Energy Market Advisors LLC

To: NEPOOL Participants

From: Brian Forshaw

Date: December 6, 2017

Subject: Agenda Item #12 - Proposed Amendment to Sponsored Policy Resource Definition

Representatives of certain public power systems[1] intend to propose an amendment for your consideration on Friday and we have included in this memorandum information about that proposal. On November 30, 2017 ISO-NE posted a memorandum outlining three changes to its *Competitive Auctions with Sponsored Policy Resources (CASPR)* proposal. These revisions included the FirstLight amendment to limit capacity transfers between zones, the CLF/NRDC amendment to modify the definition of a sponsored policy resource, and the Calpine amendment to establish a resource-specific "floor price" review process for capacity supply participating as demand in the Substitution Auction starting with FCA #14. While public power systems individually and collectively have concerns with the implications of all three of these revisions, we are ***only*** proposing an amendment to the definition of a Sponsored Policy Resource to replace that CLF/NRDC language with the definition that is designed to ensure CASPR remains technology neutral as originally proposed and advocated by the ISO and included in the original ISO package that was voted on at the November 8, 2017 Markets Committee meeting.

Reasons for Proposing this Amendment

ISO provides scant explanation about why it has deviated from its long-held position that its market design should remain technology neutral and is now proposing to narrow the definition of Sponsored Policy Resources. While some stakeholders have argued that IMAPP (and then CASPR) was all about clean energy resources and carbon reduction, at the first IMAPP meeting public power pointed out that broader policy objectives including fuel diversity, local area resiliency, maintaining competitive electric rates, and mitigating the volatility of capacity costs in addition to environmental stewardship objectives. In its September 30, 2016 memo to NEPOOL concerning State IMAPP Objectives, NESCOE explicitly does not limit the policy mandates to be accommodated only to a *"renewable, clean, or alternative energy resources under renewable portfolio standard, clean energy standard, alternative energy portfolio standard, renewable energy goal, or clean energy goal enacted (either by statute or regulation)"* that was in effect on January 1, 2018. In fact, the ISO's sole rationale appears to be that *"a narrower approach will help ensure competitively-based prices in the primary FCA."* If the CASPR mechanism is not robust enough to accommodate the full range of Policy Resources required to meet going-forward statutory mandates, then perhaps we need to go back to the drawing board and seek another approach.

ISO also indicates that while its proposal does not allow fossil fuel resources in the Substitution Auction, resource owners can still offer such resources into the primary FCA at prices down to their offer floor. Unfortunately, this rationale fails to recognize that many of the policy resources that States and local communities are seeking to meet fuel diversity and local area resiliency objectives (including microgrid facilities and battery storage projects) are smaller and limited to specific locations, making it highly

[1] Due to the late notice of the ISO's changes to CASPR, at this point the sponsors of this amendment include CMEEC, NHEC, VPPSA, MMWEC and Energy New England. Other sponsors may be added prior to the Participants Committee meeting.

unlikely that such resources will be able to clear in the primary FCA, even if those States and communities are willing to absorb the incremental costs above the FCA clearing price. While not proposing this, if all we want to do is address existing environmental statutes and regulations, a more straightforward approach would be to amend the eligibility provisions or the existing Renewable Technology Resource (RTR) exemption to include large scale hydro and focus our efforts on a new market design approach that really works to accommodate the full range of going-forward statutory and regulatory mandates.

In addition, we further believe that limiting Sponsored Policy Resources to only those consistent with statutes or regulations in effect on January 1, 2018 is equally shortsighted. What this means is that if a State or local utility wants to develop a battery storage project (outside of a limited quantity in Massachusetts) or a fuel cell-based combined heat and power project (outside of Connecticut) it would be precluded from having such projects acquire a Capacity Supply Obligation through the Substitution Auction. This limitation also ignores the possibility that States will develop other new electric resource policy mandates that would similarly be precluded from participating in the capacity markets, leaving the region in the same position as today.

Conclusion and Proposed Amendment

For these reasons, public power is proposing to replace the definition of a Sponsored Policy Resource contained in the ISO's November 30, 2017 transmittal with the following:

> **Sponsored Policy Resource** is a New Capacity Resource that is either: (i) developed pursuant to a requirement of a New England state's law, or at the direction of a New England state electric utility regulatory authority or energy department, or meets the eligibility requirements of a New England States' renewable portfolio standard or similar standard, or alternatively; (ii) designated as a Self-Supplied FCA Resource by a municipal utility (acting individually, or jointly with other municipal utilities, including through a joint action agency) or by a cooperatively owned electric utility.

We would also note that over the last month, to accommodate concerns of others, we have proposed for consideration by others a potentially narrower definitions of Sponsored Policy Resources from the one above. While we remain open to considering this or other formulations of Sponsored Resource eligibility, given the timing of the ISO revisions we believe that this amendment appropriately addresses the legal expectation that CASPR remain technology neutral, which increases the potential chance for FERC approval, and accordingly is the most prudent course of action at this time. Please feel free to reach out if you have any specific questions or concerns and thank you for your consideration.

efforts to improve its methodology for accounting for BTM solar in its forecasts, and noted that the ICR values for the FCAs had consistently over-estimated resource requirements, with material downward changes in resource requirements for subsequent Annual Reconfiguration Auctions.

The Committee then voted the motion and that motion passed~~failed~~ with a 60.63% Vote in favor (Generation Sector – 0.95%; Transmission Sector – 15.2%; Supplier Sector – 0%; AR Sector – 10.17%; Publicly Owned Entity Sector – 17.10%; End User Sector – 17.1%; and Provisional Member Group – 0.11%). (See Vote 1 on Attachment 2).

Mr. Doot explained in response to a question that he expected the ISO would file its proposed ICR Values ~~notwithstanding the failed vote~~ and NEPOOL would provide comments on the stakeholder process, reporting on the votes and concerns that had been raised. Mr. Raymond Hepper confirmed that the ISO intended to file its proposed ICR Values as voted.

ISO CEO REPORT

Mr. Gordon van Welie, ISO CEO, referred the Committee to the summaries of the ISO Board and Board Committee meetings that had occurred since the September 15 Participants Committee meeting, which had been circulated and posted in advance of the meeting. There were no questions or comments on the summaries.

He then updated the Committee on the ISO's planned response to the Department of Energy's Grid Resiliency Pricing Rule Proposal (DOE NOPR). He explained that the ISO planned to delay finalizing its planned operational fuel security study until after responsive comments to the DOE NOPR had been filed. Noting that the DOE NOPR directed the FERC to make changes to the markets to provide full cost recovery for coal and nuclear resources, since those resources had the potential for a 90-day supply of fuel on-site, he stated that the ISO disagreed with the premise and the expedited notice/comment process. He expressed the ISO's

NEPOOL PARTICIPANTS COMMITTEE
VOTES TAKEN AT
NOVEMBER 3, 2017 MEETING

PUBLICLY OWNED ENTITY SECTOR

Participant Name	Vote 1	Vote 2
Ashburnham Municipal Light Plant	F	F
Belmont Municipal Light Dept.	F	F
Boylston Municipal Light Dept.	F	F
Chester Municipal Light Dept.	F	F
Chicopee Municipal Lighting Plant	F	F
Concord Municipal Light Plant	F	F
Conn. Mun. Electric Energy Coop.	F	F
Danvers Electric Division	F	F
Georgetown Municipal Light Dept.	F	F
Groton Electric Light Dept.	F	F
Groveland Electric Light Dept.	F	F
Hingham Municipal Lighting Plant	F	F
Holden Municipal Light Dept.	F	F
Hull Municipal Lighting Plant	F	F
Ipswich Municipal Light Dept.	F	F
Littleton (MA) Electric Light Dept.	F	F
Mansfield Municipal Electric Dept.	F	F
Marblehead Municipal Light Dept.	F	F
Mass. Development Finance Agency	F	F
Mass. Municipal Wholesale Electric Co.	F	F
Merrimac Municipal Light Dept.	F	F
Middleborough Gas & Elec. Dept.	F	F
Middleton Municipal Electric Dept.	F	F
New Hampshire Electric Coop.	F	F
Pascoag Utility District	F	F
Paxton Municipal Light Dept.	F	F
Peabody Municipal Light Plant	F	F
Princeton Municipal Light Dept.	F	F
Reading Municipal Light Dept.	F	F
Rowley Municipal Light Plant	F	F
Russell Municipal Light Dept.	F	F
Shrewsbury's Electric & Cable Ops.	F	F
South Hadley Electric Light Dept.	F	F
Sterling Mun. Elec. Light Dept.	F	F
Stowe (VT) Electric Dept.	F	F
Taunton Municipal Light Plant	F	F
Templeton Mun. Lighting Plant	F	F
VT Public Power Supply Authority	F	F
Wakefield Mun. Gas & Light Dept.	F	F
Wallingford, Town of	F	F
Wellesley Municipal Light Plant	F	F
West Boylston Municipal Lighting Plant	F	F
Westfield Gas & Electric Light Dept.	F	F
IN FAVOR (F)	43~~27~~	43
OPPOSED	0	0
TOTAL VOTES	43~~27~~	43
ABSTENTIONS (A)	0	0

