared commercial and had a part of its capacity rating verified by the ISO and the applicable Designated FCM Participant indicates no additional portions of that Resource will become commercial, that portion of the Resource shall no longer be considered Non-Commercial Capacity under the ISO New England Financial Assurance Policy and will instead become subject to the provisions of the ISO New England Financial Assurance Policy relating to Commercial Capacity; provided that in either such case, the Designated FCM Participant will need to include in the calculation of its Financial Assurance Requirement an amount attributable to any remaining Non-Commercial Capacity.

Once Non-Commercial Capacity associated with a Capacity Supply Obligation awarded in the ninth Forward Capacity Auction and all Forward Capacity Auctions thereafter becomes commercial, the Non-Commercial Capacity Financial Assurance Amount for any remaining Non-Commercial Capacity shall be recalculated according to the process outlined above for Non-Commercial Capacity participating in the ninth Forward Capacity Auction and all Forward Capacity Auctions thereafter.

4. Credit Test Percentage Consequences for Provisional Members

If a Provisional Member is required to provide additional financial assurance under the ISO New England Financial Assurance Policy solely in connection with (A) a supply offer of Non-Commercial Capacity into any Forward Capacity Auction and (B) its obligation to pay Participant Expenses as a Provisional Member, and that Provisional Member is maintaining the amount of additional financial assurance required under the ISO New England Financial Assurance Policy, then the provisions of Section III.B of the ISO New England Financial Assurance Policy relating to the consequences of that

Market Participant's Market Credit Test Percentage equaling 80 percent (80%) or 90 percent (90%) shall not apply to that Provisional Member.

C. FCM Capacity Charge Requirements

The FCM Capacity Charge Requirements shall be calculated for the current month and all previously unbilled months. The FCM Capacity Charge Requirements shall be the product of the Estimated Capacity Load Obligation times the FCM Charge Rate for the applicable Capacity Zone. For purposes of this calculation, the Estimated Capacity Load Obligation shall be the Capacity Requirement from the latest available month, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supplied FCA Resource Designations for the applicable month. For purposes of this calculation, the FCM Charge Rate for a Capacity Zone will be calculated using the same methodology described in Section III.13.7.~~3~~ 5 of Market Rule 1 for deriving the Net Regional Clearing Price, with the exceptions that the FCM Charge Rate: will not subtract PER adjustments ~~or account for adjustments related to any Demand Resource Performance Penalties in excess of Demand Resource Performance Incentives, each~~ as described in ~~Section III.13.7.3 of Market Rule 1~~such section; and will include the balance of the CTR fund after the value of specifically allocated CTRs has been paid, as described in Section III.13.7.~~3~~5.3.1 of Market Rule 1, but without the adjustments for PER ~~and for Demand Resource Performance Penalties net of Demand Resource Incentives~~ described in such section.

D. Loss of Capacity and Forfeiture of Non-Commercial Capacity Financial Assurance

If a Designated FCM Participant that has acquired Capacity Supply Obligations associated with Non-Commercial Capacity is in default under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy and does not cure such default within the appropriate cure period, or if a Designated FCM Participant is in default under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy during the period between the day that is three Business Days before the FCM Deposit is required and the first day of the Forward Capacity Auction and does not cure such default within the appropriate cure period, then: (i) beginning with the first Business Day following the end of such cure period that Designated FCM Participant will be assessed a default charge of one percent (1%) of its total Non-Commercial Capacity Financial Assurance Amount at that time for each Business Day that elapses until it cures

Summary of ISO New England Board and Committee Meetings

March 2, 2018 Participants Committee Meeting

Since the last update, the Compensation and Human Resources Committee met by teleconference on February 6. On February 15, the Audit and Finance Committee, the Markets Committee, and the Board of Directors each met in Holyoke.

The Compensation and Human Resources Committee reviewed updated survey data regarding employers' proposed 2018 executive compensation. During the executive session, the Committee discussed corporate performance for 2017 and officer compensation for 2018.

The Audit and Finance Committee met with the investment advisors for the Company's benefits plan assets and 401(k) plan and received an analysis of investment options and details regarding the mix, cost, and performance of offerings. The investment performance costs continue to be reasonable with a weighted average expense ratio, and funds are currently scoring "in good standing" based on investment advisors' scoring methodology. The Committee then reviewed significant accounting estimates used in the Company's budgeting and financial statements, including earnings and discount rates, health care trends, and depreciation. After considering the impact of these accounting estimates, the Committee approved the rates. Finally, the Committee received a report on current cyber security areas of focus.

The Markets Committee was provided with an update on the results of the Annual Forward Capacity Auction and the resources retained for reliability and the effect on the market. Next, the Committee discussed pleadings submitted by various parties in response to the Competitive Auctions with Sponsored Policy Resources proposal submitted to FERC. The Committee also received an update on new resources, and discussed the recent court decision that remanded to FERC the decision on FCM's seven-year price lock for new resources.

The Board of Directors received reports from the standing committees and the Chief Executive Officer. The Board was provided with an update on the results of the Annual Forward Capacity Auction. It was reported that the Auction concluded with sufficient resources to meet peak demand in 2021-2022, and preliminary results indicate the clearing price was the lowest in five years due to a surplus of capacity in the region. The Board then considered potential topics to discuss at their next meeting with regard to strategic planning and review of the Company's five-year business plan. During executive session, the Board approved corporate performance results for 2017, officer compensation for 2018, and elected Maria Gulluni to service as Vice President, General Counsel and Corporate Secretary beginning June 1.

NEPOOL Participants Committee Report

March 2018

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Energy market value over the period was $342M, down $998M from January and up $38M from February 2017
  - February natural gas prices over the period were 67% lower than January 2018 average values
  - Average RT Hub Locational Marginal Prices ($41.83/MWh) over the period were 61% lower than January 2018 averages
  - Average February 2018 natural gas prices and RT Hub LMPs over the period were up 36% and 49%, respectively, from February 2017 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 98.7% during February, down slightly from 99% during January*
    - The minimum value for the month was 93.5% on Sunday, February 4**

Data are through February 21, 2018 (RT NCPC through Feb. 20) unless otherwise noted.

Underlying natural gas data furnished by:

ICE Global markets in clear view

*DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market
**Daily values shown on slide 33

Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - February NCPC payments over the period totaled $1.5M over the period, down $18.7M from January 2018 and down $5.6M from February 2017
    - First Contingency* payments totaled $1.5M, down $17M from January
      - $1.5M paid to internal resources, down $16.9M from January
        - » $719K charged to DALO, $443K to RT Deviations, $364K to RTLO
      - $5K paid to resources at external locations, down $65K from January
        - » $5K to RT Deviations
    - Second Contingency payments were zero, down $1.7M from January
  - NCPC payments over the period as percent of Energy Market value were 0.4%

*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $135K; Rapid Response Pricing (RRP) Opportunity Cost - $99K; Posturing - $82K; Generator Performance Auditing (GPA) - $47K;**

Highlights, cont.

- 2017 Economic Study draft report scheduled for 2nd quarter review by the Planning Advisory Committee (PAC)
- The twelfth Forward Capacity Auction (FCA #12) was held on February 5-6
  - Auction results will be filed with the FERC by the end of February
  - FCA #12 auction results and a technical discussion on the resources retained for reliability will be presented at the March Reliability Committee meeting
- The March 15 PAC meeting will include a presentation of zonal boundary determinations for FCA #13 and an update on the 2018 long-term load, photovoltaic, and energy-efficiency forecasts

Forward Capacity Market (FCM) Highlights

- CCP #8 (2017-2018)
  - Monthly activities continue
  - New, non-commercial resources are attempting to cover in the monthly activities
- CCP #9 (2018-2019)
  - Third and final annual reconfiguration auction will be March 1-5, and results to be posted by March 19
- CCP #10 (2019-2020)
  - Second bilateral transaction window will be May 2-4, and results to be posted by June 8
  - Second reconfiguration auction will be August 1-3, and results to be posted by August 17
  - Third bilateral transaction window will be December 5-7, and results to be posted by January 11, 2019

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP #11 (2020-2021)
  - First bilateral transaction window will be April 4-6
    - Pending FERC approval, seasonal and annual bilaterals will no longer be available CCP's beginning June 1, 2020
  - First reconfiguration auction will be June 1-5, and results to be posted by June 19
- CCP #12 (2021-2022)
  - Auction was held on February 5-6
    - FERC auction results filing to be made by the end of February
    - Auction results summary will be presented at the March RC meeting, including a technical discussion on the resources retained for reliability

FCM Highlights, cont.

- CCP #13 (2022-2023)
  - Preliminary capacity zones were discussed at the PAC in November and final capacity zones to be decided in April, after priced retirement and permanent delist bids are received
  - Enhancements to the FCM Participation Guide are underway
  - Qualification process has commenced and the Existing Capacity Challenge Window opened on February 23 and will close on March 2
  - Priced retirement and permanent delist bids are due March 23
  - Pending FERC approval, Substitution Auction participation election for existing resources is due March 23
    - Initial submittals to be manual via Ask ISO tickets and Forward Capacity Tracking System (FCTS) modifications are scheduled for Q2 2018
  - Upcoming Training
    - New Capacity Qualification Package Submittal Requirements: May 1
  - Renewable technology resource election cap is approximately 537 MW for FCA #13.
  - First meeting of the Installed Capacity Requirement/Local Sourcing Requirement stakeholder process was held on February 13

FERC Order 1000

- Intraregional Planning
  - 20 companies have achieved Qualified Transmission Project Sponsor (QTPS) status
  - 2018 Annual QTPS Certification
    - All 20 QTPSs submitted completed Annual QTPS Certification forms within the January 1 - 31 Certification Window
    - ISO notified the 20 QTPSs on February 16 that they met the 2018 Annual Certification requirements and, as such, QTPS status is maintained

Highlights, cont.

- The lowest 50/50 and 90/10 Spring Operable Capacity Margin Week is projected for week beginning May 12, 2018.

- The lowest 50/50 and 90/10 Preliminary Summer Operable Capacity Margin Week is projected for week beginning June 23, 2018.
  - **Note**: Preliminary Summer projections reflect current 2018-2019 Capacity Supply Obligations.

2017/18 Winter Reliability Program As of December 1, 2017

- **Oil Program**
  - As of December 1st, participation from 86 units for a total of 3.868 million barrels of oil
  - 2.867 million barrels of the total inventory on December 1 are eligible for compensation per the winter program rules
  - Total oil program cost exposure is expected to be $29.62M (@$10.33/barrel)
- **LNG Program**
  - As of December 1st, no participation
- **DR Program**
  - As of December 1st, participation from 3 assets providing 7.5 MW of interruption capability
  - Total DR program cost exposure is anticipated to be $23.2K

2017/18 Winter Program Usage (Feb. Data will be available during the week of March 5)

- Winter Program Oil Inventory Changes:
  - Dec 2017: 548,410 BBLs
  - Jan 2018: 524,447 BBLs

- Winter Program DR Events:
  - Dec 2017: None
  - Jan 2018: None

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (+5.7°F) Max: 72°F, Min: 10°F Precipitation: 3.76" – Above Normal Normal: 2.86" Snow: 9.8"	Hartford	Temperature: Above Normal (+5.0°F) Max: 77°F, Min: 9°F Precipitation: 5.13" – Above Normal Normal: 2.56" Snow: 8.3"

Peak Load:	18,164 MW	Feb 07, 2018	18:00 (ending)

MLCC2: None		
OP-4 : None		

NPCC Simultaneous Activation of Reserve Events:

Date	Area	MW
2/3	NYISO	1,302
2/16	NYISO	1,000

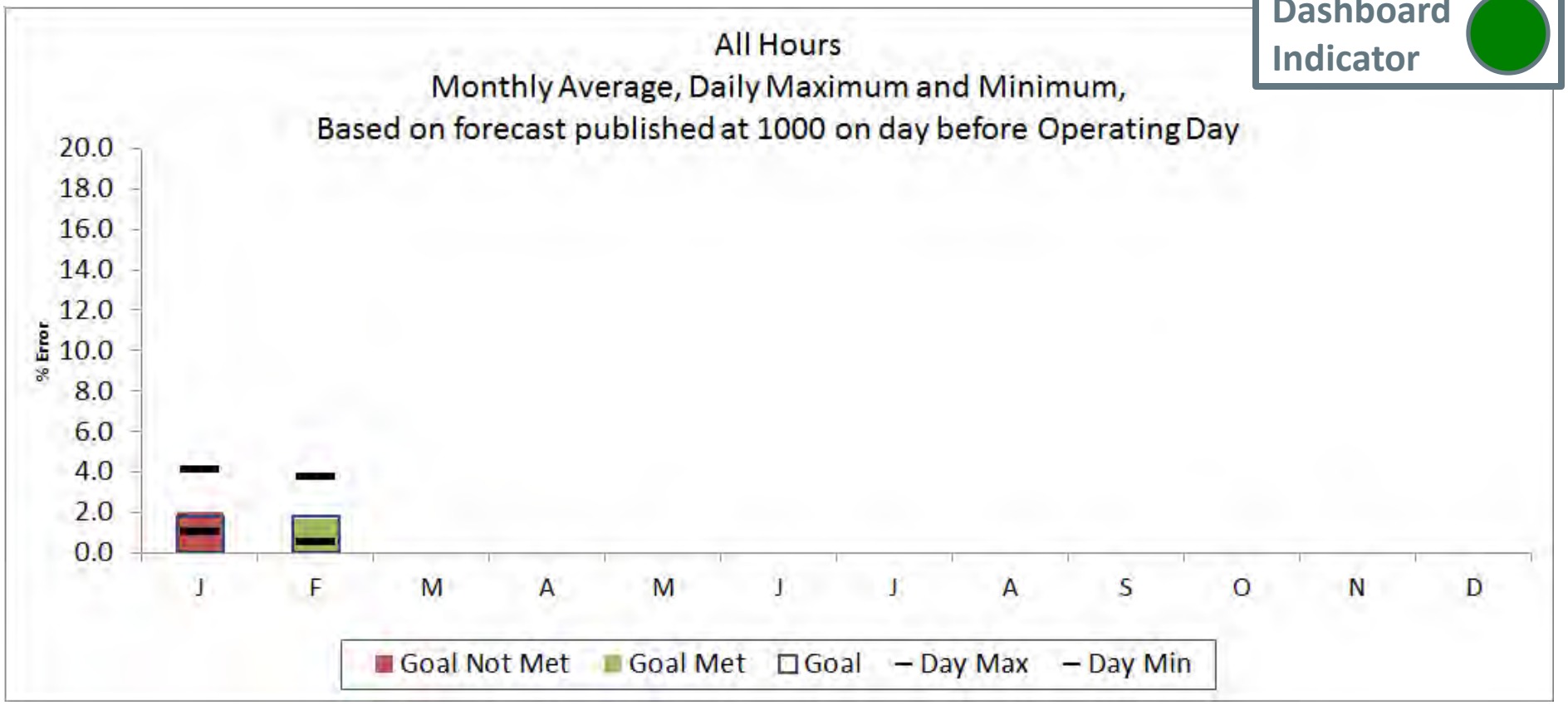
System Operations, cont.

Minimum Generation Warnings & Events:

None		

2018 System Operations - Load Forecast Accuracy

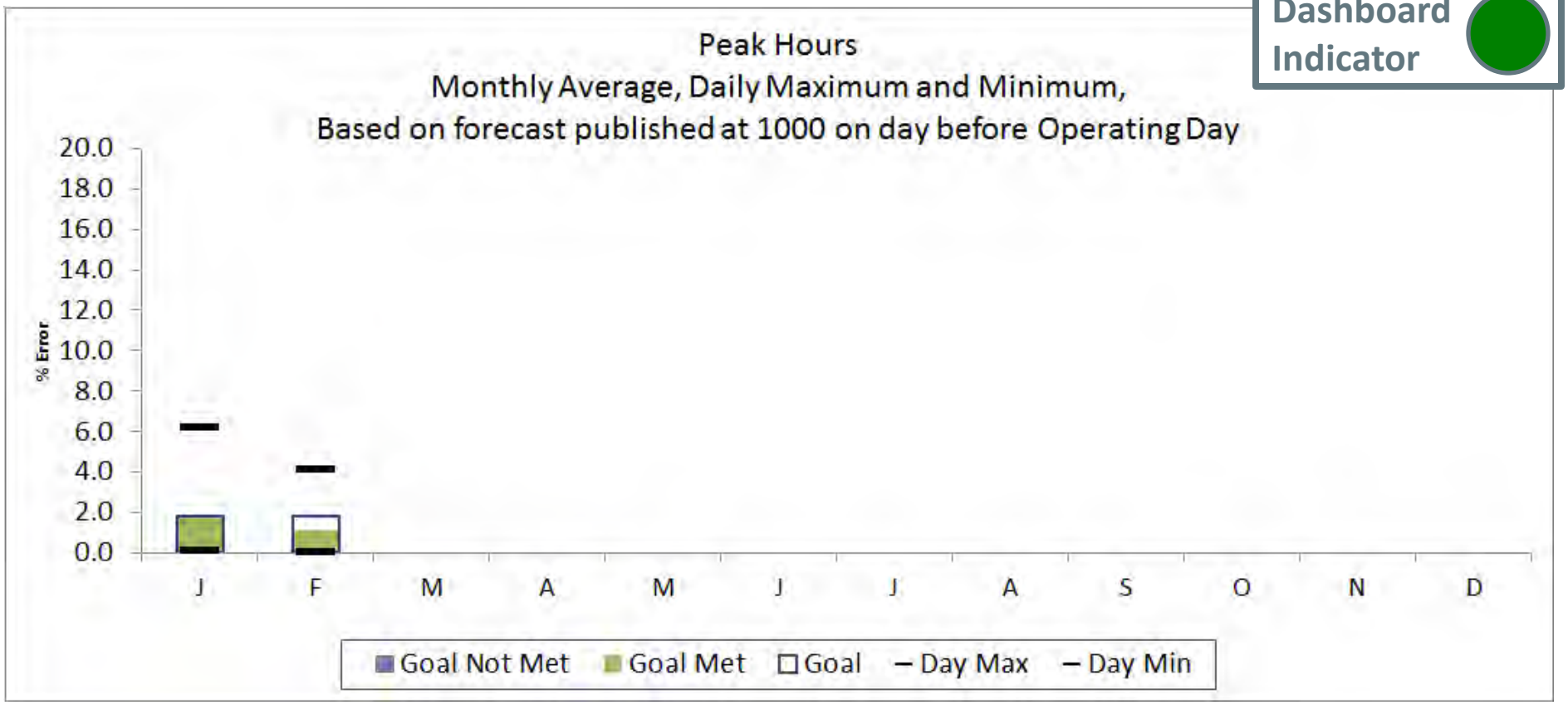
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.05	3.69											4.05
Day Min	1.02	0.53											0.53
MAPE	2.04	1.70											1.88
Goal	1.80	1.80											

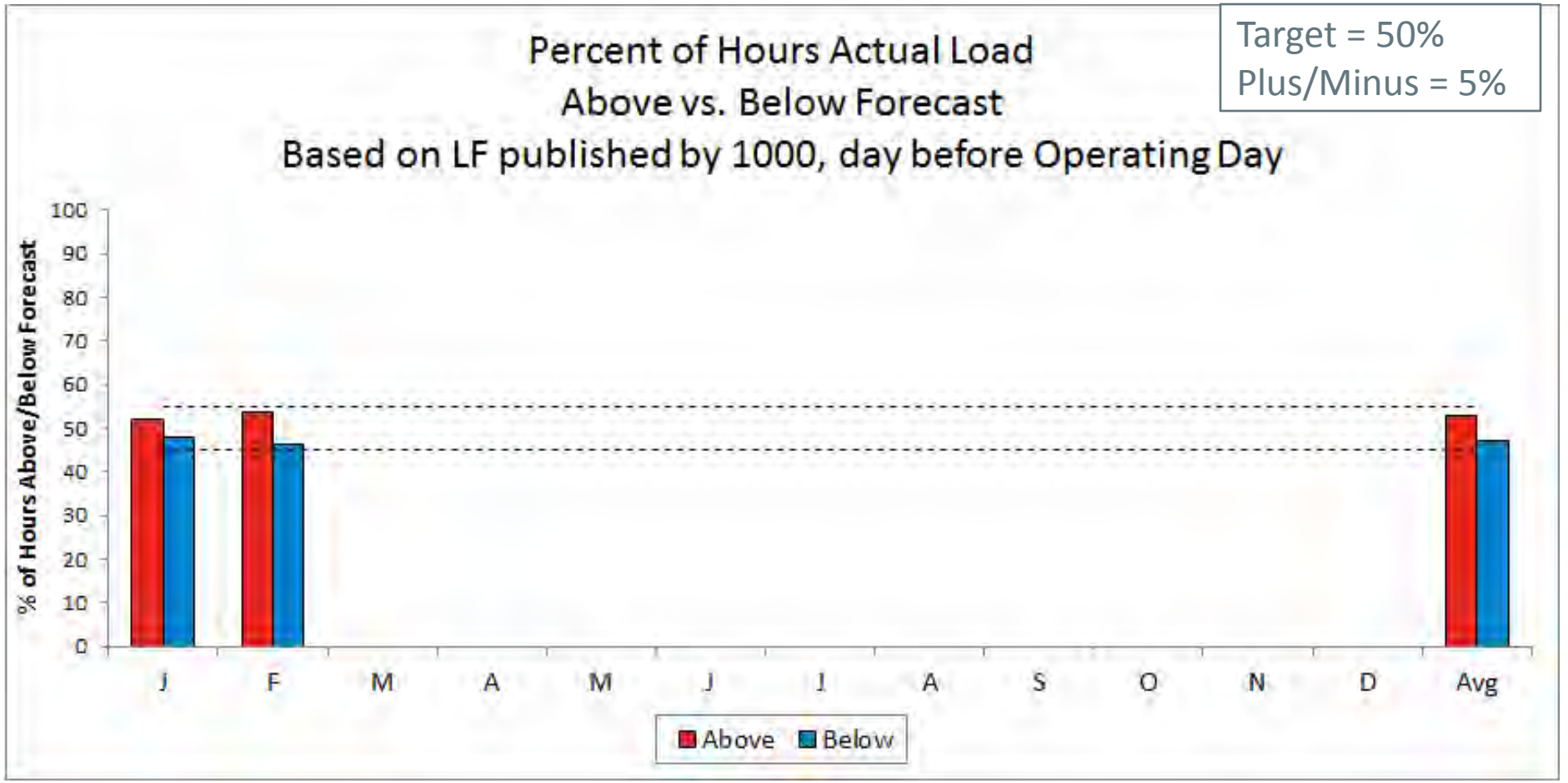
2018 System Operations - Load Forecast Accuracy, cont.

Dashboard Indicator



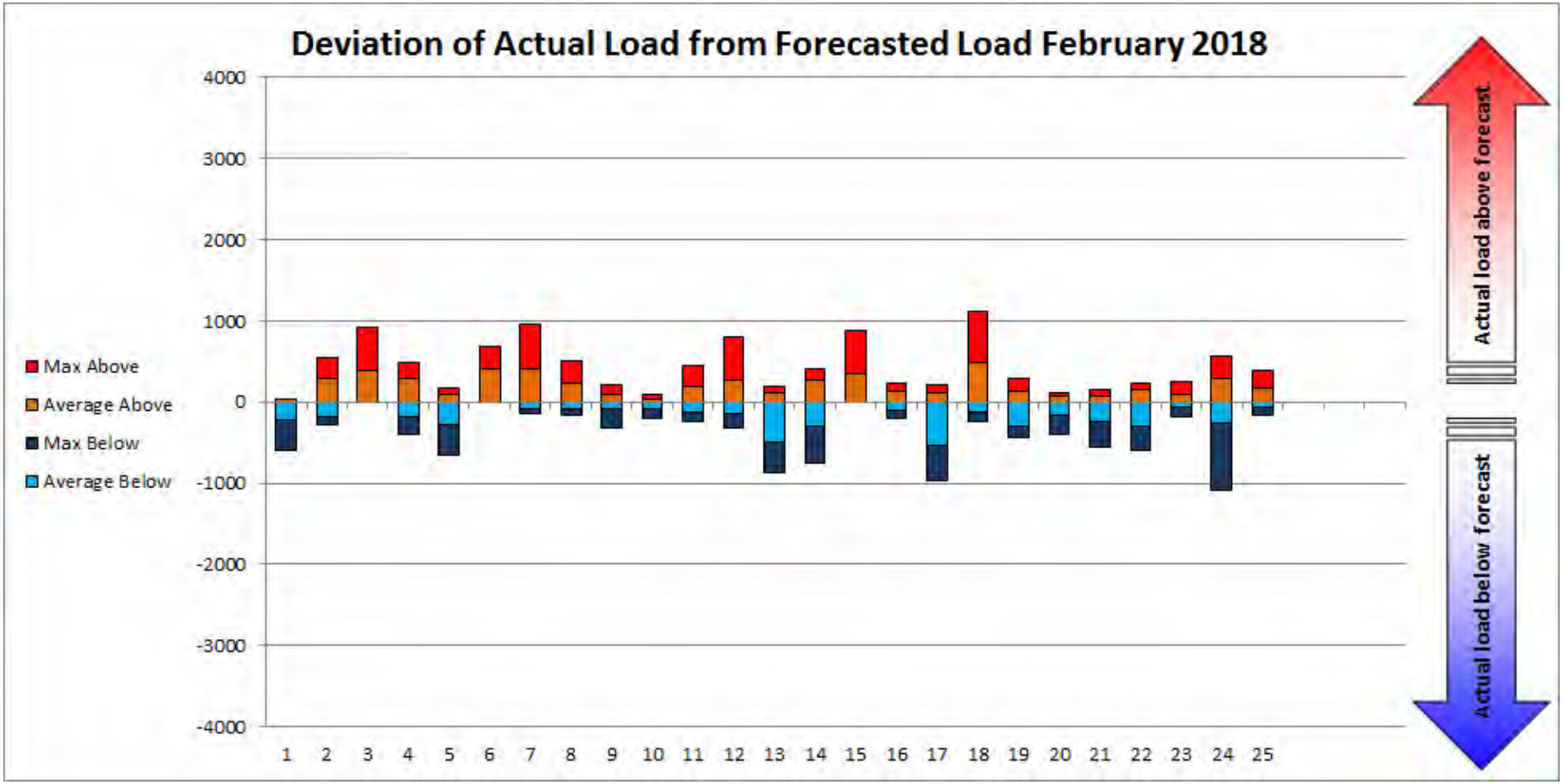
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	6.15	4.08											6.15
Day Min	0.04	0.03											0.03
MAPE	1.73	1.13											1.45
Goal	1.80	1.80											

2018 System Operations - Load Forecast Accuracy, cont.

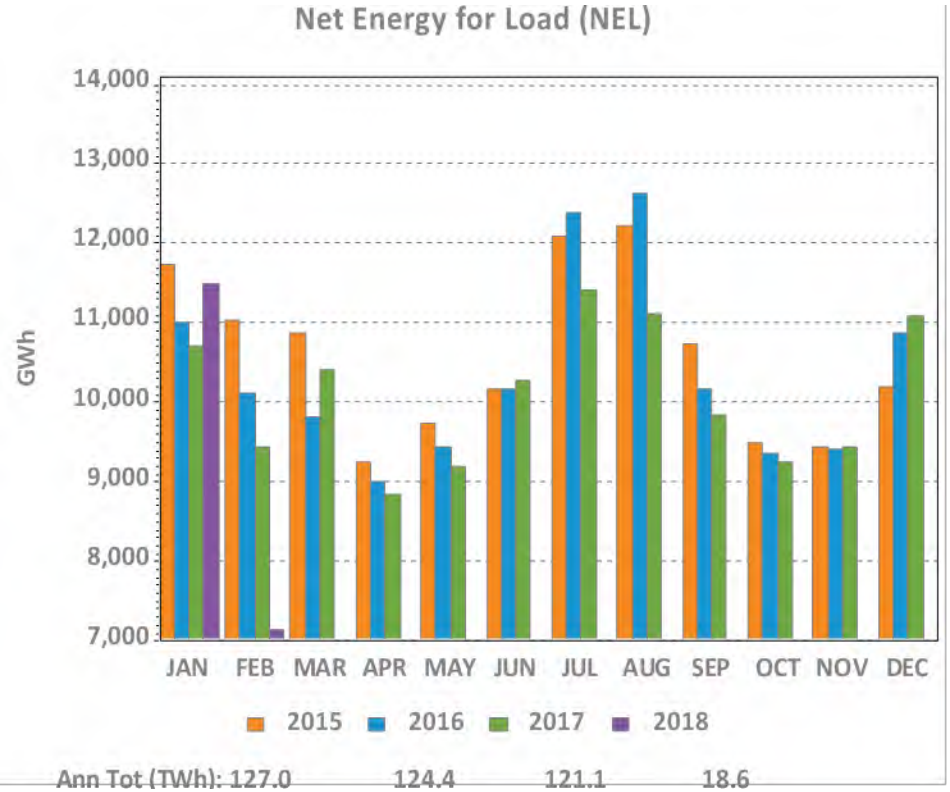


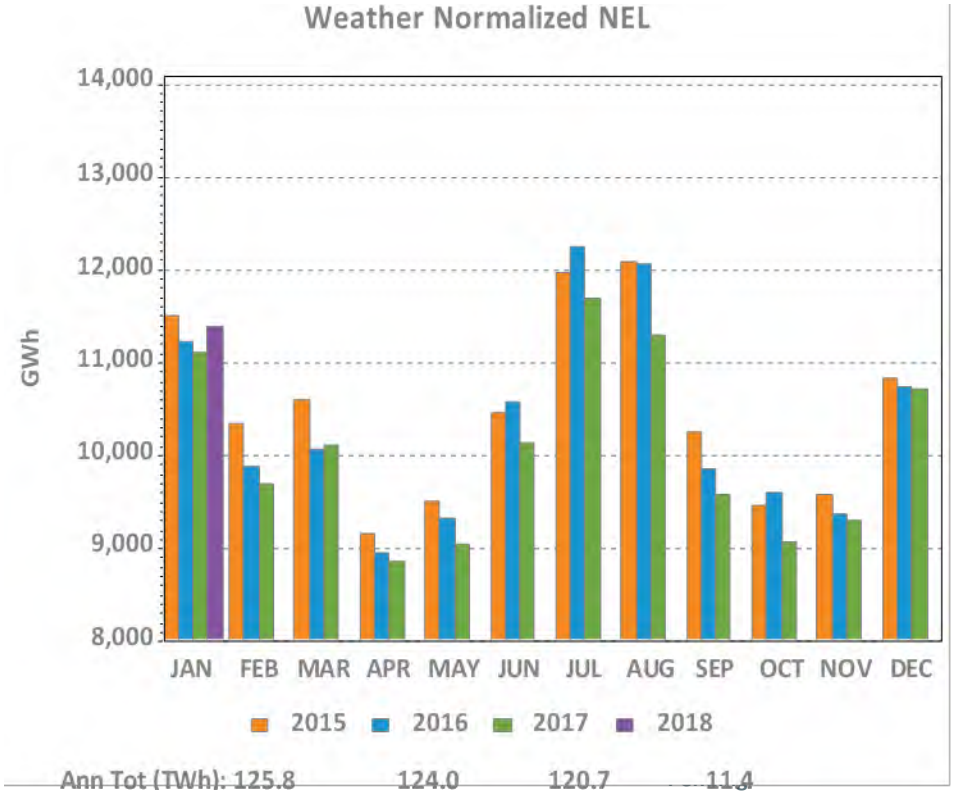
	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	52	53.5											53
Below %	48	46.5											47
Avg Above	222.2	184											222
Avg Below	-242.6	-157.9											-243
Avg All	0	35											17

2018 System Operations - Load Forecast Accuracy, cont.



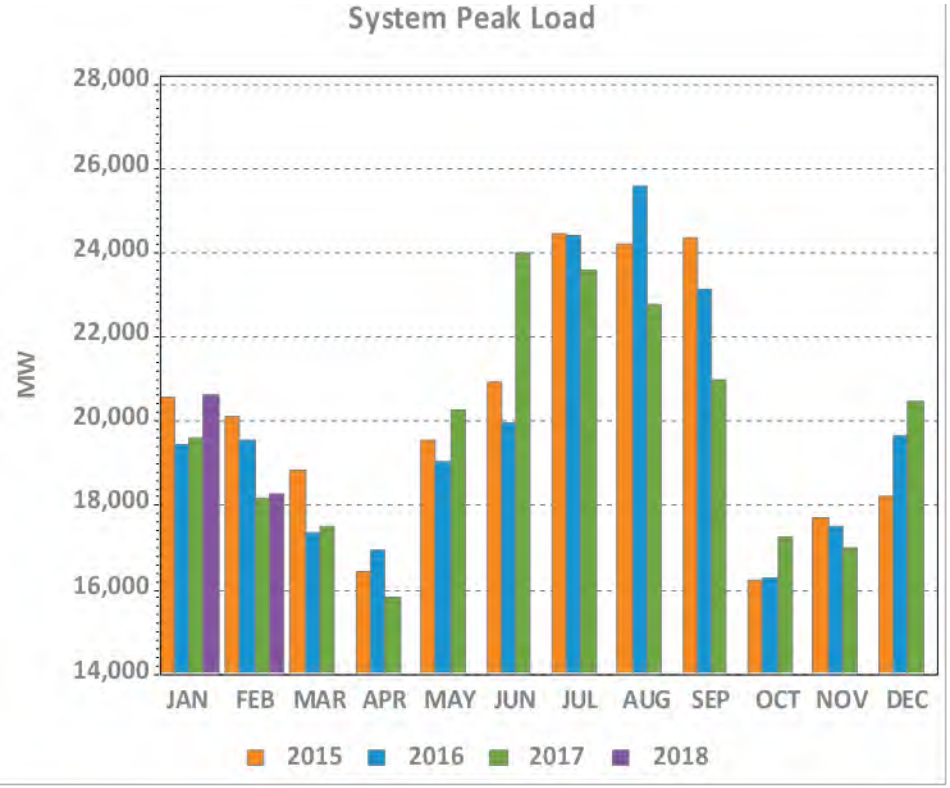
Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL

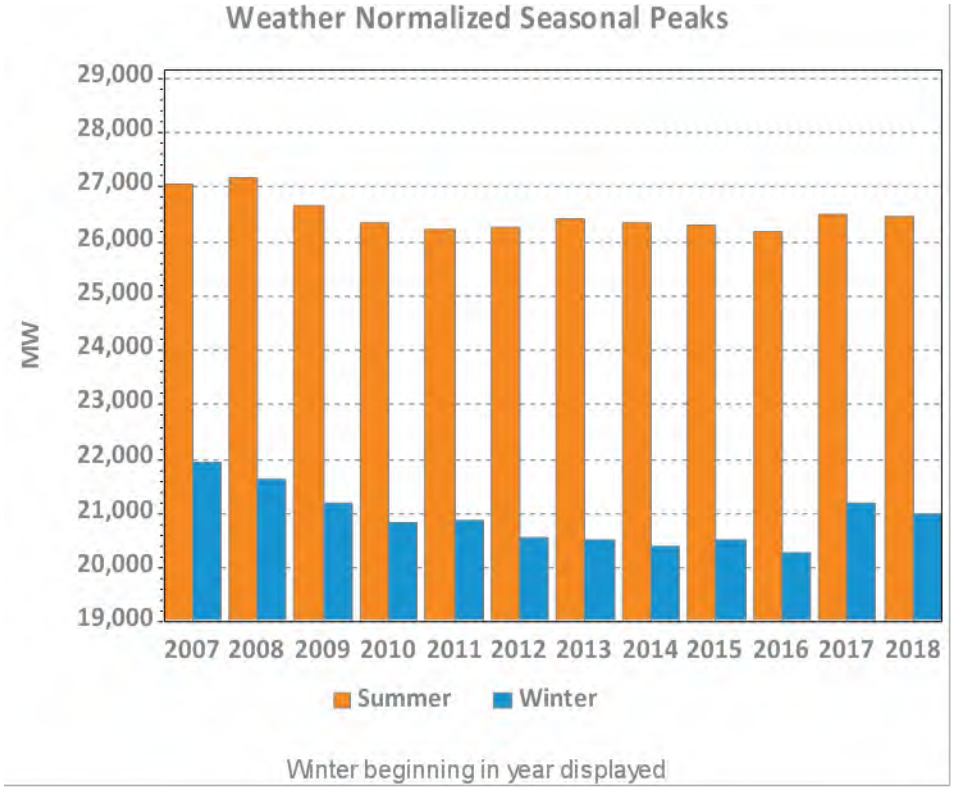




NEPOOL NEL is the total net energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation – pumping load + net interchange where imports are positively signed.
Current month's data may be preliminary. Weather normalized NEL may be reported on a one-month lag.

Monthly Peak Loads and Weather Normalized Seasonal Peak History



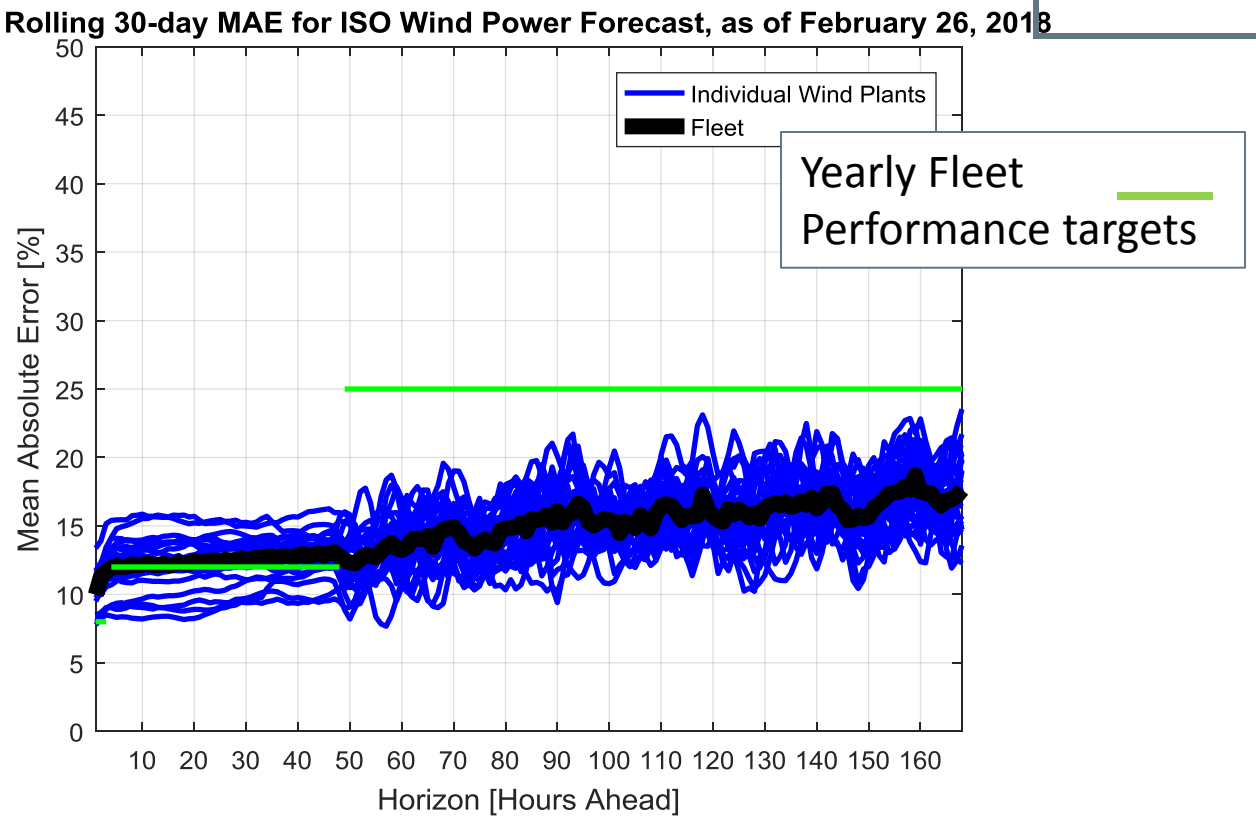


*Revenue quality metered value

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

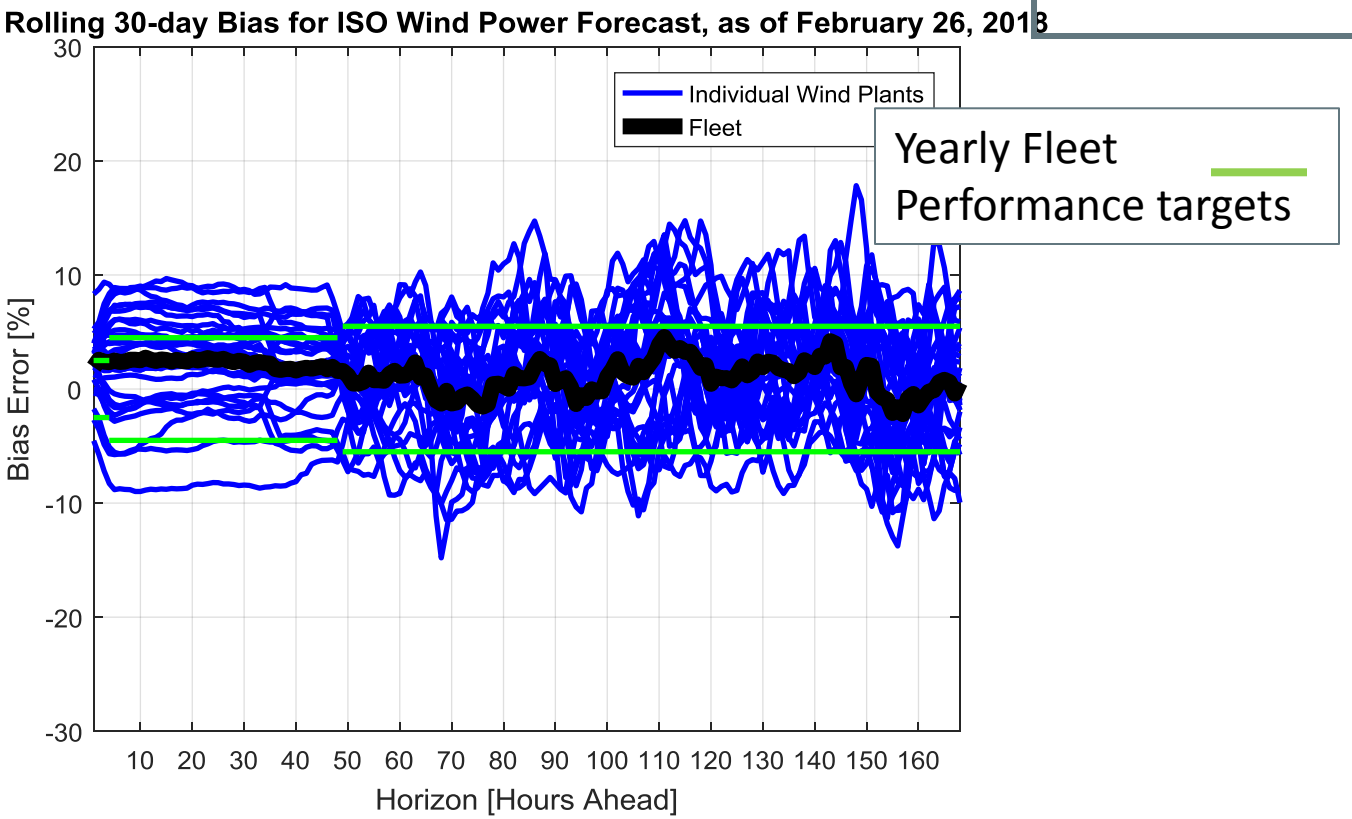
Dashboard Indicator



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 mostly well-within the yearly performance targets.

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

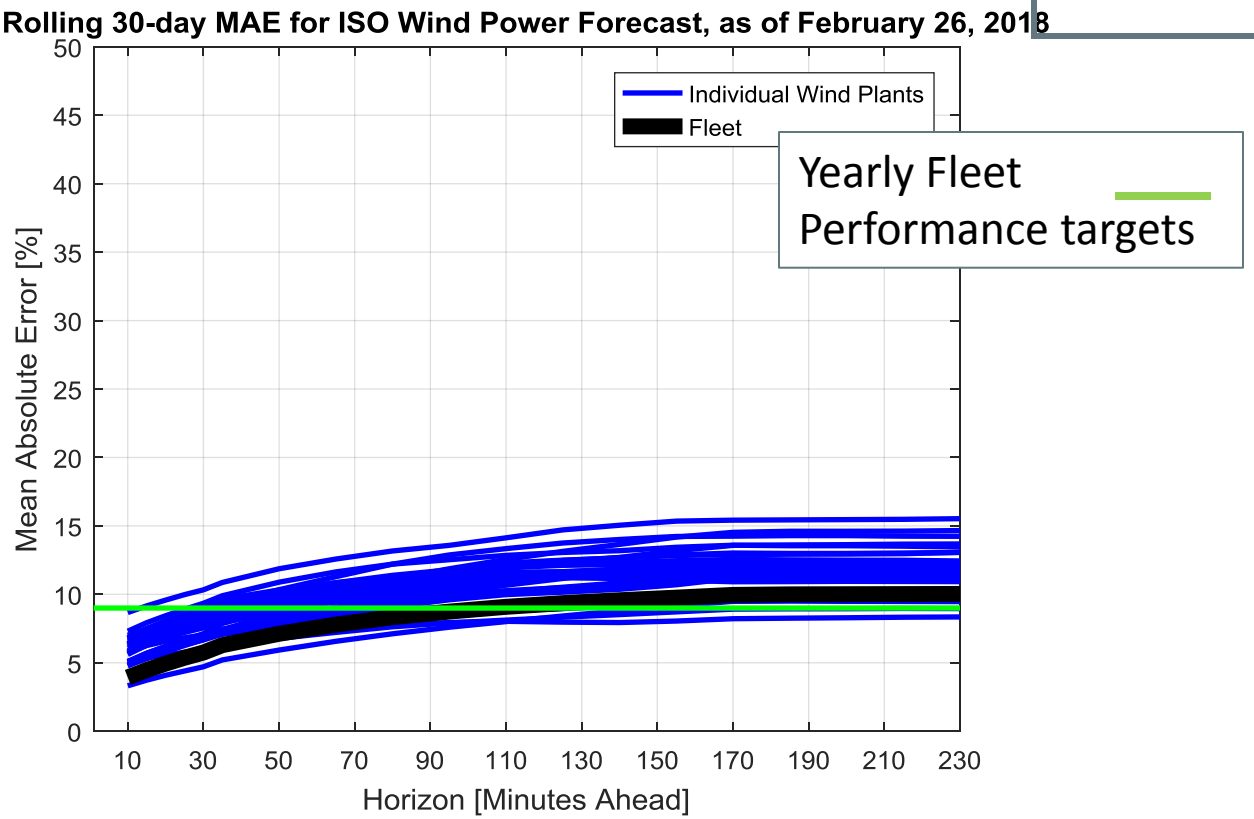
Dashboard Indicator



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



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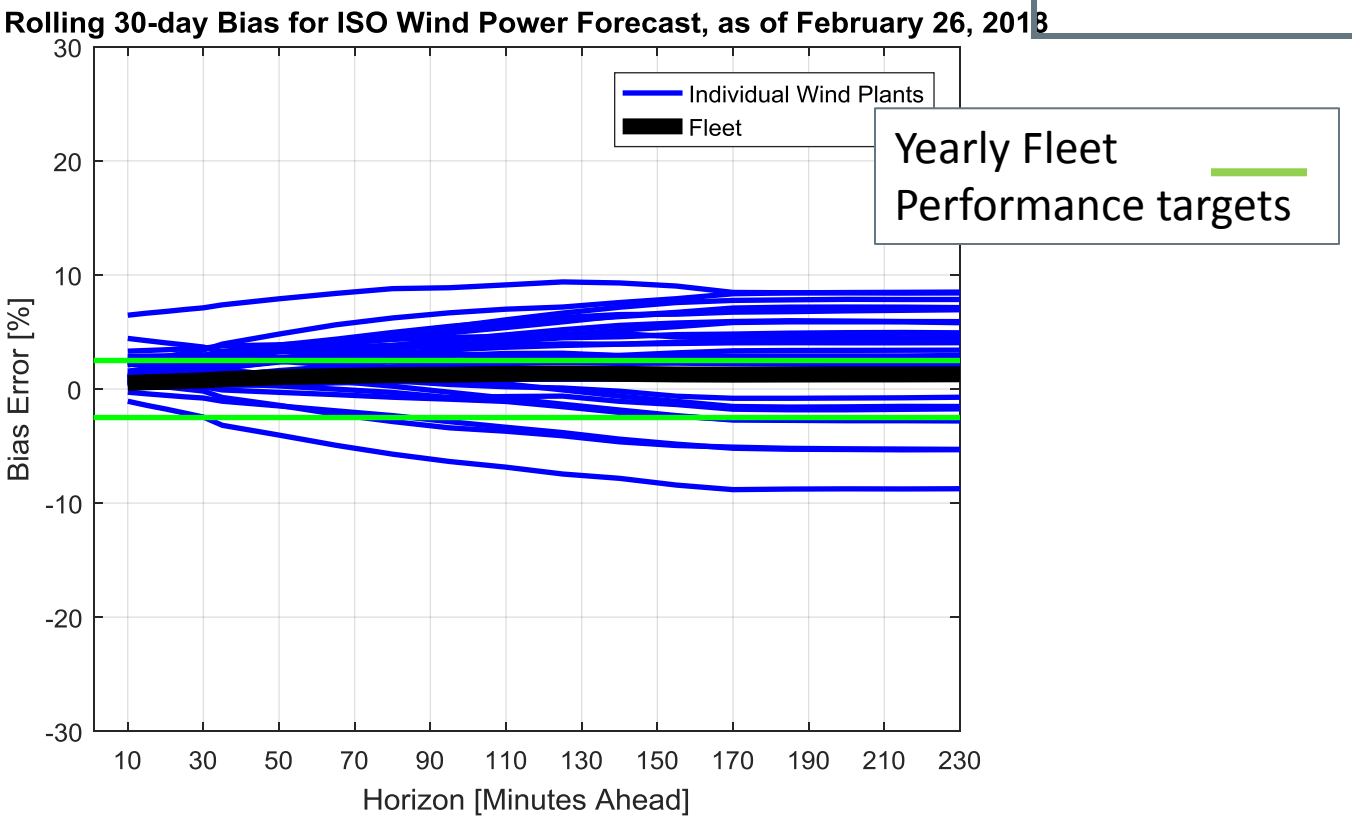
Wind Power Forecast Error Statistics: Short Term Forecast Bias

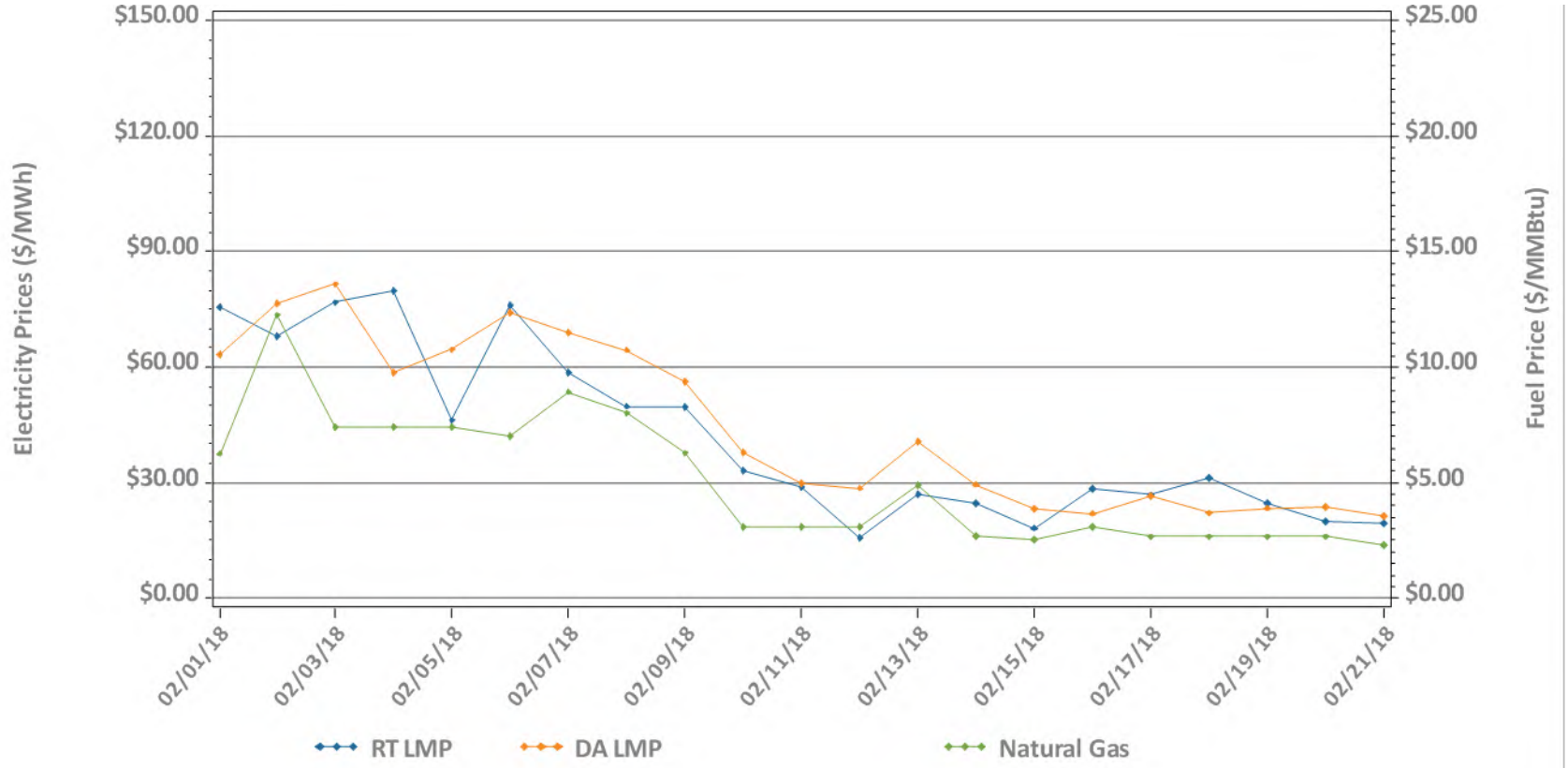
Dashboard Indicator



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: February 1-21, 2018

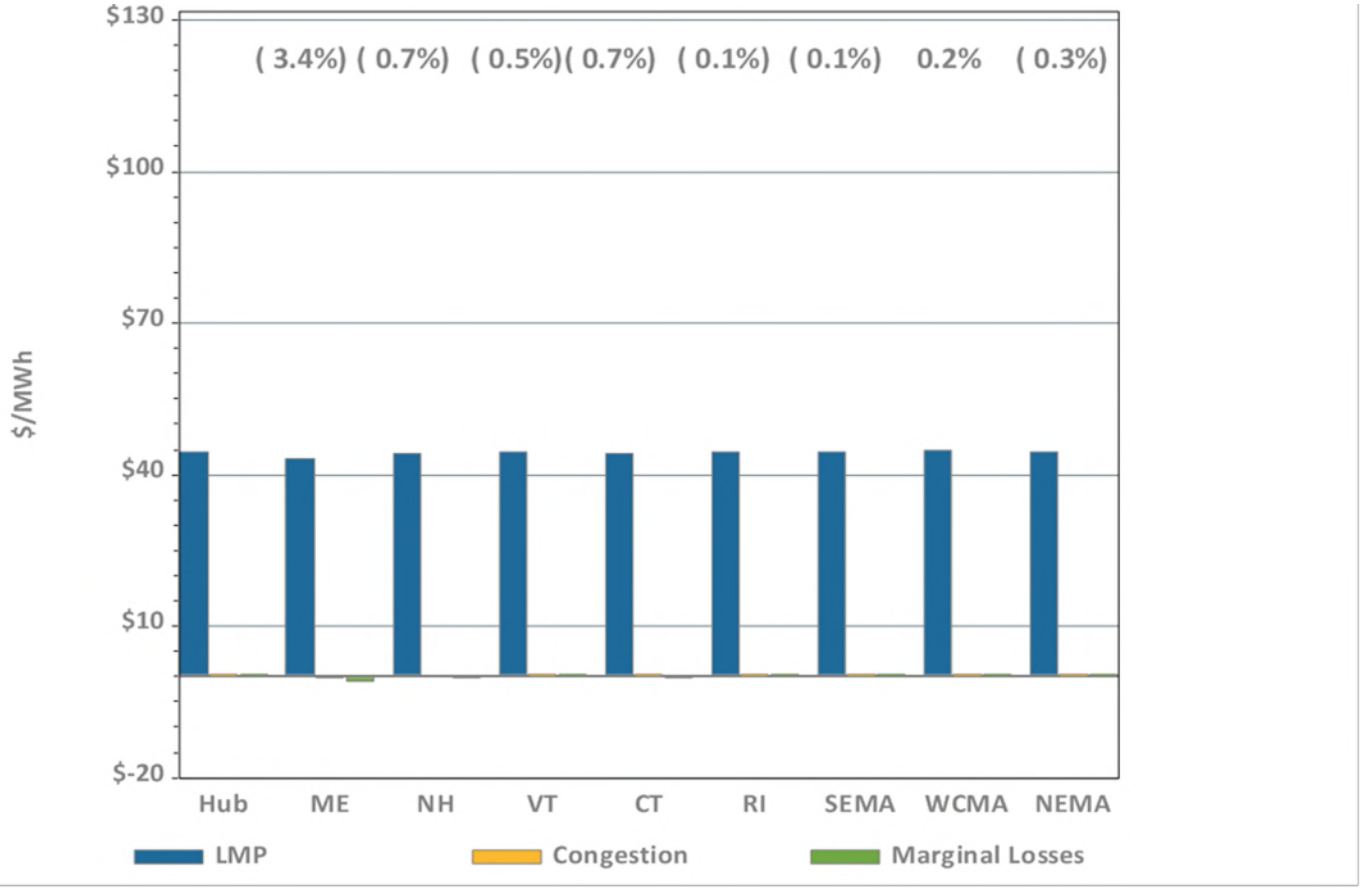


Underlyi

IC

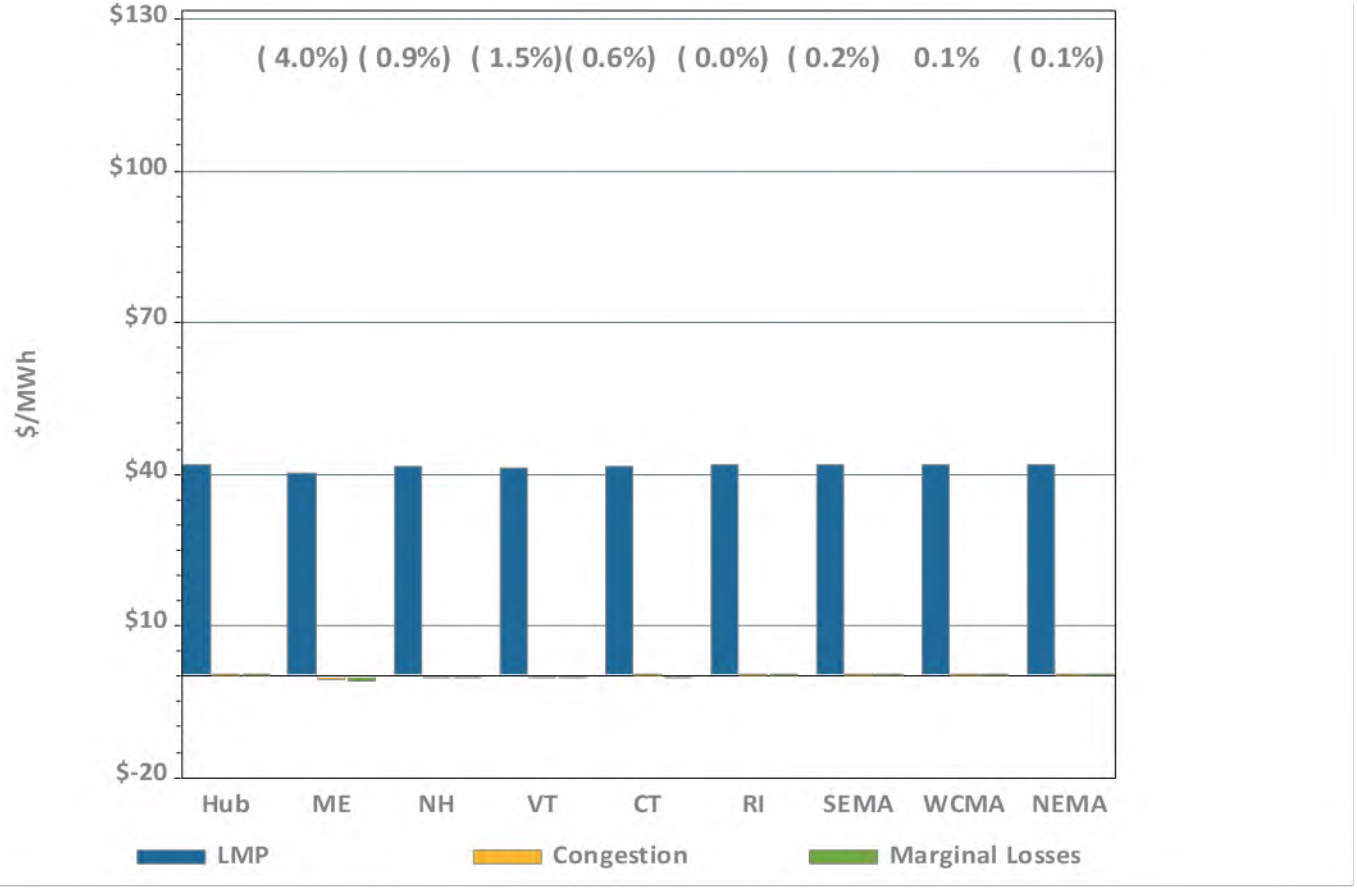
Average price difference over this period (DA-RT): $2.81
Average price difference over this period ABS(DA-RT): $7.76
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 19%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, February 2018



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

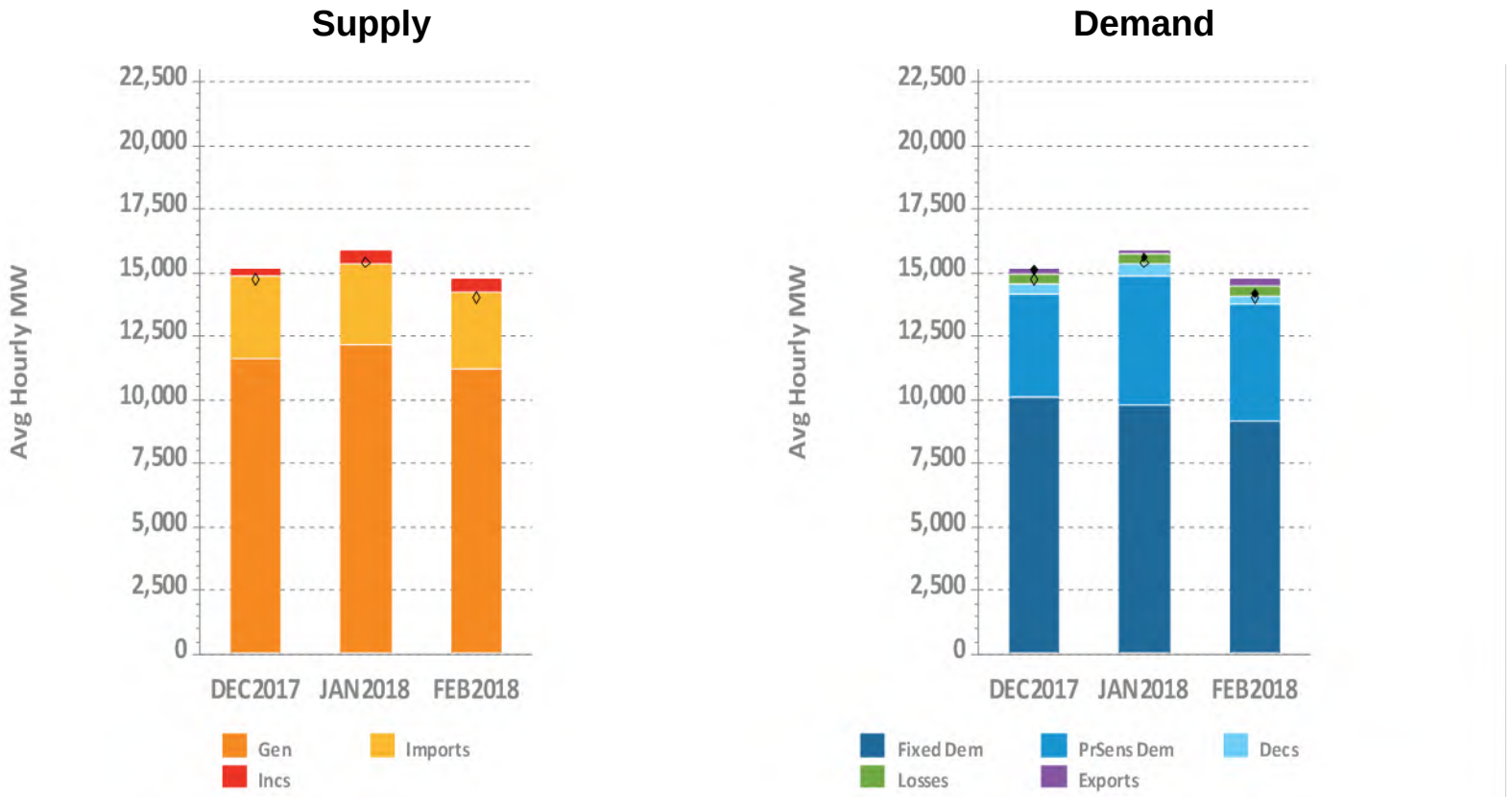
RT LMPs Average by Zone & Hub, February 2018



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

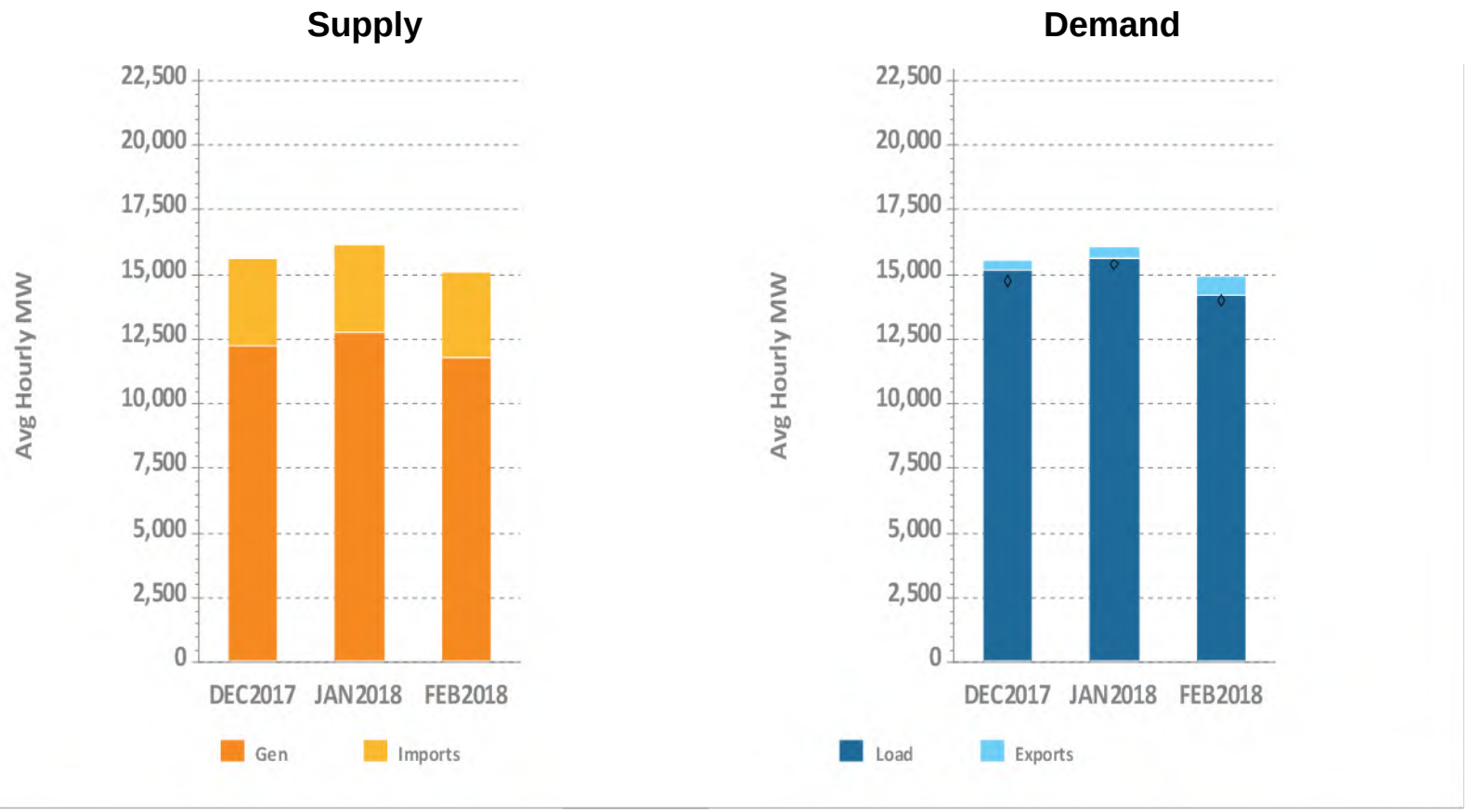
Components of Cleared DA Supply and Demand – Last Three Months



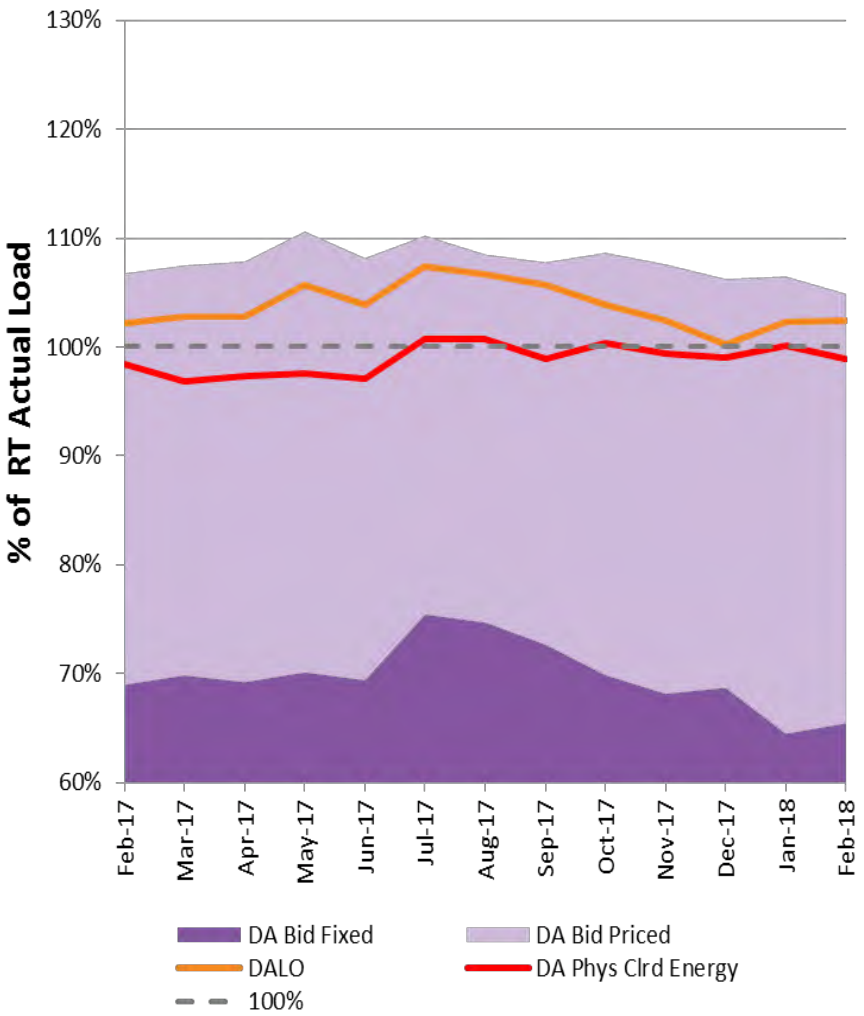
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load

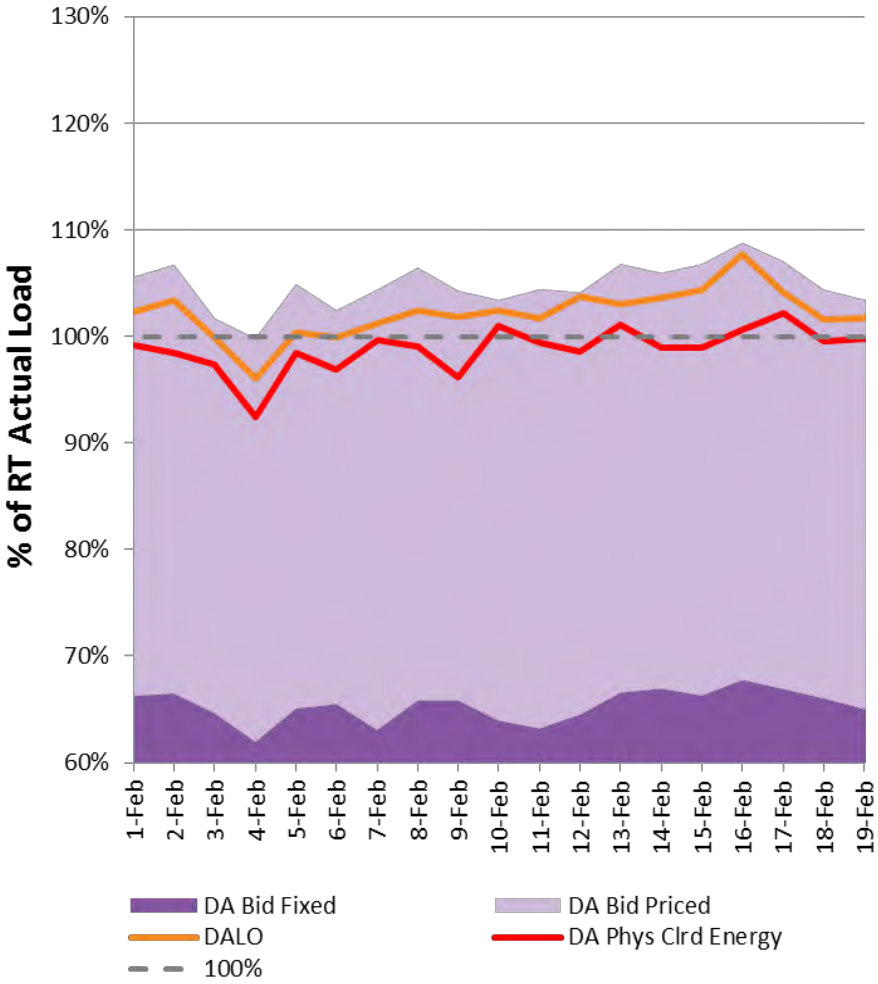
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

Components of RT Supply and Demand – Last Three Months



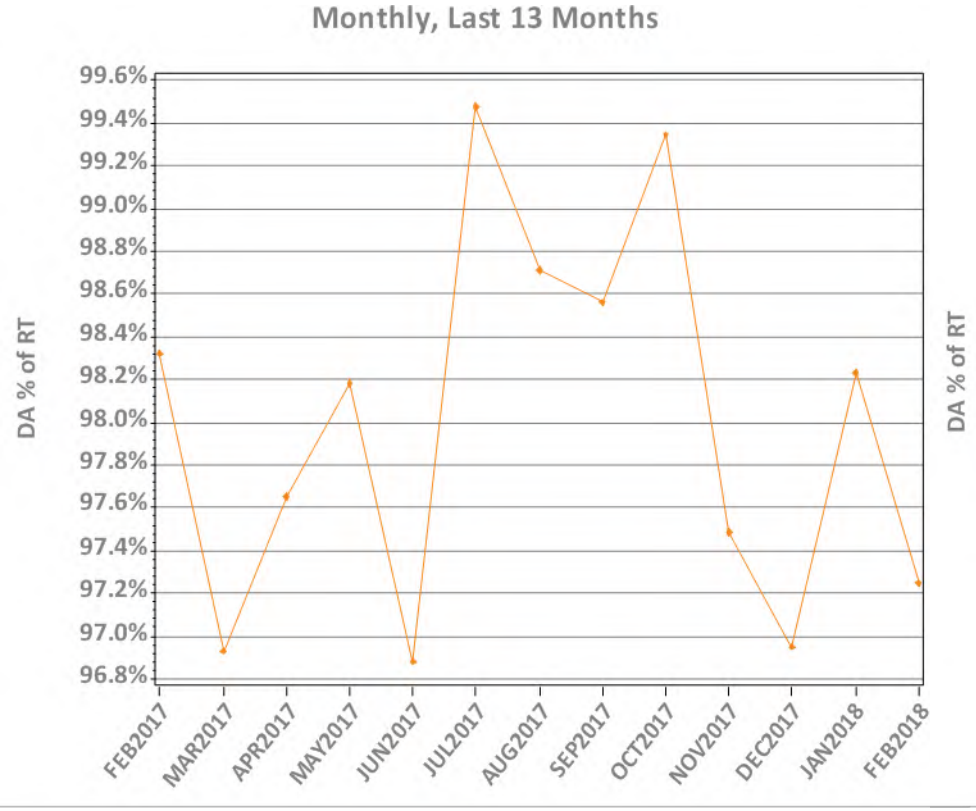
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

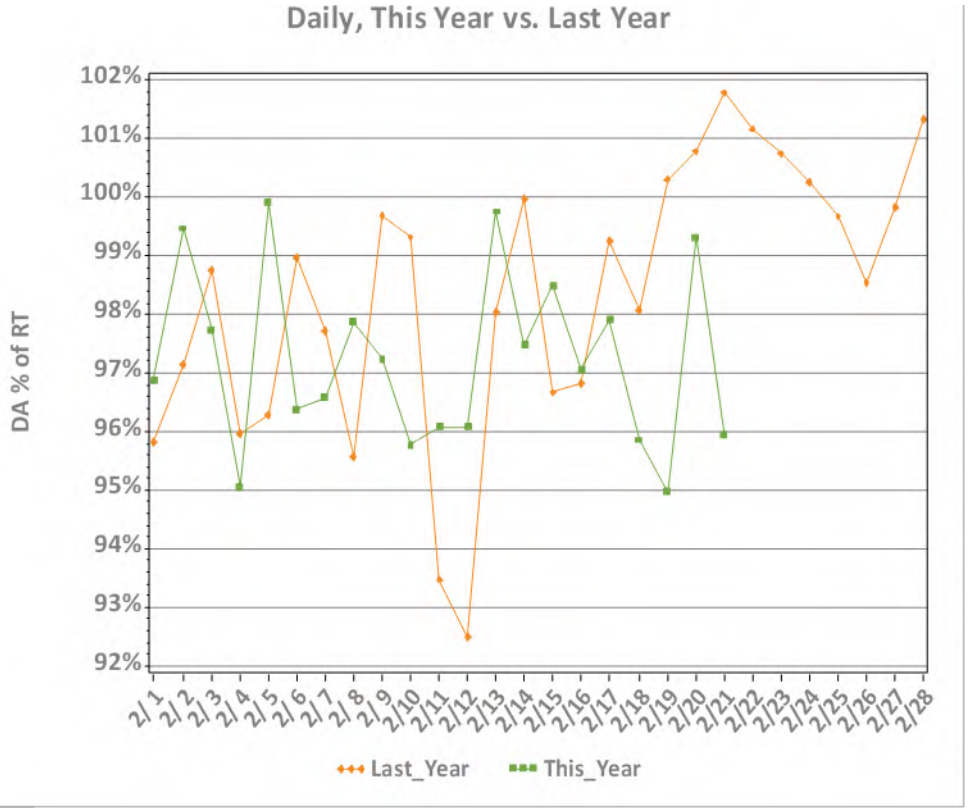




Note: Percentages were derived for the peak hour of each day (shown on right), then averaged over the month (shown on left). Values at hour of forecasted peak load. DA Bid categories reflect internal load asset bidding behavior (Virtual demand and export bid behavior not reflected).

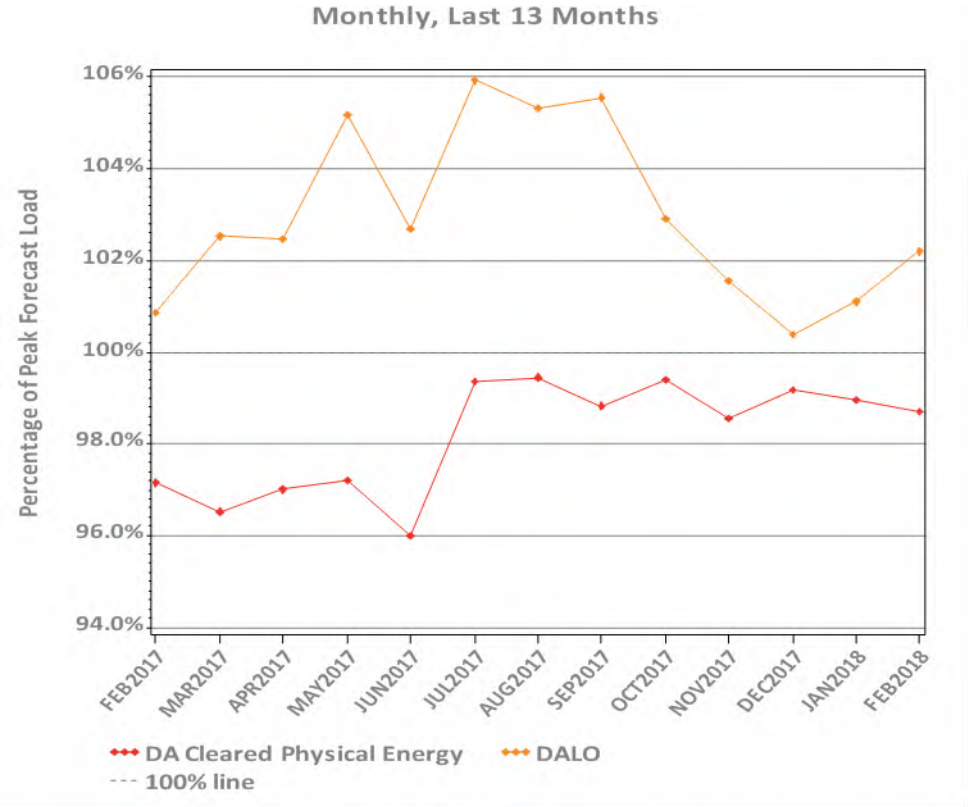
DA vs. RT Load Obligation: February, This Year vs. Last Year

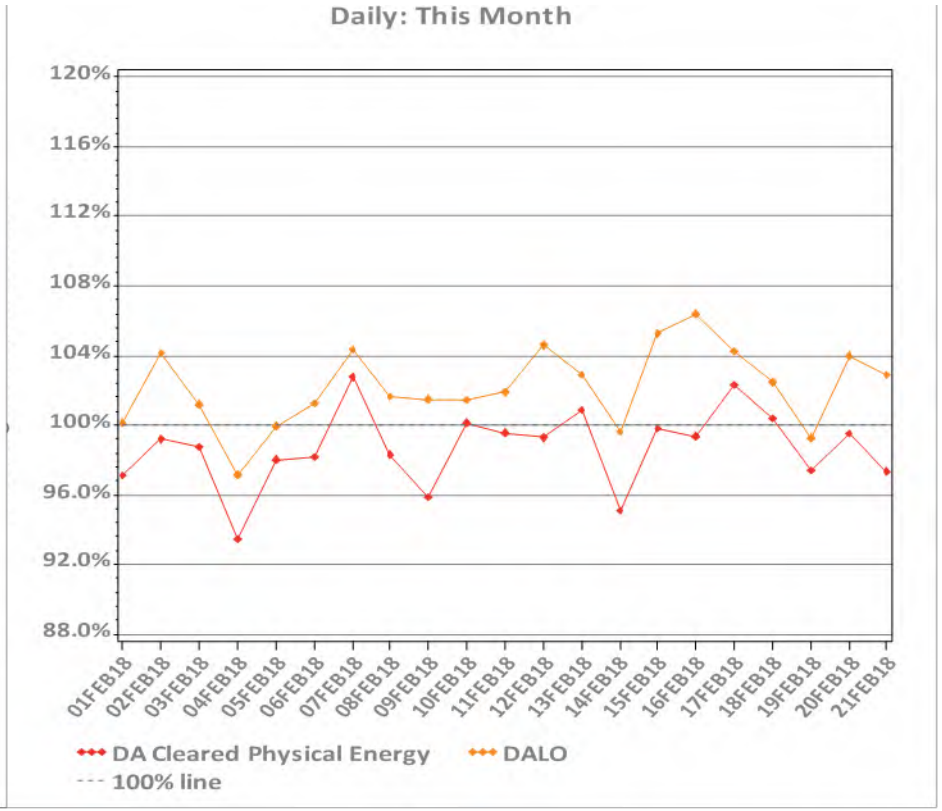




*Hourly average values

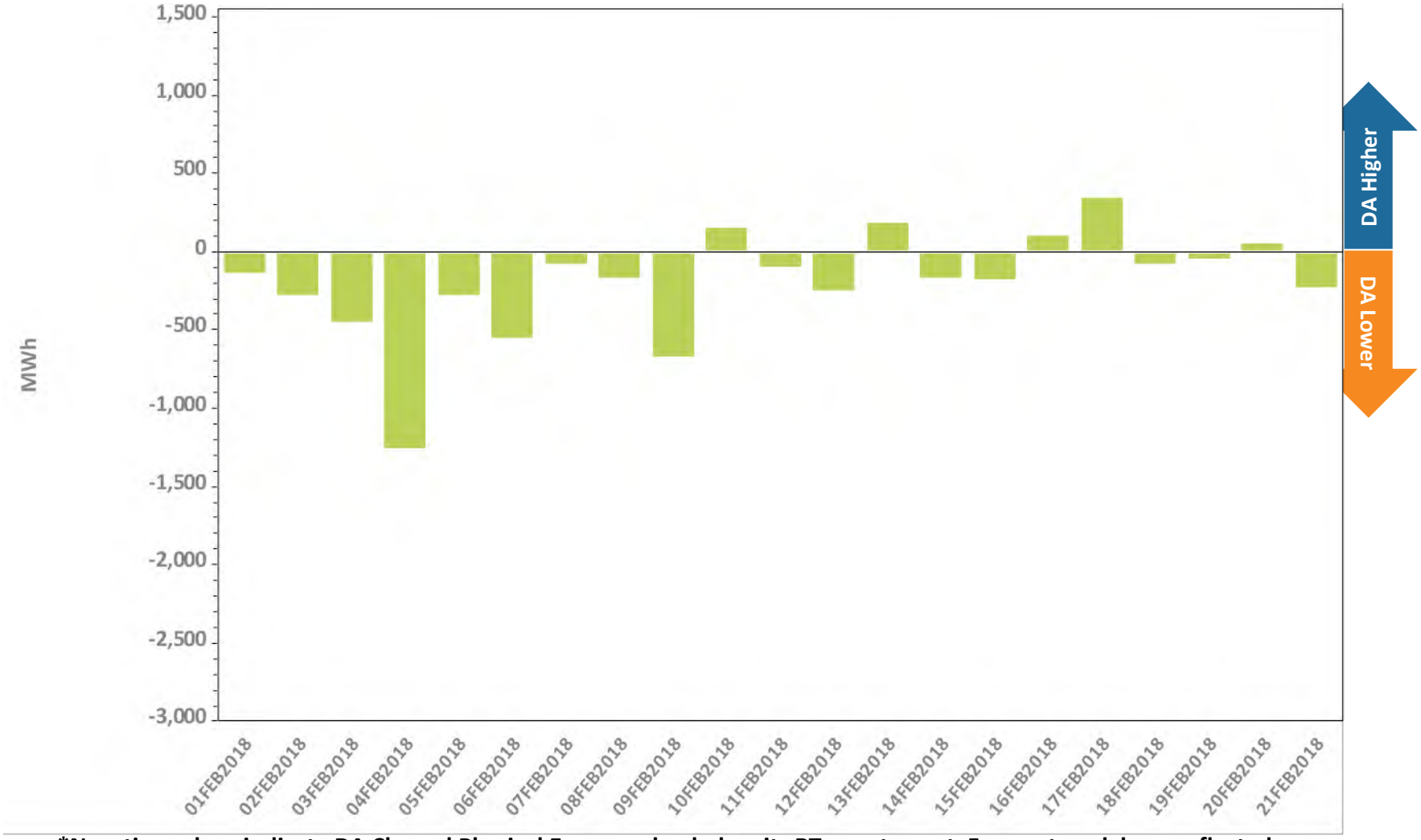
DA Volumes as % of Forecast in Peak Hour





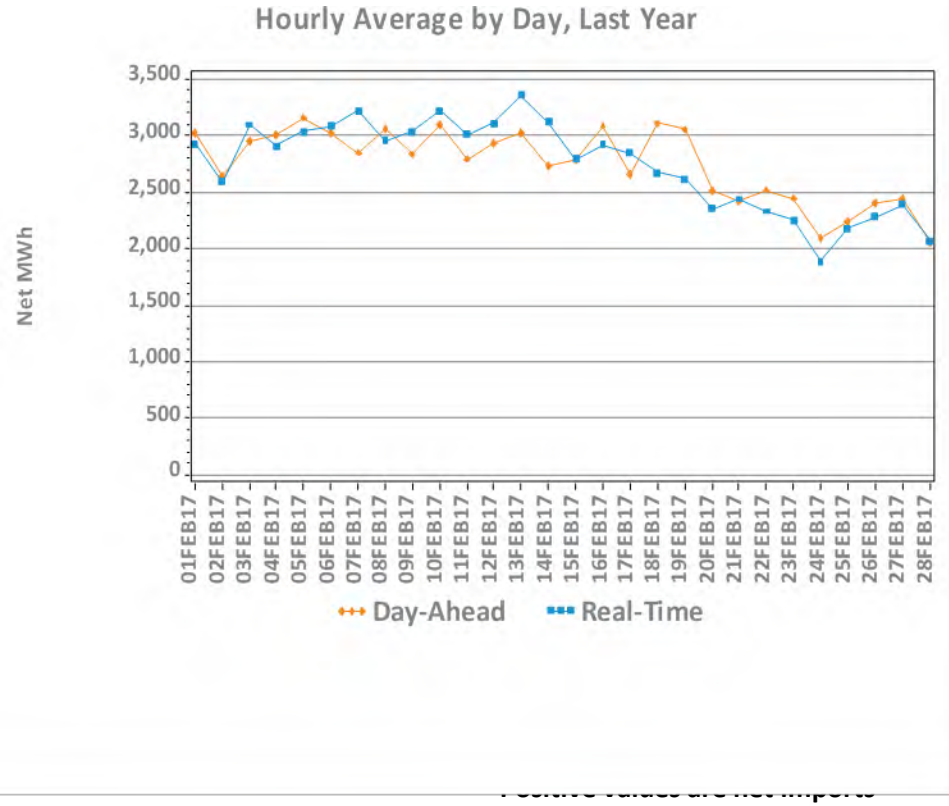
***There was one supplemental commitment required for capacity during the Reserve Adequacy Assessment (RAA) for February 6.**

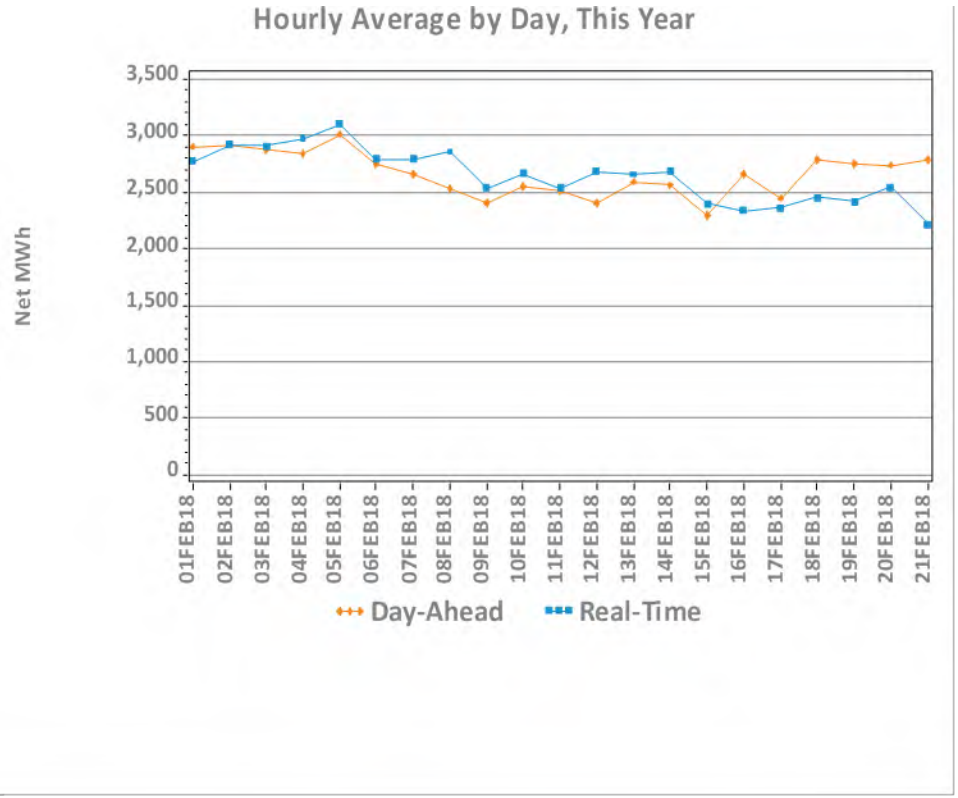
DA Cleared Physical Energy Difference from RT System Load at Peak Hour*



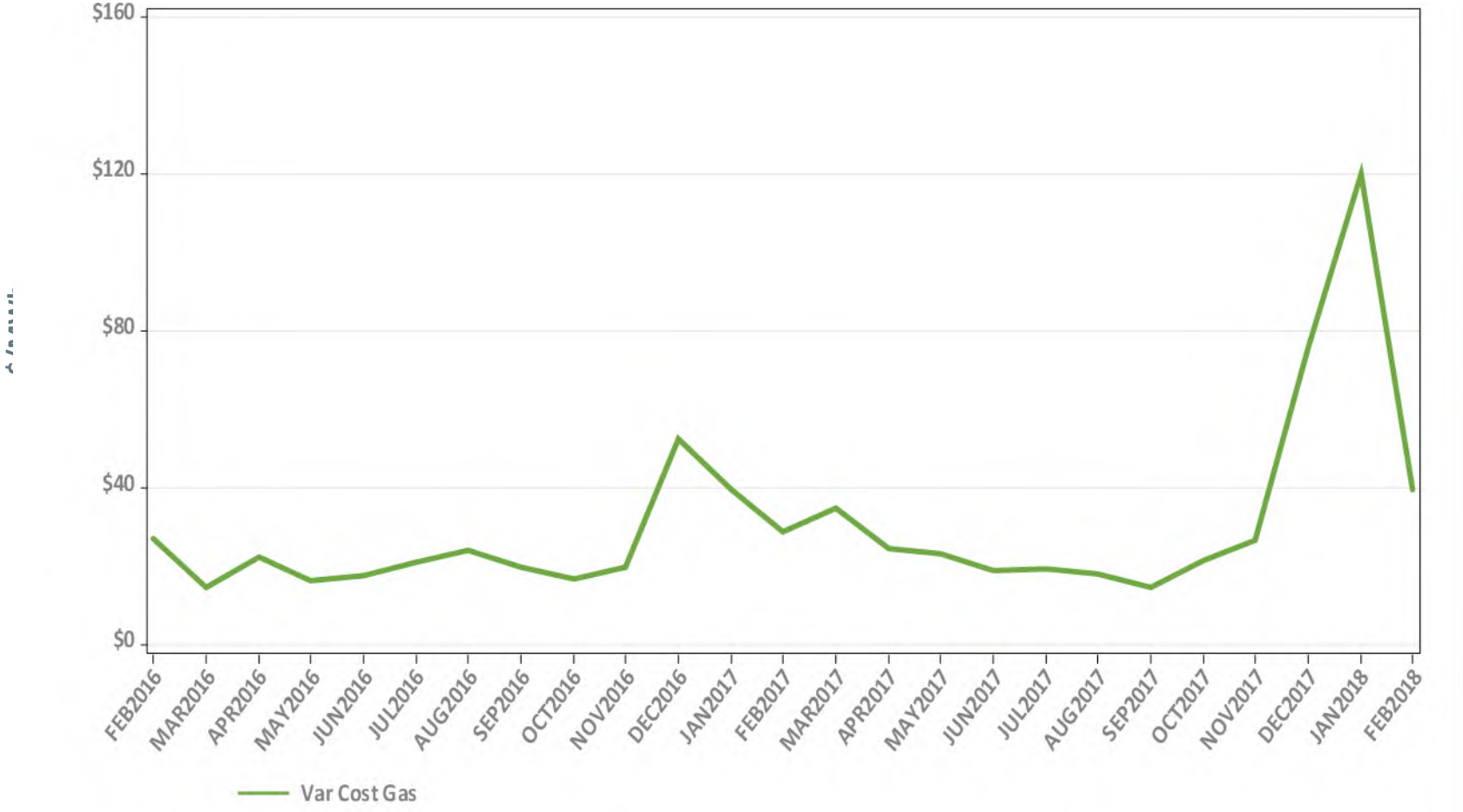
*Negative values indicate DA Cleared Physical Energy value below its RT counterpart. Forecast peak hour reflected.