END USER SECTOR

Participant Name	Vote 1	Vote 2
Associated Industries of MA	F	F
Conn. Office of Consumer Counsel	F	F
Environmental Defense Fund	F	F
Harvard Dedicated Energy Limited	F	F
High Liner Foods (USA) Inc.	F	F
Maine Public Advocate's Office	F	F
Mass. Attorney General's Office	F	F
Natural Resources Defense Council	F	F
NH Office of Consumer Advocate	F	F
PowerOptions, Inc.	F	F
Shipyard Brewing Co., LLC	F	F
The Energy Consortium	F	F
Union of Concerned Scientists	F	--
Utility Services, Inc.	F	A
IN FAVOR (F)	14	12
OPPOSED	0	0
TOTAL VOTES	14	12
ABSTENTIONS (A)	0	1

PROVISIONAL MEMBERS

Participant Name	Vote 1	Vote 2
Maine Power LLC	F	F
IN FAVOR (F)	1	1
OPPOSED	0	0
TOTAL VOTES	1	1
ABSTENTIONS (A)	0	0

Summary of ISO New England Board and Committee Meetings

December 8, 2017 Participants Committee Meeting

Since the last update, the Audit and Finance Committee met in Boston on November 1. The Compensation and Human Resources Committee, the Markets Committee, and the Board of Directors each met on November 2 in Boston. The Markets Committee also met by teleconference on November 27.

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

The Compensation and Human Resources Committee convened and reviewed the goal setting, assessment and compensation schedule for 2018. The Committee also considered its annual calendar for 2018.

The Markets Committee was provided with a summary of market performance for the 2017 summer season, and had a general discussion on the process by which wholesale capacity costs are reflected in retail rates. The Committee then received a report on recent developments concerning the Competitive Auctions for Sponsored Policy Resources (CASPR) stakeholder review process, and discussed the progress and the procedural aspects of the review process. At the November 27 meeting, the Committee received an update on the CASPR proposal, including the States' backstop proposal and the stakeholder amendments to be incorporated into the ISO's final proposal and FERC filing.

The Board of Directors received reports from the standing committees, including the committees' risk assessments for the key risks that fall within the scope of each committee's oversight. Next, the Board conducted its annual risk management review and discussed the various topics related to potential risks, including the primary risks that the New England wholesale electricity market faces. The Board also approved the 2017 Regional System Plan as recommended by the System Planning and Reliability Committee. Finally, the Board prepared for the upcoming sector meetings with NEPOOL and reviewed topics proposed by stakeholders for discussion.

NEPOOL Participants Committee Report

December 2017

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 $336M, up $34M from October and up $83M from November 2016
    - November natural gas prices over the period were 23% higher than October average values
    - Average RT Hub Locational Marginal Prices ($33.27/MWh) over the period were 4.9% higher than October averages
    - Average November 2017 natural gas prices and RT Hub LMPs over the period were up 32% and up 37%, respectively, from November 2016 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 98.5% during November, down from 99.4% during October*

Data are through November 29, 2017 unless otherwise noted.

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

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

Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - November NCPC payments totaled $7M over the period, up $3.2M from October and down $8M from November 2016
    - First Contingency* payments totaled $2.8M, down $0.6M from October
      - $2.7M paid to internal resources, down $0.4M from October
        - » $992K charged to DALO, $1.025M to RT Deviations, $634K to RTLO
      - $132K paid to resources at external locations, down $214K from October
        - » $44K charged to DALO at external locations, $87K to RT Deviations
    - Second Contingency payments totaled $4.2M, up $3.9M from October
  - NCPC payments over the period as percent of Energy Market value were 2.1%

* NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $241K; Rapid Response Pricing (RRP) Opportunity Cost - $184K; Generator Performance Auditing (GPA) - $207K; Posturing - $2K

Highlights, cont.

- 2016 Economic Study - NEPOOL Scenario Analysis
  - Final Phase I report was issued on November 20
  - Phase II - analysis of regulation, ramping, and reserves is on schedule for completion by the end of 2017
- Final RSP17 report was posted on November 2
- A preview of likely capacity zones for the 2022-2023 Capacity Commitment Period (CCP) was discussed at the November 16 PAC meeting
- Certification of transmission topology for the 2022-2023 CCP is nearly complete, and will be presented at the January RC meeting

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 bilateral transaction window will be December 4-8, 2017
  - Third reconfiguration auction will be March 1-5, 2018, and results to be posted by March 19, 2018
  - ICR & related values for ARA3 were filed with FERC on December 1
- CCP #10 (2019-2020)
  - Second bilateral transaction window will be May 2-4, 2018
  - Second reconfiguration auction will be August 1-3, 2018
  - ICR & related values for ARA2 were filed with FERC on December 1

CCP – Capacity Commitment Period
ARA – Annual Reconfiguration Auction
ICR – Installed Capacity Requirement

FCM Highlights, cont.

- CCP #11 (2020-2021)
  - First bilateral transaction window will be April 4-6, 2018.
  - First reconfiguration auction will be June 1-5, 2018.
  - ICR & related values for ARA1 were filed with FERC on December 1.
- CCP #12 (2021-2022)
  - FERC Informational Filing was made on November 7.
  - ICR & related values were filed with FERC on November 7.
  - Auction will commence on February 5, 2018.
  - The Renewable Technology Resource election cap is approximately 514 MW.

FCM Highlights, cont.

- CCP #13 (2022-2023)
  - Topology certification nearly complete and results to be presented to the RC in January
  - Preliminary capacity zones were discussed at the PAC in November
  - Efforts focused on updating and enhancing training materials in preparation for qualification which begins in spring 2018

FERC Order 1000

- Intraregional Planning
  - Several parties have submitted information to be considered as Qualified Transmission Project Sponsors, and 21 companies have been approved
  - Appendix 3 to Attachment K has been updated to reflect these approvals and was accepted by FERC on November 13

Highlights, cont.

- The lowest 50/50 and 90/10 Winter Operable Capacity Margins are projected for week beginning January 13, 2018.