DA vs. RT Net Interchange
February 2018 vs. February 2017





Variable Production Cost of Natural Gas: Monthly



rnished by:

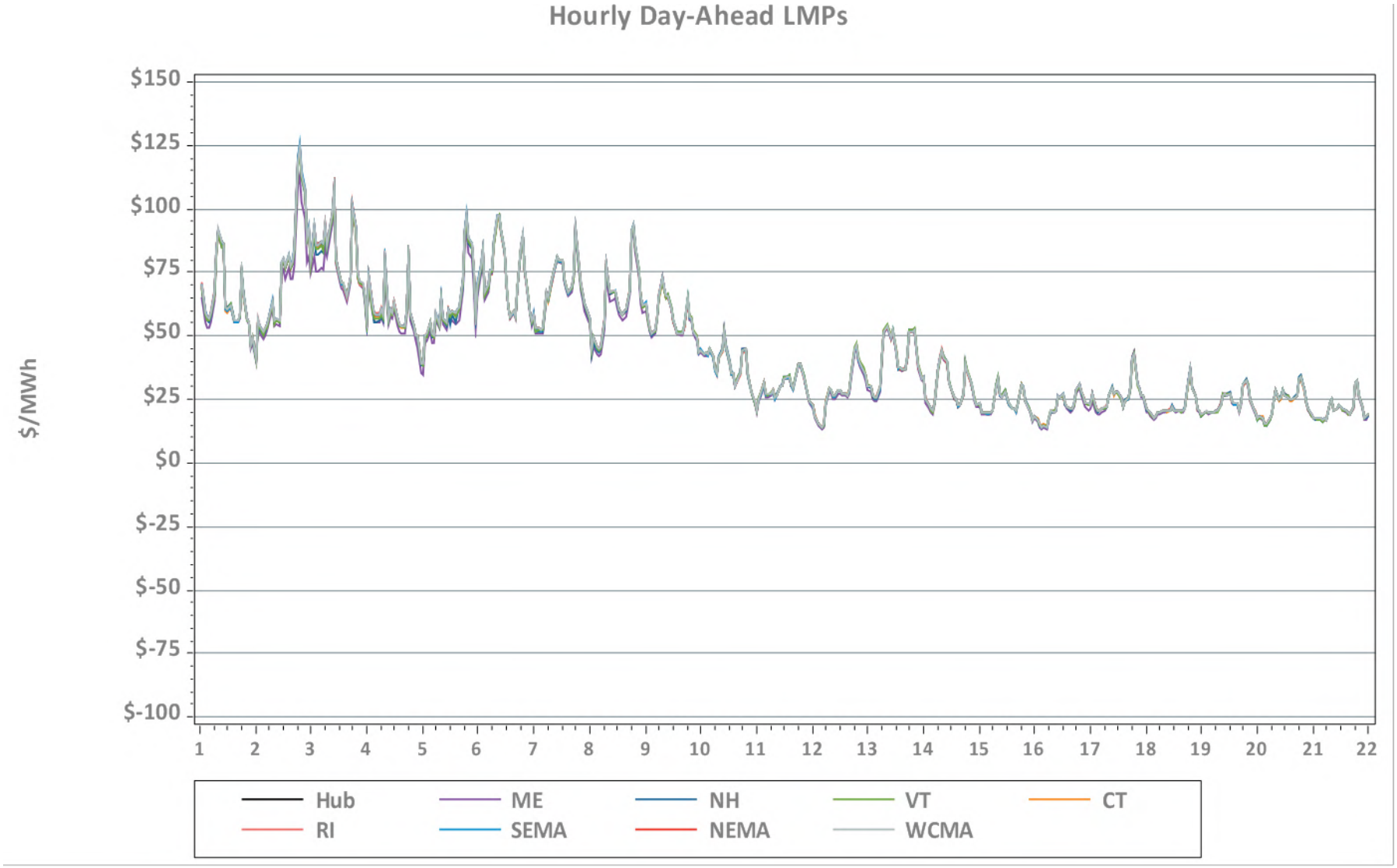
ICE Global markets in clear view

Variable Production Cost of Natural Gas: Daily

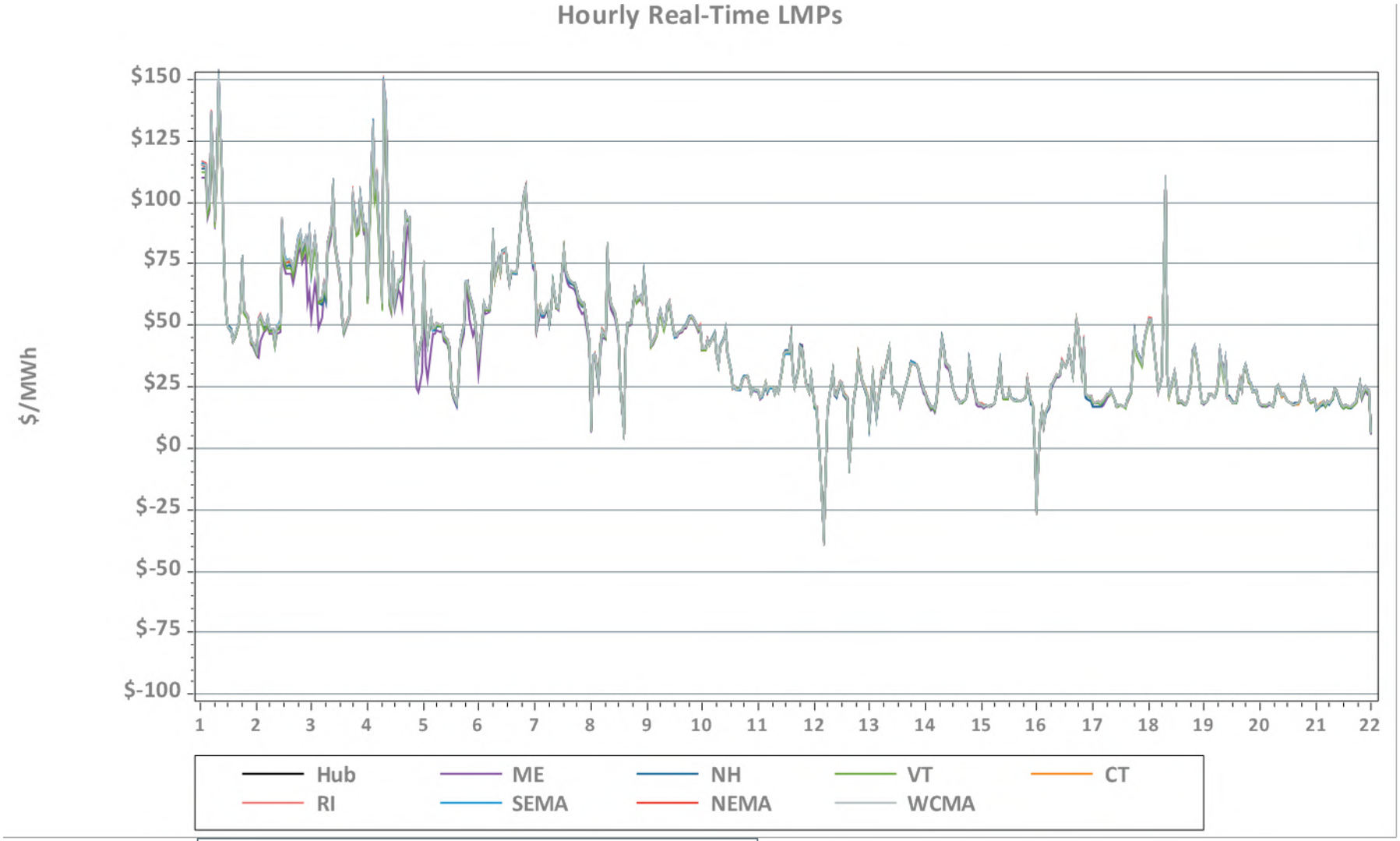
rnished by:

ICE Global markets in clear view

Hourly DA LMPs, February 1-21, 2018

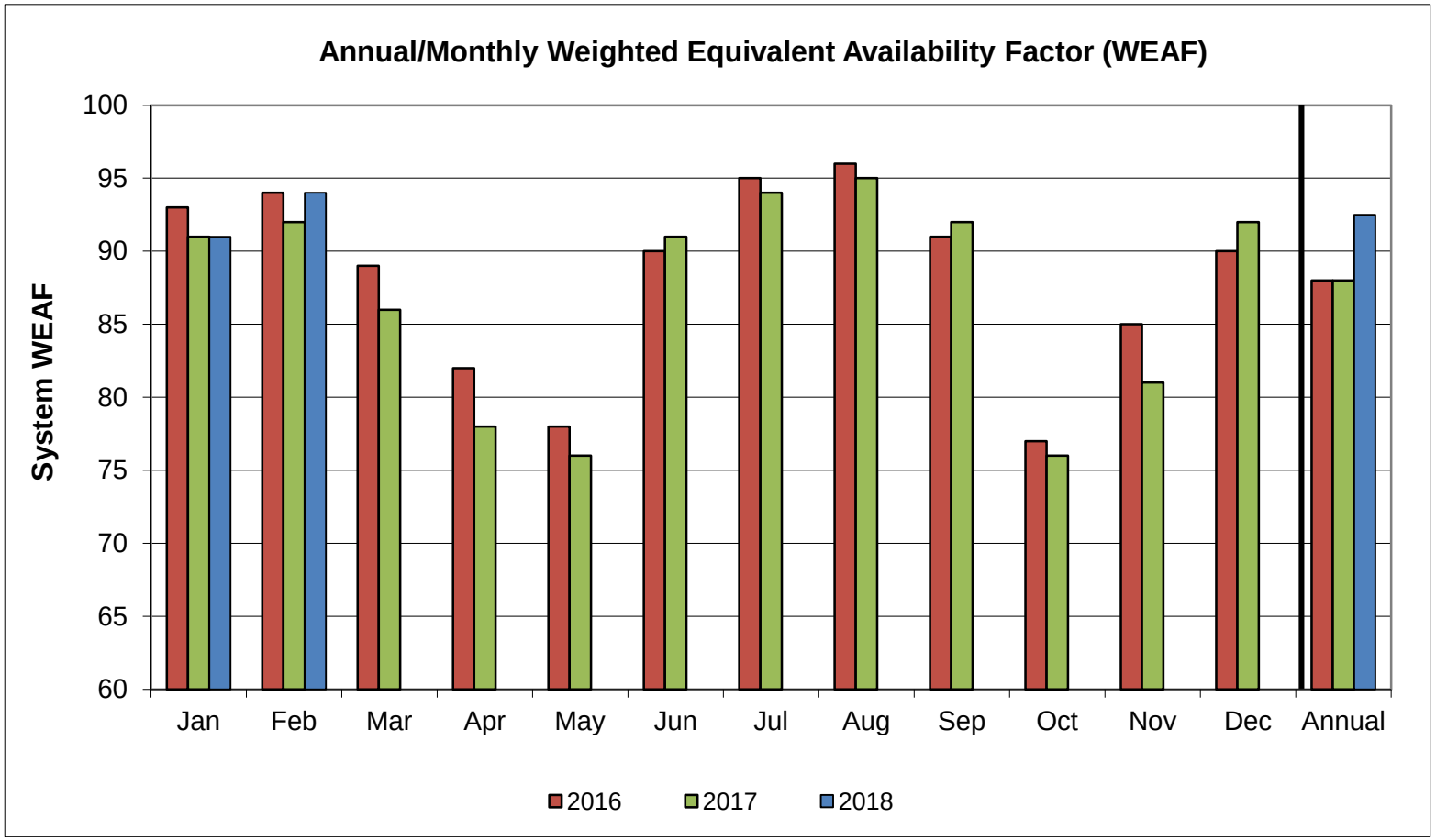


Hourly RT LMPs, February 1-21, 2018



* No Minimum Generation Emergencies were declared in February.

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2018	91	94											93
2017	91	92	86	78	76	91	94	95	92	76	81	92	88
2016	93	94	89	82	78	90	95	96	91	77	85	90	88

Data as of 2/26/18

BACK-UP DETAIL

LOAD RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for March 2018

Load Zone	RTDR*	RTEG**	On Peak	Seasonal Peak	Total
ME	96.0	0.0	162.4	0.0	258.4
NH	10.6	0.0	87.8	0.0	98.4
VT	29.2	0.0	132.6	0.0	161.7
CT	80.5	1.5	59.8	457.8	599.6
RI	10.9	0.0	213.5	0.0	224.4
SEMA	23.0	0.0	320.4	0.0	343.4
WCMA	33.9	0.0	296.0	49.0	378.9
NEMA	33.5	-0.2	597.2	0.0	630.4
Total	**317.6**	**1.3**	**1,869.4**	**506.8**	**2,695.1**

*** Real Time Demand Response**
**** Real Time Emergency Generation**
[1] Negative CSO resulting from reconfiguration auction activity
NOTE: CSO values include T&D loss factor (8%).

NEW GENERATION

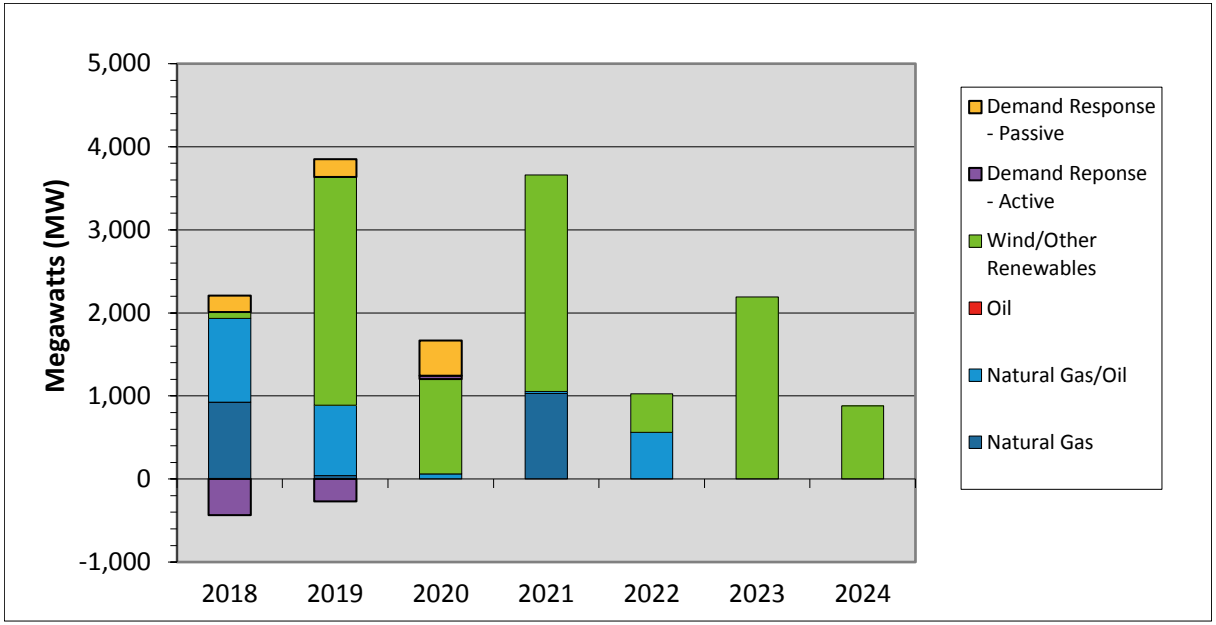
New Generation Update

Based on Queue as of 2/26/18

- No new projects have applied for interconnection study since the last update
- Four projects withdrew from the queue and no projects went commercial, resulting in a net decrease in new generation projects of 157 MW
- In total, 89 generation projects are currently being tracked by the ISO, totaling approximately 14,600 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



	2018	2019	2020	2021	2022	2023	2024	Total MW	% of Total[1]
Demand Response - Passive	196	212	422	0	0	0	0	830	5.6
Demand Response - Active	-433	-270	42	0	0	0	0	-660	-4.5
Wind & Other Renewables	76	2,751	1,141	2,607	463	2,193	880	10,111	68.4
Oil	0	0	0	0	0	0	0	0	0.0
Natural Gas/Oil[2]	1,009	844	62	23	563	0	0	2,501	16.9
Natural Gas	926	43	0	1,030	0	0	0	1,999	13.5
Totals	**1,774**	**3,581**	**1,668**	**3,660**	**1,026**	**2,193**	**880**	**14,781**	**100.0**

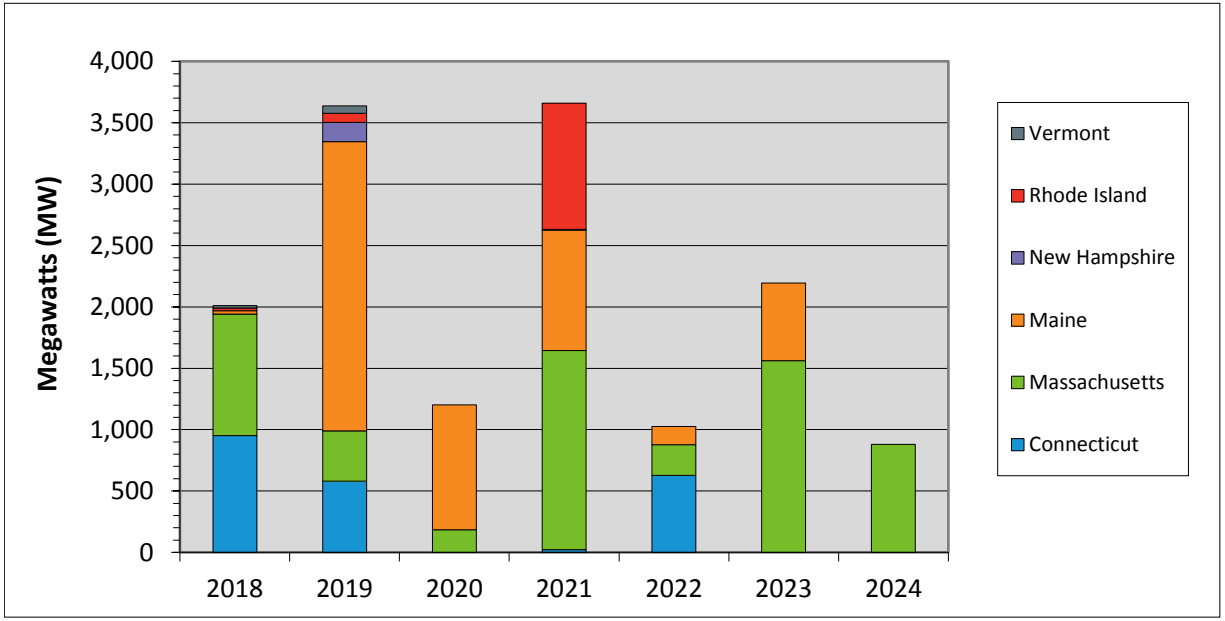
[1] **Sum may not equal 100% due to rounding**

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

- DR reflects changes from the initial FCM Capacity Supply Obligations in 2010-11

Actual and Projected Annual Generator Capacity Additions

By State



	2018	2019	2020	2021	2022	2023	2024	Total MW	% of Total[1]
Vermont	20	60	0	0	0	0	0	80	0.5
Rhode Island	21	74	0	1,030	0	0	0	1,125	7.7
New Hampshire	0	158	0	5	0	0	0	163	1.1
Maine	30	2,356	1,018	982	150	630	0	5,166	35.4
Massachusetts	989	411	185	1,620	250	1,563	880	5,898	40.4
Connecticut	951	579	0	23	626	0	0	2,179	14.9
Totals	**2,011**	**3,638**	**1,203**	**3,660**	**1,026**	**2,193**	**880**	**14,611**	**100.0**

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

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	1	37	0	0	1	37
Hydro	3	99	0	0	3	99
Landfill Gas	0	0	0	0	0	0
Natural Gas	8	2,062	2	816	6	1,246
Natural Gas/Oil	8	2,501	2	1,009	6	1,492
Oil	0	0	0	0	0	0
Solar	31	1,110	0	0	31	1,110
Wind	33	8,400	0	0	33	8,400
Battery Storage	5	402	0	0	5	402
Total	89	14,611	4	1,825	85	12,786

- 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	3	105	0	0	3	105
Intermediate	11	3,802	2	1,517	9	2,285
Peaker	42	2,304	2	308	40	1,996
Wind Turbine	33	8,400	0	0	33	8,400
Total	89	14,611	4	1,825	85	12,786

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

New Generation Projection

By Operating Type and Fuel Type

Fuel Type	Total		Baseload		Intermediate		Peaker		Wind Turbine	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	1	37	1	37	0	0	0	0	0	0
Hydro	3	99	1	5	1	28	1	66	0	0
Landfill Gas	0	0	0	0	0	0	0	0	0	0
Natural Gas	8	2,062	1	63	6	1,899	1	100	0	0
Natural Gas/Oil	8	2,501	0	0	4	1,875	4	626	0	0
Oil	0	0	0	0	0	0	0	0	0	0
Solar	31	1,110	0	0	0	0	31	1,110	0	0
Wind	33	8,400	0	0	0	0	0	0	33	8,400
Battery Storage	5	402	0	0	0	0	5	402	0	0
Total	89	14,611	3	105	11	3,802	42	2,304	33	8,400

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

FORWARD CAPACITY MARKET

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	601.852	-170.5	400.487	-201.365	381.941	-18.546
	Passive Demand	1,960.517	1,958.874	-1.64	1,956.663	-2.211	2025.383	68.72	2,036.906	11.523	2,112.758	75.852	2,308.73	195.972
Demand Total		**3,040.596**	**2,846.367**	**-194.23**	**2,848.267**	**1.9**	**2,797.735**	**-50.532**	**2,638.758**	**-158.977**	**2,513.245**	**-125.513**	2,690.671	177.426
Generator	*Non-Intermittent*	28,547.813	28,523.796	-24.02	28,666.87	143.074	28,658.35	-8.52	28,863.752	205.402	28,888.84	25.092	28,833.605	-55.235
	Intermittent	876.925	898.955	22.03	922.173	23.218	918.782	-3.391	920.037	1.255	916.51	-3.527	823.162	-93.348
Generator Total		**29,424.738**	**29,422.751**	**-1.99**	**29,589.043**	**166.292**	**29,577.132**	**-11.911**	**29,783.789**	**206.657**	**29,805.35**	**21.565**	29,656.767	-148.583
Import Total		**1,237.034**	**1,237.034**	**0.00**	**1,375.53**	**138.496**	**1,375.53**	**0**	**1314.43**	**-61.1**	**1,394.43**	**80**	1,345.998	-48.432
***Grand Total**		**33,702.368**	**33,506.152**	**-196.22**	**33,812.84**	**306.688**	**33,750.397**	**-62.443**	**33,736.977**	**-13.417**	**33,713.03**	**-23.948**	33,693.436	-19.594
Net ICR (NICR)		**33,855**	**34,061**	**206.00**	**34,061**	**0**	**33,442**	**-619**	**33,442**	**0**	**33,138**	**-304**	33,138	**0**

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

** A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond bilaterals and reconfiguration auction may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2020 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

*** Grand Total reflects both CSO Grand Total and the net total of the Change Column. The Grand Total for FCA 8 does not reflect a Supplemental Information filing in March of 2014.

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	525.843	-28.014	484.972	-40.871	438.282	-46.690		
	Passive Demand	2,156.151	2,153.94	-2.211	2,150.196	-3.744	2,150.196	0	2,389.958	239.762	2,394.341	4.380		
Demand Total		**2,803.411**	**2,750.641**	**-52.77**	**2,704.053**	**-46.588**	**2,676.039**	**-28.014**	**2,874.93**	**198.891**	**2,832.623**	**-42.310**		
Generator	*Non-Intermittent*	29,550.564	29,558.181	7.617	29,783.831	225.65	29,803.997	20.166	29,833.445	29.448	29,720.393	-113.060		
	Intermittent	891.616	864.924	-26.692	872.425	7.501	853.414	-19.011	870.558	17.144	855.947	-14.611		
Generator Total		**30,442.18**	**30,423.105**	**-19.075**	**30,656.256**	**233.151**	**30,657.41**	**1.155**	**30,704.003**	46.593	**30,576.34**	**-127.660**		
Import Total		**1,449**	**1,449**	**0**	**1,449**	**0**	**1,449**	**0**	**1,449**	0	**1,599**	**150.000**		
***Grand Total**		**34,694.591**	**34,622.746**	**-71.845**	**34,809.309**	**186.563**	**34,782.45**	**-26.859**	**35,027.933**	245.483	**35,007.963**	**-19.970**		
Net ICR (NICR)		**34,189**	**33,883**	**-306**	**33,883**	**0**	**33,421**	**-462**	**33,421**	0	**33,247**	**-174**		

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

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*** Grand Total reflects both CSO Grand Total and the net total of the Change Column. The Grand Total for FCA 8 does not reflect a Supplemental Information filing in March of 2014.

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	367.227	-10.298	464.715	97.488								
	Passive Demand	2,368.631	2,366.783	-1.848	2,363.949	-2.834								
Demand Total		**2,746.156**	**2734.01**	**-12.146**	**2,828.664**	**94.654**								
Generator	*Non-Intermittent*	30,520.433	30,462.67	-57.763	30,048.398	-414.272								
	Intermittent	850.143	893.189	43.046	904.311	11.122								
Generator Total		**31,370.576**	**31,355.86**	**-14.716**	**30,952.709**	**-403.151**								
Import Total		**1,449.8**	**1,449.8**	**0**	**1,451**	**1.2**								
***Grand Total**		**35,566.532**	**35,539.668**	**-26.864**	**35,232.373**	**-307.295**								
Net ICR (NICR)		**34,151**	**33,755**	**-396**	**33,755**	**0**								

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

** A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond bilaterals and reconfiguration auction may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2020 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

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Capacity Supply Obligation FCA 11

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*	419.928												
	Passive Demand	2,791.019												
Demand Total		**3,210.947**												
Generator	*Non-Intermittent*	30,494.8												
	Intermittent	894.217												
Generator Total		**31,389.02**												
Import Total		**1,235.4**												
***Grand Total**		**35,835.368**												
Net ICR (NICR)		**34,075**												

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

** A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond bilaterals and reconfiguration auction may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2020 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

*** Grand Total reflects both CSO Grand Total and the net total of the Change Column. The Grand Total for FCA 8 does not reflect a Supplemental Information filing in March of 2014.

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**
2020-21	Active	334.634	85.294	419.928
	Passive	2236.727	554.292	2791.019
	Grand Total	**2571.361**	**639.586**	**3210.947**

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

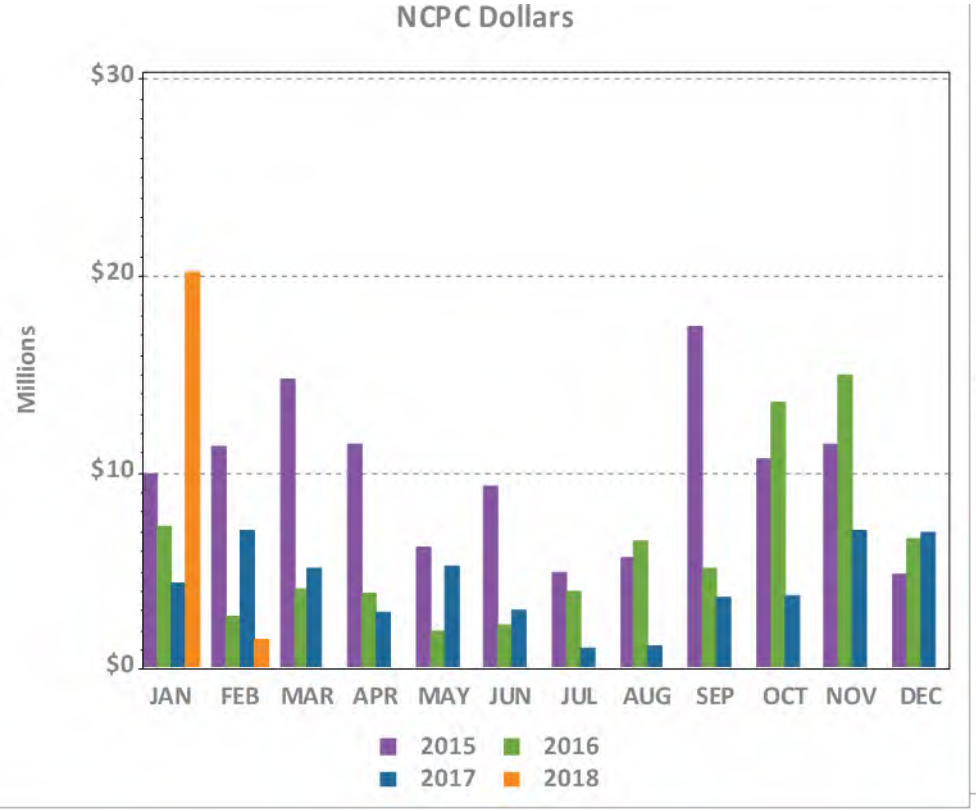
Definitions

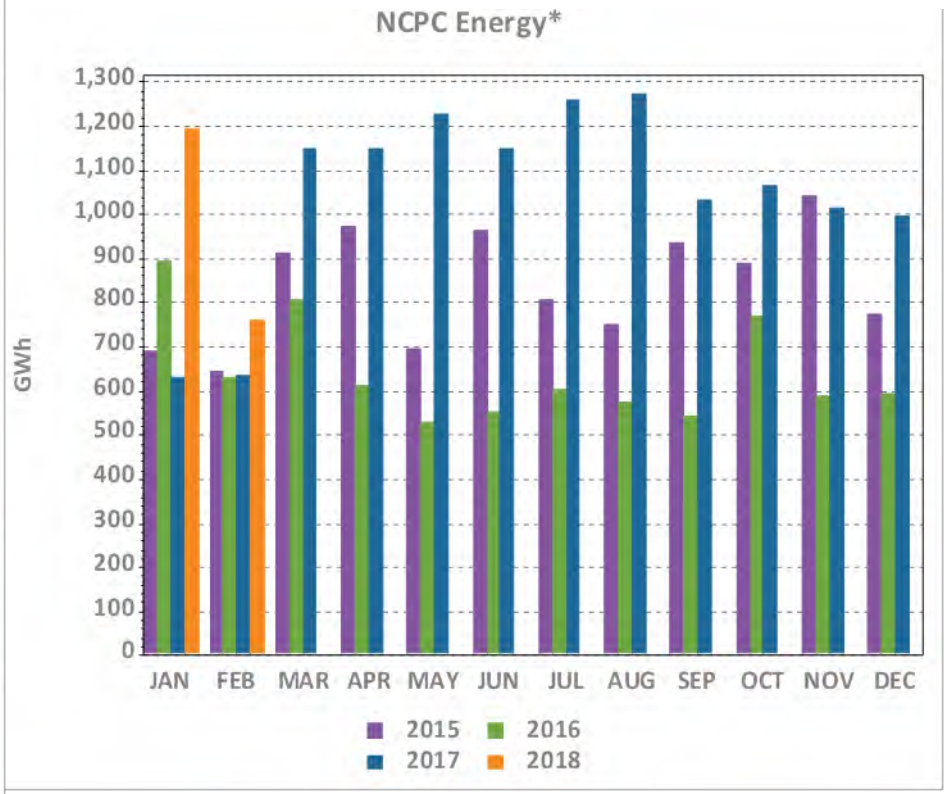
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing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

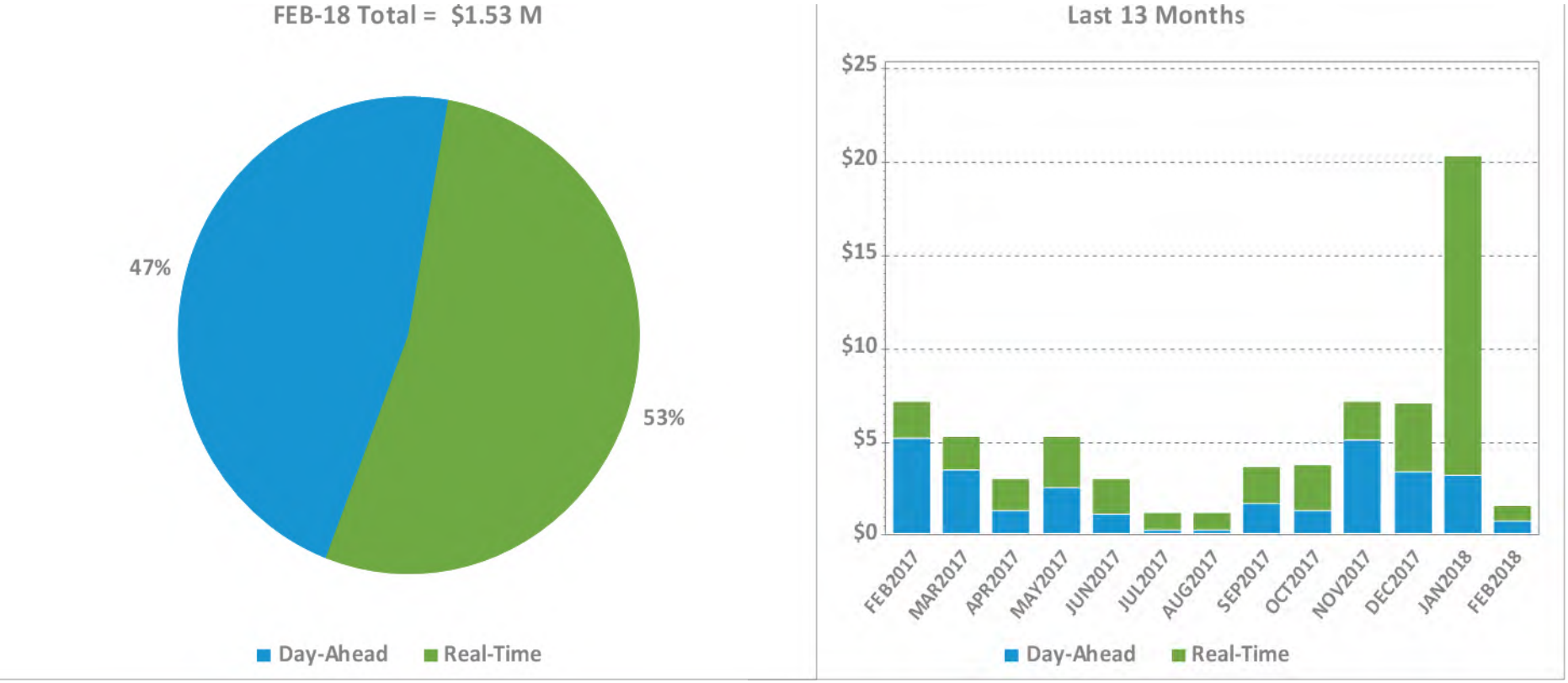
Year-Over-Year Total NCPC Dollars and Energy



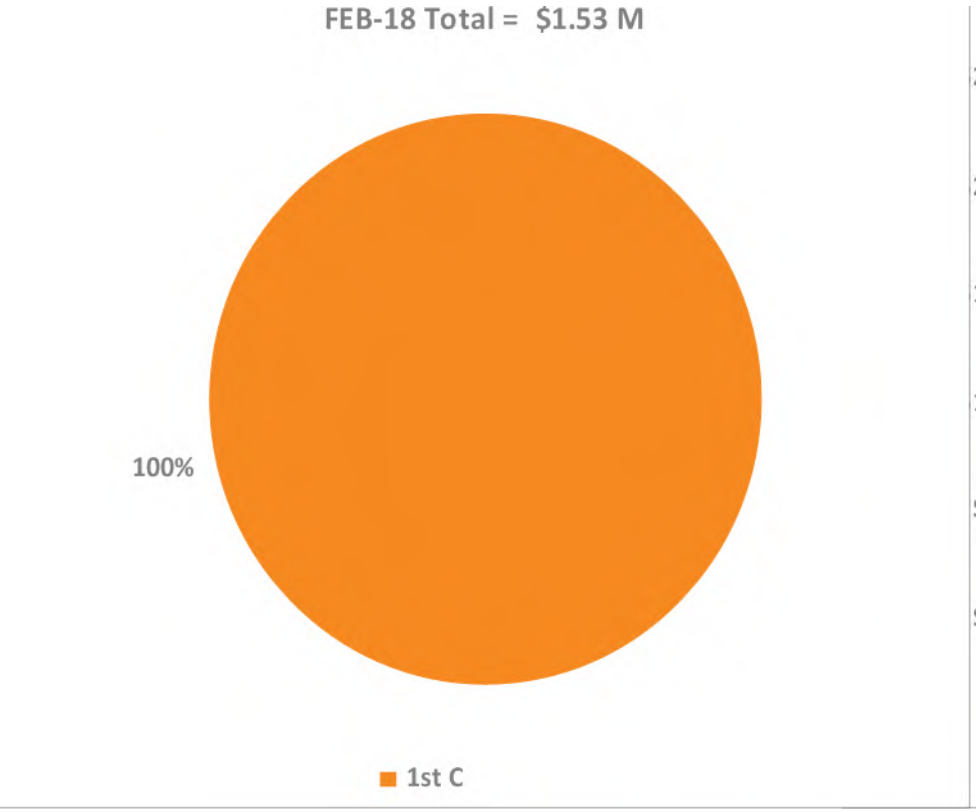


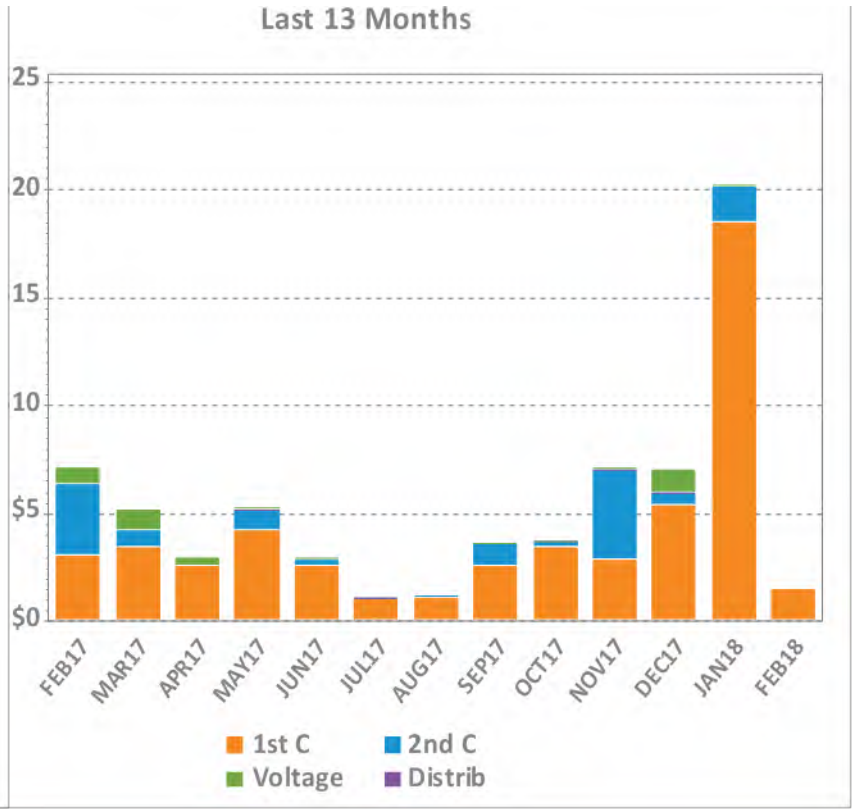
*** NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

DA and RT NCPC Charges



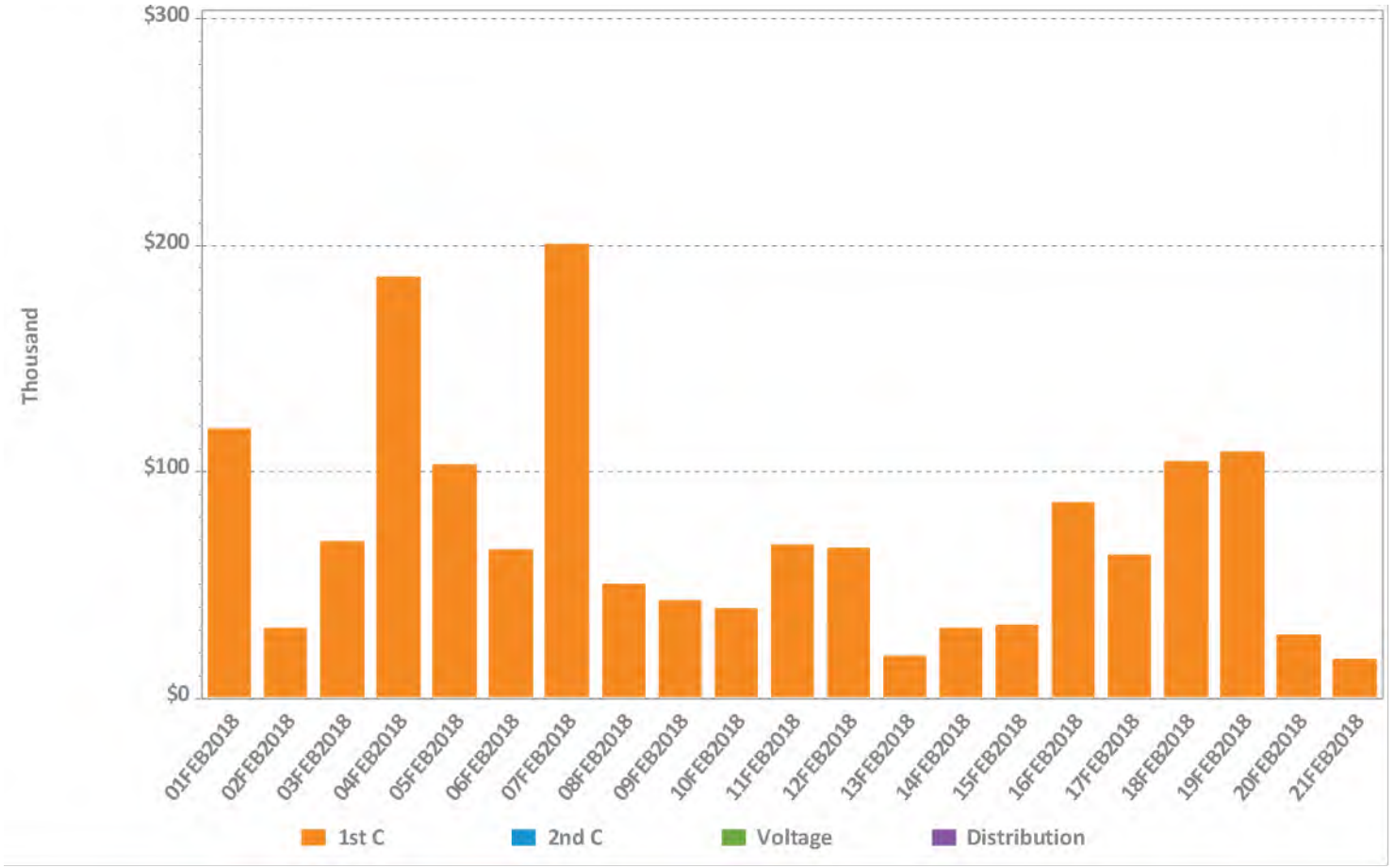
NCPC Charges by Type



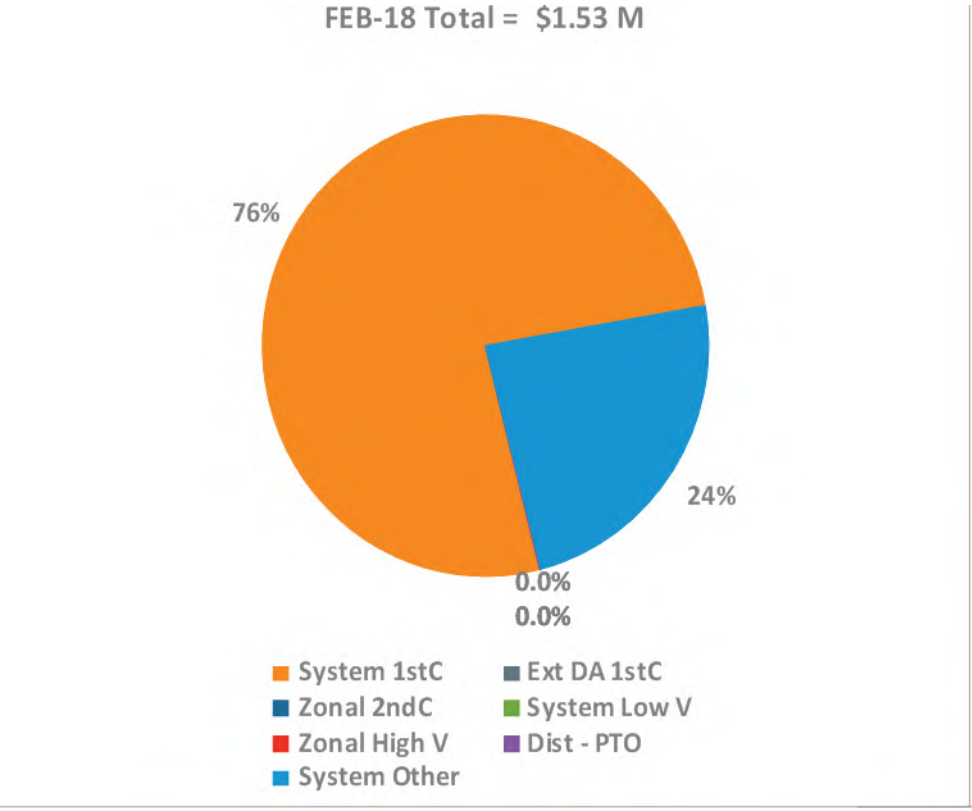


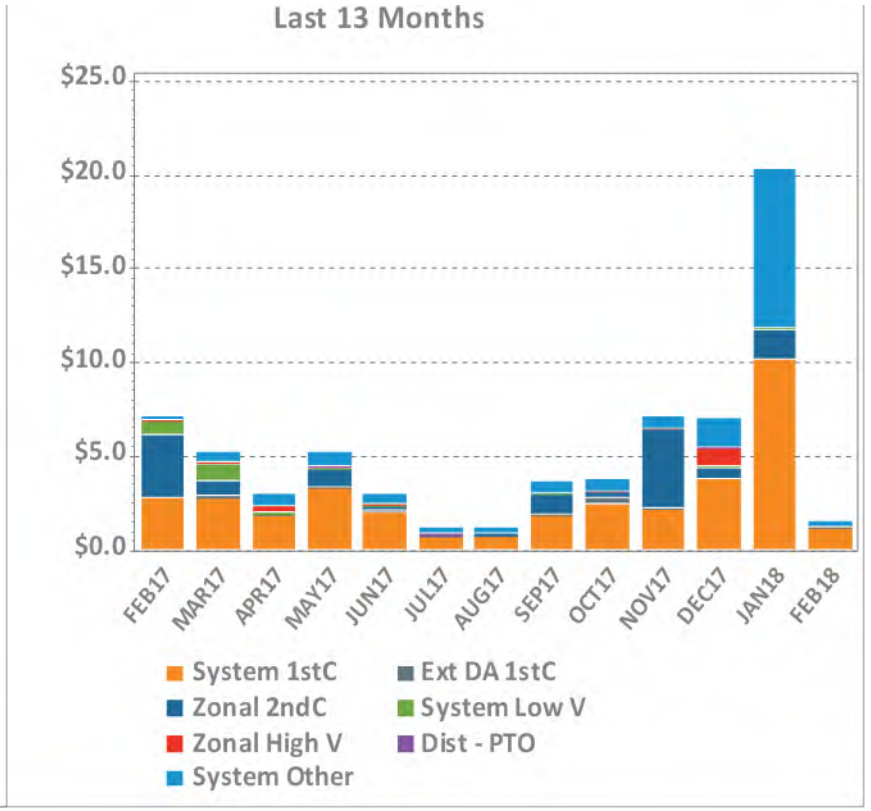
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



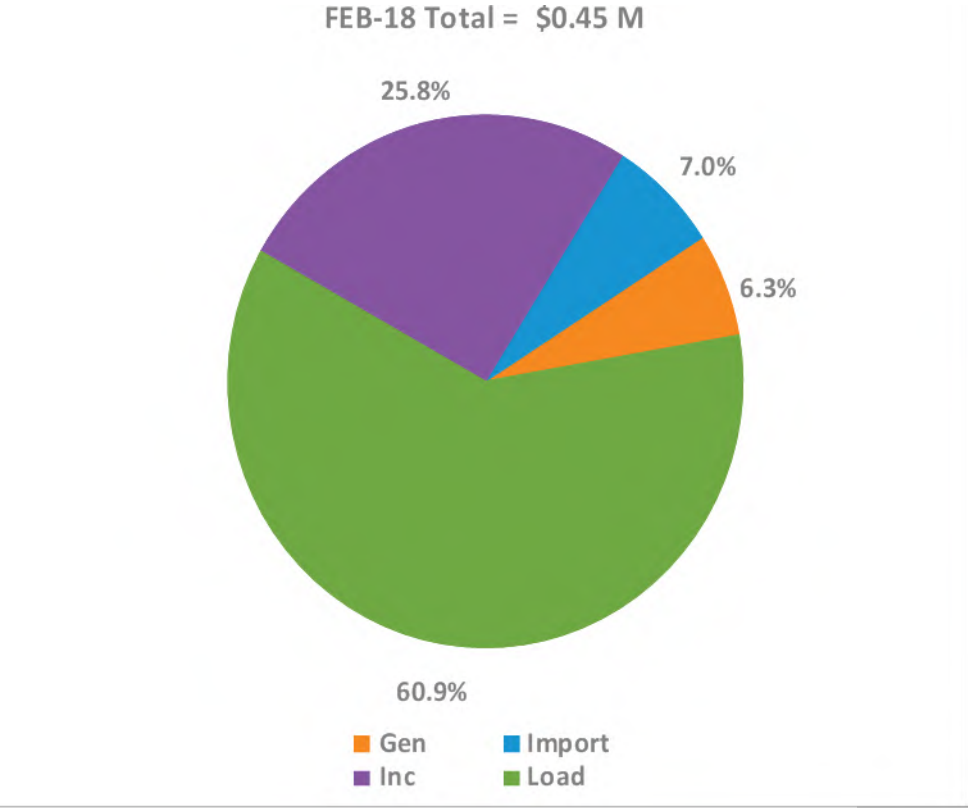
NCPC Charges by Allocation

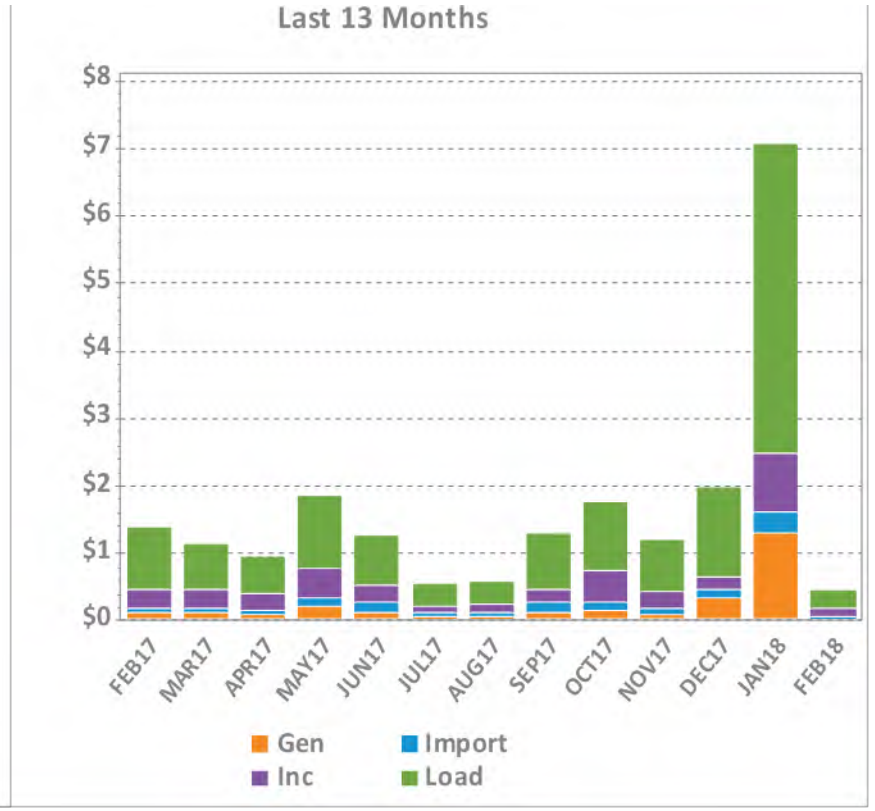




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

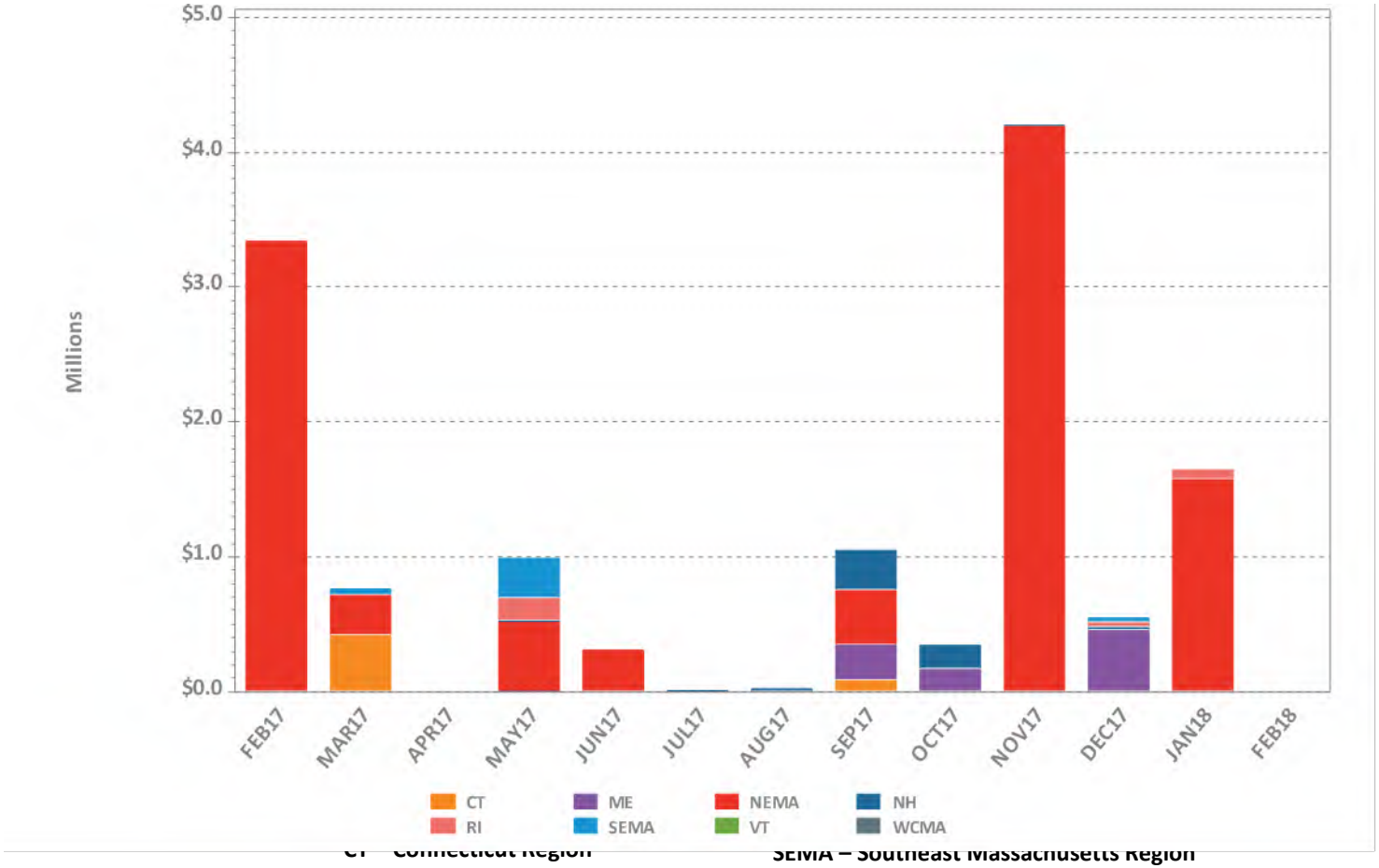
RT First Contingency Charges by Deviation Type





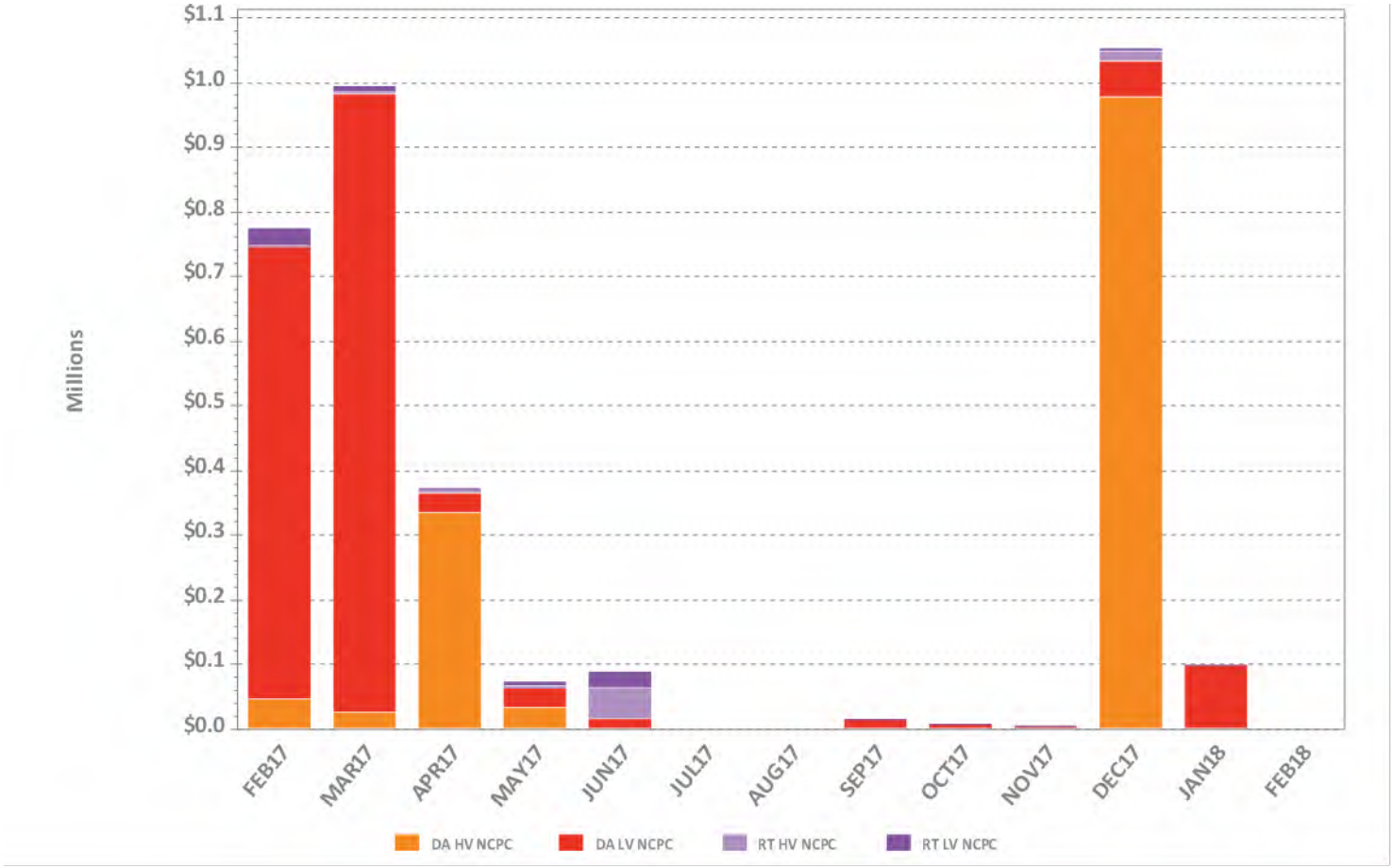
Gen – Generator deviations
Inc – Increment Offer deviations
Import – Import deviations
Load – Load obligation deviations

LSCPR Charges by Reliability Region

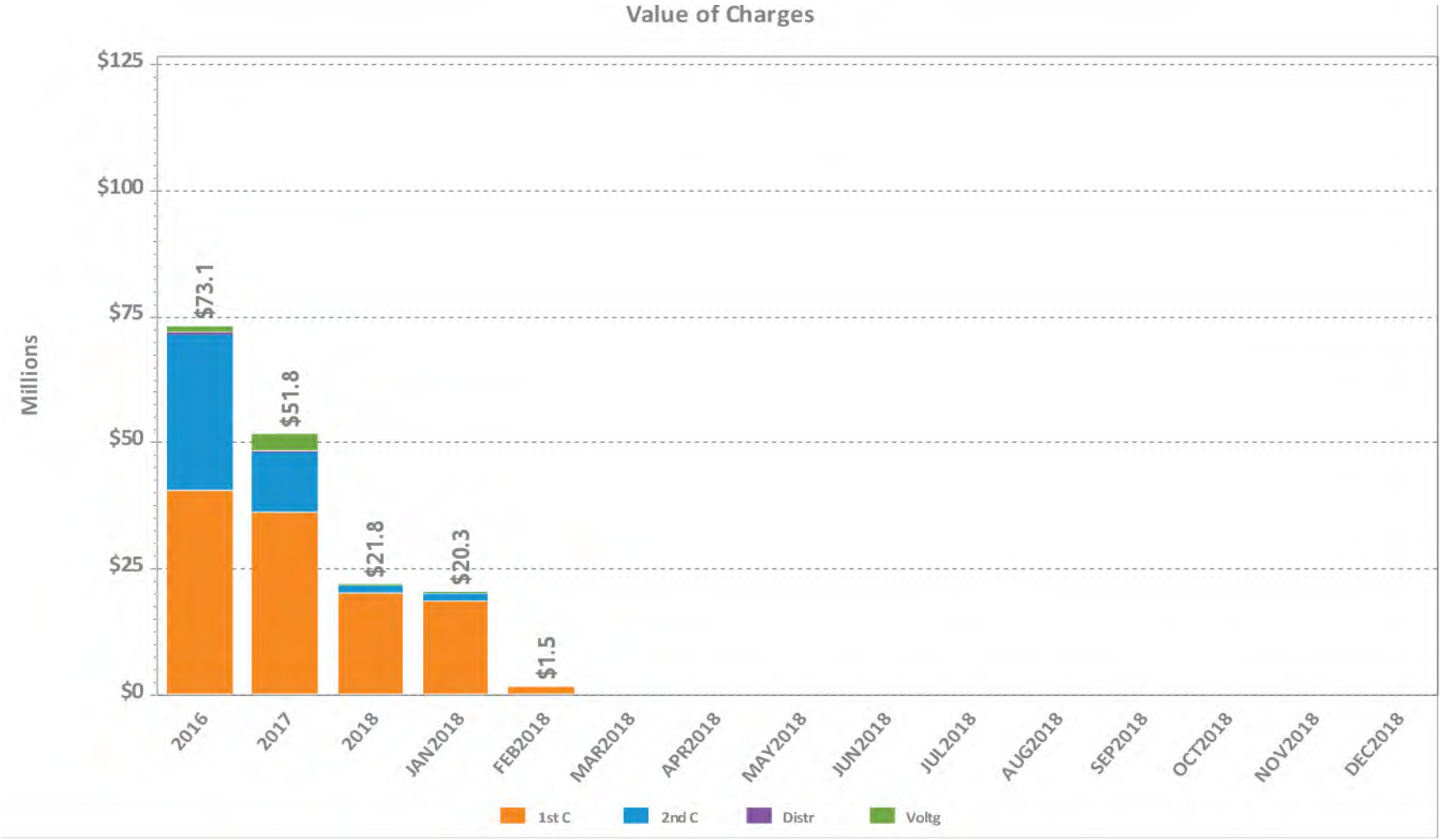


CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region
SEMA – Southeast Massachusetts Region
WCMA – Western/Central Massachusetts Region
NEMA – Northeast Massachusetts Region
EXT – External Locations

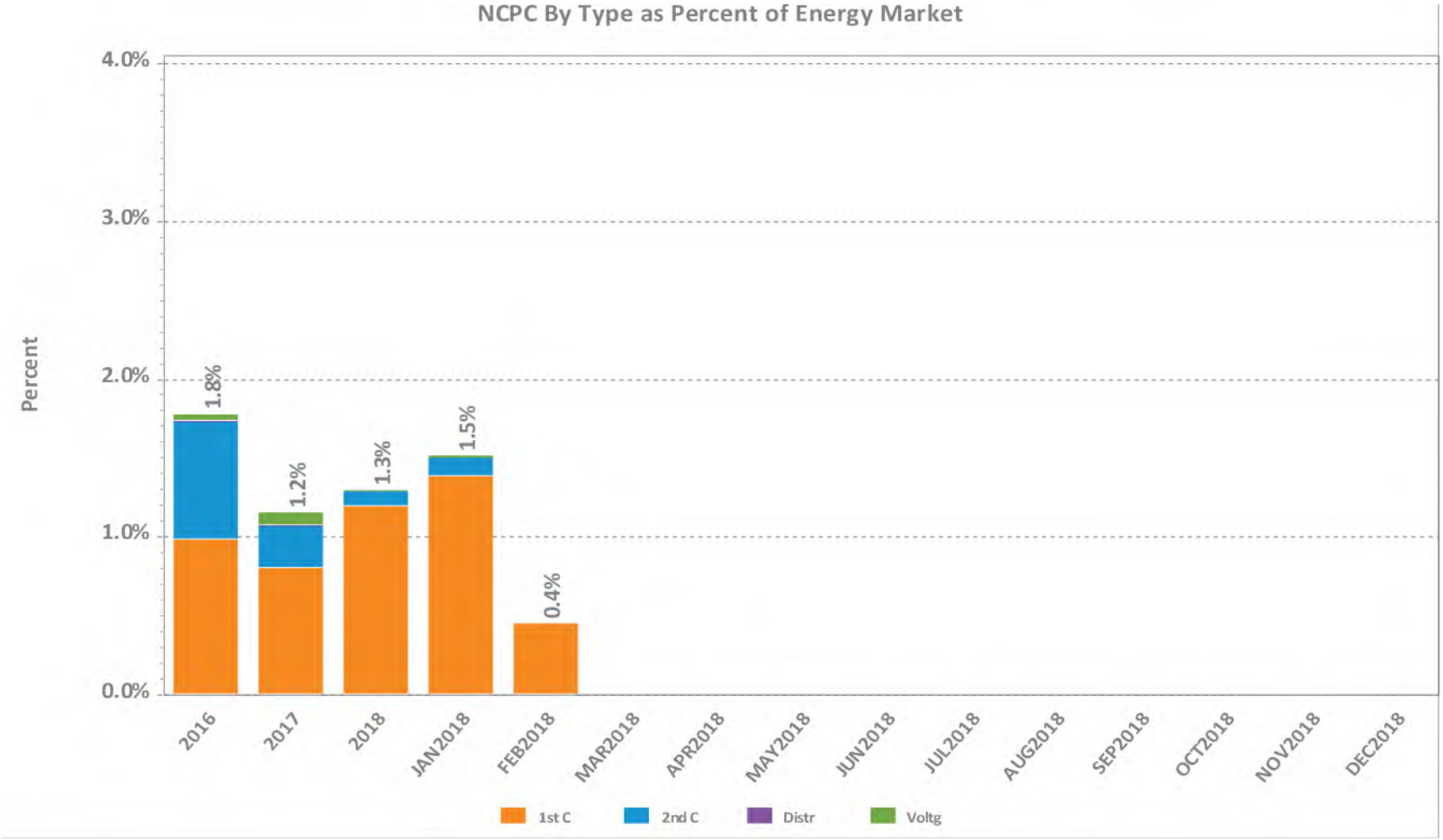
NCPC Charges for Voltage Support and High Voltage Control



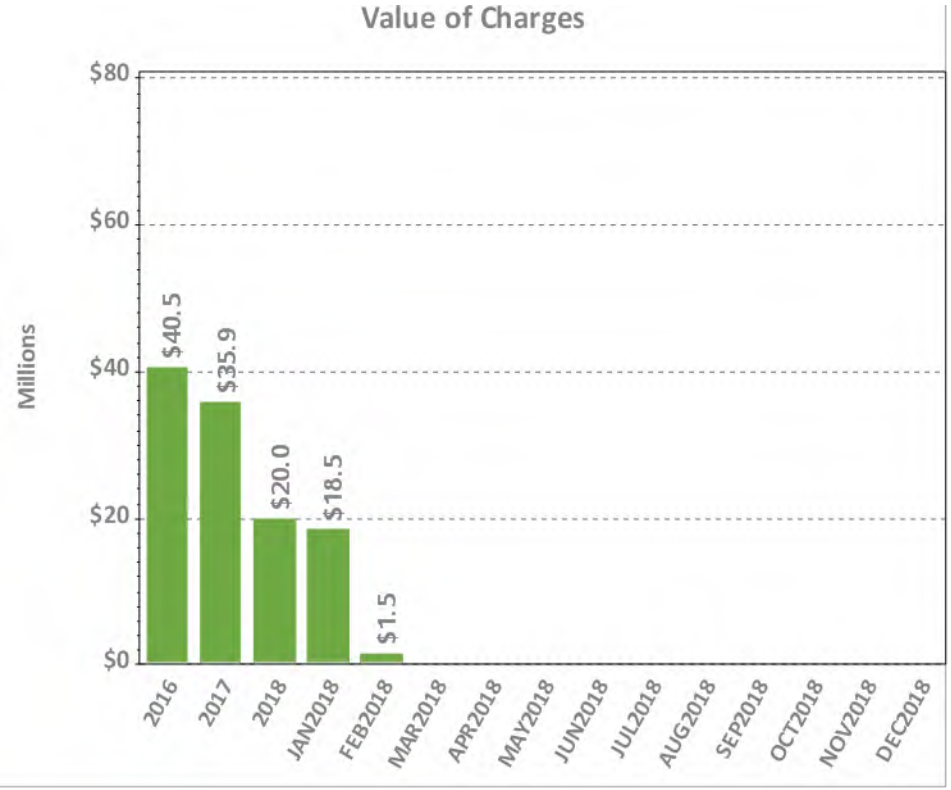
NCPC Charges by Type

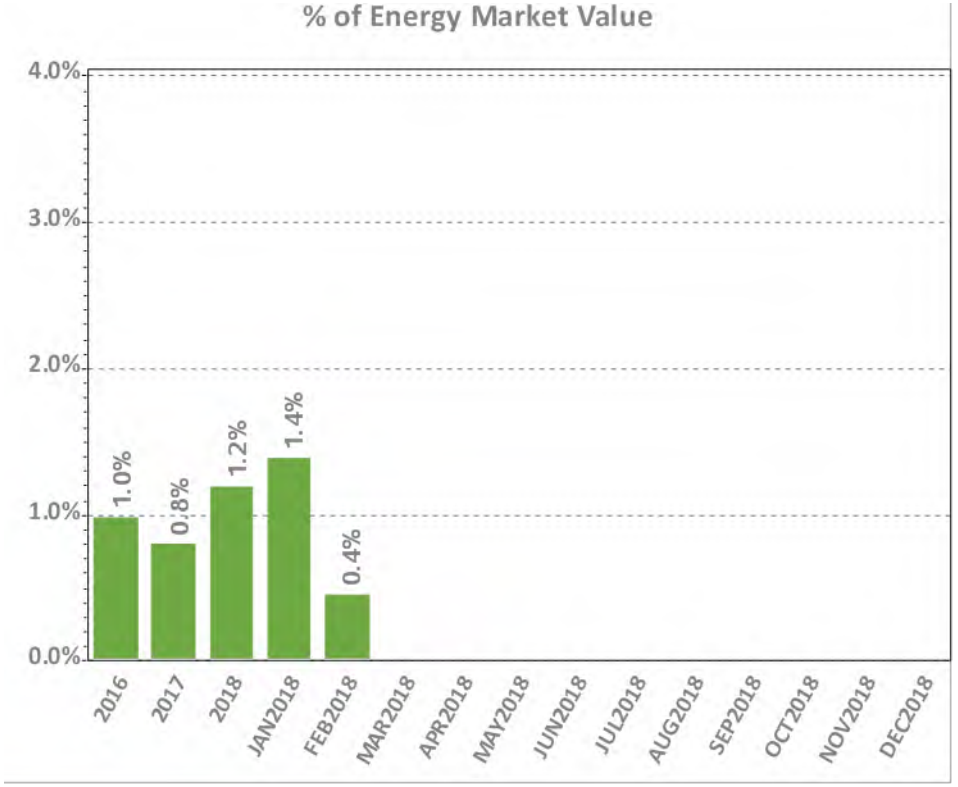


NCPC Charges as Percent of Energy Market



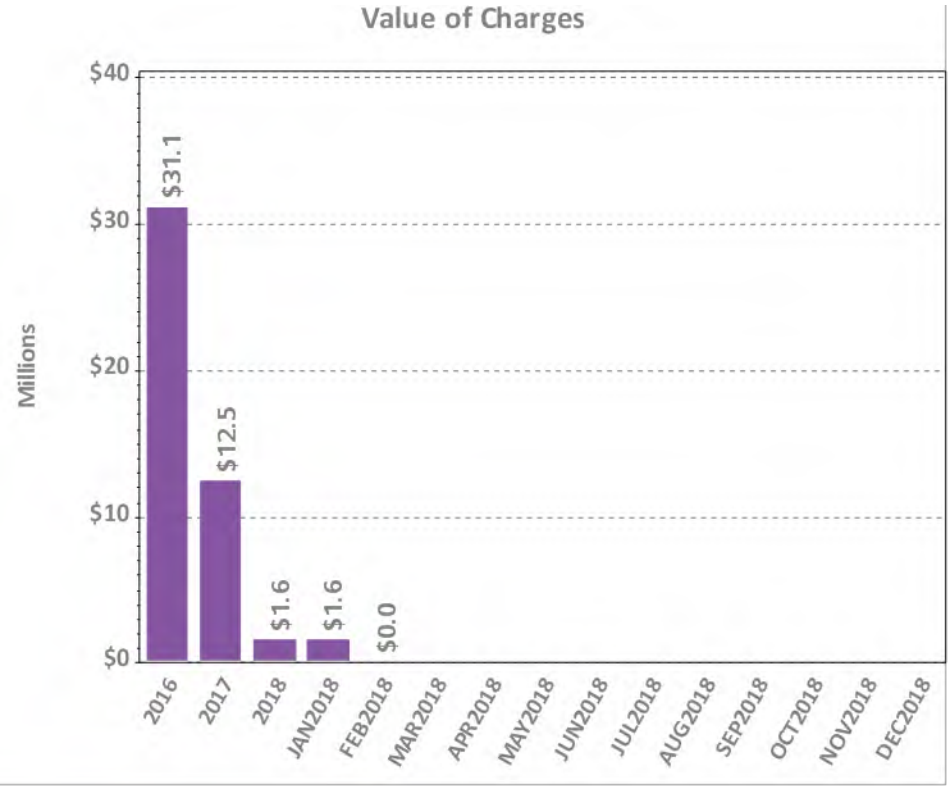
First Contingency NCPC Charges

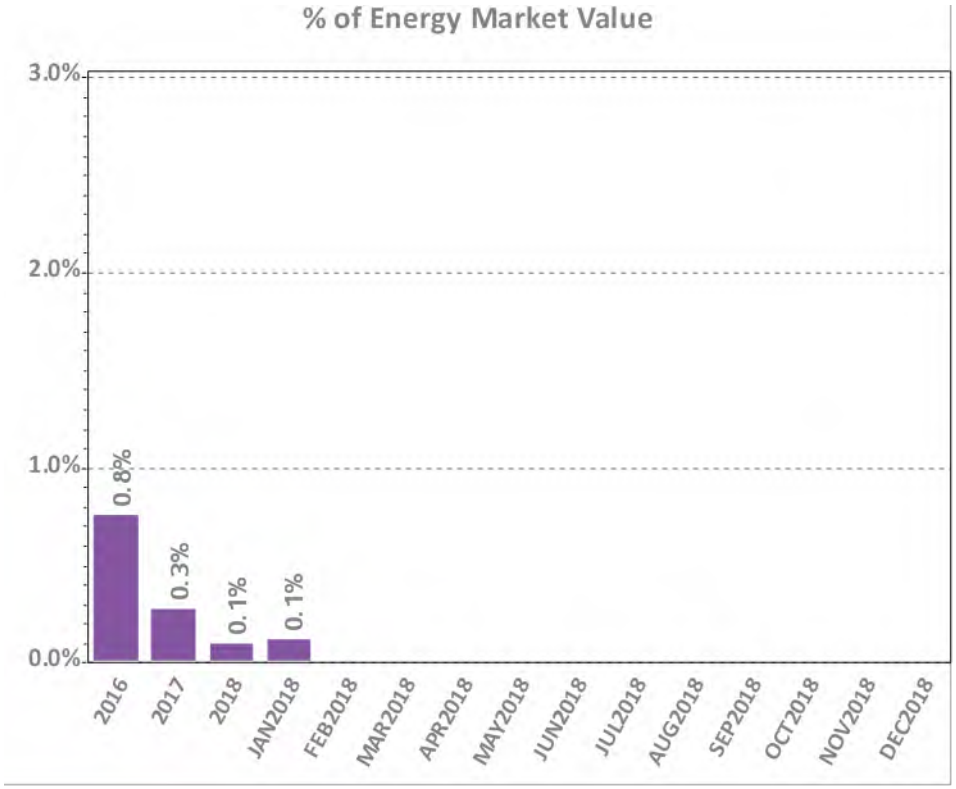




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

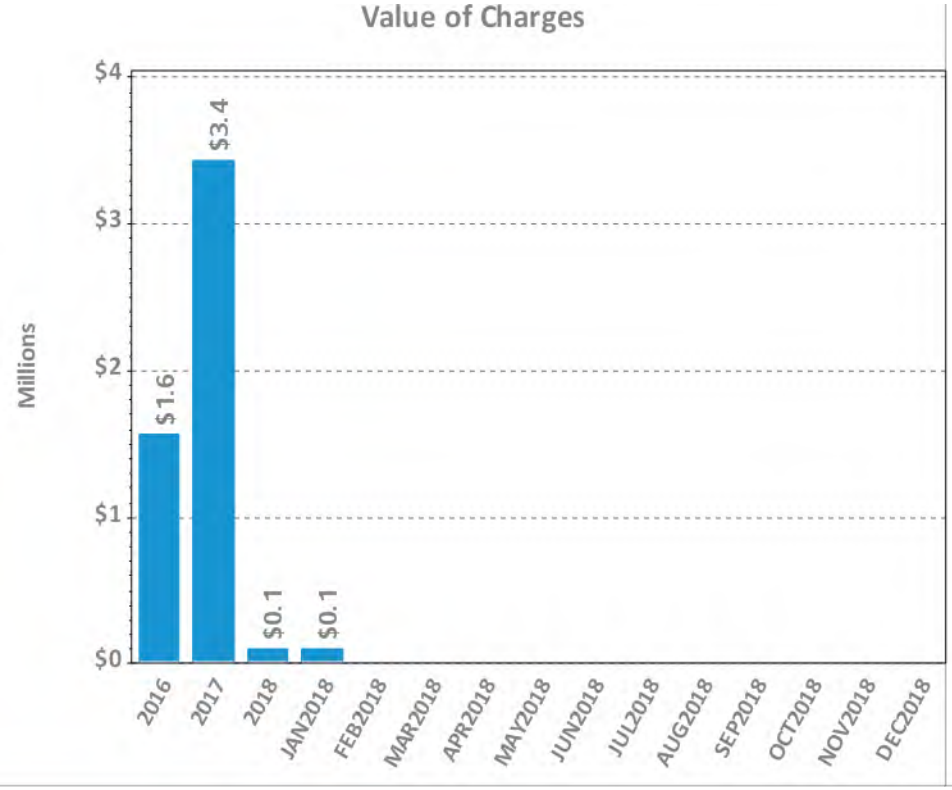
Second Contingency NCPC Charges

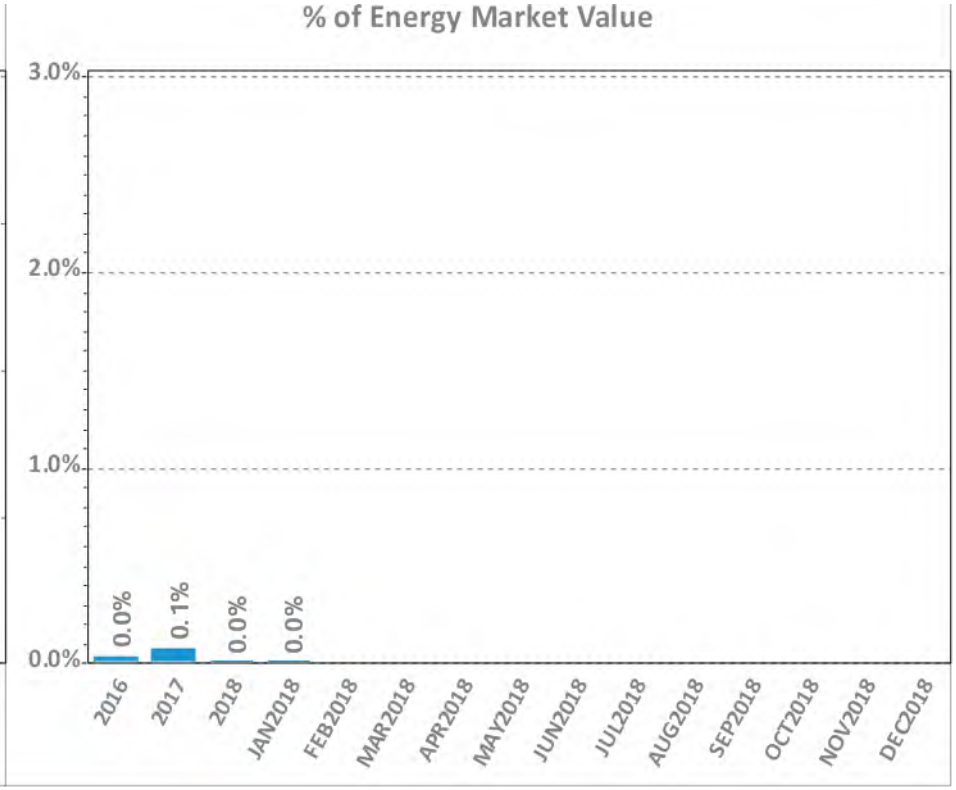




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

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

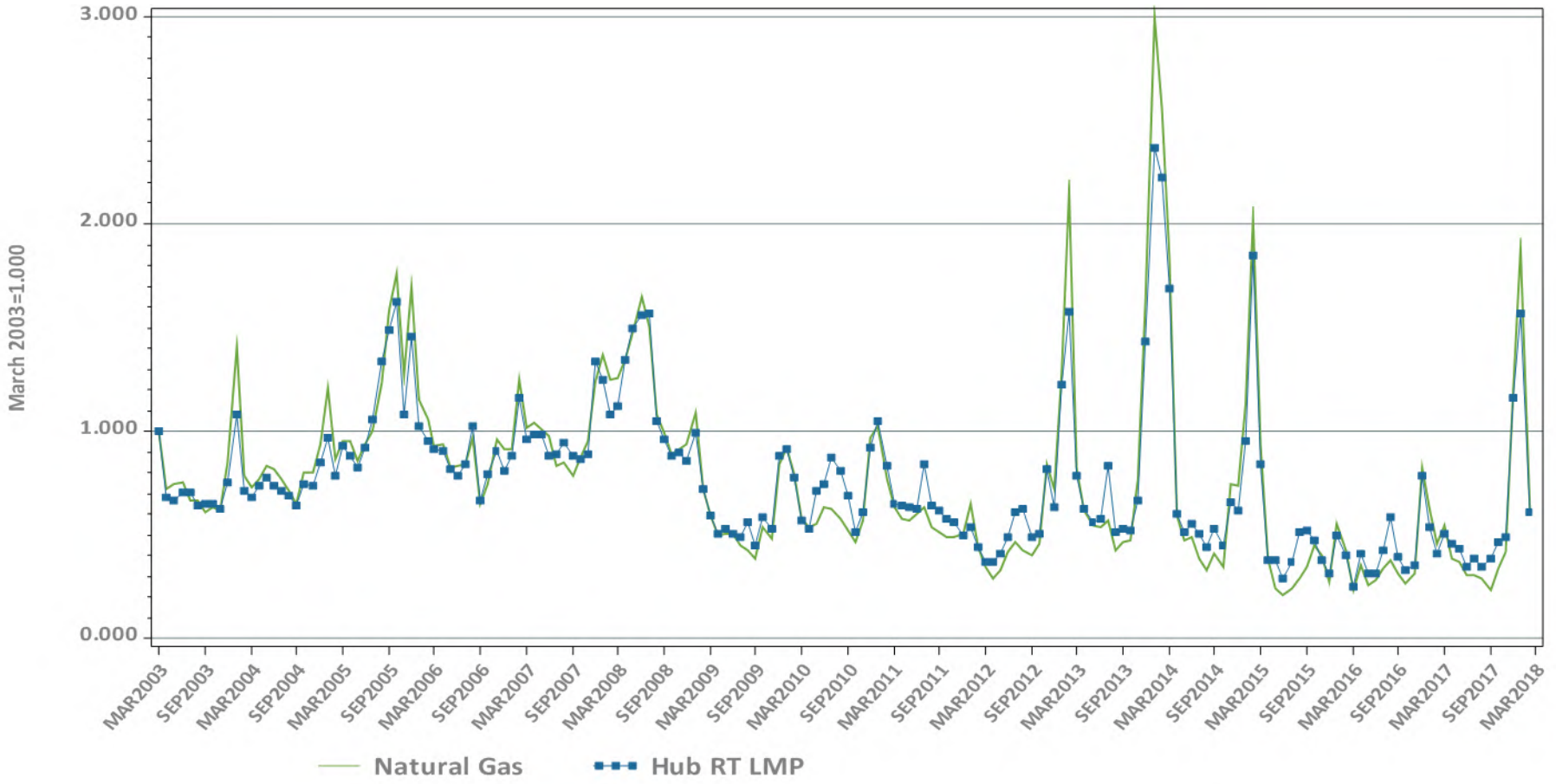
DA vs. RT LMPs ($/MWh)

Arithmetic Average

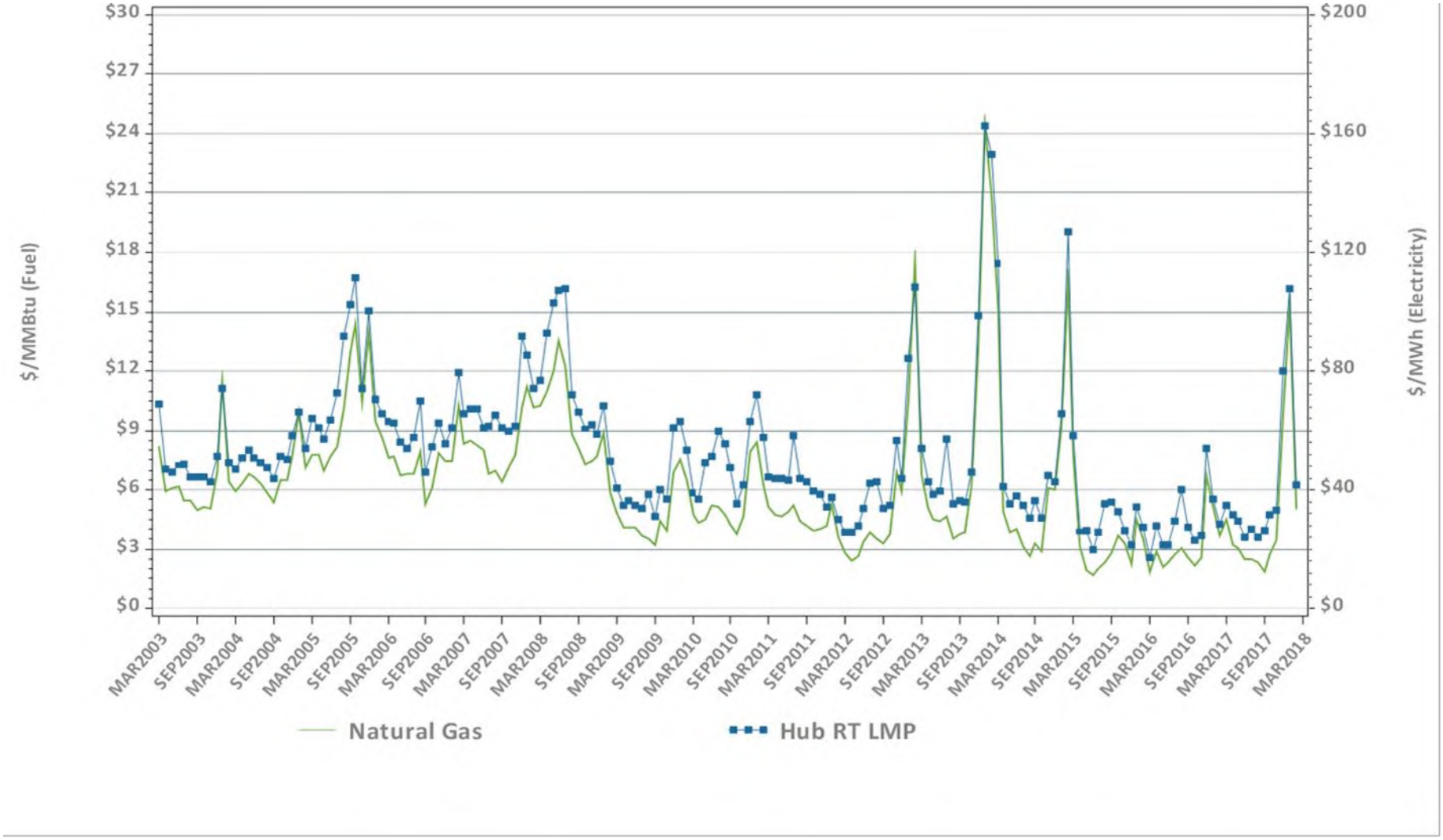
Year 2016	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$30.66	$29.77	$29.07	$29.64	$29.66	$29.66	$29.88	$29.85	$29.78
Real-Time	$29.74	$29.00	$27.81	$28.60	$28.49	$28.87	$29.01	$28.98	$28.94
RT Delta %	-3.0%	-2.6%	-4.3%	-3.5%	-3.9%	-2.7%	-2.9%	-2.9%	-2.8%
Year 2017	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Day-Ahead	$33.46	$33.35	$32.50	$33.13	$33.05	$33.13	$33.27	$33.43	$33.35
Real-Time	$34.76	$33.93	$31.39	$32.78	$33.02	$33.78	$33.98	$33.97	$33.94
RT Delta %	3.9%	1.7%	-3.4%	-1.0%	-0.1%	2.0%	2.1%	1.6%	1.7%

February-17	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$30.33	$30.24	$29.46	$30.04	$29.83	$29.94	$29.97	$30.12	$30.02
Real-Time	$29.02	$27.99	$27.19	$27.93	$27.49	$28.02	$28.08	$28.11	$28.05
RT Delta %	-4.3%	-7.5%	-7.7%	-7.0%	-7.8%	-6.4%	-6.3%	-6.7%	-6.6%
February-18	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Day-Ahead	$44.52	$44.32	$43.14	$44.33	$44.41	$44.61	$44.58	$44.73	$44.64
Real-Time	$41.77	$41.59	$40.14	$41.45	$41.21	$41.81	$41.76	$41.89	$41.83
RT Delta %	-6.2%	-6.2%	-7.0%	-6.5%	-7.2%	-6.3%	-6.3%	-6.3%	-6.3%
Annual Diff.	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Yr over Yr DA	46.8%	46.6%	46.4%	47.6%	48.9%	49.0%	48.7%	48.5%	48.7%
Yr over Yr RT	44.0%	48.6%	47.6%	48.4%	49.9%	49.2%	48.7%	49.0%	49.1%

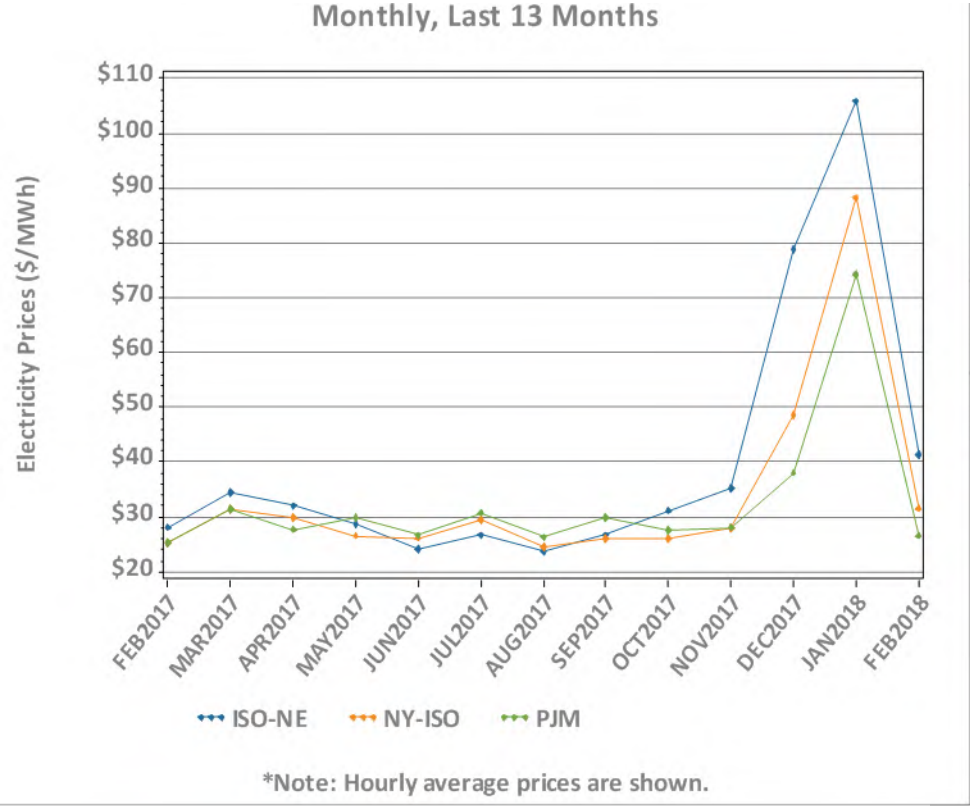
Monthly Average Fuel Price and RT Hub LMP Indexes

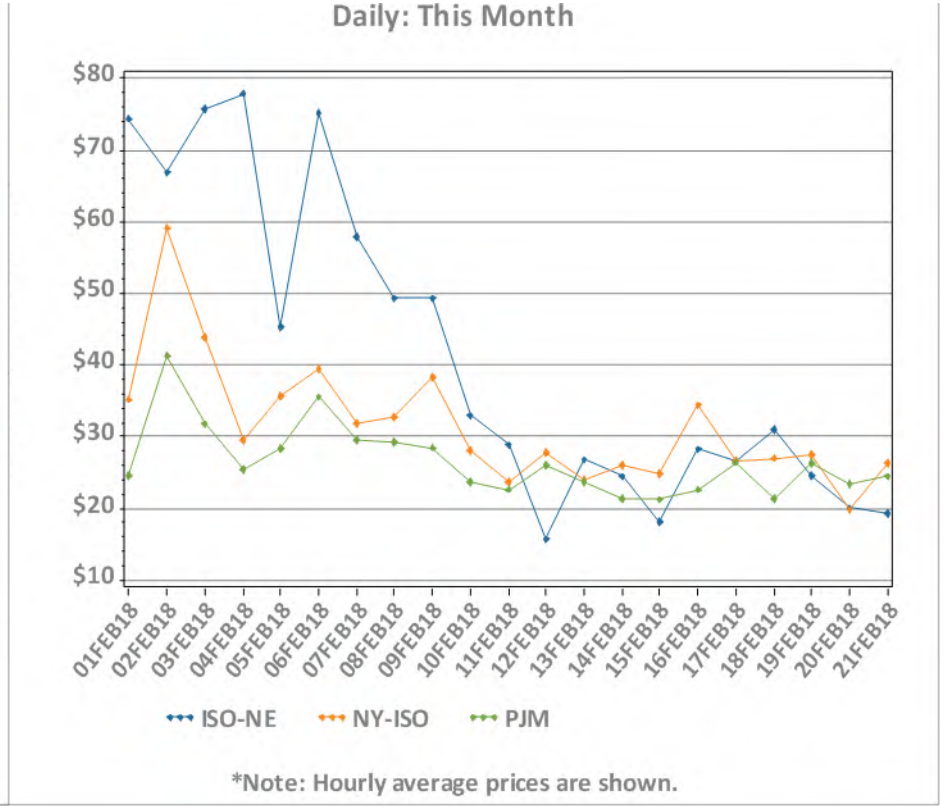


Monthly Average Fuel Price and RT Hub LMP

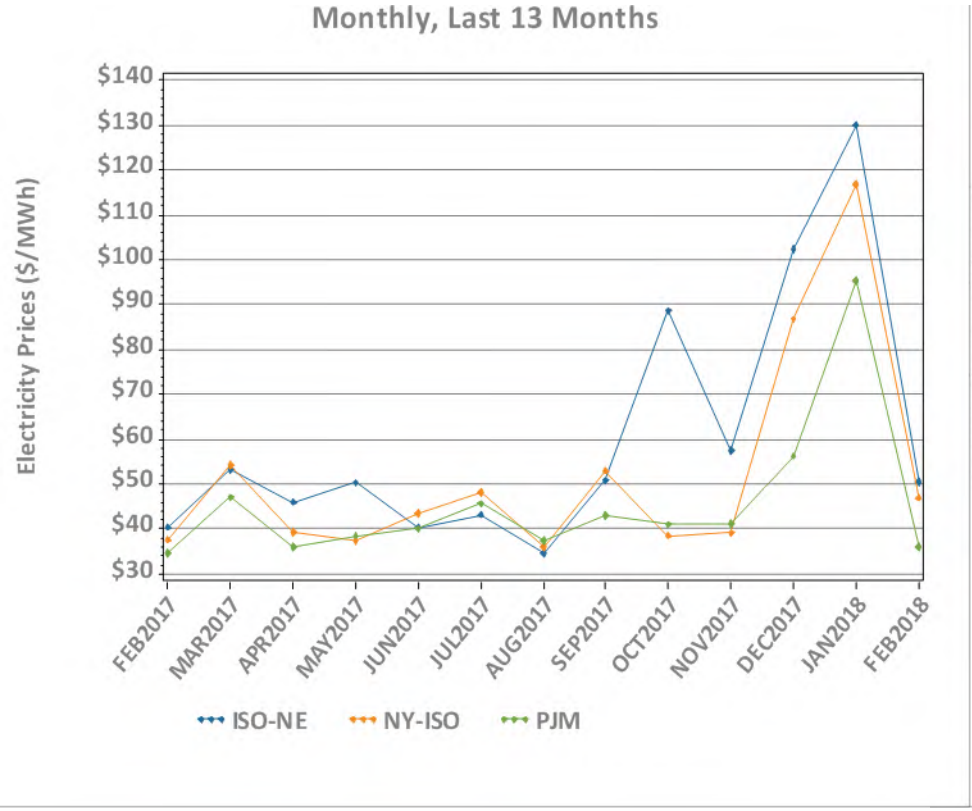


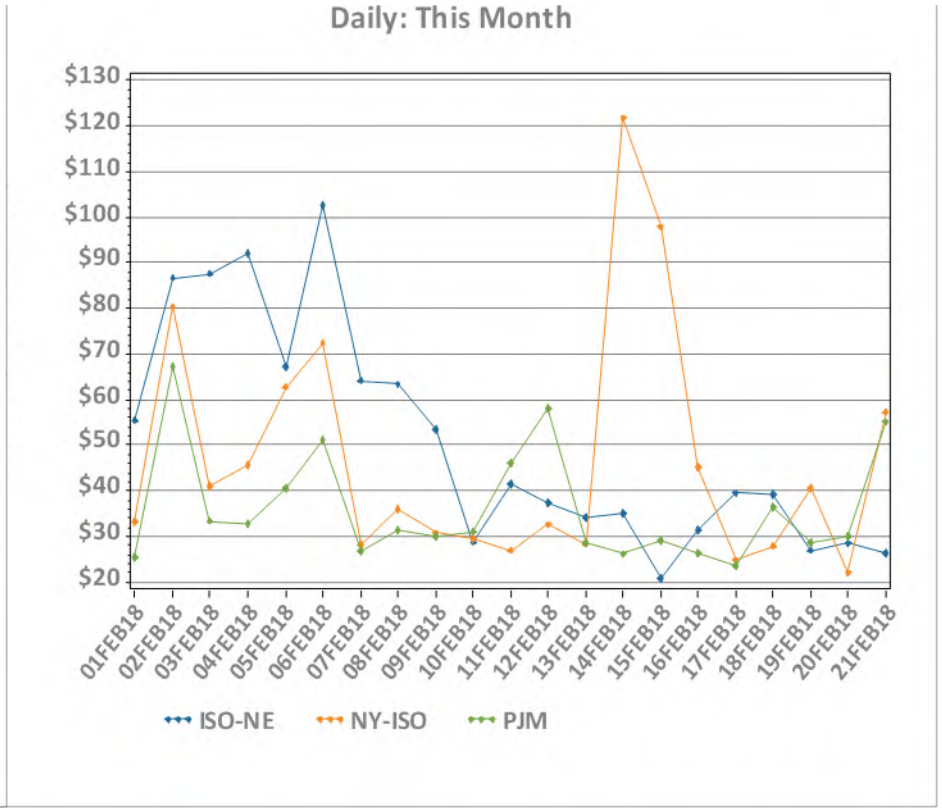
New England, NY, and PJM Hourly Average Real Time Prices by Month





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





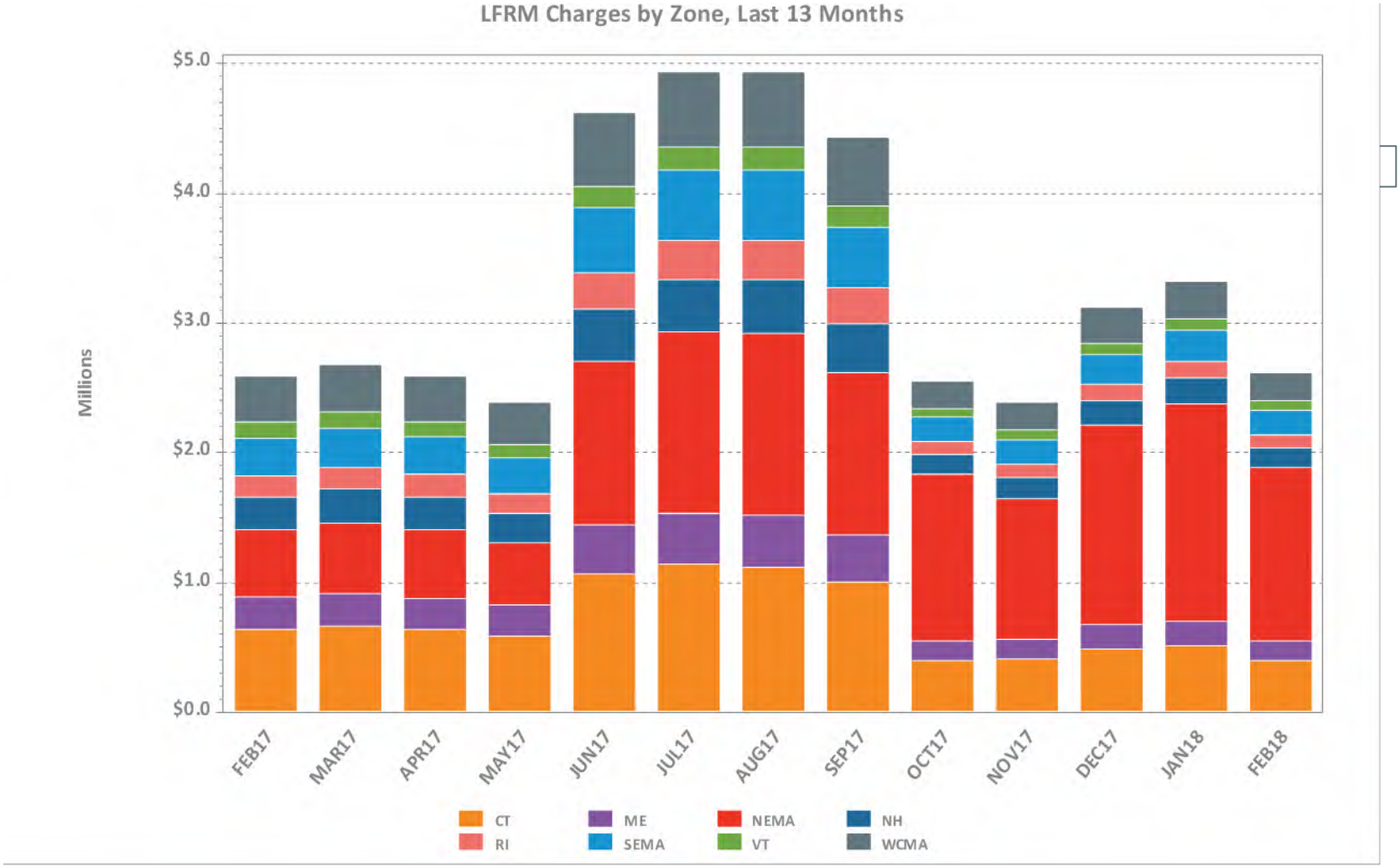
***Forecasted New England daily peak hours reflected**