2017/18 Winter Reliability Program As of December 1

- **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

GRIDEX IV Overview

- GRIDEX IV was a North American wide electric grid focused exercise and simulation that provided Reliability Coordinators, Balancing Authorities, Transmission Owners and Operators, government entities and industry the opportunity to respond to a physical, cyber and operational attack on the North American Power Grid
- The exercise took place on November 15^{th} and 16^{th}
- The simulated attackers were a determined, well-resourced adversary with robust cyber and physical security threat capabilities
- The exercise was filled with low probability, high impact events that challenged participants

GRIDEX IV Objectives

- Exercise crisis response and recovery
- Improve cross functional communications
- Identify lessons learned and take corrective actions
- Directly engage senior leadership in a high impact low probability exercise
- Explore the coordination of recovery efforts in a scenario that severely impacts the reliability of the bulk power system
- Evaluate plans, processes and procedures in a safe environment

GRIDEX IV Participants

- New England Participants
  - ISO New England, National Grid, EVERSOURCE/Massachusetts, EVERSOURCE/New Hampshire, EVERSOURCE/Connecticut, VELCO, Central Maine Power, MMWEC, UNITIL
  - All six Local Control Centers in New England were active players and participants
  - Department of Homeland Security, FBI
  - NECPUC
- NPCC Region
  - IESO, HQ, NBPOWER, NYISO, NPCC
- North America
  - All Reliability Coordinators in North America
- Thousands of Planners and Players at the Transmission Owners/Operators, Balancing Authorities
- FBI/DHS/Armed Forces
- State and Federal Agencies

GRIDEX IV Logistics

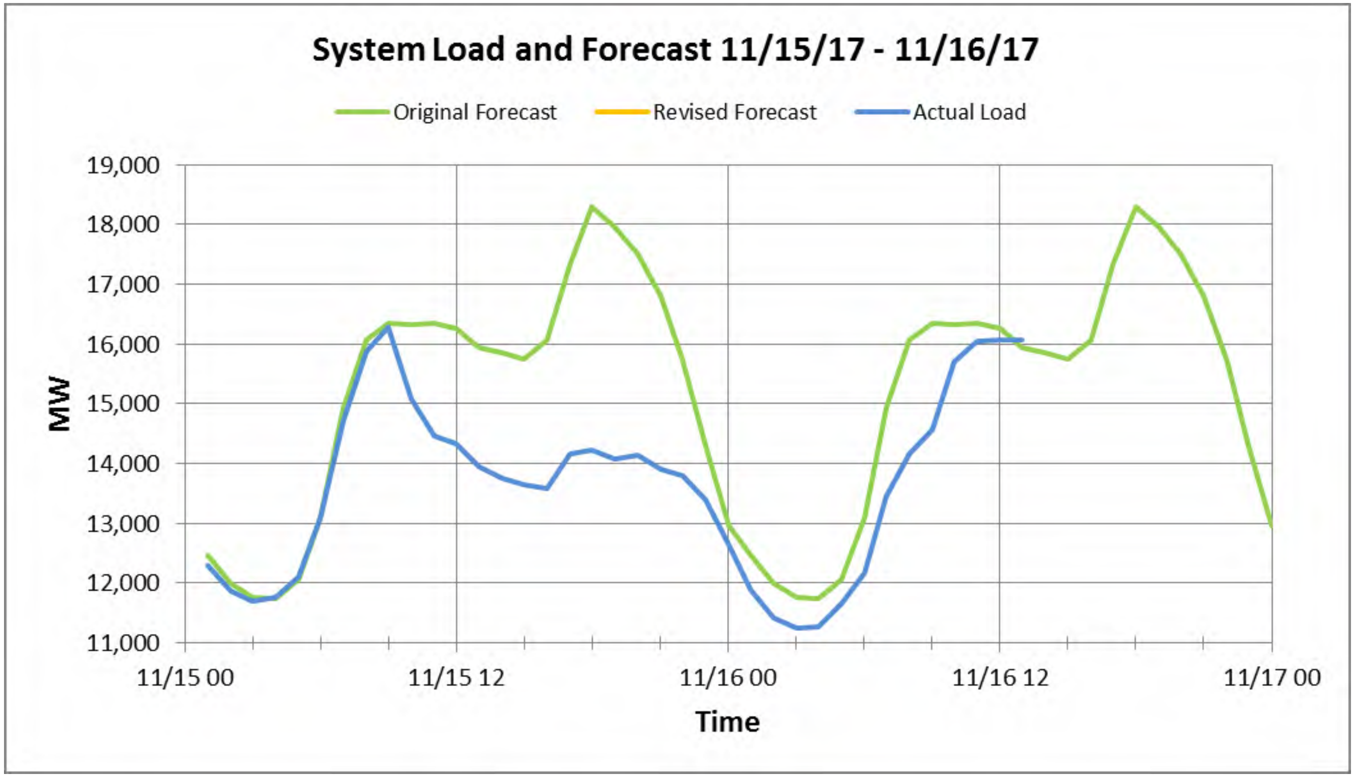
- How was it done
  - North American Wide Coordinated Simulation Injections
  - NPCC Wide Coordinated Simulation Injections
  - New England Wide Coordinated Simulation Injections
  - Heavy use of Training Simulators as exercise platforms throughout New England and North America
  - Table Top

GRIDEX IV Event Simulation

- Dozens of physical attacks including two major physical attacks at two locations on the first day causing the loss of over 6500 MW of generation
- Dozens of simulated physical and cyber attacks to transmission elements:

GRIDEX IV Events Load Curves Simulation

- The difference between the original forecast and actual load is the approximate load that was lost due to simulated cyber and physical destruction plus manual load shedding to secure the Bulk Electric System under OP 7



GRIDEX IV Next Steps

- All participants including the New England Participants are reviewing lessons learned
- New England Lead Planners are meeting to review lessons learned and draft After Action Report on December 15 at ISO New England
  - ISO New England will review results similar to GRIDEX III during early 2018 with the Reliability Committee once report is finalized
- NERC expects to have After Action Report in spring of 2018
- Implement Corrective Actions and Lessons Learned in accordance with individual corporation Causal and Preventative action processes

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Below Normal (1.4°F) Max: 75°F, Min: 22°F Precipitation: 1.80" – Below Normal Normal: 3.98"	Hartford	Temperature: Below Normal (2.4°F) Max: 77°F, Min: 19°F Precipitation: 1.03" – Below Normal Normal: 4.06"

Peak Load:	16,998MW	Nov 28, 2017	18:00 (ending)

Emergency Procedures:	**Reason**	**Status**
M/LCC 2	Severe weather	Declared: Oct 30, 2017 0630 Cancelled: Nov 1, 2017 2000 (all NE except Maine) Cancelled: Nov 3, 2017 1800 (Maine)
OP-4 : **None**		

NPCC Simultaneous Activation of Reserve Events:

Date	Area	MW
Nov 3, 2017	NYISO	1036

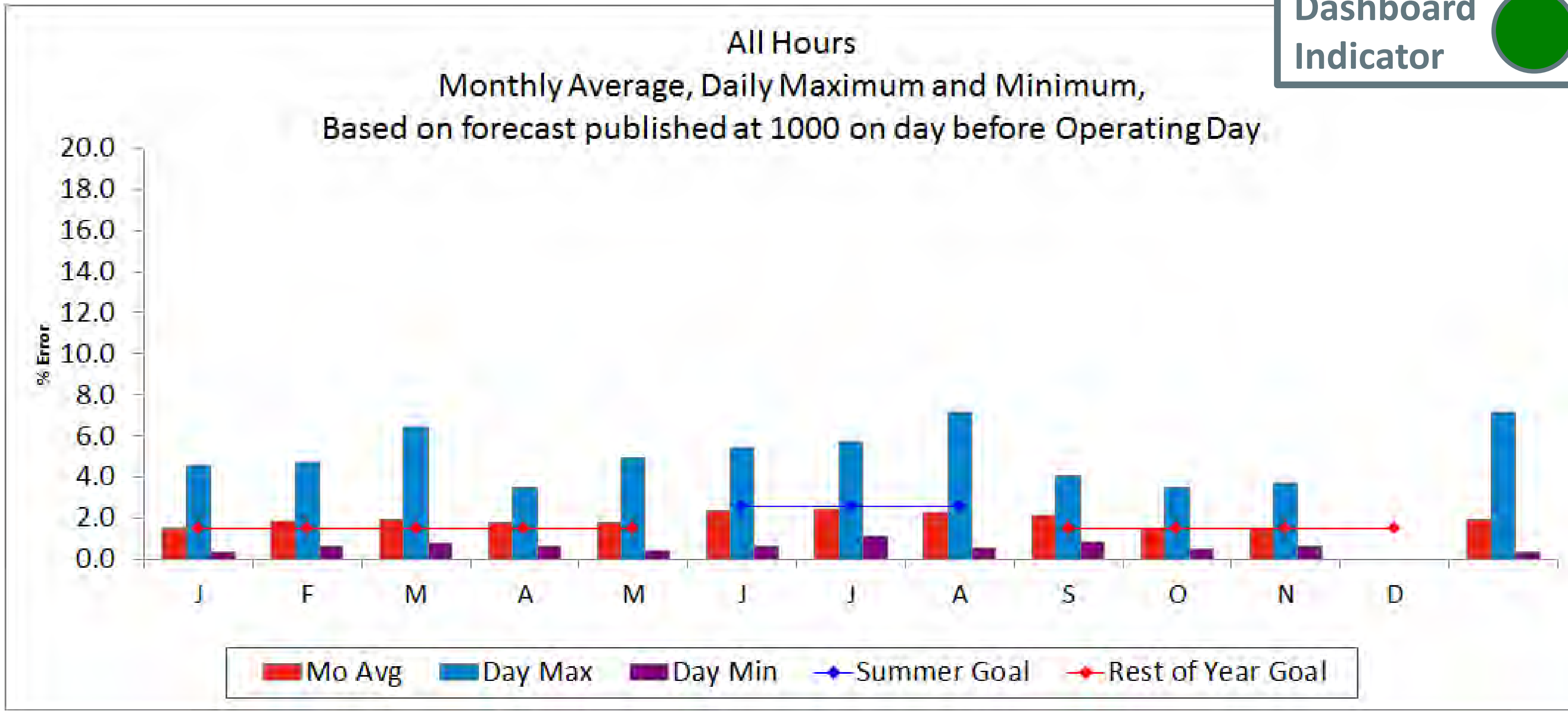
System Operations, cont.