Reserve Market Results – February 2018

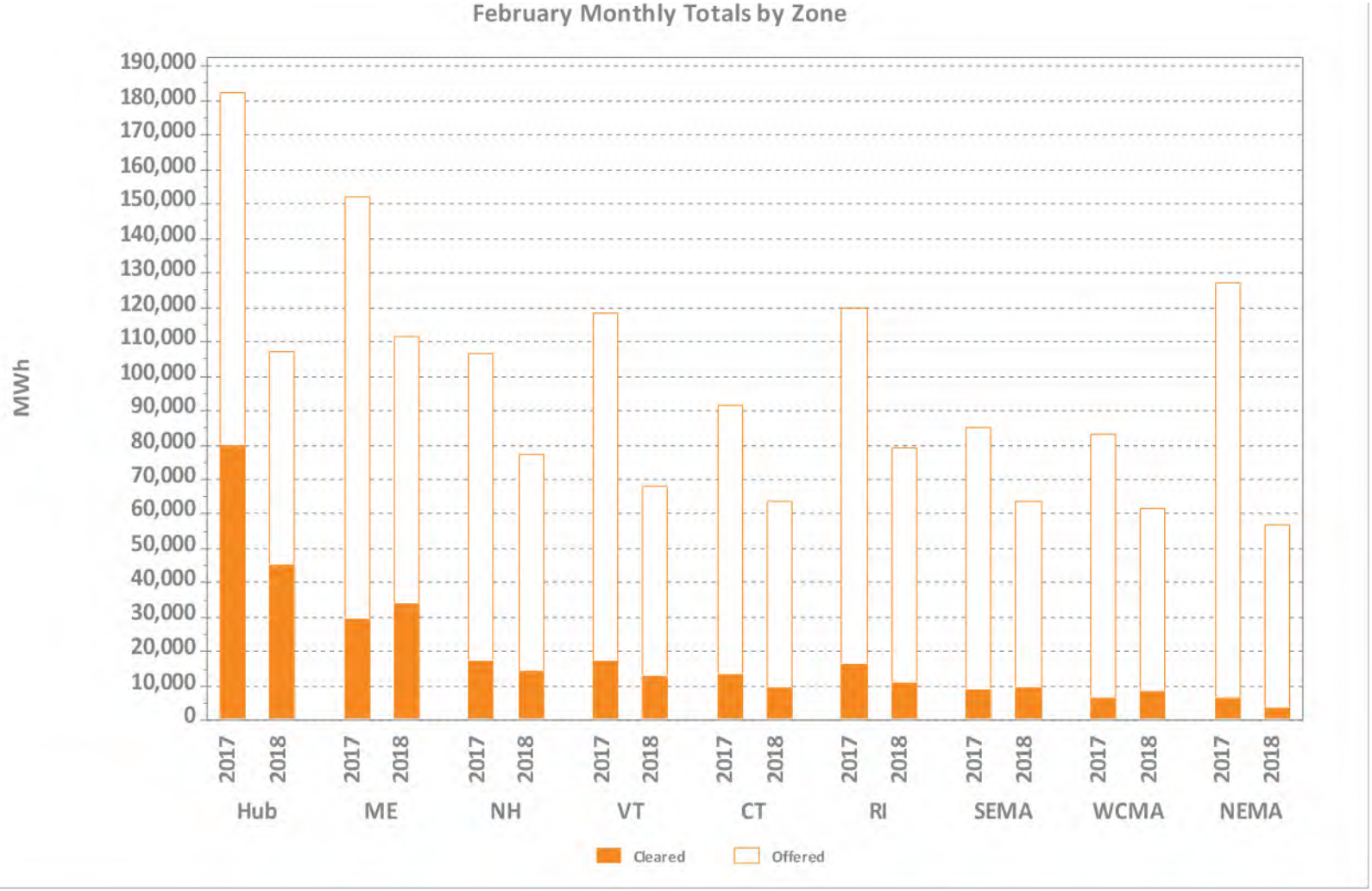
- Maximum potential Forward Reserve Market payments of $2.7M were reduced by credit reductions of $34K, failure-to-reserve penalties of $51K and no failure-to-activate penalties, resulting in a net payout of $2.6M or 97% of maximum
  - Rest of System: $0.87M/0.95M (92%)
  - Southwest Connecticut: $0.11M/0.12M (93%)
  - Connecticut: $0.41M/0.41M (100%)
  - NEMA: $1.2M/1.2M (100%)
- $382K total Real-Time credits were not reduced by any Forward Reserve Energy Obligation Charges for a net of $382K in Real-Time Reserve payments
  - Rest of System: 150 hours, $280K
  - Southwest Connecticut: 150 hours, $39K
  - Connecticut: 150 hours, $39K
  - NEMA: 150 hours, $25K

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

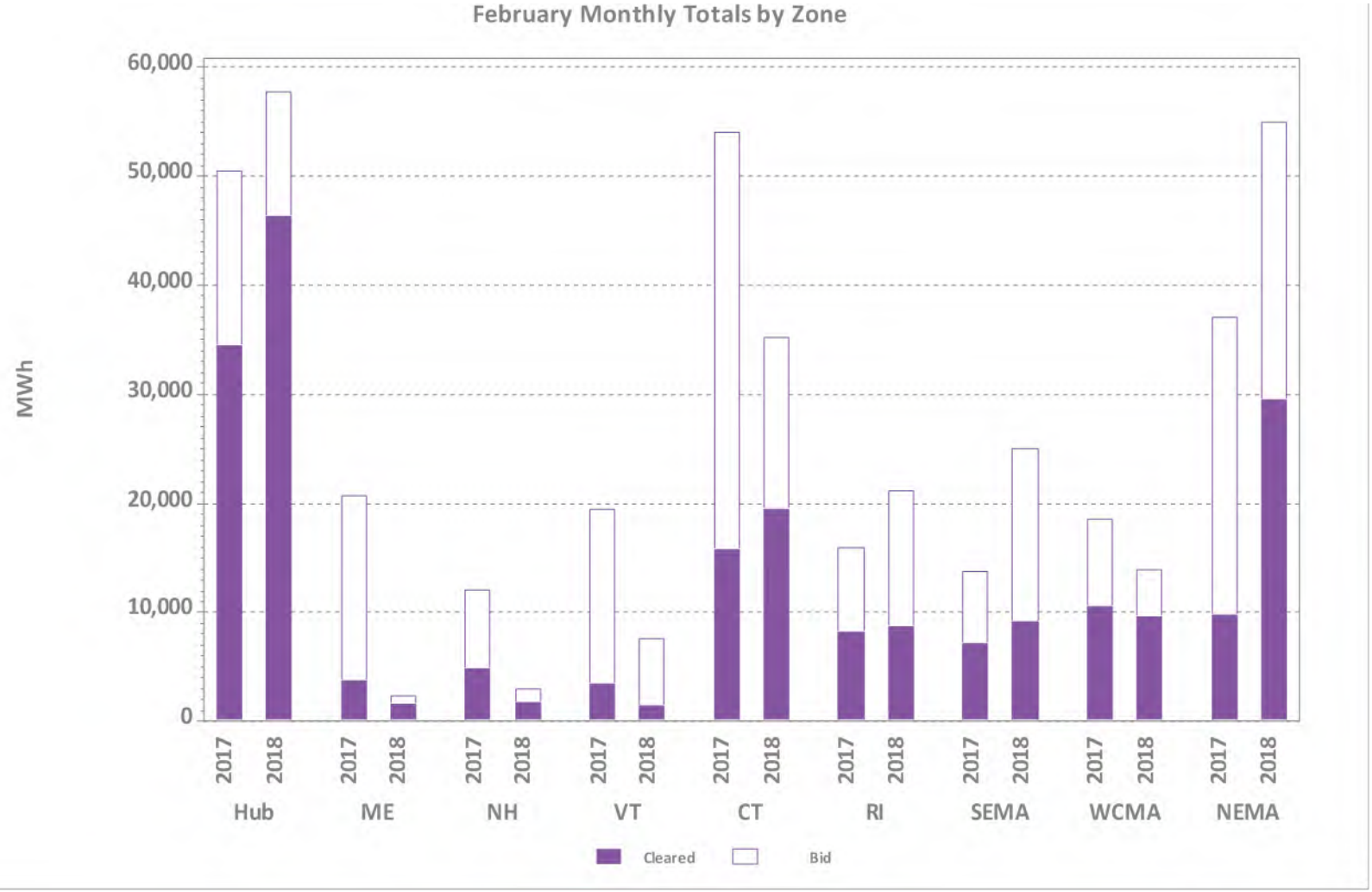
LFRM Charges to Load by Load Zone ($)



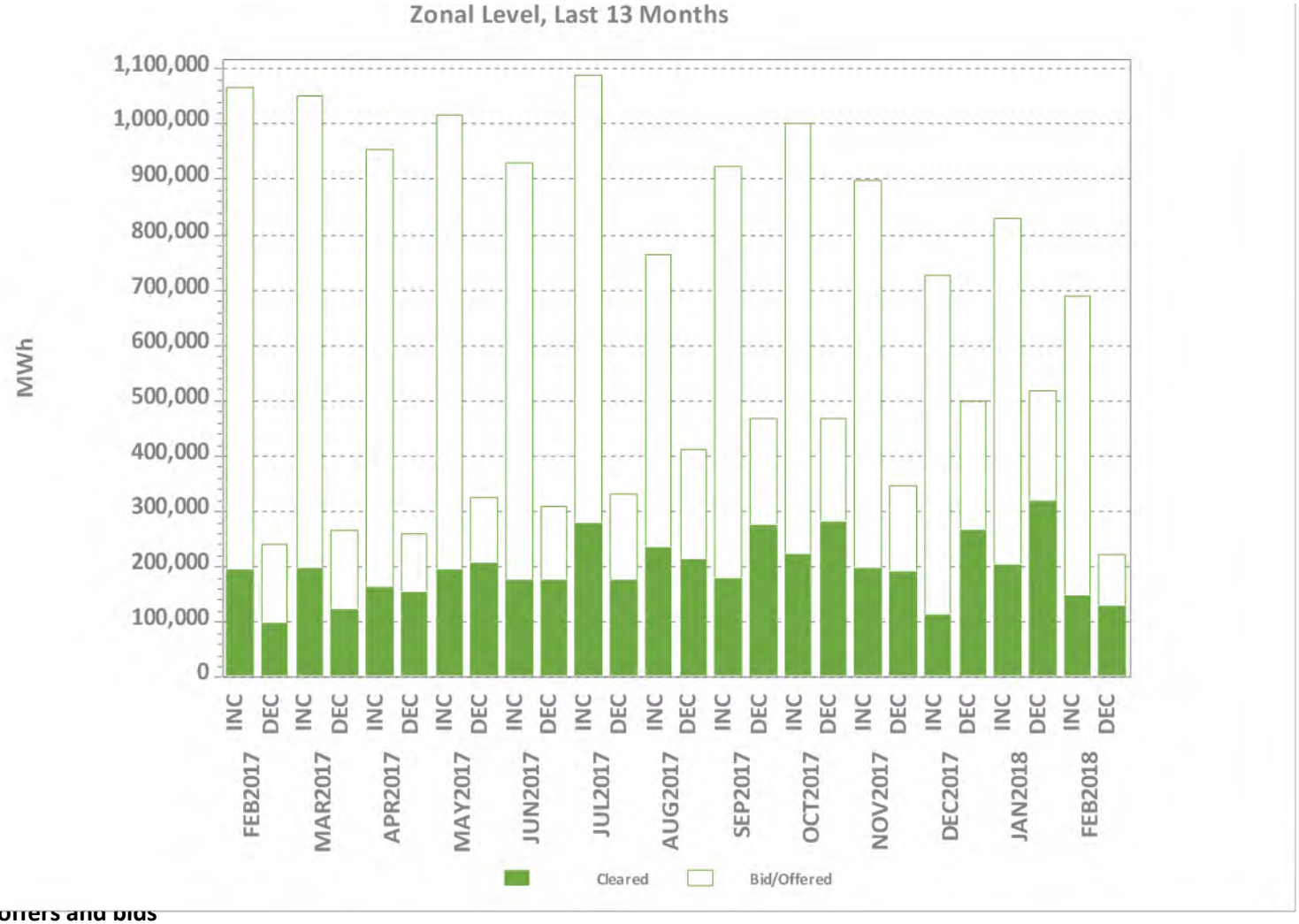
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

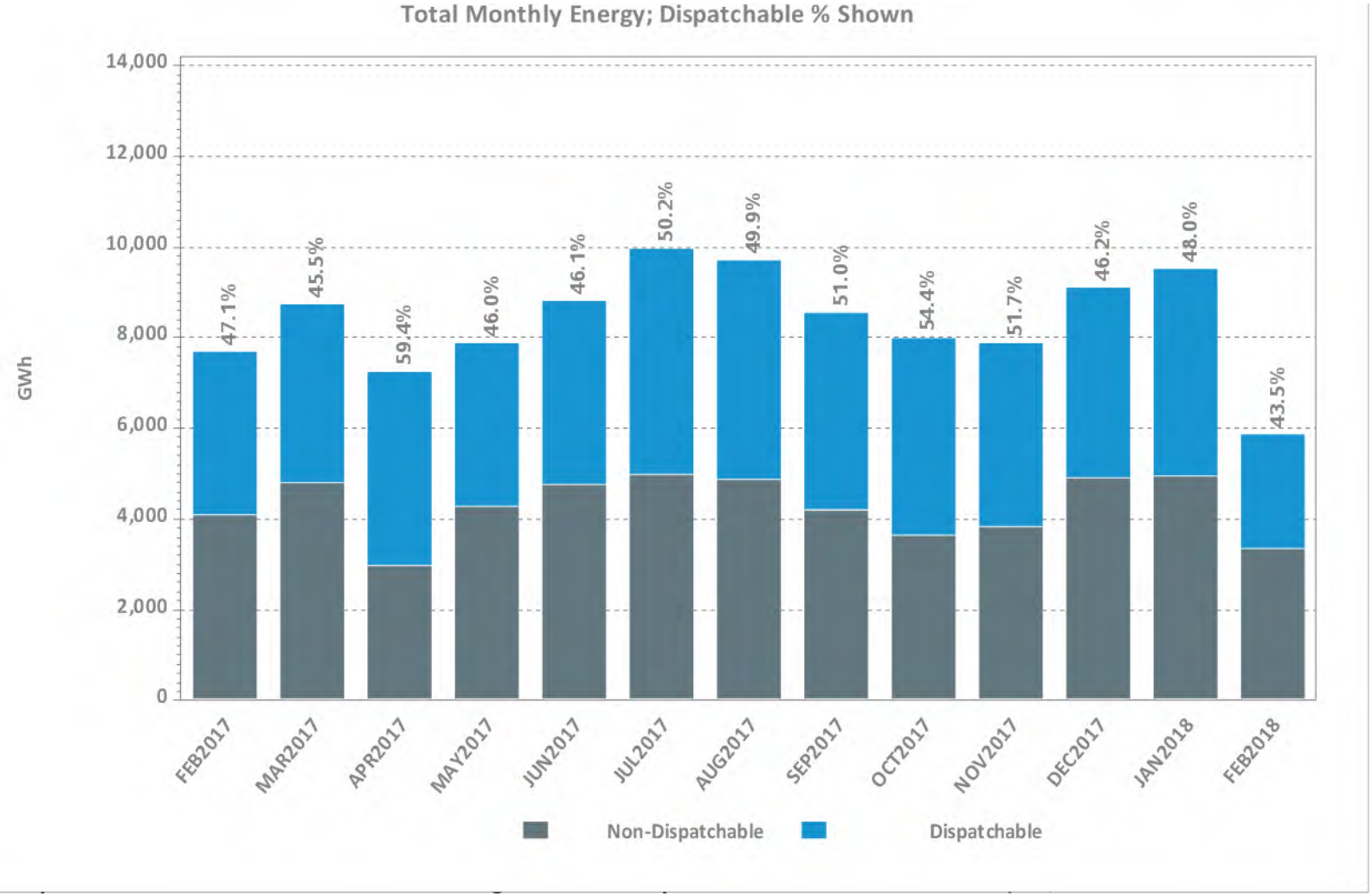


Total Increment Offers and Decrement Bids



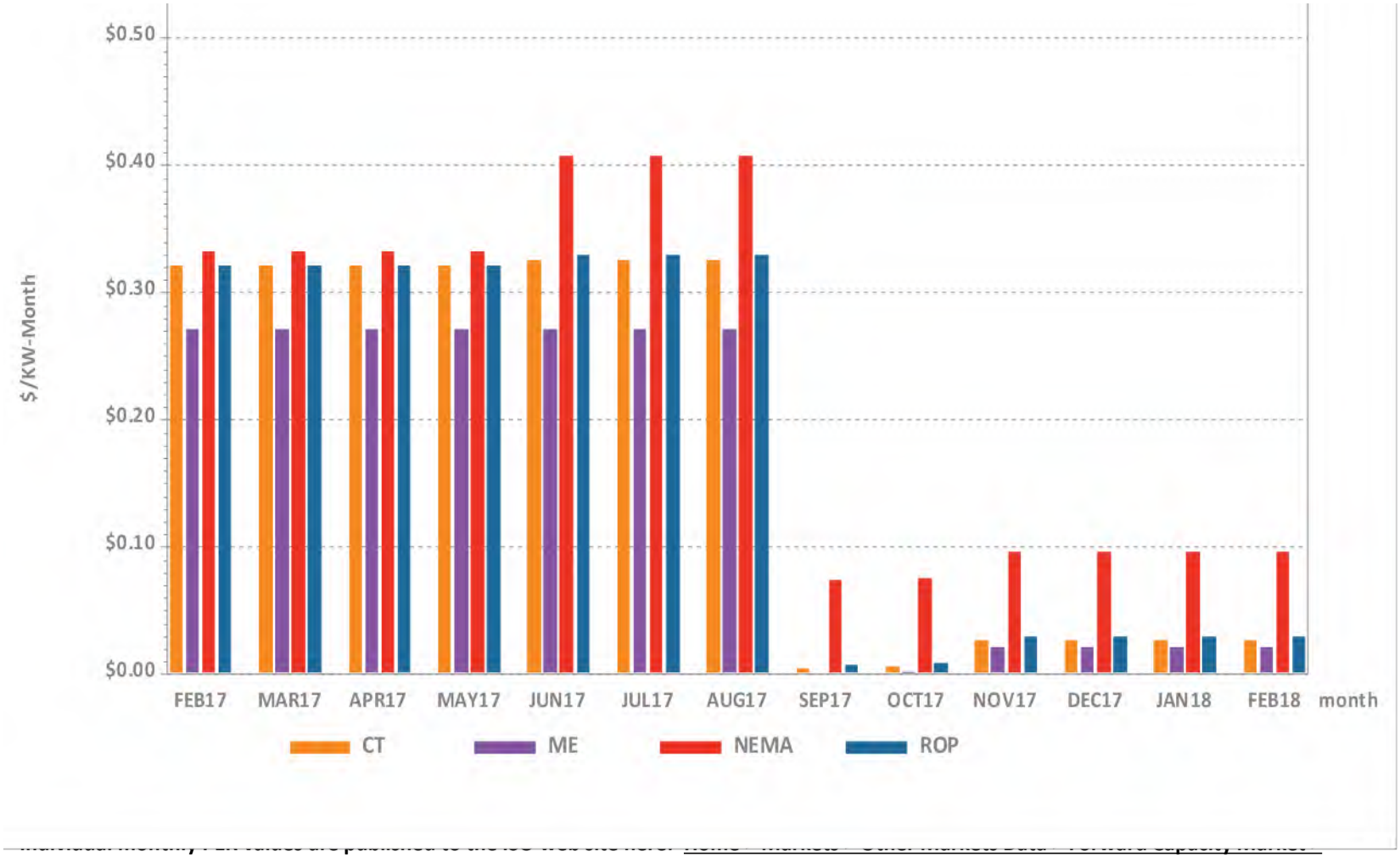
Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



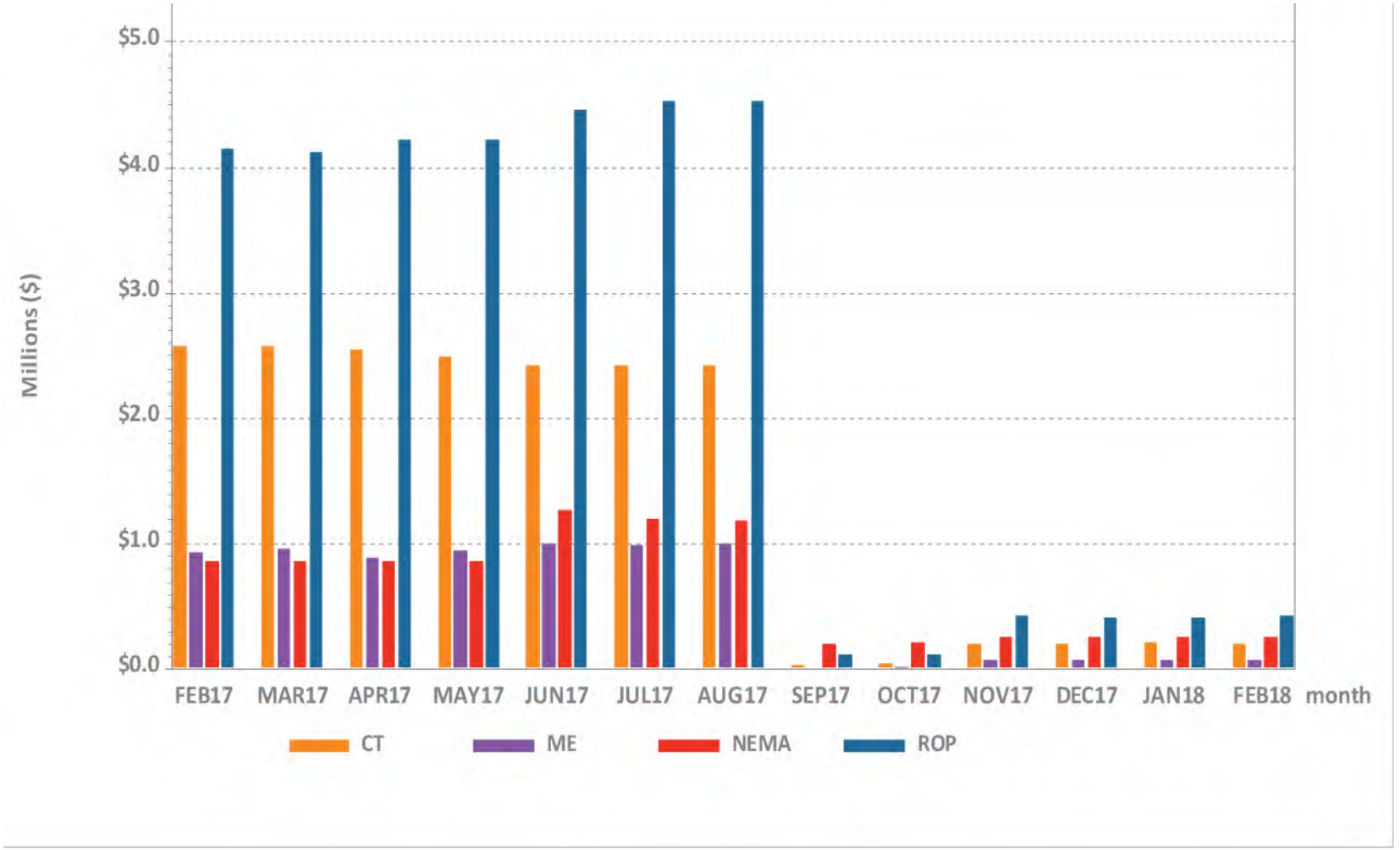
'must run' by the customer).

Rolling Average Peak Energy Rent (PER)



Reports and are subject to resettlement.

PER Adjustments



REGIONAL SYSTEM PLAN (RSP)

Planning Advisory Committee (PAC)

- March 15 PAC Meeting Agenda Topics*
  - Regional System Plan Transmission Projects and Asset Condition March 2018 Update
  - FCA #13 Zonal Boundary Determinations
  - New England EE, PV, and Load Forecast Update
  - Round 3 Updates to Transmission Planning Technical Guide
  - ECT 2027 Needs Assessment Results
  - SWCT 2027 Needs Assessment Results
  - Canal 115 kV BPS Upgrades
  - Card 5X Autotransformer Update
  - Montville 16X Autotransformer Replacement

* 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

- The forecast development process for 2018 is nearing completion. Draft forecasts will be presented to PAC in March with follow-up in April.
  - Load Forecast
    - Next Load Forecast Committee meeting will be held on March 28. Overall, the draft summer gross peak forecast is 1.3-2.7% lower than last year's forecast, depending on the forecast year.
    - Project to enhance information available on our website to be completed by Q1 2018.
  - Energy-Efficiency (EE) Forecast
    - The next EE Forecast Working Group meeting will be held on March 26. Overall, the forecast is expected to increase over last year's forecast.
  - Photovoltaic (PV) Forecast
    - The next Distributed Generation Forecast Working Group meeting will be held on March 19. Overall, the forecast is expected to increase slightly over last year's forecast.

Interregional Planning

- The Northeast Coordinated System Plan 2017 (NCSP17) is under development consistent with the scope of work discussed at the Inter-Area Planning Stakeholder Advisory Committee (IPSAC) held on 12/11/17
  - Plans call for posting the draft report for stakeholder comment in the March timeframe
  - Next IPSAC meeting is scheduled for May 18 from 9:00am – 12:00pm

Environmental Matters

- The ISO tracks environmental regulatory developments affecting new and existing generators and transmission infrastructure
  - The final 2016 system emissions report was posted at: https://www.iso-ne.com/static-assets/documents/2018/01/2016_emissions_report.pdf
  - EPA accepting comments until 4/26/18 on options for achieving greenhouse gas reductions at existing power plants
    - Also adding more public hearings on proposed Clean Power Plan repeal
  - On 1/23/18, Massachusetts DEP acknowledged questions from stakeholders about the availability of Massachusetts Global Warming Solutions Act generator emission cap allowances and concerns about:
    - Market conditions, allowance supply and price formation during the calendar year
    - Solutions that may include allowing early allowance trading, extending "emergency deferred compliance" option to emergencies that occur throughout the calendar year instead of just the year-end
  - On 1/26/18, Regional Greenhouse Gas Initiative (RGGI) states held a webinar on design issues involved with Virginia joining RGGI

2017 Economic Study Update

- The 2017 Study will examine three cases with the same basic assumptions that were used in the 2016 Study Scenario 3, but with the retirement of 2,100 MW of nuclear generation and changes in the resource mix to reflect differing amounts of energy efficiency, onshore wind, and offshore wind
  - 2017 Economic Study draft results were presented at the 2/14/18 PAC meeting
  - The draft report is scheduled to be posted 2nd quarter

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

Note: The listings in this section focus on major transmission line construction and rebuilding.

Connecticut River Valley

Status as of 2/23/18

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

Upgrade	Expected/ Actual In-Service	Present Stage
Rebuild 115 kV line K31, Coolidge-Ascutney	Aug-17	4
Ascutney Substation - Add a +50/-25 MVAR dynamic reactive device	Aug-18	3
Hartford Substation - Split 25 MVAR capacitor bank into two 12.5 MVAR banks	Dec-16	4
Chelsea Station - Rebuild to a three-breaker ring bus	Jan-18	4

New Hampshire/Vermont 10-Year Upgrades

Status as of 2/23/18

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected/ Actual 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	Feb-17	4
New 115 kV overhead line, Scobie Pond-Huse Road	Dec-15	4
New 115 kV overhead/submarine line, Madbury-Portsmouth	Dec-19	2
New 115 kV overhead line, Scobie Pond-Chester	Dec-15	4

New Hampshire/Vermont 10-Year Upgrades, cont.

Status as of 2/23/18

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected/ Actual 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	Dec-14	4
Uprate 115 kV line G146, Garvins-Deerfield	Mar-15	4
Uprate 115 kV line P145, Oak Hill-Merrimack	May-14	4

New Hampshire/Vermont 10-Year Upgrades, cont.

Status as of 2/23/18

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected/ Actual In-Service	Present Stage
Upgrade 115 kV line H141, Chester-Great Bay	Nov-14	4
Upgrade 115 kV line R193, Scobie Pond-Kingston Tap	Dec-14	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

Greater Hartford and Central Connecticut (GHCC) Projects*

Status as of 2/23/18

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/ Actual 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	Apr-17	4
Terminal equipment upgrades on the 345 kV line between Haddam Neck and Beseck (362)	Feb-17	4
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	Jun-18	3
Add a 37.8 MVAR capacitor bank at the Hopewell 115 kV substation	Dec-15	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	Mar-17	4
Increase the size of the existing 115 kV capacitor bank at Branford Substation from 37.8 to 50.4 MVAR	Jan-17	4
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	4

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 2/23/18

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/ Actual 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	3
Add a 115 kV 25.2 MVAR capacitor at Westside 115 kV substation	Dec-18	3
Loop the 1779 line between South Meadow and Bloomfield into the Rood Avenue substation and reconfigure the Rood Avenue substation	May-17	4
Reconfigure the Berlin 115 kV substation including two new 115 kV breakers and the relocation of a capacitor bank	Nov-17	4
Reconductor the 115 kV line between Newington and Newington Tap (1783)	Dec-18	3

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 2/23/18

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/ Actual 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	4
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	4
Install a 115 kV 3% reactor on the 115 kV line between South Meadow and Southwest Hartford (1704)	Dec-18	3
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-18	3
Replace the normally open 19T breaker at Southington 115 kV with a normally closed 3% series reactor	Jun-18	3
Add a 345 kV breaker in series with breaker 5T at Southington	May-17	4

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 2/23/18

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/ Actual In-Service	Present Stage
Add a new control house at Southington 115 kV substation	Dec-18	3
Add a new 115 kV line from Frost Bridge to Campville	Dec-17	4
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	4
Add a new 345/115 kV autotransformer at Barbour Hill substation	Dec-15	4
Add a 345 kV breaker in series with breaker 24T at the Manchester 345 kV substation	Dec-15	4
Reconductor the 115 kV line between Manchester and Barbour Hill (1763)	Apr-16	4

* Replaces the NEEWS Central Connecticut Reliability Project

Southwest Connecticut (SWCT) Projects

Status as of 2/23/18

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/ Actual In-Service	Present Stage
Add a 25.2 MVAR capacitor bank at the Oxford substation	Mar-16	4
Add 2 x 25 MVAR capacitor banks at the Ansonia substation	Dec-18	3
Close the normally open 115 kV 2T circuit breaker at Baldwin substation	Sep-17	4
Reconductor the 115 kV line between Bunker Hill and Baldwin Junction (1575)	Dec-16	4
Expand Pootatuck (formerly known as Shelton) substation to 4-breaker ring bus configuration and add a 30 MVAR capacitor bank at Pootatuck	Jul-18	3
Loop the 1570 line in and out the Pootatuck substation	Jul-18	3
Replace two 115 kV circuit breakers at the Freight substation	Dec-15	4

Southwest Connecticut Projects, cont.

Status as of 2/23/18

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/ Actual In-Service	Present Stage
Add two 14.4 MVAR capacitor banks at the West Brookfield substation	Dec-17	4
Add a new 115 kV line from Plumtree to Brookfield Junction	Sep-18	3
Reconductor the 115 kV line between West Brookfield and Brookfield Junction (1887)	Oct-18	2
Reduce the existing 25.2 MVAR capacitor bank at the Rocky River substation to 14.4 MVAR	Apr-17	4
Reconfigure the 1887 line into a three-terminal line (Plumtree - W. Brookfield - Shepaug)	May-18	3
Reconfigure the 1770 line into 2 two-terminal lines (Plumtree - Stony Hill and Stony Hill - Bates Rock)	May-18	3
Install a synchronous condenser (+25/-12.5 MVAR) at Stony Hill	Oct-18	3
Relocate an existing 37.8 MVAR capacitor bank at Stony Hill to the 25.2 MVAR capacitor bank side	May-18	3

Southwest Connecticut Projects, cont.

Status as of 2/23/18

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/ Actual 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	Apr-17	4
Add a 115 kV circuit breaker in series with the existing 29T breaker at the Plumtree substation	May-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	Jun-17	4
Reconductor the 115 kV line from Wilton to Ridgefield Junction (1470-1)	Jun-19	2
Reconductor the 115 kV line from Ridgefield Junction to Peaceable (1470-3)	Jun-19	2

Southwest Connecticut Projects, cont.

Status as of 2/23/18

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/ Actual 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	3
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	3
Rebuild the 115 kV lines from Housatonic River Crossing (HRX) to Barnum to Baird (88006A / 89006B)	Sep-20	2

Southwest Connecticut Projects, cont.

Status as of 2/23/18

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/ Actual In-Service	Present Stage
Remove the Sackett phase shifter	Mar-17	4
Install a 7.5 ohm series reactor on 1610 line at the Mix Avenue substation	Dec-16	4
Add 2 x 20 MVAR capacitor banks at the Mix Avenue substation	Dec-16	4
Upgrade the 1630 line relay at North Haven and Wallingford 1630 terminal equipment	Jan-17	4
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 2/23/18

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

Upgrade	Expected/ Actual In-Service	Present Stage
Install new 345 kV line from Scobie to Tewksbury	Dec-17	4
Reconductor the Y-151 115 kV line from Dracut Junction to Power Street	Apr-17	4
Reconductor the M-139 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
Reconductor the N-140 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
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	Dec-18	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	May-19	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	Jun-18	2

Greater Boston Projects, cont.

Status as of 2/23/18

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

Upgrade	Expected/ Actual In-Service	Present Stage
Separate X-24 and E-157W DCT	Jun-18	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	4
Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook	Sep-19	3
Install third 115 kV line from West Walpole to Holbrook	Sep-19	3
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	4
Install a new 115 kV line from Sudbury to Hudson	Dec-19	1

Greater Boston Projects, cont.

Status as of 2/23/18

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

Upgrade	Expected/ Actual In-Service	Present Stage
Replace 345/115 kV autotransformer, 345 kV breakers, and 115 kV switchgear at Woburn	May-19	3
Install a 345 kV breaker in series with breaker 104 at Woburn	May-17	4
Reconfigure Waltham by relocating PARs, 282-507 line, and a breaker	Dec-17	4
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	4
Install a new 115 kV 36.7 MVAR capacitor bank at Sudbury	May-17	4
Install a second Mystic 345/115 kV autotransformer and reconfigure the bus	Dec-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	May-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	May-19	2

Greater Boston Projects, cont.

Status as of 2/23/18

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

Upgrade	Expected/ Actual In-Service	Present Stage
Install a second 115 kV cable from Mystic to Woburn to create a bifurcated 211-514 line	Dec-18	3
Open lines 329-510/511 and 250-516/517 at Mystic and Chatham, respectively. Operate K Street as a normally closed station.	Dec-18	3
Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard	Dec-18	3
Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-16	4

Greater Boston Projects, cont.

Status as of 2/23/18

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

Upgrade	Expected/ Actual In-Service	Present Stage
Upgrade North Cambridge to mitigate 115 kV 5 and 10 stuck breaker contingencies	Dec-17	4
Install a 200 MVAR STATCOM at Coopers Mills	Dec-18	3
Install a 115 kV 36.7 MVAR capacitor bank at Hartwell	May-17	4
Install a 345 kV 160 MVAR shunt reactor at K Street	Dec-18	2
Install a 115 kV breaker in series with the 5 breaker at Framingham	Apr-17	4
Install a 115 kV breaker in series with the 29 breaker at K Street	Apr-17	4

Pittsfield/Greenfield Projects

Status as of 2/23/18

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

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

Pittsfield/Greenfield Projects, cont.

Status as of 2/23/18

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

Upgrade	Expected/ Actual 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	4
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	4
Reconductor A127 between Erving and Cabot Tap and replace switches at Wendell Depot	Apr-15	4

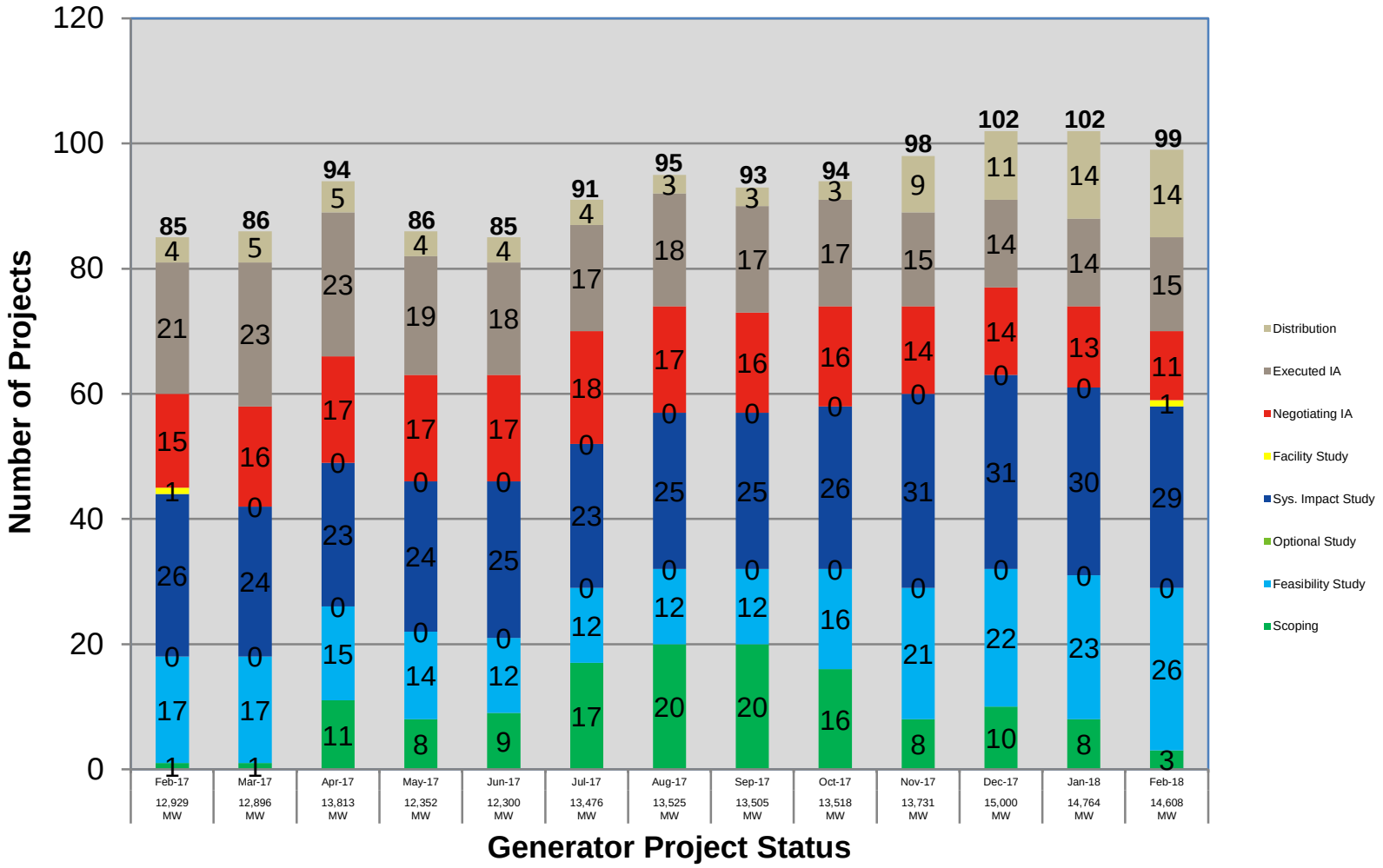
Pittsfield/Greenfield Projects, cont.

Status as of 2/23/18

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

Upgrade	Expected/ Actual 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.	Oct-17	4
Install a 75-150 MVAR variable reactor at Northfield substation	Dec-17	4
Install a 75-150 MVAR variable reactor at Ludlow substation	Dec-17	4
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: February 2018 based on partial data

Note: As of February 2018, there are 12 ETU's in SIS, 4 in FS, 1 in Scoping, 1 in FAC, and 4 in Neg. IA

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

OPERABLE CAPACITY ANALYSIS

Spring 2018

Spring 2018 Operable Capacity Analysis

50/50 Load Forecast (Reference)	May - 2018[2] CSO	May - 2018[2] SCC
Operable Capacity MW [1]	29,755	31,526
OP CAP From OP-4 RTDR (+)	380	380
OP CAP From OP-4 RTEG (+)	2	2
Operable Capacity with OP-4 DR and RTEG	30,137	31,908
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,202	1,202
Non Commercial Capacity (+)	0	0
Non Gas-fired Planned Outage MW (-)	2,087	2,205
Gas Generator Outages MW (-)	2,238	1,785
Allowance for Unplanned Outages (-) [5]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [4]	0	0
Net Capacity (NET OPCAP SUPPLY MW) [3]	23,614	25,720
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,507	20,507
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,812	22,812
Operable Capacity Margin [3]	802	2,908

[1]Operable Capacity is based on data as of **February 14, 2018** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Operable Capacity (CSO) and SCC values are based on data as of **February 14, 2018.**

[2] Load forecast that is based on the current CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 12, 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.

Spring 2018 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	May - 2018[2] CSO	May - 2018[2] SCC
Operable Capacity MW [1]	29,755	31,526
OP CAP From OP-4 RTDR (+)	380	380
OP CAP From OP-4 RTEG (+)	2	2
Operable Capacity with OP-4 DR and RTEG	30,137	31,908
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,202	1,202
Non Commercial Capacity (+)	0	0
Non Gas-fired Planned Outage MW (-)	2,087	2,211
Gas Generator Outages MW (-)	2,238	1,785
Allowance for Unplanned Outages (-) [5]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [4]	0	0
Net Capacity (NET OPCAP SUPPLY MW) [3]	23,614	25,720
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	22,420	22,420
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	24,725	24,725
Operable Capacity Margin [3]	-1,111	995

[1]Operable Capacity is based on data as of **February 14, 2018** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Operable Capacity (CSO) and SCC values are based on data as of **February 14, 2018.**

[2] Load forecast that is based on the current CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 12, 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.

Spring 2018 Operable Capacity Analysis (MW)

50/50 Forecast (Reference)

ISO-NE 2018 OPERABLE CAPACITY ANALYSIS

March 2, 2018 - 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]
2/24/2018	29,997	940	0	2,224	545	3,100	1,947	23,121	19,366	2,305	21,671	1,450	353	1,803	1	1,804
3/3/2018	30,020	940	0	1,694	526	2,200	1,550	24,990	19,004	2,305	21,309	3,681	318	3,999	1	4,000
3/10/2018	30,020	940	0	2,104	526	2,200	1,412	24,718	18,802	2,305	21,107	3,611	318	3,929	1	3,930
3/17/2018	30,020	940	0	3,471	526	2,200	858	23,905	18,424	2,305	20,729	3,176	318	3,494	1	3,495
3/24/2018	30,020	940	0	4,178	770	2,200	199	23,613	17,839	2,305	20,144	3,469	318	3,787	1	3,788
3/31/2018	29,755	1,302	0	4,788	1,775	2,700	0	21,794	17,071	2,305	19,376	2,418	380	2,798	2	2,800
4/7/2018	29,755	1,302	0	4,614	1,810	2,700	0	21,933	16,811	2,305	19,116	2,817	380	3,197	2	3,199
4/14/2018	29,755	1,202	0	4,971	2,001	2,700	0	21,285	16,283	2,305	18,588	2,697	380	3,077	2	3,079
4/21/2018	29,755	1,202	0	4,539	1,441	2,700	0	22,277	16,009	2,305	18,314	3,963	380	4,343	2	4,345
4/28/2018	29,755	1,202	0	4,338	1,171	3,400	0	22,048	15,291	2,305	17,596	4,452	380	4,832	2	4,834
5/5/2018	29,755	1,202	0	3,073	2,252	3,400	0	22,232	19,473	2,305	21,778	454	380	834	2	836
5/12/2018	**29,755**	**1,202**	**0**	**2,087**	**2,238**	**3,400**	**0**	**23,232**	**20,507**	**2,305**	**22,812**	**420**	**380**	**800**	**2**	**802**
5/19/2018	29,755	1,091	0	1,932	951	3,400	0	24,563	21,467	2,305	23,772	791	380	1,171	2	1,173
5/26/2018	29,755	1,202	0	908	698	3,400	0	25,951	22,521	2,305	24,826	1,125	380	1,505	2	1,507

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 2017 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 26,482 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV) 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).

Spring 2018 Operable Capacity Analysis (MW)

90/10 Forecast (Extreme)

ISO-NE 2018 OPERABLE CAPACITY ANALYSIS

March 2, 2018 - 90/10 FORECAST using CSO values with RTDR and RTEG

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

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERATOR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW	OPCAP FROM OP4 REAL-TIME EMER. GEN MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
2/24/2018	29,997	940	0	2,224	545	3,100	2,223	22,845	20,009	2,305	22,314	531	353	884	1	885
3/3/2018	30,020	940	0	1,694	526	2,200	1,781	24,759	19,636	2,305	21,941	2,818	318	3,136	1	3,137
3/10/2018	30,020	940	0	2,104	526	2,200	1,627	24,503	19,428	2,305	21,733	2,770	318	3,088	1	3,089
3/17/2018	30,020	940	0	3,471	526	2,200	1,012	23,751	19,038	2,305	21,343	2,408	318	2,726	1	2,727
3/24/2018	30,020	940	0	4,178	770	2,200	307	23,505	18,436	2,305	20,741	2,764	318	3,082	1	3,083
3/31/2018	29,755	1,302	0	4,788	1,775	2,700	0	21,794	17,652	2,305	19,957	1,837	380	2,217	2	2,219
4/7/2018	29,755	1,302	0	4,614	1,810	2,700	0	21,933	17,384	2,305	19,689	2,244	380	2,624	2	2,626
4/14/2018	29,755	1,202	0	4,971	2,001	2,700	0	21,285	16,841	2,305	19,146	2,139	380	2,519	2	2,521
4/21/2018	29,755	1,202	0	4,539	1,441	2,700	0	22,277	16,558	2,305	18,863	3,414	380	3,794	2	3,796
4/28/2018	29,755	1,202	0	4,338	1,171	3,400	0	22,048	15,839	2,305	18,144	3,904	380	4,284	2	4,286
5/5/2018	29,755	1,202	0	3,073	2,252	3,400	0	22,232	21,301	2,305	23,606	(1,374)	380	(994)	2	(992)
5/12/2018	**29,755**	**1,202**	**0**	**2,087**	**2,238**	**3,400**	**0**	**23,232**	**22,420**	**2,305**	**24,725**	**(1,493)**	**380**	**(1,113)**	**2**	**(1,111)**
5/19/2018	29,755	1,091	0	1,932	951	3,400	0	24,563	23,459	2,305	25,764	(1,201)	380	(821)	2	(819)
5/26/2018	29,755	1,202	0	908	698	3,400	0	25,951	24,600	2,305	26,905	(954)	380	(574)	2	(572)

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
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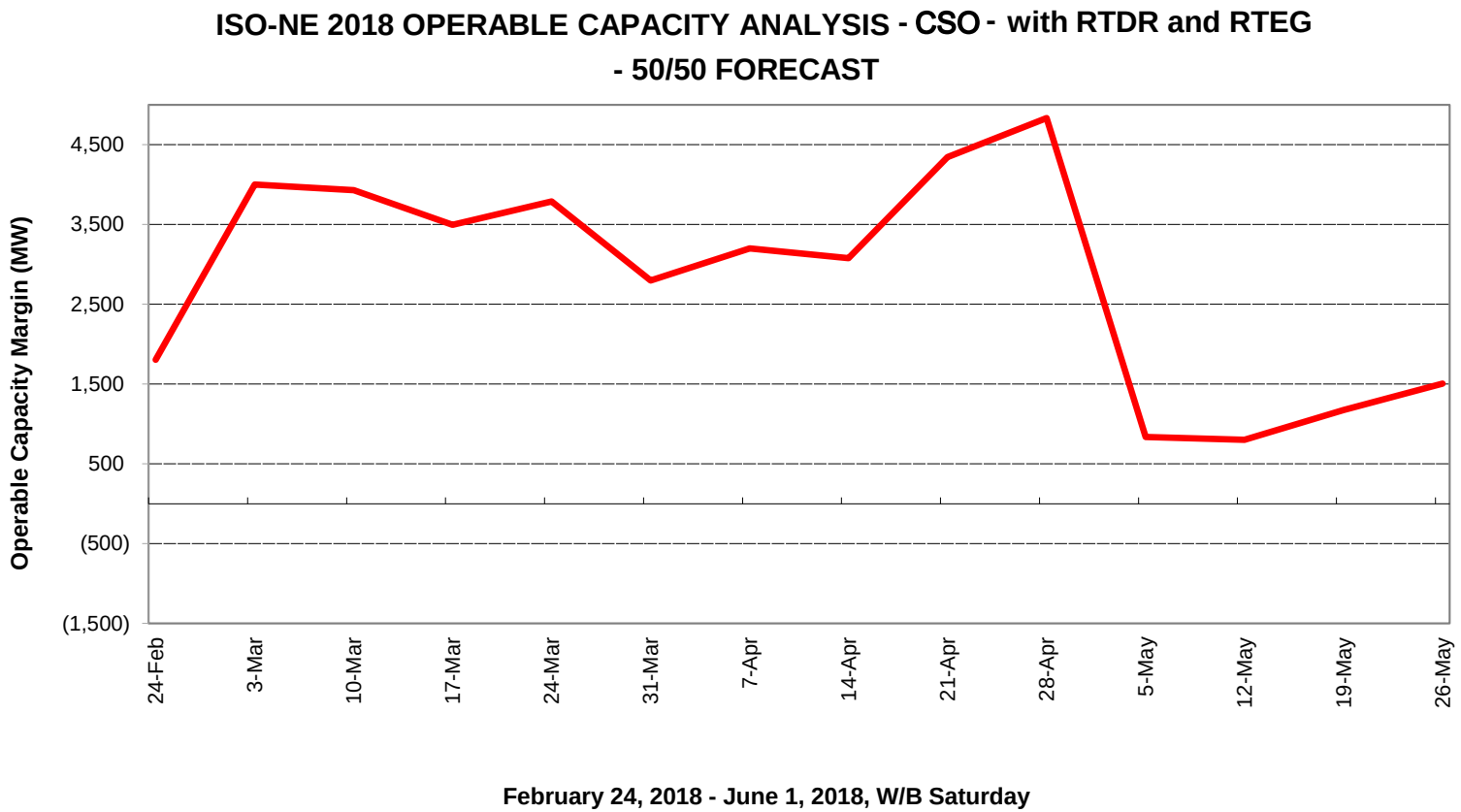
3. New resources and generator improvements that have acquired a CSO but have not become commercial.
4. Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.
5. All Planned Gas-fired 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 2017 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 26,482 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV) 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).