Minimum Generation Warnings & Events:

None

2017 System Operations - Load Forecast Accuracy

Dashboard Indicator

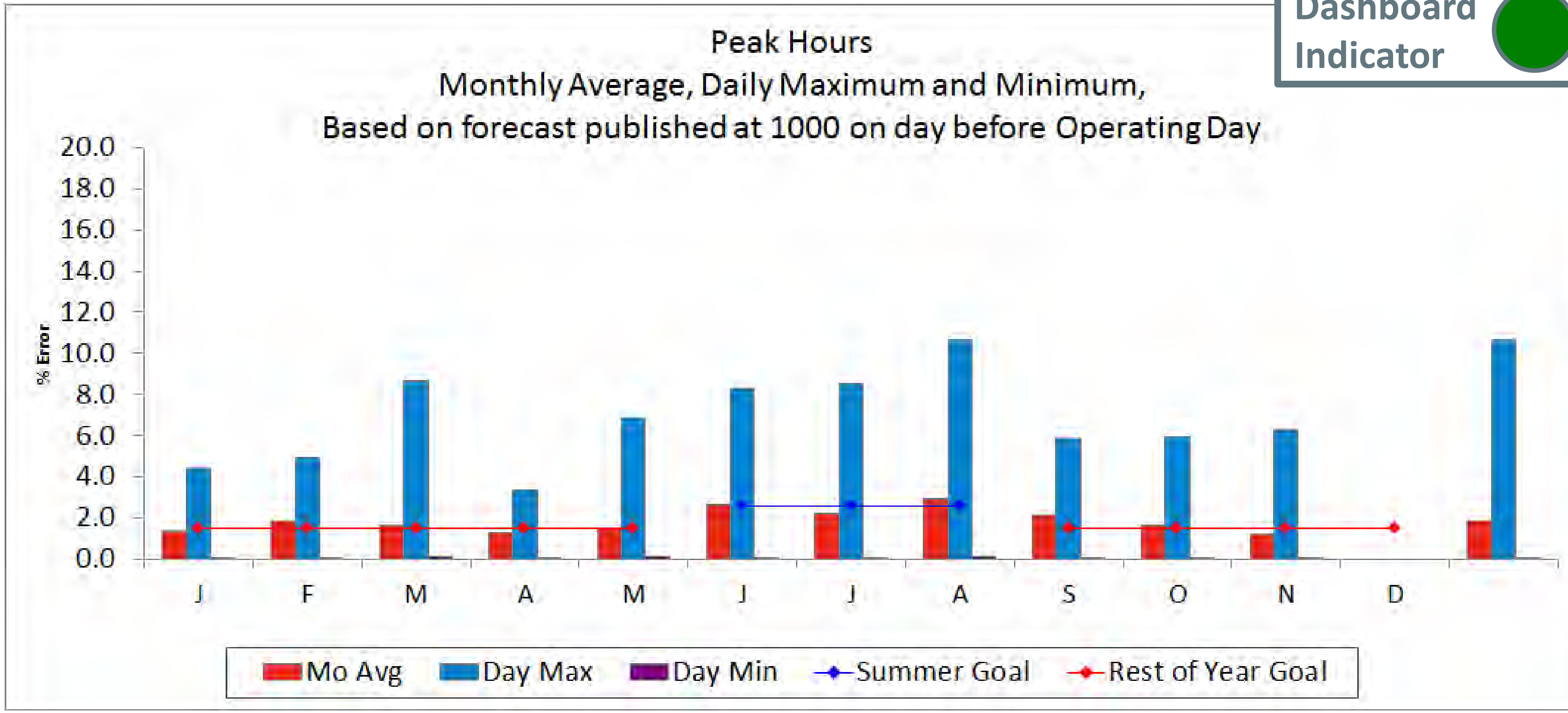


Month	J	F	M	A	M	J	J	A	S	O	N	D	
Mo Avg	1.51	1.84	1.95	1.81	1.80	2.37	2.42	2.26	2.13	1.48	1.50		1.92
Day Max	4.58	4.72	6.43	3.53	4.92	5.44	5.73	7.18	4.09	3.48	3.70		7.18
Day Min	0.33	0.62	0.77	0.65	0.42	0.62	1.17	0.54	0.89	0.53	0.64		0.33
Summer Goal						2.60	2.60	2.60					
Rest of Year Goal	1.50	1.50	1.50	1.50	1.50				1.50	1.50	1.50	1.50	
Rest of Year Actual	1.51	1.84	1.95	1.81	1.80				2.13	1.48	1.50		1.75
Summer Actual						2.37	2.42	2.26					2.35