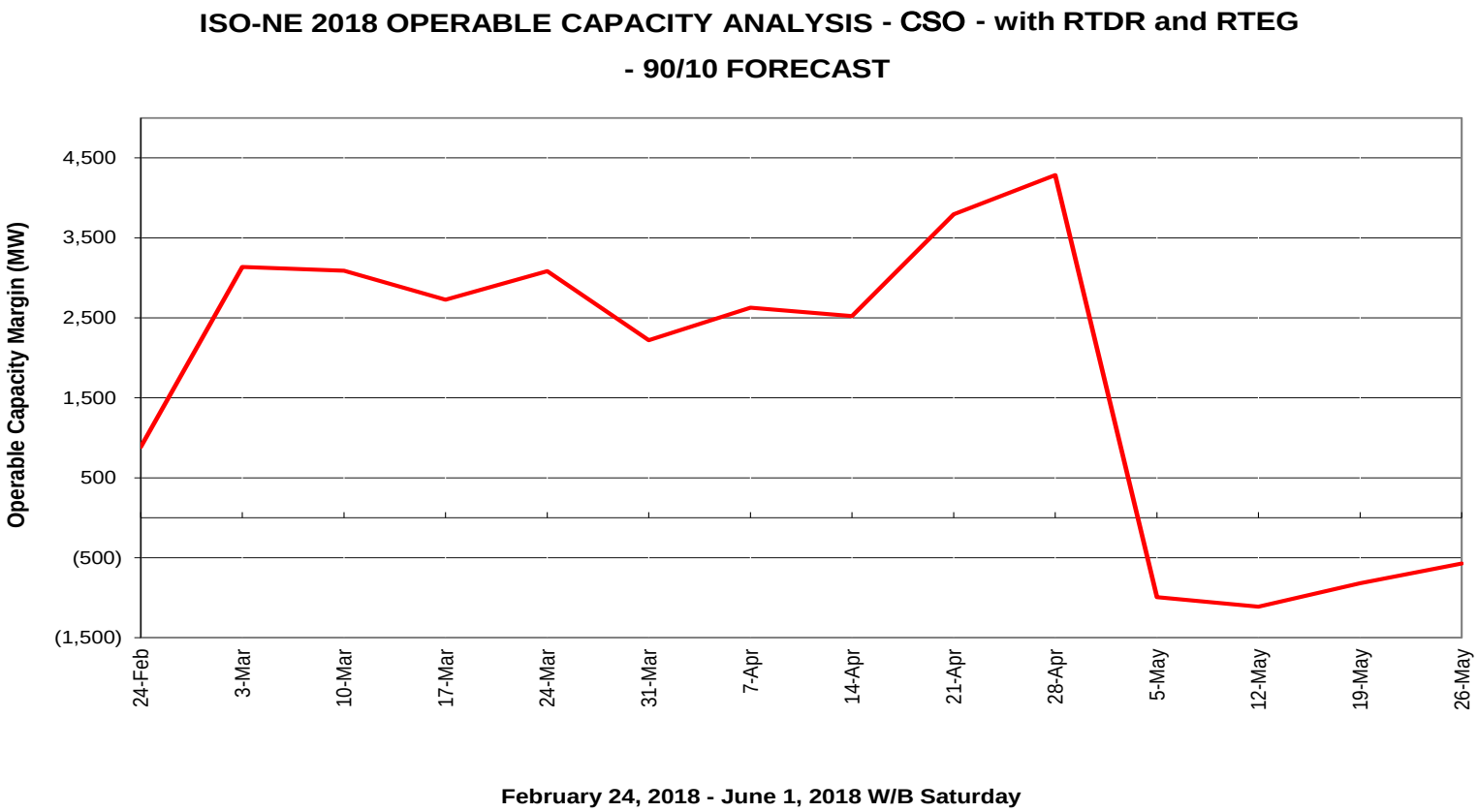
Spring 2018 Operable Capacity Analysis (MW)

50/50 Forecast (Reference)



Spring 2018 Operable Capacity Analysis (MW)

90/10 Forecast (Extreme)



OPERABLE CAPACITY ANALYSIS

Preliminary Summer 2018

Summer 2018 Operable Capacity Analysis

50/50 Load Forecast (Reference)	June - 2018[2] CSO	June - 2018[2] SCC
Operable Capacity MW [1]	29,362	28,893
OP CAP From OP-4 RTDR (+)	433	433
OP CAP From OP-4 RTEG (+)	5	5
Operable Capacity with OP-4 DR and RTEG	29,800	29,331
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,499	1,499
Non Commercial Capacity (+)	0	0
Non Gas-fired Planned Outage MW (-)	14	14
Gas Generator Outages MW (-)	674	0
Allowance for Unplanned Outages (-) [5]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [4]	0	0
Net Capacity (NET OPCAP SUPPLY MW) [3]	27,811	28,016
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	26,457	26,457
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	28,762	28,762
Operable Capacity Margin [3]	-951	-746

[1]Operable Capacity is based on data as of **February 14, 2018** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Operable Capacity (CSO) and SCC values are based on data as of **February 14, 2018.**

[2] Load forecast that is based on the current CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **June 23, 2018.**

[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.

Summer 2018 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	June - 2018[2] CSO	June - 2018[2] SCC
Operable Capacity MW [1]	29,362	28,893
OP CAP From OP-4 RTDR (+)	433	433
OP CAP From OP-4 RTEG (+)	5	5
Operable Capacity with OP-4 DR and RTEG	29,800	29,331
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,499	1,499
Non Commercial Capacity (+)	0	0
Non Gas-fired Planned Outage MW (-)	14	14
Gas Generator Outages MW (-)	674	0
Allowance for Unplanned Outages (-) [5]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [4]	0	0
Net Capacity (NET OPCAP SUPPLY MW) [3]	27,811	28,016
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	28,877	28,877
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	31,182	31,182
Operable Capacity Margin [3]	-3,371	-3,166

[1]Operable Capacity is based on data as of **February 14, 2018** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Operable Capacity (CSO) and SCC values are based on data as of **February 14, 2018.**

[2] Load forecast that is based on the current CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **June 23, 2018**.

[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.

Summer 2018 Operable Capacity Analysis (MW)

50/50 Forecast (Reference)

ISO-NE 2018 OPERABLE CAPACITY ANALYSIS

March 2, 2018 - 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]
6/2/2018	29,362	1,499	0	0	674	2,800	0	27,387	26,457	2,305	28,762	(1,375)	433	(942)	5	(937)
6/9/2018	29,362	1,499	0	0	674	2,800	0	27,387	26,457	2,305	28,762	(1,375)	433	(942)	5	(937)
6/16/2018	29,362	1,499	0	0	674	2,800	0	27,387	26,457	2,305	28,762	(1,375)	433	(942)	5	(937)
6/23/2018	**29,362**	**1,499**	**0**	**14**	**674**	**2,800**	**0**	**27,373**	**26,457**	**2,305**	**28,762**	**(1,389)**	**433**	**(956)**	**5**	**(951)**
6/30/2018	29,362	1,499	0	14	674	2,100	0	28,073	26,457	2,305	28,762	(689)	433	(256)	5	(251)
7/7/2018	29,362	1,499	0	14	674	2,100	0	28,073	26,457	2,305	28,762	(689)	433	(256)	5	(251)
7/14/2018	29,362	1,499	0	0	674	2,100	0	28,087	26,457	2,305	28,762	(675)	433	(242)	5	(237)
7/21/2018	29,362	1,499	0	0	674	2,100	0	28,087	26,457	2,305	28,762	(675)	433	(242)	5	(237)
7/28/2018	29,362	1,499	0	14	674	2,100	0	28,073	26,457	2,305	28,762	(689)	433	(256)	5	(251)
8/4/2018	29,362	1,499	0	12	674	2,100	0	28,075	26,457	2,305	28,762	(687)	433	(254)	5	(249)
8/11/2018	29,362	1,499	0	12	674	2,100	0	28,075	26,457	2,305	28,762	(687)	433	(254)	5	(249)
8/18/2018	29,362	1,499	0	14	674	2,100	0	28,073	26,457	2,305	28,762	(689)	433	(256)	5	(251)
8/25/2018	29,362	1,499	0	0	674	2,100	0	28,087	26,457	2,305	28,762	(675)	433	(242)	5	(237)
9/1/2018	29,362	1,499	0	0	674	2,100	0	28,087	26,457	2,305	28,762	(675)	433	(242)	5	(237)
9/8/2018	29,362	1,499	0	0	674	2,100	0	28,087	26,457	2,305	28,762	(675)	433	(242)	5	(237)

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.
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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 2017 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 26,482 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV) 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).

Summer 2018 Operable Capacity Analysis (MW)

90/10 Forecast (Extreme)

ISO-NE 2018 OPERABLE CAPACITY ANALYSIS

March 2, 2018 - 90/10 FORECAST using CSO values with RTDR and RTEG

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

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERATOR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW	OPCAP FROM OP4 REAL-TIME EMER. GEN MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
6/2/2018	29,362	1,499	0	0	674	2,800	0	27,387	28,877	2,305	31,182	(3,795)	433	(3,362)	5	(3,357)
6/9/2018	29,362	1,499	0	0	674	2,800	0	27,387	28,877	2,305	31,182	(3,795)	433	(3,362)	5	(3,357)
6/16/2018	29,362	1,499	0	0	674	2,800	0	27,387	28,877	2,305	31,182	(3,795)	433	(3,362)	5	(3,357)
6/23/2018	**29,362**	**1,499**	**0**	**14**	**674**	**2,800**	**0**	**27,373**	**28,877**	**2,305**	**31,182**	**(3,809)**	**433**	**(3,376)**	**5**	**(3,371)**
6/30/2018	29,362	1,499	0	14	674	2,100	0	28,073	28,877	2,305	31,182	(3,109)	433	(2,676)	5	(2,671)
7/7/2018	29,362	1,499	0	14	674	2,100	0	28,073	28,877	2,305	31,182	(3,109)	433	(2,676)	5	(2,671)
7/14/2018	29,362	1,499	0	0	674	2,100	0	28,087	28,877	2,305	31,182	(3,095)	433	(2,662)	5	(2,657)
7/21/2018	29,362	1,499	0	0	674	2,100	0	28,087	28,877	2,305	31,182	(3,095)	433	(2,662)	5	(2,657)
7/28/2018	29,362	1,499	0	14	674	2,100	0	28,073	28,877	2,305	31,182	(3,109)	433	(2,676)	5	(2,671)
8/4/2018	29,362	1,499	0	12	674	2,100	0	28,075	28,877	2,305	31,182	(3,107)	433	(2,674)	5	(2,669)
8/11/2018	29,362	1,499	0	12	674	2,100	0	28,075	28,877	2,305	31,182	(3,107)	433	(2,674)	5	(2,669)
8/18/2018	29,362	1,499	0	14	674	2,100	0	28,073	28,877	2,305	31,182	(3,109)	433	(2,676)	5	(2,671)
8/25/2018	29,362	1,499	0	0	674	2,100	0	28,087	28,877	2,305	31,182	(3,095)	433	(2,662)	5	(2,657)
9/1/2018	29,362	1,499	0	0	674	2,100	0	28,087	28,877	2,305	31,182	(3,095)	433	(2,662)	5	(2,657)
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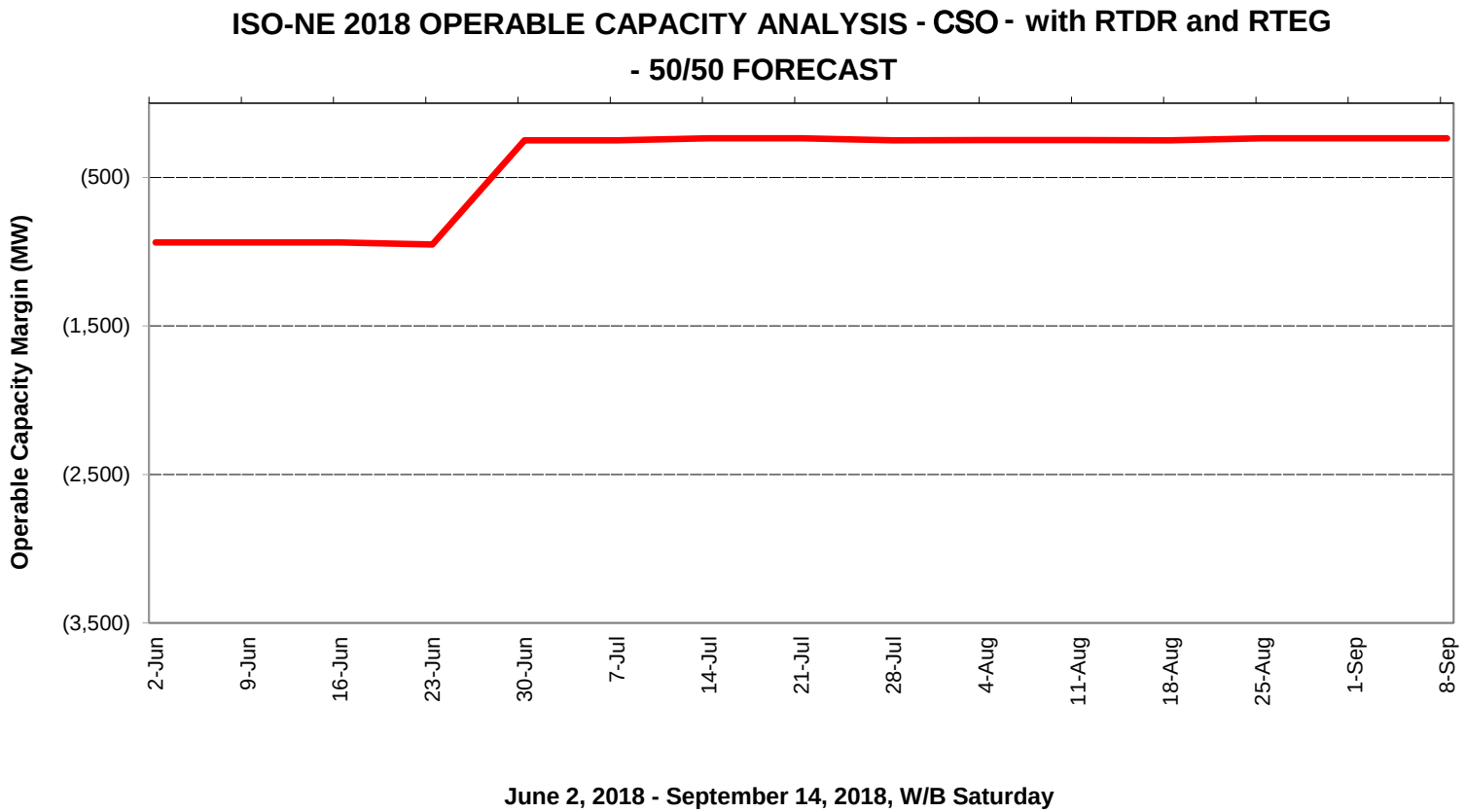
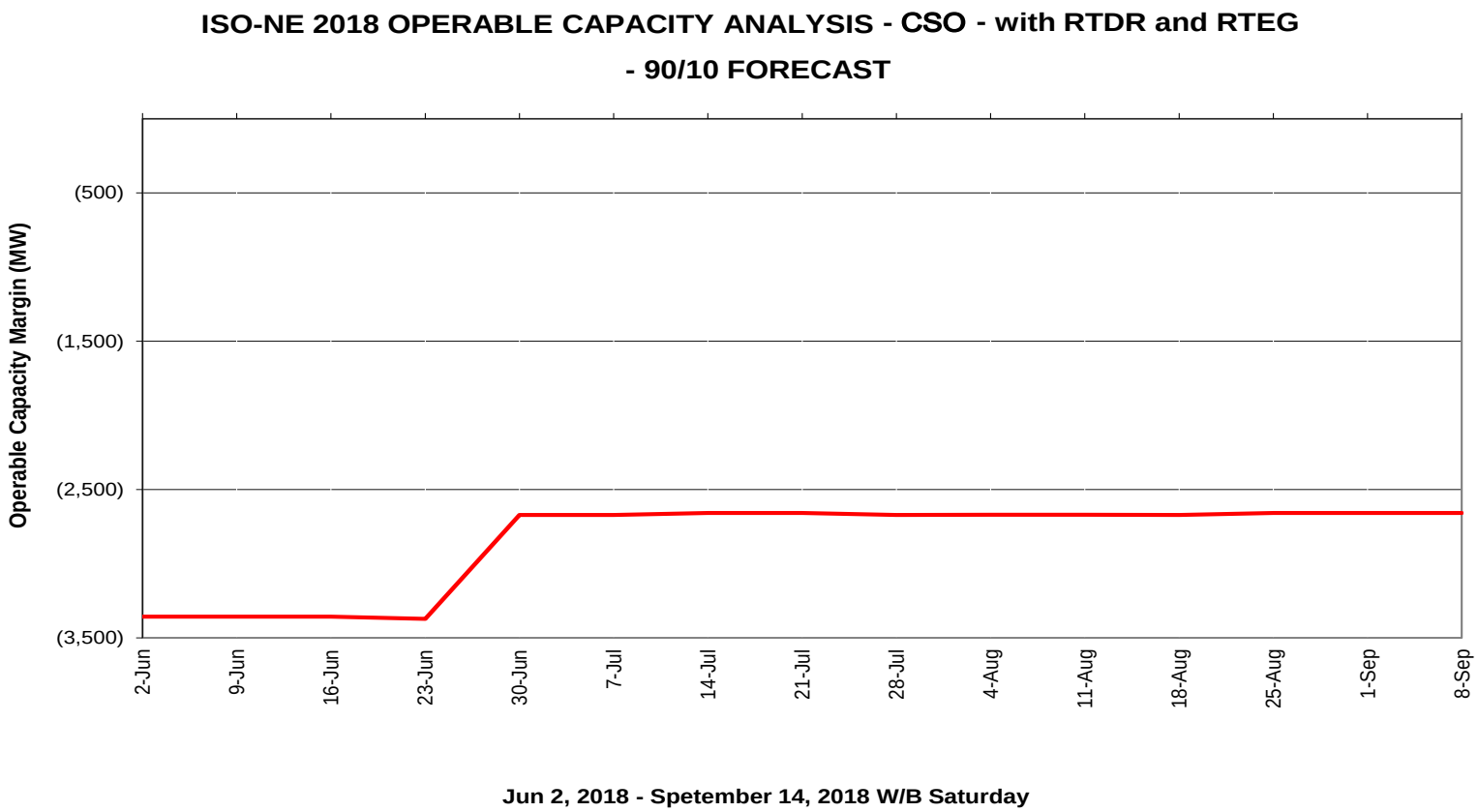
Summer 2018 Operable Capacity Analysis (MW)

50/50 Forecast (Reference)



Summer 2018 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.	**February 353** [3] **March 318** [3] **April & May 380** [3] **June – September 433** [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] **February & March 1** [3] **April & May 2** [3] **June – September 5** [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 February 14, 2018.
4. The MW values are based on a 26,482 MW system load and the most recent voltage reduction test % achieved.

Possible Relief Under OP4: Appendix A, cont.

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		**February 2,900 [3]** **March 2,865 [3]** **April & May 2,928 [3]** **June – September 2,984 [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 February 14, 2018.
4. The MW values are based on a 26,482 MW system load and the most recent voltage reduction test % achieved.

Updated 2018 Annual Work Plan

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Objective and Highlights

- The objective of this report is to reflect changes to the Annual Work Plan since its initial release in September, 2017
  - In Q3 2018, the ISO will begin the full cycle again and release a new Work Plan for discussion covering Q4 2018—Q2 2020
- Highlights of this update include:
  - Implementation of Key Projects
  - Assessment of Assumptions Associated with Installed Capacity Requirement (ICR) and Local Sourcing Requirement (LSR)
  - Continued Emphasis on Cyber Security
  - Resilience Docket
  - Operational Fuel Security Analysis
  - Market Updates

Highlights: Implementation of Key Projects

- The interconnection clustering revisions are in effect
  - Since Q4 2017, the Federal Energy Regulatory Commission (FERC) approved the ISO's cluster filing and the ISO published the draft Maine Resource Integration Study
  - In Q1 2018, the ISO prepares the final Maine Resource Integration Study
    - Once the ISO issues the final study, the window for the first Cluster System Impact Study applications will open
  - From Q2 2018 to Q4 2018, the ISO will proceed with the Cluster System Impact Studies

Highlights: Implementation of Key Projects, Continued

- Three significant implementation projects will go-live June 1, 2018:
  - Pay-for-Performance
    - Increases financial incentives for resource owners to make investments to ensure their resource's reliability during periods of scarcity
  - Price Responsive Demand (PRD)
    - Fully integrates demand response into New England's wholesale electricity markets
  - Forward Capacity Market (FCM) Improvements
    - Introduces sloped zonal demand curves into Annual Reconfiguration Auctions (ARA) associated with Capacity Commitment Period (CCP) 11

Highlights: Assessment of Assumptions Associated with ICR/LSR

- The ISO is discussing with stakeholders some of the assumptions and methodologies used in the ICR and LSR, such as:
  - The assumed level of 10-minute operating reserves maintained before load shedding
  - The amount of load relief assumed due to voltage reduction
  - The assumed 20% derate of peaking generation resources when calculating the Transmission Security Analysis (TSA) Requirement
  - The Behind-the-Meter Photovoltaics (PV) Forecast
- Plans include enhanced stakeholder discussions in 2018 for evaluating some of the inputs used in the ICR/LSR calculations
  - Discussion with stakeholders began in Q1 2018 at the Reliability Committee
- Potential changes could be implemented in Forward Capacity Auction (FCA) 13 or FCA 14 depending on complexity, and the amount of stakeholder and regulatory review needed

Highlights: Continued Emphasis on Cyber Security

- The ISO has a number of additional cyber security initiatives planned for Q2 2018—Q2 2019, including:
  - Preparing for the Critical Infrastructure Protection (CIP) v5 audit scheduled for Q4 2018
  - Incorporating enhanced technology to improve Identity and Access Management
  - Actively planning and coordinating compliance with Order 829 by preparing systems and processes to be ready for CIP-013-1 approval
  - Responding to Notice of Proposed Rulemakings (NOPRs) related to cyber security
  - Collaborating with the New England States and the Department of Homeland Security on security event monitoring

Highlights: Resilience Docket

- FERC issued an Order on January 8, 2018, terminating the Grid Reliability and Resilience Pricing as proposed by the Department of Energy (DOE) and opening an inquiry into resilience of the bulk power system in the regions operated by Regional Transmission Organizations (RTO) and Independent System Operators (ISO)

- The ISO is currently assessing the questions posed in Docket AD18-7-000 and preparing its response
  - Based on the questions raised by FERC, the ISO's fuel security analysis will provide the basis for a number of the ISO's responses

Highlights: Operational Fuel Security Analysis

- In advance of the initial Reliability Committee discussion, held on January 24, 2018, the ISO released its Operational Fuel Security Analysis to help assess potential conditions in winter 2024/2025
- The ISO is discussing its fuel security analysis and obtaining feedback on its underlying study assumptions and will work with stakeholders to develop additional scenarios wherever feasible under the model
  - The process for review and refinement of the issues will continue into Q2 2018
- The ISO anticipates working with stakeholders to develop possible options for addressing potential fuel security risks
  - Developing a problem statement and exploring solutions is initially targeted for Q2 2018 through Q2 2019

Highlights: Market Updates

- Competitive Auctions with Sponsored Policy Resources (CASPR) is anticipated to be effective for the qualification period for FCA 13, with any conforming changes being prepared for stakeholder discussions in Q3 2018
  - As part of our efforts to address any potential conforming changes, the ISO and the IMM also plan to propose a mechanism to review the primary auction bids from existing resources that choose to participate in the Substitution Auction
    - Targeted for implementation in Q1 2019 for FCA #14
- The ISO is finishing its Multi-Period Ramp Pricing Technical Sessions on March 20, 2018, and plans to begin Day-Ahead Reserves Technical Sessions next (targeting Q4 2018)

UPDATE: PLANNING AND OPERATIONS RELATED ACTIVITIES

Planning / Operations Related Activities

2018			2019	
Q2	Q3	Q4	Q1	Q2
Operational Load Forecast: PV Integration				
Order 1000 Implementation				
Transmission Planning Studies				
Transmission Cost Allocation				
Annual Economic Studies				
Interregional Planning				
Long-Term 2018 Forecasts (PV, EE, Load)	Long-Term 2019 Forecasts (PV, EE, Load)			
FCA 13: Stakeholder and Regulatory Review of ICR/LSR				
FCA 13: Finalize Capacity Zones	FCA 13: Zonal Requirements	FCA 14 Zones: Expected Topology	Regional Transfer Limits	FCA 14: Finalize Capacity Zones
ARA 1: CCP11	ARA 2: CCP10		FCA 14/ARA 3 CCP10	ARA 1: CCP12
Operational Fuel Security Study				
Black Start Review				
Interconnection Reliability Operating Limit (IROL) Compensation for Critical Infrastructure Protection (CIP) Compensation Review				
Generator Interconnection Studies				
NERC/FERC Compliance/Cyber Security				
			RSP 2019	

Update: Planning and Operations Related Activities Completed between Q4 2017 and Q1 2018

- FCA 13 Expected Transmission Topology
- Regional System Plan 2017
- FCA 12: Stakeholder and Regulatory Review of ICR & Related Values
- 2016 Annual Economic Study Phase II
- FCA 12/ ARA3 CCP9
- Regional Transfer Limits
- 2017/2018 Winter Reliability Program
  - Program ends March 15, 2018
    - Settlement will continue into Q2 2018

UPDATE: MARKET RELATED ACTIVITIES

Markets Related Activities

Chart Key	
	Market Design Project (anticipated period of stakeholder discussion)
	Market Assessment (potential start of stakeholder discussion)
	• ◊ A diamond indicates that the ISO will continue to actively engage with Participants on their long-term approaches to public policy

2018			2019	
Q2	Q3	Q4	Q1	Q2
Integrating Markets and Public Policy (IMAPP) Related				
	CASPR Conforming Changes			
Discussions on IMAPP "Achieve" Solutions ◊				
Capacity Market				
Zonal Demand Curves: FCM Cost Allocation				
			FCA #14 CONE Adjustment	FCA #15 CONE Recalculation
Delayed Commercial Operation of New Resources				
Energy and Reserve Markets				
Enhanced Storage Participation (slide 16)				
	Day-Ahead Reserves Technical Sessions			
Other Market Related Items				
Potential Fuel Security Solutions				
FERC Orders and NOPRs				

Update: Markets Related Activities Completed between Q4 2017 and Q1 2018

- Competitive Auctions with Sponsored Policy Resources (CASPR)
- Zonal Demand Curves: Capacity Supply Obligation (CSO) Transactions using Marginal Reliability Impact (MRI) Demand Curves
- Dynamic De-list Bid Threshold
- Real-Time Reserve Designation & Settlement Rules
- FCM Pay-for-Performance (FCM Performance Incentives) Conforming Changes
- FCM Enhancements Phase II

Market Related Projects Updates: Enhanced Storage Participation

- The FERC issued a Final Rule, February 15, 2018, on Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators (Docket Nos. RM16-23-000; AD16-20-000; Order No. 841)
- The ISO is adjusting Enhanced Storage Participation, from Q1 2018—Q2 2018 to Q2 2018—Q3 2018, to allow time for the ISO to review any implications of the Order on what is being proposed

UPDATE: CAPITAL PROJECTS

Capital Projects

2018			2019	
Q2	Q3	Q4	Q1	Q2
Price Responsive Demand				
FCM Improvements				
Pay-for-Performance				
Balance of Planning Period (BoPP): Financial Assurance (slide 20)				
Identity and Access Management (slide 21)				
Internal Market Monitor (IMM) Data Analysis Phase I	IMM Data Analysis Phase II			
Competitive Auctions with Sponsored Policy Resources				
Operational Load Forecast: PV Integration				
Energy Management Platform (EMP) 3.2 Upgrade and Customs Reduction (slide 22)				
Storage Device Alternatives (Energy Storage Devices)				
CMINET Simultaneous Feasibility Test (SFT) with Data Transfer Elements				
nGEM Software Development				
2018 Issue Resolution			2019 Issue Resolution	
	Annual Reconfiguration Transactions*			

* Title changed to more accurately reflect the project (formerly, FCA #13)

Update: Capital Projects Completed between Q4 2017 and Q1 2018

Desktop Segregation Project: Cyber Security

- This project improved cyber security at the ISO by reducing and removing risks to business services by segmenting desktop access and improving incident response
  - Completed Q4 2017

Capital Project Updates: Balance of Planning Period

- The Balance of Planning Period (BoPP) Implementation has been delayed from an expected completion in Q3 2018 and is now targeting completion no later than Q4 2019

Capital Project Updates: Identity and Access Management

- The ISO has completed the proof of concept phase and has initiated the Identity and Access Management implementation
- Cyber Security resources are balancing additional activities and, therefore, the Identity and Access Management implementation has been delayed from an expected completion in Q3 2017 to Q1 2019

Capital Project Updates: Energy Management Platform (EMP) 3.2 Upgrade and Customs Reduction

- The ISO is currently in the planning process with the vendor and expects to develop an implementation plan by Q2 2018
- The current version of EMP is fully supported by the vendor for at least two more years, as such, there is minimal urgency to update right away
- In light of immediate priorities, the ISO is allocating resources to this project as they become available
- The upgrade is not expected to be completed before mid-2019

MEMORANDUM

To: ISO New England Inc.

From: NEPOOL Officers

Date: February 23, 2018

Re: NEPOOL Input to ISO-NE on Grid Resilience Comments in FERC Docket No. AD18-7

This memorandum summarizes several points the NEPOOL officers believe are important for the ISO to consider as it prepares its upcoming comments in the Grid Resilience proceeding in FERC Docket No. AD18-7. The purpose of this memo is to inform the ISO of these views in advance of a discussion on this topic at the March 2 Participants Committee meeting.

General

1. It would be useful for the ISO to clarify that the ISO began the operational fuel security analysis ("OFSA") process well before any requirement from the Commission and, in conjunction with NEPOOL stakeholders, is taking proactive steps to review bulk power system grid reliability and resilience. This practice is a continuation of the region's history of proactively addressing bulk power system reliability and resilience over the past several decades, including the formation of NEPOOL in 1971 and the establishment of the ISO in 1997.

2. The ISO has indicated its intent to focus its comments in AD18-7 on winter fuel security. In the event that the ISO offers comments on other areas of resilience, the NEPOOL officers request the opportunity for stakeholder discussions on those areas as well and request that the ISO comments in AD18-7 acknowledge the need for such stakeholder process.

3. Given the nature of the OFSA to date and the ISO's commitment to consider potential market and other solutions- if any are necessary- in the stakeholder process over the next year (or possibly longer), the NEPOOL officers would appreciate the ISO comments to clarify that the fuel security analysis was issued to initiate further review, dialogue, and analysis, as well as to explore any potential responses to the challenges (or lack thereof) identified by the analysis for NEPOOL (and ultimately FERC) consideration and approval. In this regard, it would be helpful for the ISO comments to specifically request

that any final rule allow sufficient time for the NEPOOL process, including consideration of the OFSA, to be completed. This approach would be consistent with NEPOOL's and the ISO's generally shared desire to have regional flexibility in developing compliance responses to any final rule, thus permitting the region to develop responses consistent with its markets and other system features.

Specific OFSA-Related Input

1. While the ISO has told stakeholders that the draft OFSA, with its initial set of scenarios, is more useful to understanding relative impacts and risks of any changes to New England infrastructure and the need for fuel inventory refills than it is predictive in terms of discrete reliability outcome metrics, it is important that the ISO make this point clear in its comments. This clarity is important because, despite the ISO's explanations within NEPOOL, there have been multiple citations in press reports incorrectly interpreting the operating reserve deficiency and load shed results as "predictions". The NEPOOL officers understand that the draft OFSA is intended to initiate further review and dialogue with NEPOOL Participants through the NEPOOL process, including the opportunity for additional scenarios to be analyzed and discussion of any potential market rule changes and any other solutions. With the benefit of those discussions and additional analysis, the region, working together through the regional stakeholder process, can then explore potential responses developed by New England to meet the challenges faced by New England.

2. Based on the nature of the OFSA, the NEPOOL officers request that the ISO responses to questions regarding the likelihood of resilience risks properly explain that the OFSA does not provide any probabilistic or even predictive likelihood of occurrence of any of the initial set of scenarios or additional scenarios that the ISO might study.

3. The NEPOOL officers request that the ISO comments acknowledge that the draft OFSA to date does not consider any anticipated response from the competitive markets and/or other potential responses, including any responses to the FCM Pay-for-Performance rules for non-performance consequences and over-performance incentives.

Resilience Criteria and Mitigation

1. The NEPOOL officers anticipate that the ISO would discuss any specific new reliability or resilience criteria with stakeholders before making any such recommendations at FERC. For example, the NEPOOL officers look forward to discussion of the ISO's perspectives, before the ISO forms an official recommendation, regarding specific criteria (e.g., load loss (MW), duration of load loss, vulnerability of generator outages, duration of generator outages, recovery from a bulk power system event, etc.) that might be

considered in studies to determine if the bulk power system will reasonably be able to withstand a high impact, low-frequency event.

2. While the ISO has already initiated a stakeholder process to consider fuel security related matters, the FERC proceeding in AD18-7 raises other matters potentially affecting the reliability and resilience of the grid. The NEPOOL officers seek input from the ISO on when and how such additional issues would be reviewed and considered with stakeholders. Some of these additional matters include:

    a. Whether the threats from severe disturbances, such as those from low probability, high impact events require mitigation;

    b. What, if any, further steps are needed to ensure that the New England bulk power system is capable of withstanding or reducing the magnitude of high-impact, low frequency events; and

    c. The extent to which the ISO should consider specific challenges to resilience, such as extreme weather, drought, and physical or cyber threats.

MARCH 2, 2018 | BOSTON, MA

ISO New England's Response to Resilience Order

Overview

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

OVERVIEW

Objective

- This presentation provides an overview of ISO New England Inc.'s (ISO) planned response to the Federal Energy Regulatory Commission's (FERC) order on grid resilience, issued on January 8, 2018, in Docket No. AD18-7-000 (Order)

Background

- The Order:
  - Terminates the rulemaking proceeding initiated to address the Proposed Rule on Grid Reliability and Resilience Pricing by the Department of Energy, and
  - Initiates a new proceeding to comprehensively examine the bulk power system's resilience
- The Order's goals are:
  - Develop a common understanding of resilience and how each RTO/ISO assesses resilience in its region, and
  - Evaluate whether further FERC action is needed
- Toward these goals, the Order directs RTO/ISOs to respond to a series of questions seeking information on how they assess resilience in their respective regions and mitigate resilience risks
  - The Order emphasizes resilience includes efforts in transmission planning, markets, and operational readiness

NEPOOL Feedback

- The ISO's approach to responding to the Order is generally aligned with the NEPOOL feedback received to date
- The ISO will discuss its continual efforts to support the New England's bulk power system reliability and resilience
- The ISO plans to ask FERC for the opportunity to work through our regional issues with our stakeholders, as is our tradition
- The ISO appreciates hearing any further comments during our discussions today

FOCUS OF ISO'S RESPONSE – FUEL SECURITY

Unique Regional Issue

- The ISO's response will focus on the region's unique fuel-security challenges
- The ISO's response will look at a range of efforts addressing the region's fuel-security challenges since the 2004 Cold Snap, including the Operational Fuel Security Analysis (OFSA) and its role in identifying fuel-security challenges
  - The OFSA reveals that current trends are pushing the New England power system on a path toward greater fuel-security risks
- The OFSA and the further experience gained during the December 2017 and January 2018 cold weather stretch will provide a basis for some of the responses

ISO-NE Actively Engaged with Regional Stakeholders on Fuel Security

- The ISO's response will identify the already ongoing stakeholder process to address the region's fuel-security challenges:
  - January 2018 – OFSA report released and regional stakeholder discussions on the study inputs and results initiated
  - February - May 2018 – Additional analysis based on stakeholder feedback and engaging in further discussions
  - Q2 2018 – Q2 2019 – Discussions with stakeholders on possible solutions to address fuel-security risks

Nature of Operational Fuel Security Analysis

- The ISO will make clear the nature of the OFSA as an important quantitative study focusing on operational issues for the ISO to consider should certain conditions arise
  - The ISO will note that this study is distinctive from others by looking at energy needs for the entire winter period
- As the ISO has made clear in stakeholder discussions to date, this analysis is focused on reliability and does not include iterative economic modeling to signal how possible market responses might impact the scenarios over time
- As a result of the type of analysis performed (i.e., deterministic), ISO will indicate that the OFSA models contain many hypothetical cases; none of which are precise predictions of the future
  - We will also note that stakeholders have asked us to run many more hypothetical cases to assist their understanding of operational impacts

Other Resilience Issues

- The ISO's response will recognize that there are other factors that can also impact resilience (*e.g.*, cybersecurity, physical security, extreme weather)
- As the Order indicates, significant efforts are already underway in these areas (*e.g.*, NERC CIP standards, which protect against cybersecurity and physical threats)
  - In response to some of the questions, ISO-NE will highlight how planning assessments already account for some of these threats to the extent already prescribed by NERC and NPCC requirements
- Thus, the key focus in this response is the area we are experiencing as most challenging to the region, which is not being addressed in other forums and remains without a solution – fuel security

SUMMARY OF PLANNED RESPONSES

Definition of Resilience

- In this response, the ISO does not propose new reliability or resilience criteria, rather it addresses how FERC's understanding of resilience aligns with ISO's considering in assessing the system's reliability, based on prescribed NERC and NPCC standards
  - FERC's understanding of resilience: "The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the ability to anticipate, absorb, adapt to, and/or rapidly recovery from such an event." (Order at P 23)
  - To measure the system's reliability, ISO considers two key aspects:
    - Security – the system's ability to withstand disturbances
    - Adequacy – the system's ability to supply energy to meet demand
- For the system to be resilient, both of these aspects of reliability need to be addressed, and they are at the core of ISO-NE's work in carrying out its responsibilities in planning, markets and operations
- Thus, the response will provide extensive background on how resilience is already accounted for in the ISO's work, as the RTO

How ISO-NE Assesses Resilience Threats

- Describe ISO's efforts to identify high-impact, low-frequency ("HI/LF") events, the planning studies performed to assess the system's ability to withstand such events as prescribed in NERC and NPCC requirements, and provide examples of operational measures ISO implements to prepare for such events
  - For example, responses will note how the ISO's operational measures, together with the fuel-security analysis, were applied in the recent cold weather stretch, which reinforced some of the challenges identified in the OFSA
- Describes the OFSA's role in identifying fuel-security challenges and assessing potential impacts on the system's ability to withstand certain disturbances
  - One of the purposes of conducting the OFSA is to engage with regional stakeholders on what level of risk the region will tolerate
  - The responses will note the OFSA's examination of certain outage scenarios to consider and understand relative impacts
    - OFSA does not specify the probability of each scenario, though it qualitatively recognizes the outage cases may represent HI/LF scenarios

How ISO-NE Assesses Threats (Cont.)

- Explain how the ISO assesses and plans the system based on NERC, NPCC, and ISO's reliability requirements
- Identify efforts the ISO undertakes to improve overall situational awareness and understanding of all resources comprising the New England generating fleet (*e.g.*, generator fuel surveys, nuclear facilities storm procedures, wind and solar forecasting)
- Describe robust coordination with NERC, NPCC, RTO/ISO and other relevant stakeholders, such as gas systems operators to identify and prepare for HI/LF events

How ISO-NE Mitigates Threats to Resilience

- Identify and describe existing operational measures designed to maintain the integrity of the system
- Provide examples of market mechanisms that further support resilience (*e.g.*, market design changes designed to provide performance incentives, improve gas-electric coordination, price formation improvements to send signals for performance and to appropriately value products)
- Explain how improved performance requirements as condition to interconnection (*e.g.*, frequency, voltage, reactive power requirements) contribute to the system's resilience
- Indicate that potential modifications to address fuel-security challenges will be considered with stakeholders later this year, as well as ISO-NE's ongoing analytical efforts for continued improvements to the markets, planning and operation of the system
  - Interim measures, however, may be necessary to address near-term reliability risks

Questions

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of FEBRUARY 28, 2018 (5pm)

The following activity, as more fully described in the attached litigation report, has occurred since the report dated January 31, 2018 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

	2	Calpine/LS Power Delayed Resource Complaint (EL18-53)	Feb 8	Calpine/LS Power withdraw Complaint
	2	PER Settlement Agreement (ER17-2153; EL16-120)	Feb 20	FERC approves PER Settlement, directs compliance filing
	4	Base ROE Complaint IV (2016) (EL16-64)	Feb 7 Feb 22	Parties submit post-hearing reply briefs Post-hearing briefs ' oral argument held
	4	206 Proceeding: RNS/LNS Rates and Rate Protocols (EL16-19)	Feb 1 Feb 2 Feb 26	11th settlement conf. held Settlement Judge issues status report, recommending settlement judge procedures be continued Chief Judge issues order continuing settlement judge procedures

II. Rate, ICR, FCA, Cost Recovery Filings

	6	Emera MPD OATT Attachment J Revision (ER18-210)	Feb 2 Feb 15 Feb 21	Maine Customer Group answers Emera Maine Jan 18 answer FERC accepts proposed tariff revision, suspends it for a nominal period, to become eff. Jan 1, 2018, as requested, subject to refund; establishes hearing & settlement judge procedures Chief Judge designates Judge Dring as settlement judge

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

*	7	Real-Time Reserve Designation & Settlement Rule Changes (ER18-897)	Feb 22	ISO-NE and NEPOOL file changes to become eff. Jun 1, 2018; comment date Mar 15
	7	CSO Termination: Blue Sky West (ER18-704)	Feb 1 Feb 2 Feb 2-13 Feb 13	NEPOOL submits limited comments; Blue Sky West answers ISO-NE Jan 31 answer FERC grants Blue Sky West emergency motion, directing portion of CSO involuntarily terminated by ISO-NE to be immediately reinstated pending resolution of this proceeding National Grid, NextEra, NRG/GenOn intervene Blue Sky West protests CSO termination
	8	Waiver Request: Timing of Canal-MA-GHG-Rule-Related Addl. Cost Recovery Filing (GenOn) (ER18-623)	Feb 8	FERC grants waiver requested
	9	Updated Dynamic De-List Bid Threshold (ER18-620)	Feb 13 Feb 21	NEPOOL, ISO-NE submit answers to NEPGA, PSEG protests NEPGA answers ISO-NE and NEPOOL Feb 13 answers

	9	CASPR (ER18-619)	Feb 7	NH OCA intervenes out-of-time
			Feb 12	NRECA submits answer supporting Public Systems' and APPA calls for FERC to open a Section 206 proceeding
			Feb 13	NEPOOL, ISO-NE, FirstLight file answers
			Feb 19	EMM answers ISO-NE Feb 13 answer
			Feb 22	Connecticut answers ISO-NE and FirstLight Feb 13 answers
			Feb 26	ISO-NE answers EMM Feb 19 answer
	10	Waiver Request: Restoration Plan Submission Deadline (PSNH) (ER18-465)	Feb 15	FERC grants one-day waiver of restoration plan submission deadline requested by PSNH for its Lost Nation generating unit

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-EM: Brookfield LSA (ER18-901)	Feb 23	ISO-NE and Emera file LSA with Brookfield Energy Marketing; comment date Mar 16
	12	Schedule 21-EM: Stored Solar J&WE LSA (ER18-387)	Feb 2	FERC accepts Stored Solar LSA, eff. Jan 1, 2016

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

*	13	Capital Projects Report - 2017 Q4 (ER18-841)	Feb 9	ISO-NE files Q4 Report
			Feb 22	NEPOOL intervenes and files comments supporting Q4 Report
			Feb 27-28	National Grid, Eversource intervene
*	14	IMM Quarterly Markets Reports - 2017 Fall (ZZ17-4)	Feb 21	IMM files Fall 2017 Report

IX. Membership Filings

*	14	March 2018 Membership Filing (ER18-923)	Feb 28	New members: Bruce Power, CS Berlin Ops, HSE Hydro NH AC, Optik Energy; Terminations: Cargill, RBC Energy Services; comment date Mar 21
	14	February 2018 Membership Filing (ER18-767)	Feb 2	Eversource intervenes
	15	January 2018 Membership Filing (ER18-539)	Feb 12	FERC accepts termination of the Participant status of Aspirity Energy, Constellation Energy Services and Noble Americas Power & Gas
*	15	Suspension Notice – OhmConnect (not docketed)	Feb 21	ISO-NE files notice of suspension of OhmConnect from the New England Markets
*	15	Suspension Notice – Millennium Power Partners (not docketed)	Feb 16	ISO-NE files notice of suspension of Millennium Power Partners from the New England Markets

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

	15	NOPR: Cyber Security Incident Reporting Rel. Standards (RM18-2)	Feb 7-26	Over 15 parties submit comments
	16	NOPR: New Rel. Standards: PRC-027-1 and PER-006-1 (RM16-22)	Feb 12	Hydro One Networks Inc submits comments
*	17	Rules of Procedure Changes (Sections 600 and 900) (RR17-2)	Feb 27	NERC files amended changes to Rules of Procedure; comment date Mar 20

XI. Misc. - of Regional Interest

*	18	203 Application: NRG/GIP III Zephyr Acquisition Partners (EC18-61)	Feb 23	NRG requests authorization for transactions pursuant to which GIP will acquire NRG Yield, NRG Renew and their public utility subsidiaries, and Carlsbad
	18	203 Application: PSNH/HSE Hydro NH (EC18-42)	Feb 28	FERC authorizes transaction
	18	203 Application: Dynegy/Vistra (EC18-23)	Feb 5	Applicants answer Public Citizen protest; supplement app. with delivered price test for MISO
	18	203 Application: Calpine/ECP (EC17-182)	Feb 21	FERC authorizes transaction
	19	IA Cancellation: Superseded NGrid/Casella Waste Systems IA (ER18-791)	Feb 2	National Grid files notice of cancellation of IA with Casella Waste Systems superseded by conforming 3-party SGIA with Southbridge Recycling and Disposal Park
	20	LGIAs: PSNH/GSP Newington/GSP White Lake /GSP Lost Nation (ER18-785, -786, -787)	Feb 2 Feb 23	Eversource files LGIAs GSP Lost Nation intervenes
	20	REMVEC II & REMVEC SAS Agreement Terminations (ER18-716)	Feb 27	FERC accepts agreement terminations, eff. Mar 28, 2018
	20	LGIA: Emera Maine/Penobscot Energy Recovery Co (ER18-505)	Feb 1	FERC accepts LGIA, eff. Mar 1, 2018
	20	Anbaric's Ocean Grid Project: Transmission Rights at Negotiated Rates (ER18-435)	Feb 12	FERC conditionally authorizes Anbaric to sell transmission rights at negotiated rates on its Ocean Grid Project
	21	NEP/HQUS Phase I/II HVDC-TF Service Agreement (ER18-388)	Feb 1	FERC accepts agreement, eff. Jan 1, 2018

XII. Misc. - Administrative & Rulemaking Proceedings

*	22	DER Participation in RTO/ISOs (AD18-10; RM18-9)	Feb 15	FERC issues notice of Apr 10-11 tech conf.; those wishing to speak should submit a nomination form by Mar 15, those interested in attending should register by Apr 3
	22	Grid Resilience in RTO/ISOs; DOE NOPR (AD18-7; RM18-1)	Feb 7	Foundation for Resilient Societies requests rehearing of FERC order terminating DOE NOPR rulemaking proceeding (RM18-1)
*	23	NOPR: Withdrawal of Pleadings (RM18-7)	Feb 15	FERC issues NOPR; comment date Mar 26

25	*Order 841*: Electric Storage Participation in RTO/ISO Markets (RM16-23; AD16-20)	Feb 15	FERC issues *Order 841*, eff. [90 days after publication in the *Federal Register*]
26	*Order 842*: Primary Frequency Response (RM16-6)	Feb 15	FERC issues *Order 842*, eff. [70 days after publication in the *Federal Register*

XIII. Natural Gas Proceedings

26	FERC Staff Inquiry in Response to EDF Allegations of Pipeline Capacity Withholding (not docketed)	Feb 27	FERC issues press release stating that Staff found no evidence of withholding
29	New England Pipeline Proceedings		
	• Atlantic Bridge Project (CP16-9)	Feb 16	Algonquin requests DC Circuit Court of Appeals issue an order establishing a deadline for the MA DEP to issue, condition, or deny the minor-source air permit for Algonquin's proposed Weymouth, MA natural gas compressor station
	• Constitution Pipeline (CP18-5)	Feb 12	Constitution Pipeline Co. requests reh'g of Jan 11, 2018 order denying its Petition requesting that FERC find that NY DEC waived its authority under section 401 of the Clean Water Act by failing to act within a "reasonable period of time"
28	Natural Gas-Related Enforcement Actions: BP (IN13-15)	Feb 9	FERC Staff responds to BP's Dec 11 motion

XIV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XV. Federal Courts

34	FCM Resource Retirement Reforms (17-1275)	Feb 1 Feb 7, 15 Feb 16 Feb 23	Constellation submits statement of issues and other prelim docs FERC counsel enters appearance, submits certified index to record Constellation submits joint motion for proposed briefing schedule Clerk issues order establishing briefing schedule
34	Demand Curve Changes (17-1110**)	Feb 1	Petitioners, Respondent and Intervenors for Respondent final briefs; Petitioners file final reply brief; Court issues order scheduling oral argument for Apr 13, 2018
35	FCA10 Results (16-1408) and FCA9 Results (16-1068)	Feb 9	Oral argument held before Judges Rogers, Millett and Pillard
35	Base ROE Complaints II & III (2012 & 2014) (15-1212)	Feb 13	Parties file 10th status report indicating that proceedings upon which request for abeyance was requested remain ongoing
36	FCM Pricing Rules Complaints (15-1071**, 16-1042) (consol.)	Feb 2	Court grants NEPGA's and Exelon's petitions for review of orders accepting the FCM's 7-year price lock-in (EL14-7) and capacity-carry-forward rules (EL15-23); remanding to FERC for further proceedings

M E M O R A N D U M

TO: NEPOOL Participants Committee Member and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: February 28, 2018

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"),[1] state regulatory commissions, and the Federal Courts and legislatures through February 28, 2018. If you have questions, please contact us.