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

2017 System Operations - Load Forecast Accuracy, cont.

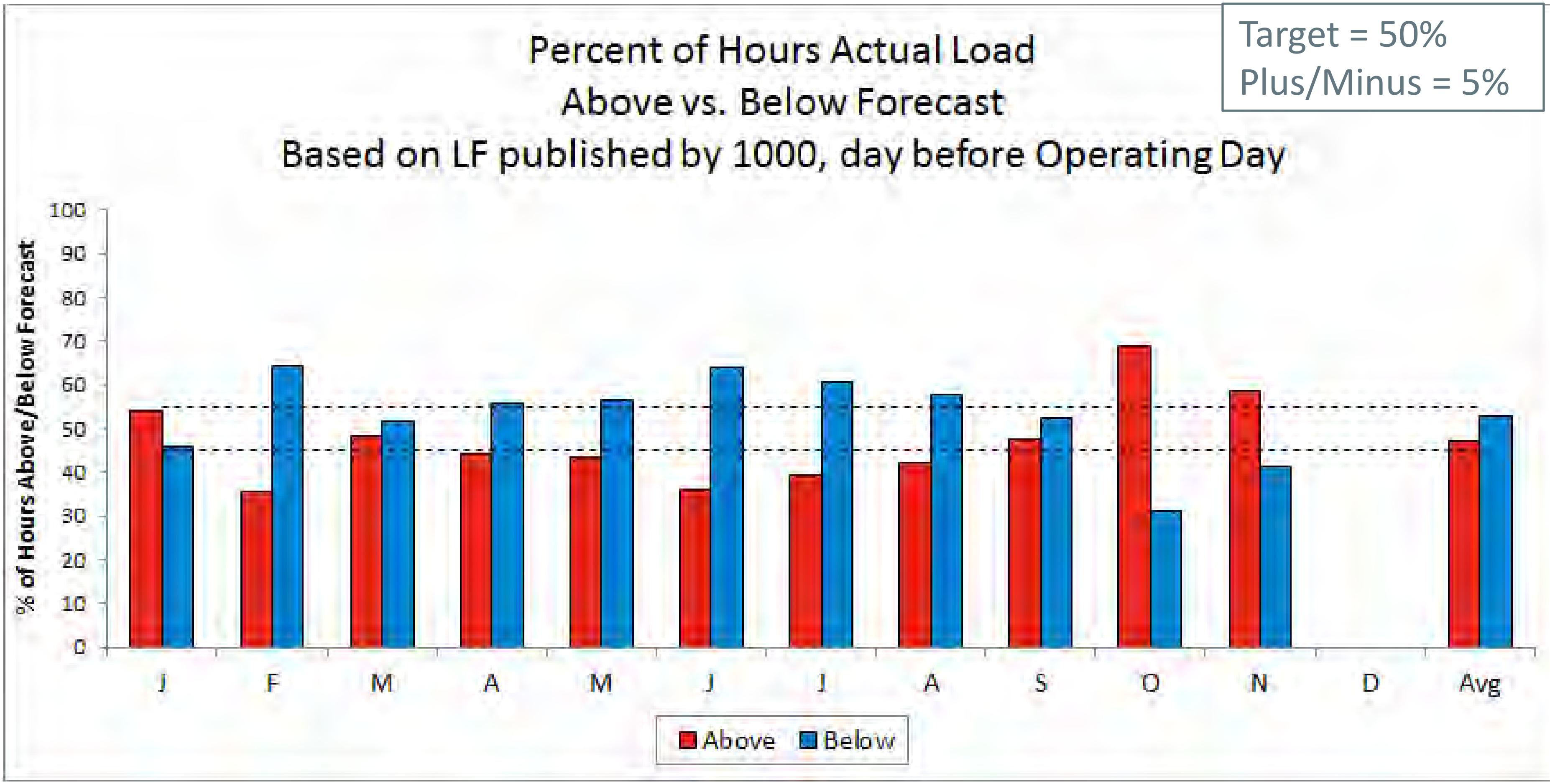
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Mo Avg	1.38	1.83	1.63	1.26	1.52	2.65	2.25	2.92	2.12	1.68	1.20		1.86
Day Max	4.41	4.91	8.70	3.39	6.91	8.30	8.53	10.65	5.90	5.98	6.32		10.65
Day Min	0.01	0.05	0.14	0.01	0.11	0.05	0.01	0.17	0.03	0.03	0.04		0.01
Summer Goal						2.60	2.60	2.60					
Rest of Year Goal	1.50	1.50	1.50	1.50	1.50				1.50	1.50	1.50	1.50	
Rest of Year Actual	1.38	1.83	1.63	1.26	1.52				2.12	1.68	1.20		1.58
Summer Actual						2.65	2.25	2.92					2.61

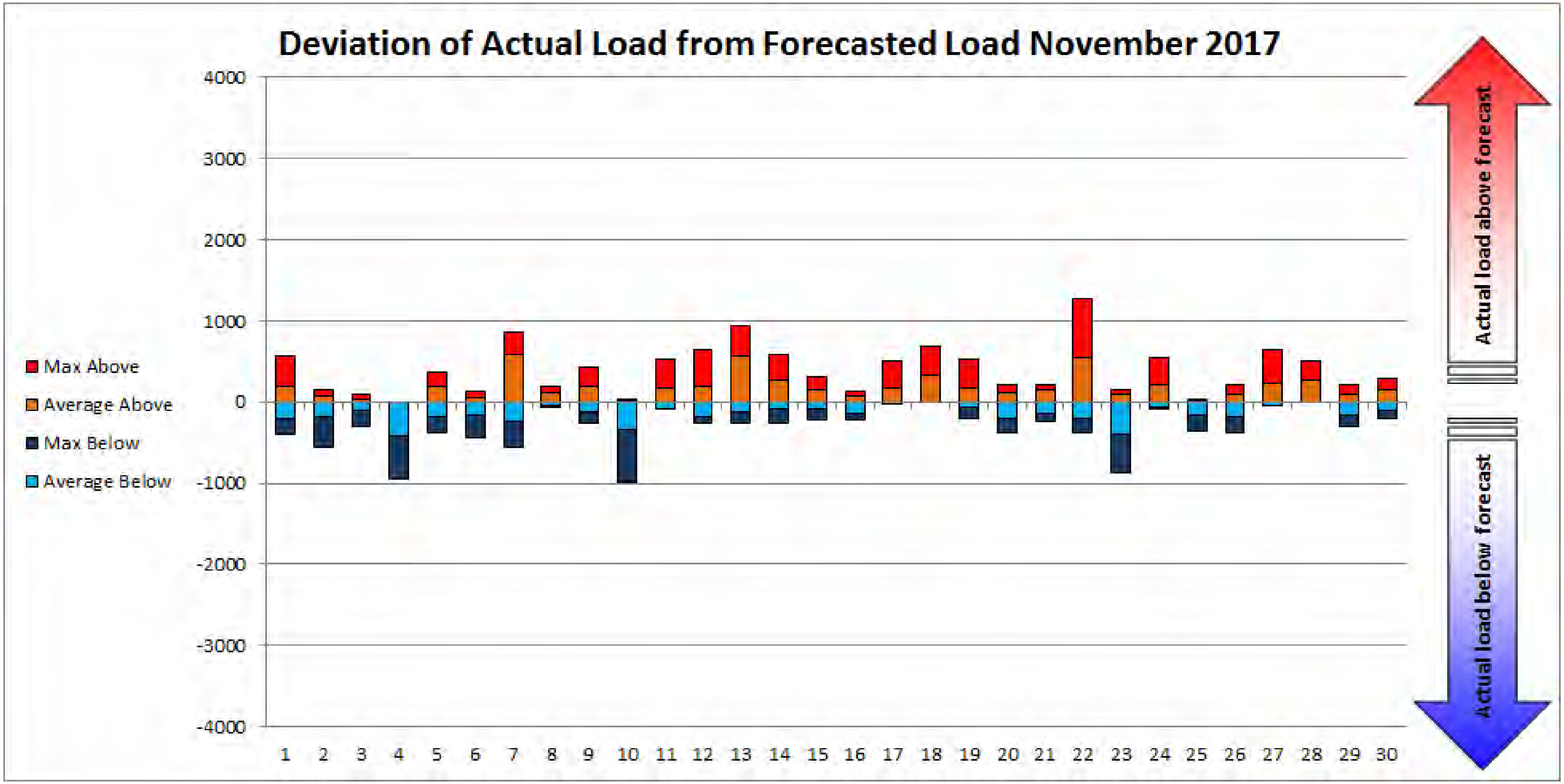
Rest of Year Goal < 1.5%
Summer Goal < 2.6%

2017 System Operations - Load Forecast Accuracy, cont.

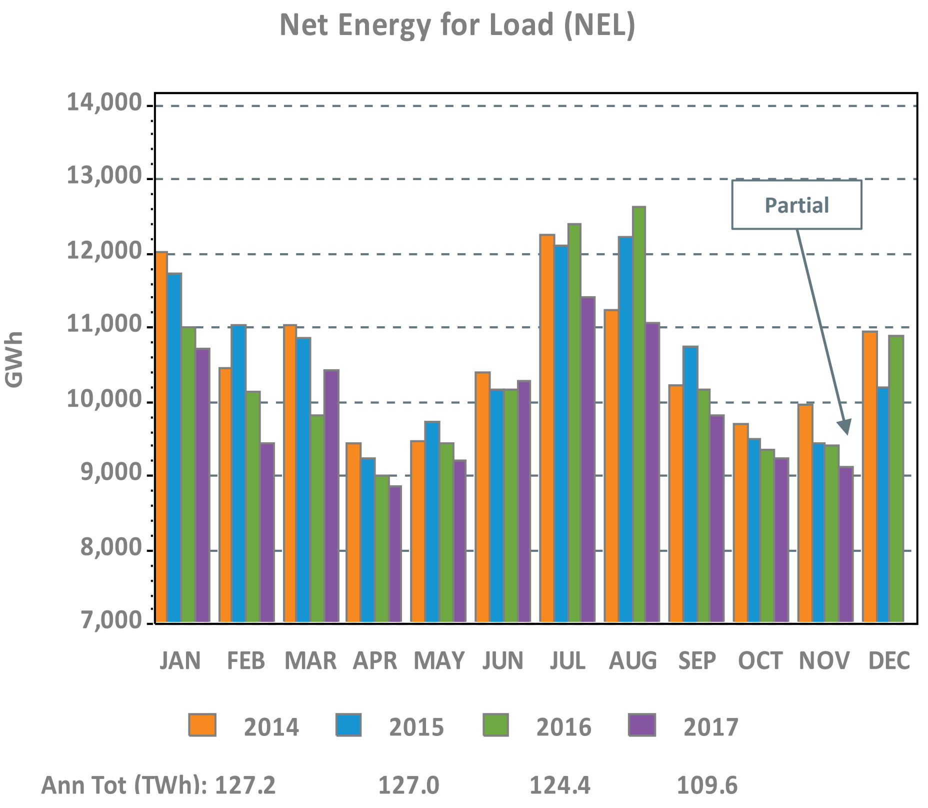


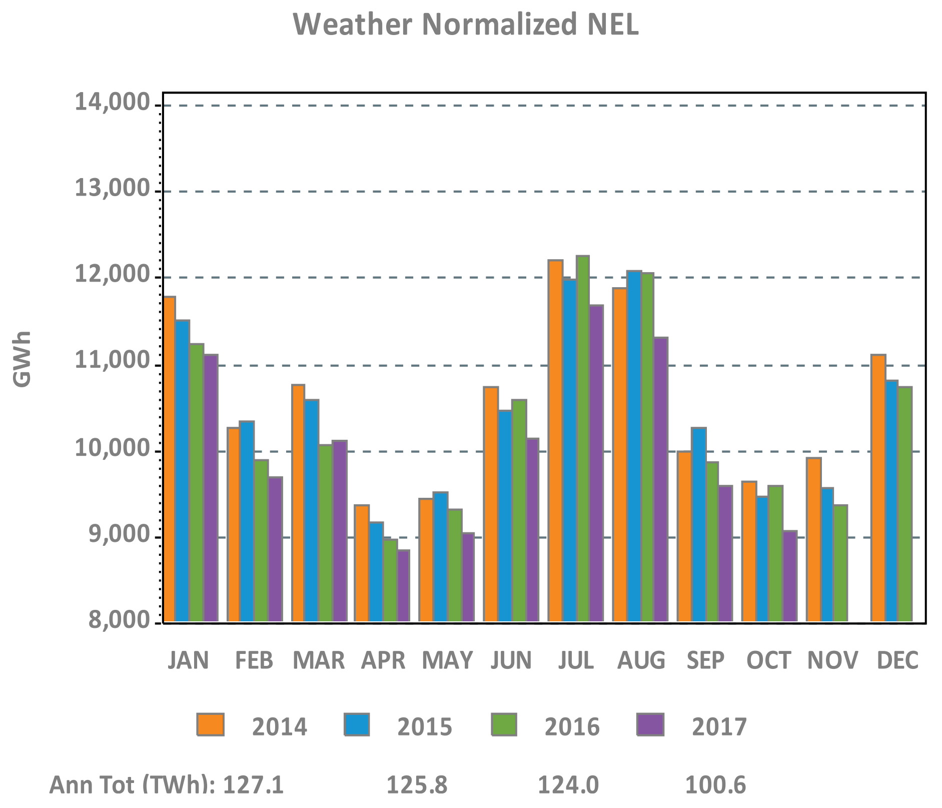
	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	54.3	35.6	48.5	44.2	43.4	36.2	39.4	42.1	47.4	69	58.7		47
Below %	45.7	64.4	51.5	55.8	56.6	63.8	60.6	57.9	52.6	31	41.3		53
Avg Above	175.5	137.4	192.2	171.9	179.6	179.3	215	173.1	243.4	155.1	184.6		243
Avg Below	-174.1	-209.5	-206.6	-156.8	-190.0	-297.8	-363.5	-313.0	-193.1	-111.5	-148.8		-364
Avg All	20	-76	-32	-4	-27	-119	-149	-115	26	62	34		-34

2017 System Operations - Load Forecast Accuracy, cont.



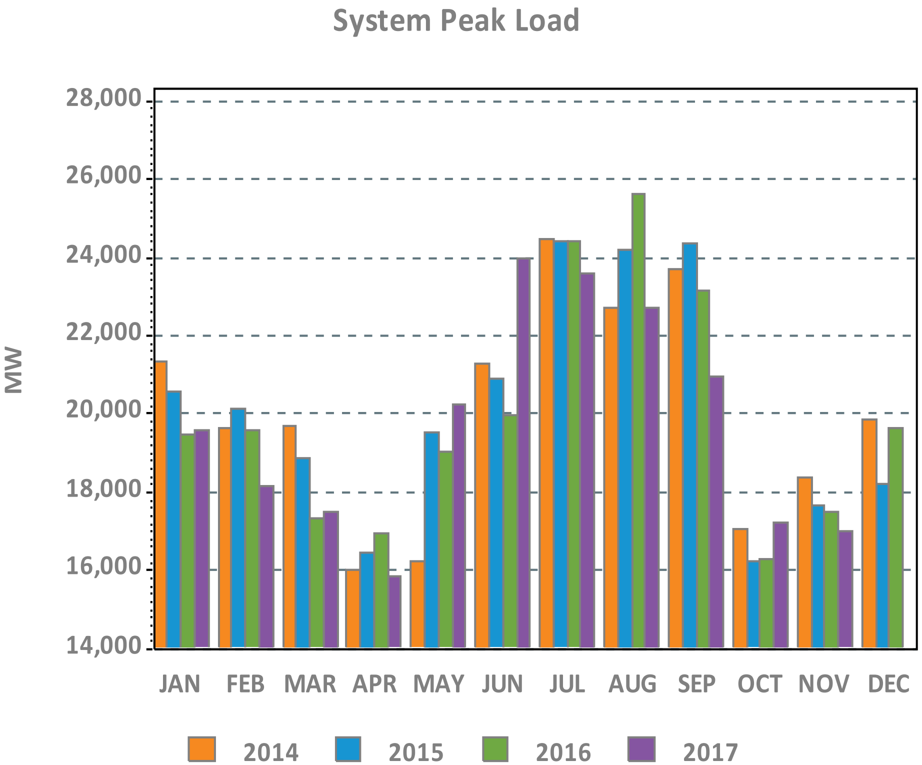
Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL



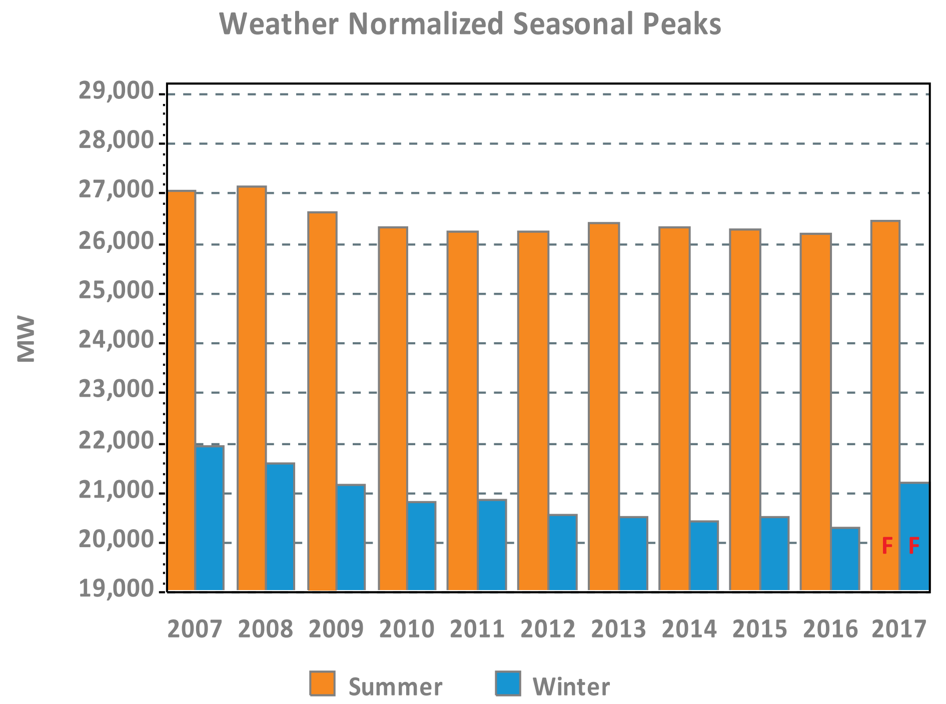


NEPOOL NEL is the total net energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation – pumping load + net interchange where imports are positively signed.
Current month's data may be preliminary. Weather normalized NEL may be reported on a one-month lag.