I. Complaints/Section 206 Proceedings

- **Calpine/LS Power Delayed Resource Complaint (EL18-53)**

On February 8, Calpine Corporation ("Calpine") and LS Power Associates ("LS Power", and together with Calpine, "Complainants") withdrew their December 21, 2017 complaint ("Delayed Resource Complaint"), which had asked the FERC to adopt an interim change to the Tariff, to be effective for FCA12, "to ensure that a resource that is not reasonably expected to be operational during the 2021-22 Capacity Commitment Period is not permitted to interfere with efficient price formation and artificially suppress prices in FCA 12 by entering a zero dollar offer for its capacity" and to "require ISO-NE to work with its stakeholders to file Tariff modifications in time for [FCA13] addressing the requirements for a Delayed Resource to participate in future FCAs, resume receiving its Lock-In Price, and extend its Lock-In Period."

In their notice of withdrawal, Complainants explained that, because FCA12 "concluded on February 6, 2018, and because Complainants have not requested that the [FERC] require ISO-NE to re-run the auction after it is conducted, Complainants are now withdrawing the [Delayed Resource] Complaint." Reporting on this proceeding is now concluded. If you have any remaining questions, 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).

- **PER Settlement Agreement (ER17-2153; EL16-120)**

On February 20, the FERC approved[2] the Offer of Settlement and settlement materials ("PER Settlement") filed July 28, 2017[3] by the Settling Parties[4] to resolve the issue set for hearing and settlement

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

[2] *New England Power Generators Assoc. v. ISO New England Inc.*, 162 FERC ¶ 61,144 (Feb 20, 2018) ("*PER Settlement Order*").

[3] The Settlement was initially filed on July 26 under different eTariff codes and subsequently withdrawn in favor of the July 28 filing. The Docket Number (ER17-2153) remained the same. The withdrawal of the July 26 filing was accepted on August 31.

[4] PER "Settling Parties" are: NEPGA, NESCOE, the Retail Energy Supply Association ("RESA"), NEPOOL, Exelon, H.Q. Energy Services (U.S.) ("HQUS"), Eversource, Dominion, Entergy, NRG, and Cogentrix. Intervenors in the proceeding not opposing the Settlement ("Non-Opposing Intervenors") are: ISO-NE, PSEG, Consolidated Edison Energy, Inc. ("ConEd"), Verso Corp., GenOn Energy Management LLC, National Grid, NextEra, the New Hampshire Electric Coop. ("NHEC"), and Calpine.

judge procedures by the FERC in this proceeding.[5] Under the FERC-approved PER Settlement, ISO-NE will calculate Adjusted Hourly Strike Price as the sum of the daily Strike Price (as calculated under the existing Tariff) and a newly-defined Hourly PER Adjustment. The Hourly PER Adjustment will be equal to the average over each hour of a newly-defined Five-Minute PER Strike Price Adjustment. The Five-Minute Strike Price Adjustment[6] will be equal to any positive difference between a five-minute Thirty Minute Operating Reserves Clearing Price or Ten-Minute Non-Spinning Reserves Clearing Price that exceeds the maximum allowable reserves clearing prices for those reserves products (i.e., the Reserve Constraint Penalty Factors) in effect before December 2014.

As previously reported, the PER Settlement did not resolve the issues of the applicability of the Strike Price methodology to FCA9.[7] In its comments, in which it neither supported nor objected to the proposed PER strike price methodology, ISO-NE requested that the FERC resolve how the Average Monthly PER will be calculated on and after June 1, 2018. NESCOE asked the FERC to reject the position advocated by NEPGA that the agreed-upon Adjusted Hourly Strike Price as defined in the Settlement should extend beyond May 31, 2018. NEPGA, NRG, HQUS, Dominion, and Verso jointly asked the FERC to approve the Settlement and order ISO-NE to make a compliance filing, but decline to address NESCOE's request until some later date. In the *PER Settlement Order*, the FERC found the issues of the applicability of the Strike Price methodology to FCA9 beyond the scope of the settlement agreement proceeding.[8]

ISO-NE was directed to make a compliance filing in eTariff format to reflect the FERC's action in the *PER Settlement Order*.[9] The FERC stated that the *PER Settlement Order* "terminates Docket Nos. EL16-120-000 and ER17-2153-000."[10] If you have any questions concerning this matter, please contact Joe Fagan (202-218-

[5] *See New England Power Generators Assoc., Inc. v. ISO New England Inc., 158 FERC ¶ 61,034 (Jan. 19, 2017) ("PER Complaint Order"), reh'g and clarif. denied, 161 FERC ¶ 61,193 (Nov. 16, 2017)* ("*PER Complaint Rehearing Order*"). The *PER Complaint Order* (i) granted in part NEPGA's complaint and (ii) set in part for hearing and settlement judge procedures the question of the appropriate method of calculating the PER Strike Price under Market Rule 1 Section III.13.7.2.7.1.1.1. The FERC found that "for the period at issue in NEPGA's complaint (September 30, 2016 – May 31, 2018), the PER mechanism has become unjust and unreasonable as a result of the interaction between the PER mechanism and the higher Reserve Constraint Penalty Factors." Accordingly, the FERC required ISO-NE to revise the method by which it calculates the PER Strike Price as set forth in Tariff section III.13.7.2.7.1.1.1. But, finding NEPGA's request that the PER Strike Price be increased by $250 per MWh "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", the FERC set the question of for hearing and settlement judge procedures under section 206 of the FPA. The FERC established a refund effective date of September 30, 2016 (the date of the complaint). In establishing a September 30, 2016 effective date, the FERC clarified that "any changes to the calculation of the PER Strike Price under ISO-NE Tariff section III.13.7.2.7.1.1.1 would be prospective only from September 30, 2016, as required by FPA section 206, and would not impact the application of any PER Adjustment occurring before September 30, 2016."

[6] Five-Minute PER Strike Price Adjustment will be calculated according to the following formula: Five-Minute PER Strike Price Adjustment = MAX (Thirty Minute Operating Reserves Clearing Price - $500/MWh, 0) + MAX (Ten Minute Non-Spinning Reserves Clearing Price – Thirty Minute Operating Reserves Clearing Price - $850/MWh, 0).

[7] In its *PER Complaint Rehearing Order*, the FERC clarified that it "intended for ISO-NE to use the difference between the former strike price and the LMP for event hours that occurred prior to September 30, 2016, and for ISO-NE to use the new strike price only for event hours that occur after September 30, 2016 … [t]he Commission's order is clear in that it addresses a change to the calculation of the PER strike price as set forth in section 111.13.7.2.7.1.1.1 and such change is prospective only."

[8] *PER Settlement Order* at P 3.

[9] While the *PER Settlement Order* acknowledged NEPOOL's s request that, "in order to accommodate participation in the stakeholder process for modifying the market rules, the Commission allow at least sixty days following any Settlement approval for ISO-NE to file tariff revisions to implement the Settlement," the *PER Settlement Order* is silent on the timing for the compliance filing directed. Pursuant to Rule 1907 of the FERC's Rules of Practice and Procedure, unless otherwise provided, "when any … person subject to the jurisdiction of the Commission is required to do or perform any act by Commission order, … there must be filed with the Commission within 30 days following the date when such requirement became effective, a notice, under oath, stating that such requirement has been met or complied with." 18 CFR § 385.1907.

[10] *PER Settlement Order* at P 4.

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)**

Hearings in this matter were held December 11-15, 2017. Transcripts of the hearings are posted on the FERC's eLibrary. Corrections to the transcripts, jointly filed by the hearing participants, were accepted by Judge Glazer on January 2, 2018. EMCOS, Complainant-Aligned Parties, TOs, and FERC Trial Staff submitted their initial post-hearing briefs on January 16 and their reply briefs on February 7. Post-hearing briefs ' oral argument was held on February 22, 2018. An initial decision is expected to be issued on or before March 27, 2018.

As previously reported, the FERC, on September 20, 2016, established hearing and settlement judge procedures (and set a refund effective date of April 29, 2016) for the 4th ROE Complaint filed by EMCOS on April 29, 2016.[11] The 4th ROE Complaint asked 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 4th ROE Complaint: (1) the continuing decline of the market cost of equity capital, which makes TOs' 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 discounted cash flow ("DCF") methodology, and particularly the DCF midpoint, for determining ROE remains unclear." Both the TOs and EEI requested rehearing of the *Base ROE Complaint IV Order.* The FERC denied the requests for rehearing on January 16, 2018.[12]

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).

- **Base ROE Complaints I-IV: TOs' Motion to Dismiss or Consolidate Complaints I-IV (EL16-64; EL14-86; EL13-33; EL11-66)**

The TOs' October 5, 2017 motion to dismiss all four ROE complaints (captioned above) in light of the *Emera Maine*[13] decision remains pending. The October 5 motion alternatively requested that the FERC consolidate the four ROE complaints for decision and use expedited procedures to resolve them. The TOs stated that this motion was motivated in part by *Emera Maine*, but also by what they describe as the "enormous investment uncertainty" resulting from the various litigation proceedings. On October 20, Complainant-Aligned Parties and EMCOS submitted answers opposing TOs' requests. The TOs' motion and the motions filed in response are pending before the FERC.

- **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-NE Tariff is unjust, unreasonable, and unduly

[11] *Belmont Mun. Light Dept. v. Central Me. Power Co.*, 156 FERC ¶ 61,198 (Sep. 20, 2016) ("*Base ROE Complaint IV Order*"), *reh'g denied*, 162 FERC ¶ 61,035 (Jan. 18, 2018).

[12] *Belmont Mun. Light Dept. v. Central Me. Power Co.*, 162 FERC ¶ 61,035 (Jan. 18, 2018) ("*Base ROE Complaint IV Rehearing Order*").

[13] *Emera Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017) ("*Emera Maine*"). *Emera Maine* vacated the FERC's prior orders in the Base ROE Complaint I proceeding, and remanded the case for further proceedings consistent with its order. The Court agreed with both the TOs (that the FERC did not meet the Section 206 obligation to first find the existing rate unlawful before setting the new rate) and "Customers" (that the 10.57% ROE was not based on reasoned decision-making, and was a departure from past precedent of setting the ROE at the midpoint of the zone of reasonableness).

discriminatory or preferential because the Tariff "lacks adequate transparency and challenge procedures with regard to the formula rates" for Regional Network Service ("RNS") and Local Network Service ("LNS").[14] 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".[15] 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.[16] Hearings continue to be held in abeyance pending the outcome of settlement judge procedures underway.[17] The FERC-established refund date is January 4, 2016.[18]

Settlement Judge Procedures. As previously reported, John P. Dring was designated the Settlement Judge in these proceedings. Five settlement conferences were held in 2016: January 19, March 24, April 28, August 30, and November 18 (telephonically); four settlement conferences were held in 2017: April 5, May 9, July 7, and November 13, 2017; and two settlement conferences, on January 9 and February 1, thus far in 2018. Judge Dring's most recent status report was issued on February 2, noting that, at the February 1 settlement conference, significant progress was made and a schedule was established for finalizing the necessary settlement documents for filing with the FERC. Accordingly, he recommended that settlement procedures be continued. On February 26, Chief Judge Cintron issued an order continuing settlement judge procedures. The Transmission Committee is being kept apprised, as appropriate, 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)[19] and third (EL14-86)[20] 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;[21] the second, in EL14-86, was issued on November 24, 2014, established a 15-month refund period beginning July 31, 2014,[22] and, because of "common issues of law and fact", consolidated the two proceedings for purposes of hearing and decision, with

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

[15] *Id.* at P 8.

[16] *Id.* at P 11.

[17] *Id.*

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

[19] 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%.

[20] 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.

[21] *Environment Northeast v. Bangor Hydro-Elec. Co.*, 147 FERC ¶ 61,235 (June 19, 2014) ("*2012 Base ROE Initial Order*"), *reh'g denied,* 151 FERC ¶ 61,125 (May 14, 2015).

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

the FERC finding it "appropriate for the parties to litigate a separate ROE for each refund period."[23] The TOs requested rehearing of both orders. On May 14, 2015, the FERC denied rehearing of both orders.[24] On July 13, 2015, the TOs appealed those orders to the DC Circuit Court of Appeals (*see* Section XIV below), and that appeal continues to be held in abeyance.

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 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.[25] 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

- **Emera MPD OATT Attachment J Revision (ER18-210)**

On February 15, the FERC accepted Emera's s proposed revision to Attachment J of the MPD OATT,[26] but established hearing & settlement judge procedures because its "preliminary analysis indicates that Emera Maine's proposed tariff revision has not been shown to be just and reasonable and may be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful."[27] The FERC suspend the tariff revision for a nominal period, to become effective January 1, 2018, as requested, subject to refund. As previously reported, the prosed tariff revision was to permit adjustments to formula rate inputs (historical load, revenue, sales data) to reflect "known and measurable" anticipated changes, subject to a true-up. Emera stated that, absent an ability to adjust its formula rate calculations to account for material losses of load, like that of Houlton Water Company expected to occur early next year, Emera Maine will suffer a significant under-recovery in its transmission revenue requirement. The Maine Customer Group ("MCG")[28] protested the revision for a number of reasons, with the principal objection being the fact that "Emera already has a true-up mechanism in place under the MPD OATT to accommodate loss of Houlton load".

[23] *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).

[24] *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).

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

[26] *Emera Maine*, 162 FERC ¶ 61,131 (Feb. 15, 2018).

[27] *Id.* at P 24.

[28] MCG consists of consists of: Maine's 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").

Settlement Judge Procedures. On February 21, Chief Judge Cintron designated Judge John P. Dring as the Settlement Judge in these proceedings. Judge Dring has not as of the date of this Report scheduled a first settlement conference.

If there are any questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

Rehearing remains pending of the FERC's October 6, 2017 order rejecting the TOs' June 5, 2017 filing in this proceeding.[29] As previously reported, the June 5 filing was designed to reinstate TOs' transmission rates to those in place prior to the FERC's orders later vacated by the DC Circuit's *Emera Maine*[30] decision. In its *Order Rejecting Filing*, the FERC required the TOs to continue collecting their ROEs currently on file, subject to a future FERC order.[31] The FERC explained that it will "order such refunds or surcharges as necessary to replace the rates set in the now-vacated order with the rates that the Commission ultimately determines to be just and reasonable in its order on remand" so as to "put the parties in the position that they would have been in but for [its] error." For the time being, so as not to "significantly complicate the process of putting into effect whatever ROEs the Commission establishes on remand" or create "unnecessary and detrimental variability in rates," the FERC has temporarily left in place the ROEs set in *Opinion 531-A*, pending an order on remand.[32] On November 6, the TOs requested rehearing of the *Order Rejecting Filing*. On December 4, 2017, the FERC issued a tolling order providing it additional time to consider the TOs' request for rehearing of the *Order Rejecting Filing*, which remains pending. 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).

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

- **Real-Time Reserve Designation & Settlement Rule Changes (ER18-897)**

On February 22, 2018, ISO-NE and NEPOOL jointly filed changes to differentiate between Operating Reserve requirements and the reserve products used to satisfy those requirements and to add details about how Operating Reserve is designated to individual resources in the operation of the Real-Time Energy Market. Specifically, the changes (i) enhance the differentiation between reserve requirements and the reserve products that can be used to meet those requirements; (ii) add detail as to how reserves are designated for individual resources in the operation of the Real-Time Energy Market; (iii) restructure and clarify the financial settlement for resources providing Real-Time Reserves; and (iv) implement a handful of clean-up and conforming edits to the Tariff. ISO-NE requested the changes become effective June 1, 2018. The Real-Time Reserve Designation & Settlement Rule Changes were supported by the Participants Committee at the December 8, 2017 meeting (Consent Agenda Item #4). Comments on this filing are due on or before March 15, 2018. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **CSO Termination: Blue Sky West (ER18-704)**

As previously reported, ISO-NE filed on January 23, pursuant to Market Rule 1 § 13.3.4(c), to terminate a portion of the CSO held by Project Sponsor Blue Sky West ("BSW") for Resource No. 37105 -- BSW's Bingham, ME wind generation facility. ISO-NE explained that the involuntary termination was for the portion of the CSO that had not achieved commercial operation and had not been covered by BSW. ISO-NE reported that it terminated

[29] *ISO New England Inc.*, 161 FERC ¶ 61,031 (Oct. 6, 2017) ("*Order Rejecting Filing*"), *reh'g requested*.

[30] *Emera Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017) ("*Emera Maine*").

[31] *Order Rejecting Filing* at P 1.

[32] *Id.* at P 36.

the portion of the CSO for the FCA8 through FCA11 Capacity Commitment Periods concurrently with the termination filing. ISO-NE indicated that, upon FERC acceptance of the filing, it would draw down the amount of financial assurance provided by BSW with respect to the portion of the CSO to be terminated.

Emergency Motion to Reinstate Terminated MWs. On January 29, BSW filed an emergency motion asking the FERC to immediately reinstate the portion of BSW's CSO involuntarily terminated by ISO-NE on Jan 23 ("Disputed MWs") pending resolution of this CSO Termination Filing. The Emergency Motion presented a threshold issue of first impression, namely whether the involuntary termination of all or a portion of a CSO may become effective upon ISO-NE submission of an involuntary termination filing with the FERC (as ISO-NE asserted) or upon resolution of the involuntary termination filing (as Blue Sky West asserted). The distinction impacted the MWs with which Blue Sky West was eligible to participate in FCA12. ISO-NE answered the Emergency Motion on January 31. NEPOOL also submitted limited comments prior to the FERC-imposed February 1, 10am deadline for answers to the Emergency Motion (noting that the FERC needed to resolve the dispute between ISO-NE and BSW, and that, should the FERC conclude the Tariff required additional clarity, those changes be permitted to be proposed using the established NEPOOL Participant Processes). The FERC granted the Emergency Motion on February 2.[33] In directing the Disputed MWs be reinstated through March 24, 2018 (the end of the 60-day notice period required under FPA § 205), the FERC found that the filing, and ISO-NE's right to involuntarily terminate the Disputed MWs, could not be made, absent waiver, prior to March 24, 2018.

On the Merits of the Involuntary Termination of the Disputed MWs. On February 13, Blue Sky West protested the termination of the Disputed MWs. Blue Sky asserted that CPS monitoring requirements for the as-built portion of its resource terminated when that portion of the resource achieved Commercial Operation on December 13, 2016 and, as a result, Blue Sky West was not required to cover any MW up to the as-built CSO after that time. Blue Sky West further argued that, should the FERC find that ISO-NE had the discretion to terminate the Disputed MWs based on more recent Seasonal Claimed Capability audit results, it would be unjust and unreasonable to do so in this case (particularly given the unseasonably low wind resource period during the ISO-NE-selected audit period, and ISO-NE's pending revisions to ISO-NE audit procedures). Doc-less motions to intervene were filed by National Grid, NextEra and NRG/GenOn. This matter is now pending before the FERC.

If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Waiver Request: Timing of Canal-MA-GHG-Rule-Related Addl. Cost Recovery Filing (GenOn) (ER18-623)**

On February 8, the FERC granted GenOn's request for a waiver of certain timing requirements set forth in Market Rule 1 Appendix A Section 15 related to the timing of filings for additional cost recovery that may be made under Section 205 of the FPA if a Market Participant "believes that it will not recover the fuel and variable operating and maintenance costs of the Resource" ("GenOn Request").[34] Pursuant to Section III.A.15, "a Market Participant may make such a Section 205 filing "within ***60 days*** of the receipt of the first Invoice issued containing credits or charges for the applicable Operating Day." GenOn requested waiver of the 60-day and associated deadlines in order to allow for the purchase of MA GHG Allowances associated with the Canal unit for which it is the lead Participant, up to the March 1, 2019 compliance deadline under the MA GHG Rule, and the submission of an additional cost recovery filing as late as (but no later than) April 30, 2019. GenOn stated that ISO-NE and the Internal Market Monitor ("IMM") supported the requested waiver, with the understandings and limitations set forth in its request. In granting the request, the FERC found that the request met the FERC's criteria for granting one-time waivers of tariff provisions.[35] The FERC rejected Public Citizen's request to deny the waiver request, finding GenOn's litigation against Massachusetts was "not a reason to deny a request for waiver that would

[33] *ISO New England Inc.*, 162 ¶ 61,088 (Feb. 2, 2018).

[34] *GenOn Energy Management, LLC*, 162 FERC ¶ 61,094 (Feb. 8, 2018).

[35] *Id.* at P 19.

facilitate GEM's compliance."[36] Unless the February 8 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Updated Dynamic De-List Bid Threshold (ER18-620)**

On January 8, ISO-NE and NEPOOL jointly filed changes to reduce the FCM Dynamic De-List Bid Threshold ("DDBT"),[37] beginning with FCA13, to $4.30/kW-mo. ISO-NE and NEPOOL requested that lower DDBT become effective March 9, 2018 (coincident with the start of the FCA13 qualification period). The updated DDBT was supported by the Participants Committee at the November 3 meeting (Agenda Item #6). On January 23, ISO-NE submitted supplemental information to clarify the "impact of potential capacity retirements for its argument that recent capacity surpluses warrant a reduction in the DDBT." Comments on this filing were due on or before January 29, 2018. Protests were filed by NEPGA and PSEG. ISO-NE and NEPOOL answered the protests on February 13; NEPGA answered the February 13 ISO-NE and NEPOOL answers on February 21. Doc-less interventions were filed by Calpine, Cogentrix, ConEd, ENE, Dominion, ENE, Eversource, FirstLight, National Grid, NESCOE, NextEra, NRG, and Public Citizen. 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).

- **CASPR (ER18-619)**

Also on January 8, ISO-NE filed its Competitive Auctions with Sponsored Policy Resources ("CASPR") Proposal. ISO-NE stated that its CASPR proposal is designed "to meet the region's objectives of accommodating the entry of sponsored new resources into the FCM over time and maintaining competitive capacity pricing." ISO-NE stated that wherever possible, it had prioritized the preservation of competitive prices in the FCM, and the Market Rules proposed include "financial incentives for existing resources to transfer their capacity obligations to new sponsored policy resources and to permanently exit the capacity market." ISO-NE requested that the bulk of the CASPR rules become effective on March 9, 2018 (coincident with the beginning of the approximately year-long auction-administration cycle for FCA13), with the remainder to become effective on June 1, 2018 (for a small number of Tariff changes related to FCM settlements, where changes to become effective on June 1, 2018 are already pending). The Participants Committee considered but did not support the CASPR Proposal at its December 8 Annual Meeting.

Comments on this filing were due on or before January 29, 2018 and were filed by NEPOOL, Calpine, CPV Towantic, Dominion, the EMM (out-of-time), Exelon, FirstLight, NECOS, NEPGA, NextEra, NRG, Public Systems, Verso, CT PURA/DEEP/OCC, MA AG, MA DPU, MPUC, NHPUC, NESCOE, AEMA, APPA, Clean Energy Advocates, NGSA, Public Citizen, and RESA. A high level summary of those pleadings has been separately prepared and is being circulated and posted with this Report. Entities that intervened, but that did not submit comments and/or protests either individually or as part of a group, included: Avangrid, AWEA, Champlain VT, ConEd, CT PURA, Direct Energy, Dynegy, EEI, Emera, ENE, EPSA, Eversource, HQUS, LS Power, National Grid, NH OCA (out-of-time), NRECA, and PSEG. Answers to the pleadings were submitted by NEPOOL, ISO-NE, FirstLight and NRECA. On February 19, the EMM answered ISO-NE's February 13 answer. On February 22, Connecticut answered the February 13 ISO-NE and FirstLight answers. On February 26, ISO-NE answered the EMM's February 19 answer. This matter is now pending before the FERC. If you have any questions concerning this proceeding, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

[36] *Id.* at P 20.

[37] The FCM Dynamic De-List Bid Threshold is an IMM-established value below which existing resources that have chosen to be price takers in an Forward Capacity Auction ("FCA") can opt to leave the auction without further review by the IMM. The Dynamic De-List Bid Threshold is designed to prevent the exercise of market power by maximizing the likelihood that the IMM reviews the pricing competitiveness of all bids from existing resources in a position to increase the clearing price (exercise market power) by leaving the FCA. The Tariff requires that the threshold price be re-set no less than once every three years. In the January 8 filing, ISO-NE committed to recalculate the Dynamic De-List Bid Threshold for FCA15 to reflect the change in the Capacity Performance Payment Rate scheduled to be in place for FCA15.

- **Waiver Request: Restoration Plan Submission Deadline (PSNH) (ER18-465)**

On February 15, 2018, the FERC granted Public Service Company of New Hampshire ("PSNH") a one-day waiver of the submission deadline for the restoration plan for the Lost Nation[38] generating unit.[39] PSNH stated it missed the Tariff deadline for the submission of a plan (set forth in Section III.13.4.2.1.3(a)) by one business day because of what it described as two unforeseen and unavoidable events.[40] The FERC found that PSNH satisfied its conditions for granting waiver of tariff provisions.[41] Unless the February 15 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **ART Market Rule Changes (ER18-455)**

On December 15, 2017, as corrected by ISO-NE on December 20,[42] ISO-NE and NEPOOL jointly filed changes to establish a new capacity market bilateral transaction -- an Annual Reconfiguration Transaction ("ART") and to make other changes to the FCM rules ("ART Market Rule Changes"). ISO-NE and NEPOOL requested that the ART Market Rule Changes become effective in two stages, with most of the rule changes becoming effective on March 1, 2018 and the remainder becoming effective on June 1, 2018. The ART Market Rules Changes were supported by the Participants Committee at the November 3 meeting (Agenda Item #7). Comments on this filing, as corrected , were due on or before January 10, 2018. Two protests, on limited aspects of the Changes, were filed by (i) FirstLight (which, as it did at the November 3 meeting, protested the proposed exemption for deficiencies of less than 2 MW in the significant decrease provisions) and (ii) jointly by Exelon, CPV Towantic and NRG ("Indicated Generators"), who asked that the proposed "Required Demand Bid change"[43] take effect in the third ARA for FCA9, which will be held in March 2018, rather than in the ARA3 for FCA11. Doc-less interventions were filed by Brookfield, ConEd, Dominion, Eversource, National Grid, NESCOE, and PSEG (out-of-time). On January 25, NEPOOL and ISO-NE answered the FirstLight and Indicated Generators' protests. On January 29, FirstLight answered ISO-NE's January 25 answer. 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).

- **CONE & ORTP Updates (ER17-795)**

Rehearing remains pending of the FERC's October 6 order accepting updated FCM Cost of New Entry ("CONE"), Net CONE and Offer Review Trigger Price ("ORTP") values filed by ISO-NE in January.[44] In accepting the changes, the FERC disagreed with the challenges to ISO-NE's choice of reference technology (gas-fired simple cycle combustion-turbine) and on-shore wind capacity factor (32%). The changes were accepted effective as of March 15, 2017, as requested. On November 6, NEPGA requested rehearing of the *CONE/ORTP Updates Order*. On December 4, 2017, the FERC issued a tolling order providing it additional time to consider

[38] Lost Nation, an 18 MW oil-fired combustion turbine located in Northumberland, New Hampshire, obtained a 13.97 MW CSO in FCA9. ISO-NE flagged Lost Nation as having a significant decrease in capacity in its revised list of Qualified Capacity for FCA9 ARA3.

[39] *Pub. Srvc. Co. of New Hampshire*, 162 FERC ¶ 61,104 (Feb. 15, 2018).

[40] PSNH attributed the missed deadline to the combination of the death of mother of the employee charged with submitting the Restoration Plan and the subsequent time off, as well as the employee's storm duty assignment following the October 30, 2017 "nor'easter." PSNH stated that, together, these events distracted the employee, ultimately with the effect that the deadline for submitting the Restoration Plan was missed.

[41] *Id.* at P 12. The conditions for granting waiver are: (1) the applicant acted in good faith; (2) the waiver is of limited scope; (3) the waiver addresses a concrete problem; and (4) the waiver does not have undesirable consequences, such as harming third parties.

[42] On December 20, 2017, ISO-NE submitted an errata filing to correct the clean Tariff sheets to be posted in eLibrary. The comment deadline was thereby effectively extended to January 10, 2018.

[43] The "Required Demand Bid change" is the ISO-NE proposal to submit a demand bid in the third ARA ("ARA3") only in those cases when there is a significant decrease in the capacity resource's ability to fulfill its Capacity Supply Obligation ("CSO") in all 12 months of the Capacity Commitment Period ("CCP"), beginning with ARA3 for FCA11.

[44] *ISO New England Inc.*, 161 FERC ¶ 61, 035 (Oct. 6, 2017)("*CONE/ORTP Updates Order*"), *reh'g requested*.

NEPGA's request for rehearing of the *CONE/ORTP Updates Order*, which remains pending. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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

Still pending before the FERC is ISO-NE's compliance filing in response to the FERC's August 8, 2016 remand order.[45] In the *2013/14 Winter Reliability Program Remand Order*, the FERC directed ISO-NE to request from Program participants the basis for their bids, including the process used to formulate the bids, and to file with the FERC 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.[46] ISO-NE submitted its compliance filing on January 23, 2017, reporting the IMM's conclusion that "the auction was not structurally competitive and a 'small proportion' of the total cost of the program may be the result of the exercise of market power" but that the "vast majority of supply was offered at prices that appear reasonable and that, for a number of reasons, it is difficult to assess the impact of market power on cost." Based on the IMM and additional analysis, ISO-NE recommended that "there is insufficient demonstration of market power to warrant modification of program." In February 13 comments, both TransCanada and the MA AG protested ISO-NE's conclusion and recommendation that modification of the program was unwarranted. TransCanada requested that FERC establish a settlement proceeding where market participants could "exchange confidential information to determine what the rates should be" and refunds and "such other relief as may be warranted" provided. On February 28, ISO-NE answered the TransCanada and MA AG protests. On March 10, 2017, TransCanada answered ISO-NE's February 28 answer. This matter is pending before the FERC. If you have any questions concerning these matters, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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

- **Schedule 21-EM: Brookfield LSA (ER18-901)**

On February 23, 2018, ISO-NE and Emera filed a non-conforming three-party Local Service Agreement ("LSA") between Brookfield Energy Marketing, LP ("Brookfield"), Emera Maine and ISO-NE for Firm Local Point-to-Point Service under Schedule 21-EM. Under the LSA, Emera Maine will continue to provide 85 MW of firm, point-to-point transmission service from its Powersville Road Substation at the $13.82/kW-yr rate set forth in a 2003 transmission service agreement that will expire May 16, 2018. Comments on this filing are due on or before March 16. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

[45] *ISO New England Inc.*, 156 FERC ¶ 61,097 (Aug. 8, 2016) ("*2013/14 Winter Reliability Program Remand Order*"). 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. *TransCanada Power Mktg. Ltd. v. FERC,* 2015 U.S. App. LEXIS 22304 (D.C. Cir. 2015).

[46] *2013/14 Winter Reliability Program Remand Order* at P 17.

- **Schedule 21-ES: PSNH/VEC LSA (ER18-745)**

On January 30, 2018, ISO-NE and Eversource, on behalf of PSNH, filed a non-conforming three-party Local Service Agreement ("LSA") between Vermont Electric Cooperative ("VEC"), PSNH and ISO-NE for Non-Firm Local Point-to-Point Service under Schedule 21-ES. The LSA is non-conforming in that it contains provisions reflecting a long-standing agreement between PSNH and VEC to provide each other with back-up transmission service. A January 1, 2018 effective date was requested. Comments on this filing were due on or before February 20; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-EM: Stored Solar J&WE LSA (ER18-387)**

On February 2, the FERC accepted an LSA by and among Emera Maine, Stored Solar J&WE, and ISO-NE for Local Non-Firm Point-to-Point Transmission Service under Schedule 21-EM of the ISO-NE OATT (the "Stored Solar LSA"). The Stored Solar LSA extends the same discounted service rate to Stored Solar that was offered to its predecessors, Indeck Maine and Covanta Maine. The Stored Solar LSA was accepted effective as of January 1, 2016 (the date Stored Solar acquired the Jonesboro facility), as requested. Unless the February 2 order is challenged, this proceeding will be concluded. If there are any questions on these matters, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **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,[47] 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.[48] 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.[49] 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.[50] The separate compliance filing dockets were consolidated for the purposes of settlement, hearing and decision.[51]

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

[48] *Id.* at P 24.

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

[50] *Id.* at P 27.

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

Settlement Judge Procedures. ALJ John Dring is the settlement judge for these proceedings. There have been five settlement conferences: three in 2016 -- June 29, October 25, and December 1; and two in 2017 -- September 6 and November 9, 2017. In his most recent January 18, 2018 status report, Judge Dring found that that the parties continue to make progress toward settlement, and recommended that settlement procedures (which are on-going) be continued.

Hearing Procedures? On October 11, Emera Maine requested that the Chief Judge establish an expedited hearing under specific terms and conditions set forth in Exhibit A to its October 11 motion ("Expedited Hearing"). The October 11 motion also asked that the answer period to its request be shortened to five days and that an order ruling on the motion be issued no later than October 18, 2017. On October 13, the Maine Customer Group, MPUC, ReEnergy Biomass Operations LLC, and FERC Trial Staff (collectively, "Intervenors and FERC Trial Staff"), filed an answer opposing the October 11 motion's request for a shortened answer period. On October 13, Chief Judge Cintron issued an order ("October 13 Order") which denied the request to shorten the answer period and identified additional questions that all participants in the proceeding were permitted the opportunity to address in their answers to the October 11 motion. Responses to the October 13 Order were filed by Emera Maine, Maine PUC/OPA, Maine Customer Group, and FERC Trial Staff ("October 26 Responses"). On November 13, Emera Maine responded to the October 26 Responses. The October 11 motion, October 26 Responses and Emera Maine's answer to the October 26 Responses are pending before Chief Judge Cintron.

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

- **Schedule 21-VEC: VEC/PSNH LSA (NJ18-10)**

On January 30, 2018, ISO-NE and VEC filed a non-conforming three-party LSA between VEC, PSNH and ISO-NE for Non-Firm Local Point-to-Point Service under Schedule 21-VEC. The LSA is non-conforming in that it contains provisions reflecting a long-standing agreement between PSNH and VEC to provide each other with back-up transmission service. The Agreement is docketed in an "NJ" docket due to VEC's representation that it is not a public utility subject to the obligations of Section 205 of the FPA. VEC asked that, if the filing of this rate schedule is not required (because, although VEC is the provider of service, VEC is not a public utility and the rates and charges for service do not affect regional service provided or are not collected by ISO-NE), the FERC reject the filing as moot or alternatively, give further guidance on how such agreements that are non-conforming should be handled in the future. A January 1, 2018 effective date was requested. Comments on this filing were due on or before February 20; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, 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 - 2017 Q4 (ER18-841)**

On February 9, ISO-NE filed its Capital Projects Report and Unamortized Cost Schedule covering the fourth quarter ("Q4") of calendar year 2017 (the "Report"). ISO-NE is required to file the Report under Section 205 of the FPA pursuant to Section IV.B.6.2 of the Tariff. Report highlights include the following new projects: (i) FCM Improvements ($965,000); (ii) Photovoltaic & Load Forecasting ($878,400); (iii) Intranet Platform Replacement ($855,000); and (iv) Mobile Application Project ($357,700). Projects with a significant changes were (i) FCA13 (2018 Budget decrease of $2 million (to be re-chartered/budgeted as "Annual Reconfiguration Transactions") - total project cost of $0); (ii) CASPR (2018 Budget decrease of $1.27 million; total project cost

$1.73 million); (iii) 2018 Issue Resolution Phase II (2018 Budget of $750,000; project removed); (iv) IMM Data Analysis Phase II (2018 Budget decrease of $700,000, for total project costs of $600,000); and (v) CIMNET Simultaneous Feasibility Test with Data Transfer Enhancements (2017 Budget decrease of $204,600, with total estimated project cost remaining at $2. 26 million). Comments on this filing are due on or before March 2. NEPOOL filed comments on February 22 supporting the Q4 Report. Thus far, National Grid and Eversource filed doc-less interventions. 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)**

FG&E's June 29, 2015 refund report for its customers taking local service during *Opinion 531-A's* refund period remains pending. 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)**

The TOs' November 2, 2015 refund report documenting resettlements of regional transmission charges by ISO-NE in compliance with *Opinions No. 531-A*[52] *and 531-B*[53] also remains pending. 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)**

The *Opinions 531-A and 531-B* refund reports filed by the following TOs for their customers taking local service during the refund period also remain pending before the FERC:

- ♦ Central Maine Power
- ♦ Emera Maine
- ♦ Eversource
- ♦ National Grid
- ♦ NHT
- ♦ NSTAR
- ♦ United Illuminating
- ♦ VT Transco

If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **IMM Quarterly Markets Reports – Fall 2017 (ZZ17-4)**

On February 21, the IMM filed with the FERC its report for the Summer quarter of 2017 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, but the Fall 2017 Report will be discussed with the Markets Committee at its March 6 meeting.

IX. Membership Filings

- **March 2018 Membership Filing (ER18-923)**

On February 28, NEPOOL requested that the FERC accept (i) the memberships of Bruce Power [Related Person to TransCanada Power Marketing (Supplier Sector)], CS Berlin Ops [Related Person to Berlin Station (Generation Sector Group Seat)], HSE Hydro NH AC [Related Person to Nautilus Hydro and Pawtucket Power (Generation Sector Group Seat)], and Optik Energy (Supplier Sector); and (ii) the termination of the Participant status of Cargill Power Markets (Supplier Sector) and RBC Energy Services [Related Person to Royal Bank of Canada (Supplier Sector)]. Comments on this filing are due on or before March 21.

- **February 2018 Membership Filing (ER18-767)**

On January 31, NEPOOL requested that the FERC accept the termination of the Participant status of Emera Energy Services Subsidiaries Nos. 10, 13 and 14 [Related Persons to Emera Maine (Transmission Sector)]; Epico

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

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

USA (AR Sector RG Sub-Sector, Small RG Group members); Shipley Choice (Supplier Sector); and WMECO [former Related Person to Eversource (Transmission Sector)]. On February 2, Eversource filed a doc-less intervention. The February membership filing is pending before the FERC.

- **January 2018 Membership Filing (ER18-539)**

On February 12, the FERC accepted the termination of the Participant status of Aspirity Energy (Supplier Sector), Constellation Energy Services [Related Person to Exelon Generation Company (Supplier Sector) and Noble Americas Power & Gas [Related Person to Mercuria Energy America (Supplier Sector)]. Unless the February 12 order is challenged, this proceeding will be concluded.

- **Suspension Notices (not docketed)**

Since the last Report, ISO-NE filed, pursuant to Section 2.3 of the Information Policy, a notice with the FERC noting that the following Participants were suspended from the New England Markets on the date indicated (at 8:30 a.m.) due to a Payment Default:

Date of Suspension/ FERC Notice	***Participant Name***	***Date Reinstated***
Feb 14/16	Millennium Power Partners, LP	--
Feb 16/21	OhmConnect, Inc.	--

Suspension notices are for the FERC's information only and are not docketed or noticed for public comment.

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

Questions concerning any of the ERO Reliability Standards or related rule-making proceedings or filings can be directed to Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **NOPR: Cyber Security Incident Reporting Reliability Standards (RM18-2)**

On December 21, 2017 the FERC issued a NOPR proposing to direct NERC to develop and submit modifications to the Critical Infrastructure Protection ("CIP") Reliability Standards to improve the reporting of Cyber Security Incidents, including incidents that might facilitate subsequent efforts to harm the reliable operation of the bulk electric system (e.g. (incidents that compromise, or attempt to compromise, a responsible entity's Electronic Security Perimeter ("ESP") or associated Electronic Access Control or Monitoring Systems ("EACMS")).[54] The mandatory reporting requirements are intended to improve awareness of existing and future cyber security threats and potential vulnerabilities. The reports would continue to go to the Electricity Information Sharing and Analysis Center ("E-ISAC"), but reports would also go to the Industrial Control Systems Cyber Emergency Response Team ("ICS-CERT"), with an annual, public, and anonymized summary of the reports. Comments on the *Cyber Security Incident Reporting NOPR* were due on or before February 26, 2018,[55] and were filed by over 15 parties, including by NY PSC, NRG and a number of individual commenters. This matter is pending before the FERC.

- **NOPR: Revised Reliability Standards: CIP-005-6, CIP-010-3, CIP-013-1 (RM17-13)**

On January 18, 2018, the FERC issued a NOPR proposing to approve revised CIP Reliability Standards -- CIP-005-6 (Cyber Security – Electronic Security Perimeter(s)), CIP-010-3 (Cyber Security – Configuration Change Management and Vulnerability Assessments) and CIP-013-1 (Cyber Security – Supply Chain Risk Management)

[54] *Cyber Security Incident Reporting Reliability Standards*, 161 FERC ¶ 61,291 (Dec. 21, 2017) ("*Cyber Security Incident Reporting NOPR*").

[55] The *Cyber Security Incident Reporting NOPR* was published in the Fed. Reg. on Dec. 28, 2017 (Vol. 82, No. 248) pp. 61,499-61,505.

(together, the "Supply Chain Cybersecurity Risk Management Changes").[56] The Supply Chain Cybersecurity Risk Management Changes are designed to further mitigate cybersecurity risks associated with the supply chain for BES Cyber Systems, consistent with *Order 829*. With respect to the proposed Reliability Standards' implementation plan and effective date, the FERC proposed to reduce the implementation period as proposed by NERC to the first day of the first calendar quarter that is 12 months following the effective date of a FERC order. In addition, the FERC proposed to direct NERC (i) to develop modifications to the CIP Reliability Standards to include Electronic Access Control and Monitoring Systems ("EACMS") associated with medium and high impact BES Cyber Systems within the scope of the supply chain risk management Reliability Standards; (ii) to evaluate the cyber security supply chain risks presented by Physical Access Control Systems ("PACS") and Protected Cyber Assets ("PCAs") in the study of cyber security supply chain risks requested by the NERC Board of Trustees ("BOT") in its resolutions of August 10, 2017; and (iii) to file the BOT-requested study's interim and final reports with the FERC upon their completion. Comments on the *Supply Chain Risk Management Standards NOPR* are due on or before March 26, 2018.[57]

- **NOPR: Revised Reliability Standard: CIP-003-7 (RM17-11)**

On October 19, 2017 the FERC issued a NOPR proposing to approve changes to Reliability Standard CIP-003 (Cyber Security - Security Management Controls), its associated implementation plan, VRFs, VSLs, and revised NERC Glossary definitions of "Removable Media" and "Transient Cyber Asset", and the retirement of the currently-effective version of CIP-003 and the NERC Glossary definitions of "Low Impact External Routable Connectivity" and "Low Impact BES Cyber System Electronic Access Point" ("CIP-003 Changes").[58] The CIP-003 Changes (i) clarify the electronic access control requirements applicable to low impact BES Cyber Systems; (ii) add requirements related to the protection of transient electronic devices used for low impact BES Cyber Systems (e.g., thumb drives, laptop computers, and other portable devices frequently connected to and disconnected from systems); and (iii) require Responsible Entities to have a documented cyber security policy related to declaring and responding to CIP Exceptional Circumstances for low impact BES Cyber Systems. In addition, the FERC proposes to direct NERC to develop certain modifications to the NERC Reliability Standards to provide clear, objective criteria for electronic access controls for low impact BES Cyber Systems; and address the need to mitigate the risk of malicious code that could result from third-party transient electronic devices. The proposed implementation plan provides that the CIP-003-Changes become effective on the first day of the first calendar quarter that is 18 calendar months after the effective date of the FERC's order approving the CIP-003 Changes. Comments on the *CIP-003-7 NOPR* were due on or before December 26, 2017,[59] and were filed by NERC, ELCON, TAPS, and Trade Associations[60] (each urging the FERC to approve the CIP-003 Changes without directives or conditions) and by an individual, Jonathan Applebaum, who submitted comments limited to, and contesting the sufficiency of, the proposed electronic access controls requirement. This matter is pending before the FERC.

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

Comments on the *Protection System Changes NOPR*[61] remain pending. Asa previously reported, the FERC issued a NOPR on November 16, 2017 proposing to approve (i) two new Reliability Standards -- PRC-027-1

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[56] *Supply Chain Risk Management Reliability Standards*, 162 FERC ¶ 61,044 (Jan. 18, 2018) ("*Supply Chain Risk Management Standards NOPR*").

[57] *Supply Chain Risk Management Reliability Standards NOPR* was published in the Fed. Reg. on Jan. 25, 2018 (Vol. 83, No. 17) pp. 3,433-3,442.

[58] *Rev. Critical Infrastructure Protection Rel. Standard CIP-003-7 – Cyber Security – Security Management Controls*, 161 FERC ¶ 61,047 (Oct. 19, 2017) ("*CIP-003-7 NOPR*").

[59] The *CIP-007-3 NOPR* was published in the Fed. Reg. on Oct. 26, 2017 (Vol. 82, No. 206) pp. 49,541-49,549.

[60] "Trade Associations" are the American Public Power Association ("APPA"), Edison Electric Institute ("EEI") and the National Rural Electric Cooperative Association ("NRECA").

[61] *Coordination of Protection Systems for Performance During Faults and Specific Training for Personnel Rel. Standards*, 161 FERC ¶ 61,159 (Nov. 16., 2017) ("*Protection System Changes NOPR*").

(Coordination of Protection Systems for Performance During Faults) and PER-006-1 (Specific Training for 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"). In addition, the FERC proposed to direct NERC to develop certain modifications to PRC-027-1. 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. Comments on the *Protection System Changes NOPR* were due on or before January 29, 2018[62] and were filed by over 15 parties. Since the last Report, Hydro One Networks Inc. submitted comments. The Protection System Changes are pending before the FERC.

- **Rules of Procedure Changes (RR18-1)**

On November 21, 2017, NERC filed for approval revisions to Appendix 3D (Registered Ballot Body Criteria) of the NERC Rules of Procedure ("ROP"). NERC stated that the purpose of the proposed revisions is to help ensure that the votes of Independent System Operators ("ISOs") and Regional Transmission Organizations ("RTOs") are appropriately represented in Segment 2 of NERC's registered ballot body for voting on Reliability Standards. Specifically, the revisions limit participation in "Segment 2" to RTO/ISOs exclusively, excluding other individuals and entities who may be consultants or vendors to RTO/ISOs from participating in that Segment. NERC requested that the proposed revisions be made effective upon FERC approval. Comments on this filing were due on or before December 12, 2017; none were filed. Dominion filed a doc-less intervention. This matter is pending before the FERC.

- **Rules of Procedure Changes (RR17-6)**

On June 26, 2017, NERC filed for approval revisions to Sections 600 (Personnel Certification Program) and 900 (Training and Education) of the NERC Rules of Procedure ("ROP"). The purpose of the revisions is to (i) clarify the scope of the Personnel Certification Program, the Training and Education Program and the Continuing Education Program; and (ii) streamline and align the language of the ROP with current practices of those programs. NERC stated that the changes are part of its first comprehensive review to modernize and align the language of the ROP with current NERC practices. NERC requested that the proposed revisions be made effective upon FERC approval. Comments on this filing were due on or before July 17, 2017 and were filed jointly by the Alberta Electric System Operator ("AESO"), The California Independent System Operator ("CAISO"), The Independent Electricity System Operator ("IESO"), ISO-NE and PJM ("System Operators"). System Operators, while agreeing that changes to Sections 600 and 900 are needed, nevertheless disagreed with the proposed changes as written and the rationale for making those changes in the first instance. On October 17, NERC answered System Operators' comments. This matter remains pending before the FERC.

- **Rules of Procedure Changes (Consolidated Hearings Process) (RR17-2)**

On February 27, NERC amended its December 9, 2016 filing that proposed changes to the compliance hearing process. Under the 2016 changes, Regional Entities would be provided an option to select NERC to manage the hearing process, rather than just allowing for the Regional entities to conduct the hearing process. The February 27 amendments adjusts how members are appointed to the Hearing Body to address concerns raised by FERC Staff in response to the initial filing. In addition, NERC proposes changes related to the use of the terms "segment" and "sector", such that they will align with the Appendix 2 definitions and the Regional Delegation Agreements between NERC and each Regional Entity. NERC requested that the proposed revisions be made effective upon FERC approval. Comments on this filing are due on or before March 20, 2018.

[62] The *Protection System Changes NOPR* was published in the Fed. Reg. on Nov. 22, 2017 (Vol. 82, No. 224) pp. 55,535-55,541.

XI. Misc. - of Regional Interest

- **203 Application: NRG/GIP III Zephyr Acquisition Partners (EC18-61)**

On February 23, 2018, NRG Energy Inc. ("NRG") requested authorization for a proposed transaction whereby GIP III Zephyr Acquisition Partners, L.P. ("Buyer") will acquire, among other things, interests currently held by NRG in NRG Yield, NRG Renew and their public utility subsidiaries and Carlsbad. Following the transaction, GenConn will no longer be an NRG Related Person. GenConn will remain a Related Person to UI, but will also be a Related Person of CPV Towantic. Applicants requested an order authorizing the transaction on or before May 24, 2018. Comments on the application were due on or before March 16, 2018.

- **203 Application: PSNH/HSE Hydro NH (EC18-42)**

On February 28, the FERC authorized[63] the acquisition by HSE Hydro NH AC, LLC ("HSE Hydro NH")[64] of PSNH's portfolio of hydroelectric generation assets (the "PSNH Hydro Transaction").[65] Among other conditions, the February 28 order required notice within 10 days of the consummation of the transaction. Subject to the required consummation notice, this proceeding will be concluded.

- **203 Application: Dynegy/Vistra (EC18-23)**

On November 22, Dynegy and Vistra Energy Corp. ("Vistra", and together with Dynegy, "Applicants") requested authorization for a proposed transaction pursuant to which Dynegy will merge with and into Vistra, with Vistra being the surviving corporation (the "Vistra Transaction"). Applicants requested an order authorizing the Vistra Transaction on or before March 15, 2018. Comments on the application were due on or before January 22, 2018. Public Citizen filed the lone protest (because the Horizontal Competitive Analysis Screen failed to include generation owned by Dynegy's major shareholder, Energy Capital Partners, including assets that are part of ECP's proposed acquisition of Calpine Corp.). Applicants answered Public Citizen's protest on February 5. Doc-less interventions were filed by PJM and the Illinois Attorney General's Office. Also on February 5, Applicants, at the request of FERC staff, supplemented their application with a delivered price test for the MISO region. Comments on the supplement were due on or before February 26; none were filed. This matter is pending before the FERC.