Monthly Peak Loads and Weather Normalized Seasonal Peak History



*Revenue quality metered value

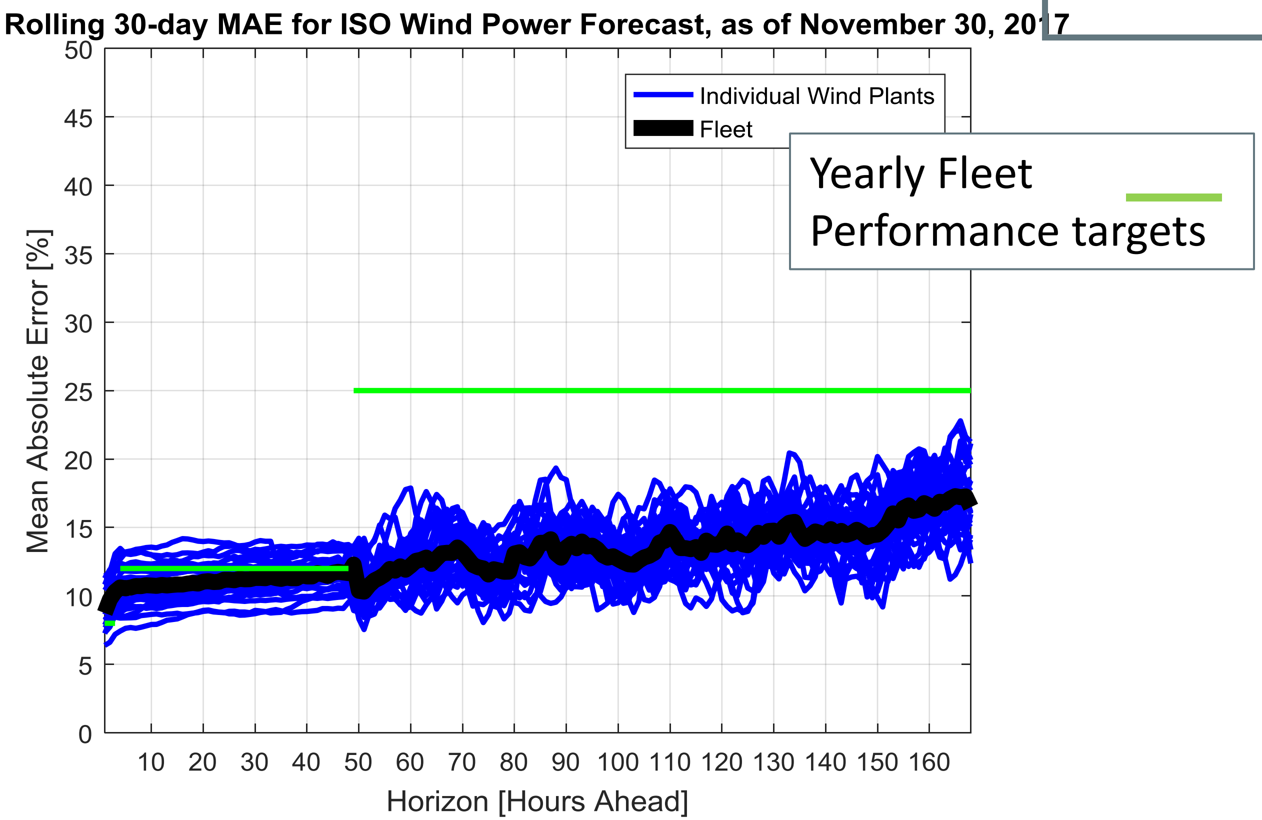


Winter beginning in year displayed

Reflects "net forecast" (i.e., the gross forecast net of passive demand response and behind-the-meter solar demand); F – designates forecasted values, updated in April/May of the following year; Forecasted winter peak reflects passive DR sourced from the capacity auction. This may underestimate passive DR performance and overestimate the (forecasted) winter peak.