- **203 Application: MATEP (EC18-10)**

On January 24, 2018, the FERC authorized[66] a transaction pursuant to which MATEP LLC, which purchases all of the output its QF affiliate's 95.8 MW cogeneration facility located in Boston's Longwood Medical and Academic Area, will be owned by a joint venture between indirect subsidiaries of Engie and Axium US and will become a Related Person to Generation Sector member ENGIE Energy Marketing. Among other conditions, the order required notice within 10 days of the consummation of the transaction. Subject to that notice, this proceeding will be concluded.

- **203 Application: Calpine/ECP (EC17-182)**

On February 21, the FERC authorized a proposed transaction pursuant to which Calpine will become an indirect, wholly-controlled subsidiary of ECP Control Co, LLC ("ECP") (the "Calpine/ECP Transaction").[67] Among other conditions, the February 21 order required notice within 10 days of the consummation of the transaction.

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[63] *Pub. Srvc. Co. of NH and HSE Hydro NH AC, LLC*, 162 FERC ¶ 62,122 (Feb. 28, 2018).

[64] HSE Hydro NH is a Related Person to Generation Sector Group Seat members Nautilus Hydro and Pawtucket Power.

[65] PSNH's hydro portfolio (61.8 MW) includes the following facilities: Smith (15.78 MW); Amoskeag (17.5 MW); Garvins Falls/Hooksett (7.09 MW); Ayers Island (8.94 MW); Eastman Falls (6.1 MW); Jackman (3.54 MW); Gorham (1.68 MW); Canaan (1.17 MW).

[66] *MATEP LLC*, 162 FERC ¶ 62,046 (Jan. 23, 2018).

[67] *Calpine Corp. and ECP ControlCo, LLC*, 162 FERC ¶ 61,148 (Feb. 21, 2018).

Upon consummation, the Calpine and Wheelabrator Participants[68] will become Related Persons. Subject to the required consummation notice, this proceeding will be concluded.

- **203 Application: GenOn Reorganization (EC17-152)**

On October 31, 2017, the FERC approved certain conversions of GenOn notes into common equity of, and corporate structure changes that will result in, a "reorganized GenOn".[69] Reorganized GenOn will emerge as a result of a plan of reorganization to be confirmed by the United States Bankruptcy Court for the Southern District of Texas in connection with GenOn's Chapter 11 restructuring (the "Restructuring"). As a result of the Restructuring, Reorganized GenOn will likely not be a subsidiary of, and GenOn Energy Management will thus likely no longer be a Related Person to, NRG. Among other conditions, the order required notice within 10 days of the consummation of the transaction. Subject to that notice, this proceeding will be concluded.

- **203 Application: Green Mountain Power/ENEL Hydros (EC17-76)**

On May 9, the FERC authorized GMP's acquisition of the following small hydroelectric generation facilities (each a QF, collectively 8.39 MW of total generating capacity) from subsidiaries of Enel Green Power North America, Inc.: Hoague-Sprague, Kelley's Falls, Lower Valley, Glen, Rollinsford, South Berwick, Somersworth, and Woodsville.[70] Among other conditions, the order required notice within 10 days of the consummation of the transaction, which as of date of this Report has not been filed. Subject to that notice, this proceeding will be concluded.

- **MOPR-Related Proceedings (PJM, NYISO) (EL16-49; EL13-62)**

In two proceedings which, unless narrowly limited solely to the unique facts of the directly applicable markets (PJM in EL16-49; NYISO in EL13-62), could impact the New England market through FERC jurisdictional or other determinations, NEPOOL filed limited comments requesting that any Commission action or decision be limited narrowly to the facts and circumstances as presented in the applicable market. NEPOOL urged that any changes that may be ordered by the Commission in the proceedings not circumscribe the results of NEPOOL's stakeholder process or predetermine the outcome of that process through dicta or a ruling concerning different markets with different history and different rules. NEPOOL's comments were filed on January 24 in the NYISO proceeding; January 30 in the PJM proceeding, and are pending before the FERC. Since the last Report, EPSA filed motions to lodge information in each proceeding. In the PJM proceeding, EPSA moved to lodge a July 14, 2017 Memorandum Opinion and Order of the United States District Court for the Northern District of Illinois, Eastern Division, which dismissed challenges to the zero emissions credits ("ZECs") legislation enacted by the State of Illinois. In the NYISO proceeding, in a substantively similar motion, EPSA moved to lodge a Memorandum and Order of the New York District Court dismissing challenges to the ZECs program implemented by the NYPSC. In each case, EPSA reiterated its position that unless addressed, the ZEC programs will adversely impact the respective markets. Answers to the EPSA motions to lodge were filed by Exelon and the NYPSC in the NYISO Proceeding and by Exelon, First Energy, the Load Group, NRECA, Talen Companies, and the Illinois Commerce Commission in the PJM Proceeding. These proceedings remain pending before the FERC. If you have any questions concerning these proceedings, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **IA Cancellation: Superseded NGrid/Casella Waste Systems IA (ER18-791)**

On February 2, National Grid filed a notice of cancellation of a 2013 Interconnection Agreement ("IA") between Massachusetts Electric Company ("NGrid") and Casella Waste Systems. NGrid stated that the IA was recently superseded by a conforming three-party SGIA among ISO-NE, NGrid and Southbridge Recycling and

[68] The Calpine Participants are Calpine Energy Services, Calpine Energy Solutions, Champion Energy Marketing, and North American Power and Gas; the Wheelabrator Participants are Wheelabrator North Andover and Wheelabrator Bridgeport.

[69] *GenOn Energy Inc.*, 161 FERC ¶ 62,063 (Oct. 31, 2017).

[70] *Green Mountain Power Corp.,* 159 FERC ¶ 62,144 (May 9, 2017).

Disposal Park, Inc. A December 21, 2016 effective date (the date the SGIA superseded the IA and is reported in ISO-NE's EQRs) was requested. Comments, if any, on this filing were due on or before February 23, 2018; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **LGIAs: PSNH/GSP Newington/GSP White Lake /GSP Lost Nation (ER18-785, -786, -787)**

On February 2, Eversource, on behalf of PSNH, filed two-party LGIAs with GSP Newington (ER18-785), GSP White Lake (ER18-786) , and GSP Lost Nation (ER18-787). The LGIAs reflect the interconnection arrangements for Newington Station (420 MW gas-oil steam), Lost Nation (19.3 MW oil combustion (gas)) and White Lake (23.2 MW oil combustion (gas)), each acquired by the respective Granite Shore Power subsidiaries on January 10, 2018.[71] The LGIAs cover previously existing interconnections, unmodified in connection with the change in ownership, and were not required to have ISO-NE as a party. A January 10, 2018 effective date was requested. Comments on the LGIAs were due on or before February 23, 2018; none were filed. GSP Lost Nation LLC filed a doc-less motion to intervene. This matter is pending before the FERC. If there are questions on these matters, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **NSTAR/WMECO Succession Proceedings (ER18-749/751)**

On January 30, Eversource, on behalf its subsidiary NSTAR and former subsidiary WMECO, submitted a pair of filings to reflect the merger of WMECO with and into NSTAR. The filings included a Notice of Succession identifying all the WMECO jurisdictional documents to which NSTAR Electric is succeeding and cancelled WMECO's eTariff database and certain WMECO jurisdictional documents not currently filed in WMECO's eTariff database. A March 31, 2018 effective date was requested. Comments on this filing were due on or before February 20, 2018; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **REMVEC II and REMVEC SAS Agreement Terminations (ER18-716)**

On February 27, the FERC accepted the termination of the Rhode Island, Eastern Massachusetts, Vermont Energy Control ("REMVEC") II Agreement and the related REMVEC Security Analysis Services ("SAS") Agreement. The Agreements were recently superseded and replaced by a Local Control Center ("LCC") Agreement (accepted by letter order dated October 3, 2017 in Docket No. ER17-2339) pursuant to which certain local control center services are provided at or through NEP's dispatching center that is operated under ISO-NE's direction/ authorization. The terminations were accepted effective as of March 28, 2018, as requested. Unless the February 27 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).

- **LGIA: Emera Maine/Penobscot Energy Recovery Co (ER18-505)**

On February 1, the FERC accepted a fully executed, non-conforming LGIA between Emera Maine and Penobscot Energy Recovery Company ("Penobscot"). The LGIA establishes the interconnection of Penobscot's solid 25 MW waste-fired generating facility (Line 247) as a direct assignment facility (possible because its radial in nature and serves a single customer) and thereby supports Penobscot's access to New England Market upon expiration of its long-time PPA with Emera Maine (through a resulting lower monthly charge). The LGIA was accepted effective as of March 1, 2018, as requested. Unless the February 1 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).

- **Anbaric's Ocean Grid Project: Transmission Rights at Negotiated Rates (ER18-435)**

On February 12, the FERC conditionally authorized[72] Anbaric Development Partners ("Anbaric") to sell transmission rights at negotiated rates on its "Ocean Grid Project".[73] The FERC conditioned its authorization

[71] See *Pub. Service Co. of New Hampshire, Granite Shore Power LLC*, 161 FERC ¶ 62,231 (Dec. 27, 2017).

[72] *Anbaric Development Partners, LLC*, 162 FERC ¶ 61,097 (Feb. 12, 2018) ("*Ocean Grid Project Order*").

on the requirement that Anbaric submit a compliance filing "within 30 days of the close of the open solicitation process disclosing the results of its capacity allocation process and demonstrating that its capacity allocation was consistent with the Policy Statement and the [FERC]'s open access policies."[74] Unless the *Ocean Grid Project Order* is challenged, and pending submission of the 30-day compliance filing, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **NEP/HQUS Phase I/II HVDC-TF Service Agreement (ER18-388)**

On February 1, the FERC accepted a new Phase I/II HVDC-TF Service Agreement between NEP and HQUS that allows the continuation without interruption of service provided pursuant to an existing agreement between NEP and HQUS. The new agreement conforms to the pro forma Phase I/II HVDC-TF Service Agreement set forth in Attachment A of Schedule 20A–Common to the ISO-NE OATT. The Agreement was filed as "non-conforming" as it was unclear whether the FERC would deem conforming the provisions included in the Agreement that accommodate HQUS' exercise of its right of first refusal to extend its transmission customer service rights beyond the five-year term of its currently effective Service Agreement with NEP pursuant to Schedule 20A (while taking into account the fact that NEP currently only has contractual rights allowing it to sell service over the Phase I/II HVDC-TF through October 31, 2020). The agreement was accepted effective as of January 1, 2018, as requested. Unless the February 1 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).

- **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 NOV, 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 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.

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[73] The "Ocean Grid Project" will be integrated offshore transmission system that includes two 1,000 to 1,200 megawatt ("MW") High-Voltage Direct Current ("HVDC") transmission lines, each approximately 40 to 60 miles in length, with a total integrated system capacity of up to 2,400 MW, connecting Massachusetts off-shore wind generation to the transmission system in the Southeastern Massachusetts Load Zone ("SEMA"). As previously reported, Anbaric anticipates that the first phase of the Project (1,200 MW) will be in service by December 2021 and the second phase in service by 2024.

[74] *Id.* at P 23.

XII. Misc. - Administrative & Rulemaking Proceedings

- **DER Participation in RTO/ISOs (AD18-10; RM18-9)**

In *Order 841*[75] (see RM16-23 below), the FERC initiated a new proceeding in order to continue to explore the proposed distributed energy resource ("DER") aggregation reforms it was considering in the *Storage NOPR*.[76] All comments filed in response to the *Storage NOPR* will be incorporated by reference into Docket No. RM18-9 and any further comments regarding the proposed distributed energy resource aggregation reforms, including comments regarding the technical conference described below, should be filed in RM18-9.

Technical Conference (AD18-10). On April 10-11, the FERC will hold a technical conference to gather additional information to help the FERC determine what action to take on DER aggregation reforms proposed in the *Storage NOPR* and to explore issues related to the potential effects of DERs on the bulk power system. Panel topics include:

- Economic Dispatch, Pricing and Settlement of DER Aggregations
- Discussion of Operational Implications of DER Aggregation with State and Local Regulators
- DER Participation in RTO/ISO Markets
- DER Installation Data Collection and Availability
- Incorporating DERs in Modeling, Planning and Operations Studies
- Coordination of DER Aggregations Participating in RTO/ISO Markets
- Ongoing Operational Coordination

Additional information regarding the technical conference will be provided in subsequent supplemental notices. Those wishing to participate in the April 10-11 conference should submit a nomination form online by March 15, 2018 at: https://www.ferc.gov/whatsnew/registration/04-10-18-speaker-form.asp. Those interested in attending are encouraged to register by April 3, 2018 at: https://www.ferc.gov/whats-new/registration/04-10-18-form.asp.

- **Grid Resilience in RTO/ISOs; DOE NOPR (AD18-7; RM18-1)**

On January 8, 2018, the FERC terminated the DOE NOPR rulemaking proceeding (RM18-1)[77] and initiated a new Grid Resilience in RTO/ISOs proceeding (AD18-7).[78] In terminating the DOE NOPR proceeding, the FERC concluded that the Proposed Rule and comments received did not support FERC action under Section 206 of the FPA, but did suggest the need for further examination by the FERC and market participants of the risks that the bulk power system faces and possible ways to address those risks in the changing electric markets. Accordingly, the FERC initiated AD18-7 to evaluate the resilience of the bulk power system in RTO/ISO regions, directed each RTO/ISO to submit information on certain resilience issues and concerns, and committed to use the information

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[75] *Electric Storage Participation in Markets Operated by Regional Transmission Orgs. and Indep. Sys. Operators*, Order No. 841, 162 FERC ¶ 61,127 (Feb. 15, 2018) ("*Order 841*").

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

[77] As previously reported, the FERC opened the DOE NOPR proceeding in response to a September 28, 2017 proposal by Energy Secretary Rick Perry, issued under a rarely-used authority under §403(a) of the Department of Energy ("DOE") Organization Act, that would have required RTO/ISOs to develop and implement market rules for the full recovery of costs and a fair rate of return for "eligible units" that (i) are able to provide essential energy and ancillary reliability services, (ii) have a 90-day fuel supply on site in the event of supply disruptions caused by emergencies, extreme weather, or natural or man-made disasters, (iii) are compliant with all applicable environmental regulations, and (iv) are not subject to cost-of-service rate regulation by any State or local authority. More than 450 comments were submitted in response to the DOE NOPR, raising and discussing an exceptionally broad spectrum of process, legal, and substantive arguments. A summary of those initial comments was circulated under separate cover and can be found with the posted materials for the November 3, 2017 Participants Committee meeting. Reply comments and answers to those comments were filed by over 100 parties.

[78] *Grid Reliability and Resilience Pricing*, 162 FERC ¶ 61,012 (Jan. 8, 2018), *reh'g requested*.

submitted to evaluate whether additional FERC action regarding resilience is appropriate. RTO submissions are due on or before March 9, 2018; reply comments by interested entities are due on or before April 9, 2018.

On February 7, Foundation for Resilient Societies ("FRS") quested rehearing of the January 8 order terminating the DOE NOPR proceeding. Absent FERC action on or before March 9, the request for rehearing will be deemed denied.

- **State Policies & Wholesale Markets Operated by ISO-NE, NYISO, PJM (AD17-11)**

As previously reported, the FERC held a 2-day technical conference (on May 1-2, 2017) to foster further discussion regarding the development of regional solutions in the Eastern RTOs/ISOs that reconcile the competitive market framework with the increasing interest by states to support particular resources or resource attributes. FERC staff sought to "discuss long-term expectations regarding the relative roles of wholesale markets and state policies in the Eastern RTOs/ISOs in shaping the quantity and composition of resources needed to cost-effectively meet future reliability and operational needs". A more detailed summary of the technical conference was circulated with the last Report. Pre-conference comments from the conference's speakers, panelists and other interested parties are available in the FERC's eLibrary and through the technical conference's calendar entry. Those interested were invited to submit post-conference comments on or before June 22, 2017. Comments were received from over 80 parties, and were briefly summarized at the Summer Meeting. Reply comments, not exceeding 10 pages, were filed by over 30 parties. This matter remains pending before the FERC.

- **NOI: FERC's Policy for Recovery of Income Tax Costs & ROE Policies (PL17-1)**

On December 15, 2016, the FERC issued a notice of inquiry ("NOI") seeking comments regarding how to address any double recovery resulting from the FERC's current income tax allowance and ROE policies.[79] The NOI followed the D.C. Circuit's *United Airlines*[80] holding that the FERC failed to demonstrate that there is no double recovery of taxes for a partnership pipeline as a result of the income tax allowance and ROE determined pursuant to the DCF methodology, and remanding the decisions to the FERC to develop a mechanism "for which the Commission can demonstrate that there is no double recovery" of partnership income tax costs".[81] Comments and reply comments were submitted by over 25 and 18 parties, respectively. Since the last Report, on January 2, 2018, R. Gordon Gooch filed a motion requesting that the FERC compel all pass-through entities to reduce their claims for income tax allowance in rates, lowering rates as necessary to make their rates "just and reasonable" in response to the passage and signature into law of the "Tax Cut and Jobs Act" (Public Law No. 115-97). A second motion for partial summary judgement was filed by Gooch on January 16. Answers to the motions of partial summary judgement were by the Liquids Shippers Group, Natural Gas Indicated Shippers, the American Public Gas Association and INGAA. This matter remains pending before the FERC.

- **NOPR: Withdrawal of Pleadings (RM18-7)**

On February 15, 2018, the FERC issued a NOPR proposing to adopt a more accurate title for, and clarify the text of, Rule 216 of the FERC's Rules of Practice and Procedure.[82] The FERC proposes to change Rule 216's the title from "Withdrawal of pleadings and tariff or rate filings (Rule 216)" to "Withdrawal of pleadings (Rule 216)", to change the first sentence of Rule 216(a) to read, "Any person may seek to withdraw its pleading by filing a notice of withdrawal," and to refer to "person" rather than "party," in Rule 216(c). Comments on the *Pleadings Withdrawal NOPR* must be submitted on or before March 26, 2018.[83]

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[79] *Inquiry Regarding the FERC's Policy for Recovery of Income Tax Costs,* 157 FERC ¶ 61,210 (Dec. 15, 2017).

[80] *United Airlines Inc. v. FERC*, 827 F.3d 122, 134, 136 (D.C. Cir. 2016) ("*United Airlines*").

[81] *Id.* at 137.

[82] *Withdrawal of Pleadings*, 162 FERC ¶ 61,111 (Feb. 15, 2018) ("*Pleadings Withdrawal NOPR*").

[83] The *Pleadings Withdrawal NOPR* was published in the *Fed. Reg.* on Feb. 23, 2018 (Vol. 83, No. 37 pp. 8,019-8,020.

- **NOPR: LGIA/LGIP Reforms (RM17-8)**

As previously reported, the FERC issued a NOPR[84] on December 15, 2016 proposing reforms designed to improve certainty,[85] promote more informed interconnection,[86] and enhance interconnection processes.[87] Based, in part, on input received in response to AWEA's petition for changes to the *pro forma* LGIP/LGIA, and the FERC's May 13, 2016 technical conference to explore generator interconnection issues (as reported previously under Docket Nos. RM16-12; RM15-21), the FERC identified proposed reforms which it states could remedy potential shortcomings in the existing interconnection processes. The FERC also sought comment on whether any of its proposed reforms should be applied to the *pro forma* SGIP/SGIA.[88] 60 sets of comments on and answer to the *LGIP/LGIA Reforms NOPR* were submitted, including comments by: NEPOOL (approved at the April 7 Participants Committee meeting), ISO-NE, Avangrid, EDF Renewable, EDP Renewables, Eversource, Exelon, Invenergy, National Grid, NextEra, APPA/LPPC/NRECA, AWEA, EEI, ELCON, ESA, and Public Interest Organizations. The *LGIP/LGIA Reforms NOPR* is pending before the FERC.

- **NOPR: Uplift Cost Allocation and Transparency in RTO/ISO Markets (RM17-2)**

On January 19, 2017, the FERC issued a NOPR proposing to require each RTO and ISO that currently allocates the costs of Real-Time uplift due to deviations to do so only to those market participants whose transactions are reasonably expected to have caused the real-time uplift costs.[89] In addition, the FERC proposed to revise its regulations to enhance transparency by requiring that each RTO/ISO post uplift costs paid (dollars) and operator-initiated commitments (MWs) on its website; and define in its tariff its transmission constraint penalty factors, as well as the circumstances under which those penalty factors can set LMPs, and any procedure for changing those factors. Comments and reply comments on the *Uplift/Transparency NOPR* were filed by over 40 parties, including: ISO-NE, Brookfield, Calpine, DC Energy,

[84] *Reform of Generator Interconnection Procedures and Agreements*, 157 FERC ¶ 61,212 (Dec. 15, 2016) ("*LGIP/LGIA Reforms NOPR*"). The *LGIP/LGIA Reforms NOPR* was published in the *Fed. Reg.* on Jan. 13, 2017 (Vol. 82, No. 9 pp. 4,464-4,501.

[85] To accomplish this goal, the FERC proposes to: (1) revise the *pro forma* LGIP to require transmission providers that conduct cluster studies to move toward a scheduled, periodic restudy process; (2) remove from the *pro forma* LGIA the limitation that interconnection customers may only exercise the option to build transmission provider's interconnection facilities and standalone network upgrades if the transmission owner cannot meet the dates proposed by the interconnection customer; (3) modify the *pro forma* LGIA to require mutual agreement between the transmission owner and interconnection customer for the transmission owner to opt to initially self-fund the costs of the construction of network upgrades; and (4) require that the RTO/ISO establish dispute resolution procedures for interconnection disputes. The Commission also seeks comment on the extent to which a cap on the network upgrade costs for which interconnection customers are responsible can mitigate the potential for serial restudies without inappropriately shifting cost responsibility. *Id.* at P 6.

[86] The FERC proposes to: (1) require transmission providers to outline and make public a method for determining contingent facilities in their LGIPs and LGIAs based upon guiding principles in the Proposed Rule; (2) require transmission providers to list in their LGIPs and on their OASIS sites the specific study processes and assumptions for forming the networking models used for interconnection studies; (3) require congestion and curtailment information to be posted in one location on each transmission provider's OASIS site; (4) revise the definition of "Generating Facility" in the pro forma LGIP and LGIA to explicitly include electric storage resources; and (5) create a system of reporting requirements for aggregate interconnection study performance. The FERC also seeks comment on proposals or additional steps that the Commission could take to improve the resolution of issues that arise when affected systems are impacted by a proposed interconnection. *Id.* at P 7.

[87] The FERC proposes to: (1) allow interconnection customers to limit their requested level of interconnection service below their generating facility capacity; (2) require transmission providers to allow for provisional agreements so that interconnection customers can operate on a limited basis prior to completion of the full interconnection process; (3) require transmission providers to create a process for interconnection customers to utilize surplus interconnection service at existing interconnection points; (4) require transmission providers to set forth a separate procedure to allow transmission providers to assess and, if necessary, study an interconnection customer's technology changes (e.g., incorporation of a newer turbine model) without a change to the interconnection customer's queue position; and (5) require transmission providers to evaluate their methods for modeling electric storage resources for interconnection studies and report to the Commission why and how their existing practices are or are not sufficient. *Id.* at P 8.

[88] *Id.* at P 11.

[89] *Uplift Cost Allocation and Transparency in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 158 FERC ¶ 61,047 (Jan. 19, 2017) ("*Uplift/Transparency NOPR*").

Direct, Exelon, Potomac Economics, Saracen, EEI, APPA/NRECA, Appian Way Energy Partners, AWEA, ELCON, EPSA, Financial Marketers Coalition, and the IRC. The *Uplift/Transparency NOPR* is pending before the FERC.

- ***Order 841*: Electric Storage Participation in RTO/ISO Markets (RM16-23; AD16-20)**

On February 15, the FERC issued *Order 841*, which requires each RTO/ISO to revise its tariff "to establish a participation model consisting of market rules that, recognizing the physical and operational characteristics of electric storage resources, facilitates their participation in the RTO/ISO markets." The participation model must:

(1) ensure that a resource using the participation model is eligible to provide all capacity, energy and ancillary services that the resource is technically capable of providing in the markets;
(2) ensure that a resource using the participation model can be dispatched and can set the wholesale market clearing price as both a wholesale seller and wholesale buyer consistent with existing market rules that govern when a resource can set the wholesale price;
(3) account for the physical and operational characteristics of electric storage resources through bidding parameters or other means; and
(4) establish a minimum size requirement for participation in the RTO/ISO markets that does not exceed 100 kW.

Additionally, each RTO/ISO must specify that the sale of electric energy from the RTO/ISO markets to an electric storage resource that the resource then resells back to those markets must be at the wholesale locational marginal price. RTO/ISOs must file any necessary tariff changes on or before [270 days from *Order 841*'s publication in the Federal Register][90] and implement those tariff provisions within one year of that compliance filing. *Order 841* will become effective [90 days from publication in the *Federal Register*].

Order 841 did not adopt the *Storage NOPR's* proposed reforms related to DER aggregations. Instead, *Order 841* instituted a new rulemaking proceeding and technical conference (*see* AD18-10/RM18-9 above) to gather additional information to help the FERC determine what action to take with respect to DER aggregation.

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

The FERC's *Data Collection NOPR* remains pending. As previously reported, the FERC issued a July 21, 2016 NOPR, which superseded 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.[91] 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

[90] *Order 841* has not, as of the date of this Report, been published in the Fed. Reg.

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

Data Collection NOPR were due on or before September 19, 2016[92] and were filed by over 30 parties, including: APPA, Avangrid, Brookfield, EPSA, Macquarie/DC Energy/Emera Energy Services, NextEra, and NRG.

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

Rehearing of *Order 833*[93] remains pending. As previously reported, *Order 833* amended FERC 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 amend other regulations that pertain to CEII. The amended procedures will be referred to as the Critical Energy/Electric Infrastructure Information (CEII) procedures. *Order 833* became effective February 21, 2017.[94] On December 19, 2016, EEI requested rehearing of *Order 833*. The FERC issued a tolling order on January 17, 2017 affording it additional time to consider the EEI request for rehearing, which remains pending.

- ***Order 842*: Primary Frequency Response - Essential Reliability Services and the Evolving Bulk-Power System (RM16-6)**

On February 15, the FERC issued *Order 842*,[95] which requires 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. The FERC also established certain uniform minimum operating requirements, including maximum droop and deadband parameters and provisions for timely and sustained response. *Order 842* requirements will also apply to *existing* large and small generating facilities that take any action that requires the submission of a new interconnection request that results in the filing of an executed or unexecuted interconnection agreement on or after *Order 842*'s effective date. These requirements will not apply to existing generating facilities, a subset of combined heat and power ("CHP") facilities, or generating facilities regulated by the Nuclear Regulatory Commission. The FERC did not impose a headroom requirement for new generating facilities, and did not mandate that new generating facilities receive compensation for complying with the primary frequency response requirements. To implement these requirements, the FERC modified the *pro forma* LGIA and the *pro forma* SGIA. *Order 842* will become effective [70 days from publication in the Federal Register].[96]

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).

- **FERC Staff Inquiry in Response to EDF Allegations of Pipeline Capacity Withholding (not docketed)**

On February 27, the FERC issued a press release stating that a staff inquiry revealed no evidence of anticompetitive withholding of natural gas pipeline capacity on Algonquin Gas Transmission by New England shippers. The inquiry arose out of allegations made by the Environmental Defense Fund ("EDF") in an August 2017 white paper, which asserted that local gas distribution companies in New England had engaged in practices to withhold pipeline capacity on the Algonquin system in order to drive up gas and/or power prices in the region. FERC staff reviewed both publicly available and non-public data. On the basis of that review, staff determined that "EDF's study was flawed and led to incorrect conclusions about the alleged withholding.

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

[93] *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*").

[94] *Order 833* was published in the *Fed. Reg.* on Dec. 21, 2016 (Vol. 81, No. 245) pp. 93,732-93,753.

[95] *Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response*, Order No. 842, 162 FERC ¶ 61,128 (Feb. 15, 2018) ("*Order 842*").

[96] *Order 842* has not, as of the date of this Report, been published in the Fed. Reg.

Commission staff found no evidence of capacity withholding." The Commission will take no further action on the matter.

- **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 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, 2016, 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, 2016; none were filed. The compliance filing remains pending before the FERC.

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

[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

- **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 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, 2016 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, 2016, 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]

BP moved, on December 11, 217, to lodge, to reopen the proceeding, and to dismiss, or in the alternative, for reconsideration based on changes in the law it asserted are dispositive and that have occurred since BP filed its request for rehearing of the *BP Penalties Order*. FERC Staff asked for, and was granted, additional time, to January 25, 2018, to file its Answer to BP's December 11 motion. FERC Staff filed its answer on January 25, 2018, and revised that answer on January 31. On February 9, BP replied to FERC Staff's revised answer. This matter is again pending before the FERC.

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

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

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

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

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

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

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

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 filed their answer on July 12, 2016. OE Staff replied to Respondents' answer on September 23, 2016. Respondents answered OE's September 23 answer on January 17, 2017, and OE Staff responded to that answer on January 27, 2017. This matter remains pending before the FERC.

Staff Notices of Alleged Violations (IN__-___)

Rover. On July 13, 2017, the FERC issued a notice that Staff has preliminarily determined that, between February 2015 and September 2016, Rover Pipeline, LLC and Energy Transfer Partners, L.P. (collectively, "Rover") violated Section 7 of the Natural Gas Act by failing to fully and forthrightly disclose all relevant information to the FERC in Rover's application for a Certificate of Public Convenience and Necessity and attendant filings in Docket No. CP15-93. Staff alleges that Rover falsely promised it would avoid adverse effects to a historic resource that it was simultaneously working to purchase and destroy, and subsequently made several misstatements in its docketed responses to FERC questions about why it had purchased and demolished the resource.

Recall that Notices of Alleged Violations ("NoVs") are issued only after the subject of an enforcement investigation has either responded, or had the opportunity to respond, to a preliminary findings letter detailing Staff's conclusions regarding the subject's conduct.[109] NoVs are designed to increase the transparency of Staff's nonpublic investigations conducted under Part 1b of its regulations. A NoV does not confer a right on third parties to intervene in the investigation or any other right with respect to the investigation.

- **New England Pipeline Proceedings**
  The following New England pipeline projects are currently under construction or before the FERC:
  - ***Atlantic Bridge Project (CP16-9)***
    - 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.

[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 bid-week designed to move indexed market prices in a way that benefited the company's related positions. Staff alleged that the West Desk implemented the bid-week 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.

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

- 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.
- Certificate of public convenience and necessity granted Jan. 25, 2017.[110]
- Certain facilities,[111] providing 40,000 out of the project's total capacity of 132,705 dekatherms per day of incremental firm transportation service, placed into service on November 1, 2017.[112] Remaining Project capacity will be available when the remaining Project facilities are placed into service following Director of OEP authorization.
- Authorization to proceed with construction of additional Project segments requested on Oct. 31, 2017. Detailed information regarding construction activities can be found in the weekly construction reports filed in this docket.
- On February 16, Algonquin filed with the DC Circuit Court of Appeals, pursuant to Section 19(d)(2) of the Natural Gas Act, a petition for review of the MA DEP's failure to issue, condition , or deny a minor-source air permit for Algonquin's proposed natural gas compressor station in the Town of Weymouth, MA by the July 31, 2016 deadline established by the FERC. Algonquin seeks an order establishing a deadline for the MA DEP to issue, condition, or deny the permit.

- ***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.
    - By letter order issued July 26, 2016, the Director of the Division of Pipeline Certificates (Director) granted Constitution's requested two-year extension of time to construct the project.
    - Construction was expected to begin Spring 2016 (after final Federal Authorizations), but has been plagued by delays (see below).
  - On April 22, 2016, New York State Department of Environmental Conservation (NY DEC) denied Constitution's application for a Section 401 permit under the Clean Water Act.
    - On August 18, 2017, the 2nd Circuit denied Constitution's petition for review of the NY DEC decision, concluding that (1) the court lacked jurisdiction over the Constitution's claims to the extent that they challenged the timeliness of the decision; and (2) the NY DEC acted within its statutory authority in denying the certification, and its denial was not arbitrary or capricious.

[110] Order Issuing Certificate and Authorizing Abandonment, *Algonquin Gas Transmission LLC and Maritimes & Northeast Pipeline, LLC*, 158 FERC ¶ 61,061 (Jan. 25, 2017), *order denying stay*, 160 FERC ¶ 61,015 (2017), *reh'g denied,* 161 FERC ¶ 61,255 (Dec. 13, 2017) ("*Atlantic Bridge Project Order*").

[111] The following facilities placed into service: Southeast Discharge Take-up and Relay (Fairfield County, CT); Modified Oxford Compressor Station (New Haven County, CT); Modified Chaplin Compressor Station (Windham County, CT); Modified Danbury (CT) Meter Station; and Modified Stony Point Compressor Station (Rockland County, NY).

[112] *Algonquin Gas Transmission, LLC*, 158 FERC ¶ 61,061 (Oct. 27, 2017).

- On October 11, 2017, Constitution filed with the FERC a petition for declaratory order ("Petition") requesting that the FERC find that NY DEC waived its authority under section 401 of the Clean Water Act by failing to act within a "reasonable period of time." (CP18-5)
  - On January 11, 2018, the FERC denied Constitution's Petition.[113] Although noting that states and project sponsors that engage in repeated withdrawal and refiling of applications for water quality certifications are acting, in many cases, contrary to the public interest and to the spirit of the Clean Water Act by failing to provide reasonably expeditious state decisions, the FERC did not conclude that the practice violates the letter of the statute, found factually that Constitution gave the NY DEC new deadlines, and found that the record did not show that the NY DEC in any instance failed to act on Constitution's application for more than the outer time limit of one year.[114]
  - On February 12, 2018, Constitution Pipeline requested rehearing of the January 11, 2018 order. Absent FERC action on the request for rehearing on or before March 14, the request will be deemed denied.
- 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.
  - In July 2016, the FERC rejected the NY AG's filing as procedurally deficient, and declined to stay of the Certificate Order
- Tree felling and site preparation continues, but the long-term status of the pipeline is currently unknown. Constitution will submit its monitoring reports monthly rather than weekly until activities resume in 2018.

- **Non-New England Pipeline Proceedings**

The following pipeline projects could affect ongoing pipeline proceeding in New England and around the country:

- ***Southeast Market Pipelines Project*** **(CP14-554, CP15-16, CP15-17)**
  - Florida Southeast Connection, LLC, Transcontinental Gas Pipe Line Company, LLC and Sabal Trail Transmission, LLC (Sabal Trail) filed for a Section 7(c) certificates in Sept. – Nov. 2014.
  - The three separate but connected natural gas transmission pipeline projects project total approximately 685.5 miles of natural gas transmission pipeline and provide transportation service for up to approximately 1.1 billion cubic feet per day of natural gas to markets in Florida and the southeast United States .
  - Certificates of public convenience and necessity were granted Feb. 2, 2016.[115]
    - Project construction began in August 2016, and in June and July 2017, Commission Staff authorized the pipelines to commence service on completed facilities.
  - On August 22, 2017, the DC Circuit vacated and remanded the FERC's certificate order, holding that the FERC's environmental review of the project failed to adequately consider the downstream effects of greenhouse gas emissions resulting from increased power

[113] *Constitution Pipeline Co.*, 162 FERC ¶ 61,014 (Jan. 11, 2018), *reh'g requested*.

[114] *Id.* at P 23.

[115] *Fla. Southeast Connection, LLC*, 154 FERC ¶ 61,080, 61 (Feb. 2, 2016) (order issuing certificate).

generation.[116]

- The DC Circuit held that FERC must either quantify and consider the project's downstream carbon emissions or explain in more detail why it cannot do so. According to the court, quantification would permit the agency to compare the emissions from this project to emissions from other projects, to total emissions from the state or the region, or to regional or national emissions-control goals. Without such comparisons, it is difficult to see how FERC could engage in "informed decision making" with respect to the greenhouse-gas effects of this project, or how "informed public comment" could be possible.
- This opinion could have significant consequences for future pipeline proceedings at FERC.

- On September 27, 2017, the FERC issued a Draft Supplemental EIS, estimating the pipeline would potentially increase the Florida GHG emission inventory between 3.7 and 9.7 percent.
  - In the supplemental EIS, the FERC stated that it "could not find a suitable method to attribute discrete environmental effects to GHG emissions."

- ***Millennium Pipeline Valley Lateral Project*** **(CP16-17)**
  - On July 21, 2017, Millennium Pipeline Company, L.L.C. (Millennium) filed a Request for Notice to Proceed with Construction of its Valley Lateral Project in Orange County, New York.
    - The Valley Lateral Pipeline will connect the existing Millennium Pipeline to the 680 MW CPV Valley Energy Center.
  - To receive a notice to proceed, Millennium was required to demonstrate that it had obtained all federally-required environmental permits and authorizations, including authorizations under the Clean Water Act (CWA). Millennium stated that the New York State Department of Environmental Conservation (New York DEC) had waived its authority to issue a water quality certification under Section 401 of the CWA by failing to act before the statutorily-imposed deadline.
    - In August 2017, the NY DEC denied the water quality certification to the Valley Lateral Project, citing the D.C. Circuit's recent ruling in *Sierra Club v. FERC* and the FERC's "lack of a complete environmental review."
  - By Letter Order issued on September 15, 2017, the FERC agreed with Millennium, finding that the New York DEC had waived its authority to issue or deny a water quality certification. Because the NY DEC had received Millennium's Section 401 certification in November 2015, but did not rule on it until August 2017, FERC ruled that NY DEC, as the certifying agency, had therefore failed to act within the statutory timeframe and had waived its certification authority.[117] The FERC's order effectively nullifies the NY DEC's August 2017 rejection of the water quality certification.
    - The NY DEC, on October 13, 2017, filed a Request for Rehearing and Stay of the FERC's September 15, 2017, Order. On November 15, the FERC denied the requests for rehearing, stay, and rescission.[118]
  - Millennium sought, and on October 3, 2017, the FERC granted, a one year extension of time to complete construction of the Valley Lateral Project and make it available for service by November 2018.

[116] *Sierra Club v. FERC*, 2017 U.S. App. LEXIS 15911 (D.C. Cir. Aug. 22, 2017).

[117] *Millennium Pipeline Co., L.L.C.,* 160 FERC ¶ 61,065 (Sept. 15, 2017), *reh'g denied*, 161 FERC ¶ 61,186 (Nov. 15, 2017).

[118] *Millennium Pipeline Co., L.L.C.,* 161 FERC ¶ 61,186 (Nov. 15, 2017) ("*November 15 Order*").

- On October 27, 2017, the FERC issued a Notice to Proceed, granting Millennium's request to begin construction of the Valley Lateral.
  - The NY DEC, on October 30, 2017, filed a Request for Stay of the Notice to Proceed. The *November 15 Order* also denied the October 30 request for stay.[119]

- ***Northern Access Project*** **(CP15-115)**
  - On Feb. 3, 2017, the FERC issued an order authorizing National Fuel Gas Supply Corporation and Empire Pipeline, Inc. to construct and operate pipeline, compression, and ancillary facilities in McKean County, Pennsylvania, and Allegany, Cattaraugus, Erie, and Niagara Counties, New York (Northern Access Project)
  - In March 2017, Allegheny Defense Project and Sierra Club (collectively Allegheny) filed a request for rehearing of the FERC's order and on August 31, 2017, FERC issued an Order Denying Stay
    - Consistent with its previous authorization, FERC found no evidence of irreparable harm in letting the project go forward.
  - Despite the FERC's Order, the project remains halted pending the outcome of National Fuel's fight with the NY DEC's April denial of a Clean Water Act permit.
    - NY DEC found National Fuel's application for a water quality certification, as well as for stream and wetlands disturbance permits, failed to comply with water regulations aimed at protecting wetlands and wildlife and that the pipeline failed to explore construction alternatives.

XIV. State Proceedings & Federal Legislative Proceedings

- **Massachusetts Emissions Allowance Auctions: Stakeholder Input on Auction Design Parameters**

In an action that could have implications for the New England Markets, the Massachusetts (MA) Department of Environmental Protection ("MassDEP") issued on August 11, 2017 final regulations to ensure that MA will meet the 2020 statewide greenhouse gas ("GHG") emissions limits mandated by MA's 2008 Global Warming Solutions Act ("GWSA"). Section 7.74[120] of those regulations reduces carbon dioxide ("CO_2") emissions from MA-based power plants by imposing an annually declining aggregate emissions cap on MA's 21 large fossil fuel-fired generators. Operators of those facilities will have to offset their CO_2 production with allowances (a limited authorization to emit one metric ton of CO_2 in a calendar year). Allowances will be allocated directly in 2018 based on historical generation. Beginning with compliance year 2019, Section 7.74 requires auctioning of the emissions allowances that facilities must use to comply with the regulation. Allowances may be traded between facilities and a limited quantity may be banked from year to year.

On December 15, 2017, MassDEP filed final amendments to correct errors for two facilities in the 2018 allowance allocations. These amendments were published in the Massachusetts register on December 29, 2017. In addition, MassDEP has committed to post on its website compliance forms and an "FAQ" document.

[119] On Oct. 30, 2017, NY DEC also petitioned the United States Court of Appeals for the Second Circuit for a temporary stay of the FERC's Notice to Proceed until the FERC acts on NY DEC's request for rehearing of the Declaratory Order. *In re New York State Department of Environmental Conservation v. FERC*, 2d Cir. No. 17-3503, Petitioner's Emergency Petition for a Writ of Prohibition (Oct. 30, 2017) (Emergency Petition). NY DEC also requested the court to stay the effectiveness of the Notice to Proceed on an interim basis while the court considers the merits of its petition. *Id.* at 34. On Nov. 2, 2017, the court granted an administrative stay pending consideration of the petition by the next available three-judge panel. *In re New York State Dep't of Envtl. Conservation v. FERC*, 2d Cir. No. 17-3503 (Nov. 2, 2017). NY DEC's Emergency Petition is pending at the court.

[120] Additional information about 310 CMR 7.74 (Reducing CO_2 Emissions from Electricity Generating Facilities) is available at: http://www.mass.gov/eea/agencies/massdep/climate-energy/climate/ghg/electricity-generatoremissions-limits.html.

The allowance tracking system will be deployed In the Spring of 2018. Detailed instructions for regulated facilities will be provided at that time. Stakeholder comments on the auction design solicited in the Fall of 2017 will be considered as the MassDEP develops procedures in preparation for allowance auctions that begin in 2019. MassDEP anticipates additional opportunities for stakeholders to participate in the auction design process in 2018, possibly including an opportunity to comment on proposed regulatory amendments. MassDEP is also in the process of soliciting market monitoring services, and will hire an auction administrator in 2018. Questions regarding 310 CMR 7.74 can be directed to Will Space (william.space@state.ma.us; 617-292-5610).

- **NG Advantage (NY) Permit Challenge (RJI No.: 2017-0799; RJI No.: 2017-0800)**

Chenango Valley Central School District and various nearby residents Petitioners have initiated proceedings against the Town of Fenton, New York Planning Board and NG Advantage, LLC to halt NG Advantage, LLC's ("NG Advantage") proposed construction of a natural gas compressor facility that would extract gas up to 4000 psi and transport the compressed natural gas to NG Advantage customers. Petitioners are concerned that the project infringes on the rights of those who live near the transfer station. They are specifically concerned about the site's proximity to schools, and the burden it could place on local roads.

A judicial decision on whether the Town of Fenton followed proper procedures with respect to zoning laws in approving the Project has been held in reserve while Supreme Court Judge Ferris Lebo's reviews oral arguments and submissions. The Project is currently halted pending judgment.

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).

- **FCM Resource Retirement Reforms (17-1275)**
  Underlying FERC Proceedings: ER16-551[121]
  Petitioner: Constellation

As previously reported, Constellation ("Petitioner") petitioned the DC Circuit Court of Appeals on December 28, 2017 for review of the FERC's *FCM Resource Retirement Reforms Orders*. Upon a joint motion of Constellation and the FERC, the following briefing schedule was ordered: Petitioner's Brief to be filed April 17, 2018; Respondent's Brief, July 2, 2018; Petitioner's Reply Brief, July 30, 2018; Deferred Appendix, August 13, 2018; and Final Briefs August 20, 2018.

- **Demand Curve Changes (17-1110**)**
  Underlying FERC Proceedings: ER14-1639[122]
  Petitioners: NextEra, NRG, PSEG

NextEra, NRG and PSEG ("Petitioners") petitioned the DC Circuit Court of Appeals for a second time for review of the FERC's Demand Curve orders, which, as previously reported, had been remanded back to the FERC at the FERC's request following the first appeal by Petitioners. Briefing was completed on February 1,

[121] *ISO New England Inc.,* 155 FERC ¶ 61,029 (Apr. 12, 2016) ("*Resource Retirement Reforms Order*"), *reh'g and clarif. denied*, 161 FERC ¶ 61,115 (Oct. 30, 2017) ("*FCM Resource Retirement Reforms Orders*").

[122] 147 FERC ¶ 61,173 (May 30, 2014) (*Demand Curve Order*); 150 FERC ¶ 61,065 (Jan. 30, 2015) (*Demand Curve Clarification Order)*; 155 FERC ¶ 61,023 (Apr. 8, 2016) (*Demand Curve Remand Order*); 158 FERC ¶ 61,138 (Feb. 3, 2017) (*Demand Curve Remand Rehearing Order*).

2018 and oral argument scheduled for April 13, 2018. The composition of the argument panel will be revealed approximately 30 days prior to the date of oral argument.

- **FCA10 Results (16-1408) and FCA9 Results (16-1068)**
  Underlying FERC Proceedings: ER16-1041[123] ER15-1137[124]
  Petitioners: UWUA Local 464 and Robert Clark

UWUA Local 464 and Robert Clark ("Petitioners") filed petitions for review of the FERC's orders on the FCA10 and FCA9 Results Filings, consolidated by the Court on January 31, 2017. All briefing is complete and oral argument was held before Judges Rogers, Millett and Pillard on February 9, 2018. This matter is pending before the Court.

- **NEPGA PER Complaint and FCM Jump Ball and Compliance Proceedings (16-1023/1024)**
  Underlying FERC Proceeding: ER14-1050;[125] EL14-52;[126] EL15-25[127]
  Petitioner: NEPGA

On January 19, 2018, the Court dismissed for lack of jurisdiction the petition for review in 16-1023 (the appeal of the FCM Jump Ball and Compliance Proceedings) and denied on the merits the petition for review in 16-1024 (the NEPGA PER Complaint appeal). As previously reported, NEPGA filed, on January 19, 2016, a petition for review of the FERC's orders on NEPGA's first PER Complaint. On February 24, 2016, the Court granted NEPGA's motion to consolidate this proceeding with 16-1024. Briefing was completed on November 28, 2016. Oral argument was held October 27, 2017 before Judges Griffith, Dentelle and Randolph. In denying 16-1024 on the merits, the Court found that the underlying orders were not arbitrary and capricious. The Court further stated that "so long as any change is reasonably explained, it is not arbitrary and capricious for an agency to change its mind in light of experience, or in the face of new or additional evidence, or further analysis or other factors indicating that the agency's earlier decision should be altered or abandoned." With respect to 16-1023, the Court found it lacked jurisdiction because petitioner NEPGA had not itself sought rehearing of the FERC order appealed from, which for the Court to have jurisdiction it would have had to do. The court is withholding the issuance of its mandate until the 45-day appeal period expires (on March 5, 2018).

- **Base ROE Complaints II & III (2012 & 2014) (15-1212)**
  Underlying FERC Proceedings: EL13-33; EL14-86[128]
  Appellants: New England Transmission Owners

As previously reported, 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 August 14, 2015, the TOs 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 the TOs' motion to hold the case in abeyance, subject to submission of status reports every 90 days. The most recent status report, the tenth such report filed, was filed on February 12, 2018. In that report, the parties again indicated, ultimately, that the proceedings upon which the TOs based their request for abeyance of this appeal remain ongoing. This case continues to be held in abeyance.

[123] 155 FERC ¶ 61,273 (June 16, 2016); 157 FERC ¶ 61,060 (Oct. 27, 2016).

[124] 153 FERC ¶ 61,378 (Dec. 30, 2015); 151 FERC ¶ 61,226 (June 18, 2015).

[125] 153 FERC ¶ 61,224 (Nov. 19, 2015); 153 FERC ¶ 61,223 (Nov. 19, 2015); 147 FERC ¶ 61,172 (May 30, 2014).

[126] 153 FERC ¶ 61,222 (Nov. 19, 2015); 150 FERC ¶ 61,053 (Jan. 30, 2015).

[127] 153 FERC ¶ 61,222 (Nov. 19, 2015); 150 FERC ¶ 61,053 (Jan. 30, 2015).

[128] 147 FERC ¶ 61,235 (June 19, 2014); 149 FERC ¶ 61,156 (Nov. 24, 2014); 151 FERC ¶ 61,125 (May 14, 2015).

- **FCM Pricing Rules Complaints (15-1071**, 16-1042) (consol.)**
  Underlying FERC Proceeding: EL14-7,[129] EL15-23[130]
  Petitioners: NEPGA, Exelon

On February 2, 2018, DC Circuit granted NEPGA's and Exelon's petitions for review of orders accepting the FCM's 7-year price lock-in (EL14-7) and capacity-carry-forward rules (EL15-23).[131] Finding that "the FERC failed to adequately explain why its rationale [for rejecting price lock-in and capacity carry forward rules] in PJM – which seems to foreclose signing off on a Tariff scheme like ISO-NE's – does not apply even more forcefully to the scheme it accepted in the Orders [appealed from]," the DC Circuit granted the Petitions and remanded to FERC for further proceedings in which the FERC, in order to accept the changes filed, must provide some analysis and explanation why it changed course.

Other Federal Court Developments of Interest

- ***California Public Utilities Commission v. FERC* (9th Cir., 16-70481)** (Jan. 8, 2018)

In a decision that could impact how the FERC approaches future orders on ROE filings, the Ninth Circuit Court of Appeals held that the FERC acted arbitrarily and capriciously, and erred, by granting a transmission owner (PG&E) an incentive adder for its participation in an RTO (CAISO) where the participation by the TO was not voluntary. Doing so created a generic incentive adder (for TO participation in an RTO) in contravention of Order 679's requirement of case-by-case review of adders to be granted, which were designed to induce voluntary RTO participation. The Ninth Circuit remanded the matter back to the FERC with instructions to follow the appeals court's reasoning.

[129] 150 FERC ¶ 61,064 (Jan. 30, 2015); 146 FERC ¶ 61,039 (Jan. 24, 2014).

[130] 154 FERC ¶ 61,005 (Jan. 7, 2016); 150 FERC ¶ 61,067 (Jan. 30, 2015).

[131] *New England Power Generators Assoc. v FERC*, 881 F.3d 202 (DC Cir. 2018).

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