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

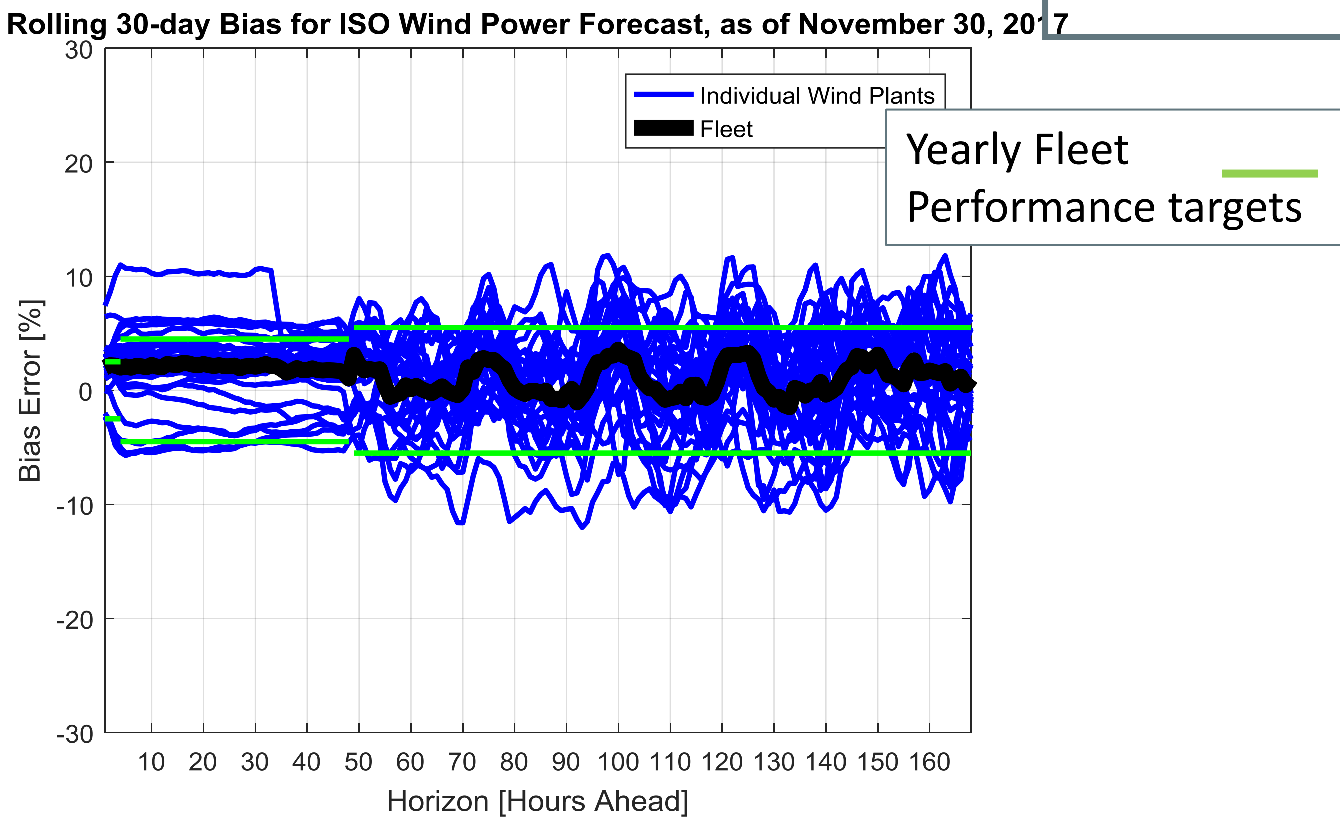
Dashboard Indicator



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

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

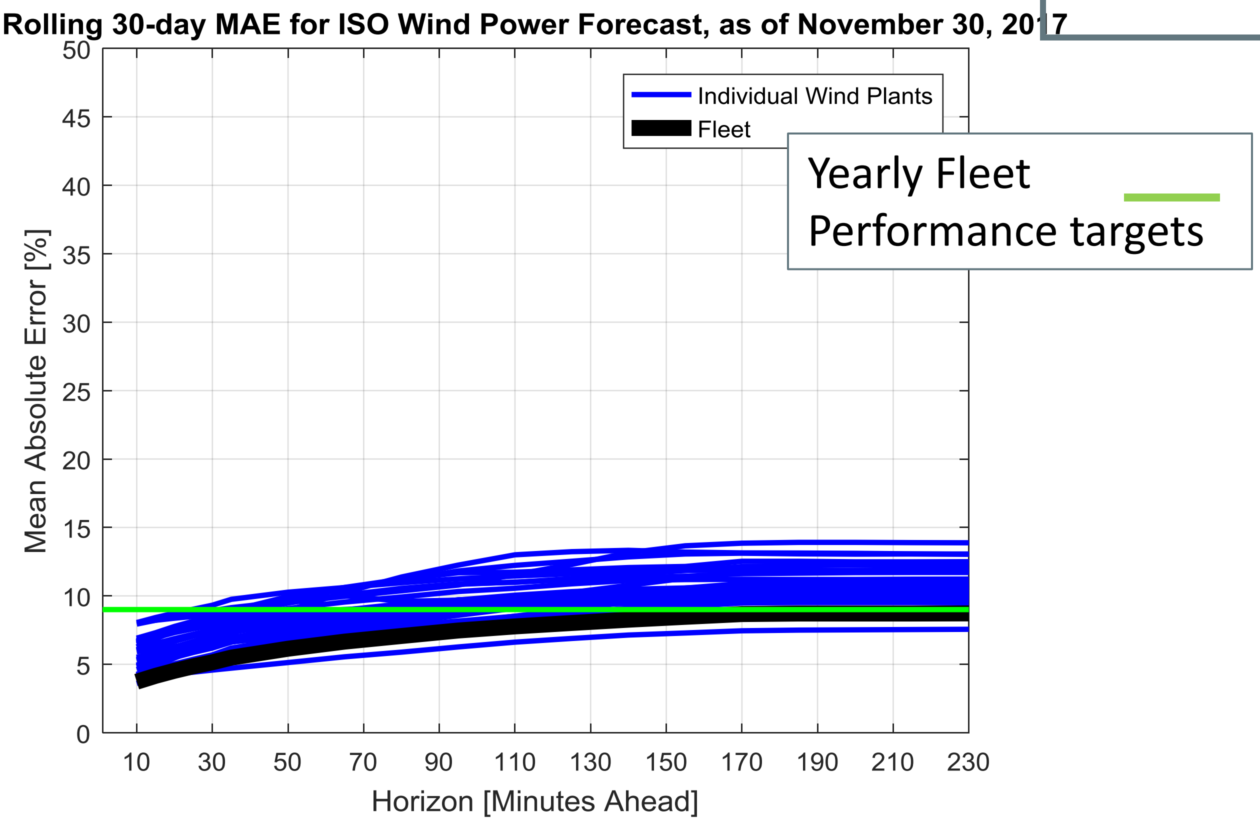
Dashboard Indicator



Ideally, MAE and Bias would be both equal to zero. Positive bias means less windpower was actually available compared to forecast. Negative bias means more windpower was actually available compared to forecast. Across all time frames, the ISO-NE/DNV-GL forecast compares well with industry standards, and monthly Bias is within yearly performance targets.

Wind Power Forecast Error Statistics: Short Term Forecast MAE

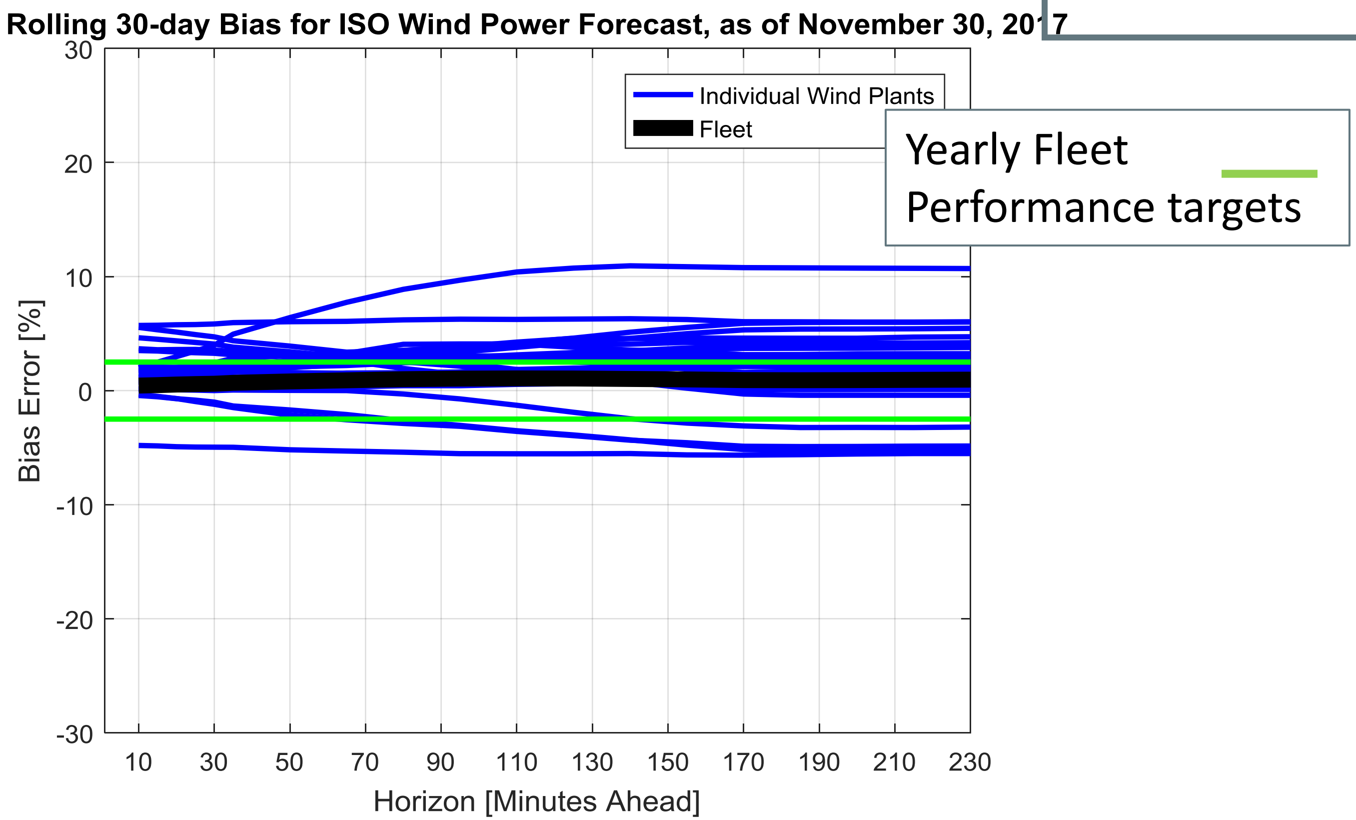
Dashboard Indicator



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

Wind Power Forecast Error Statistics: Short Term Forecast Bias

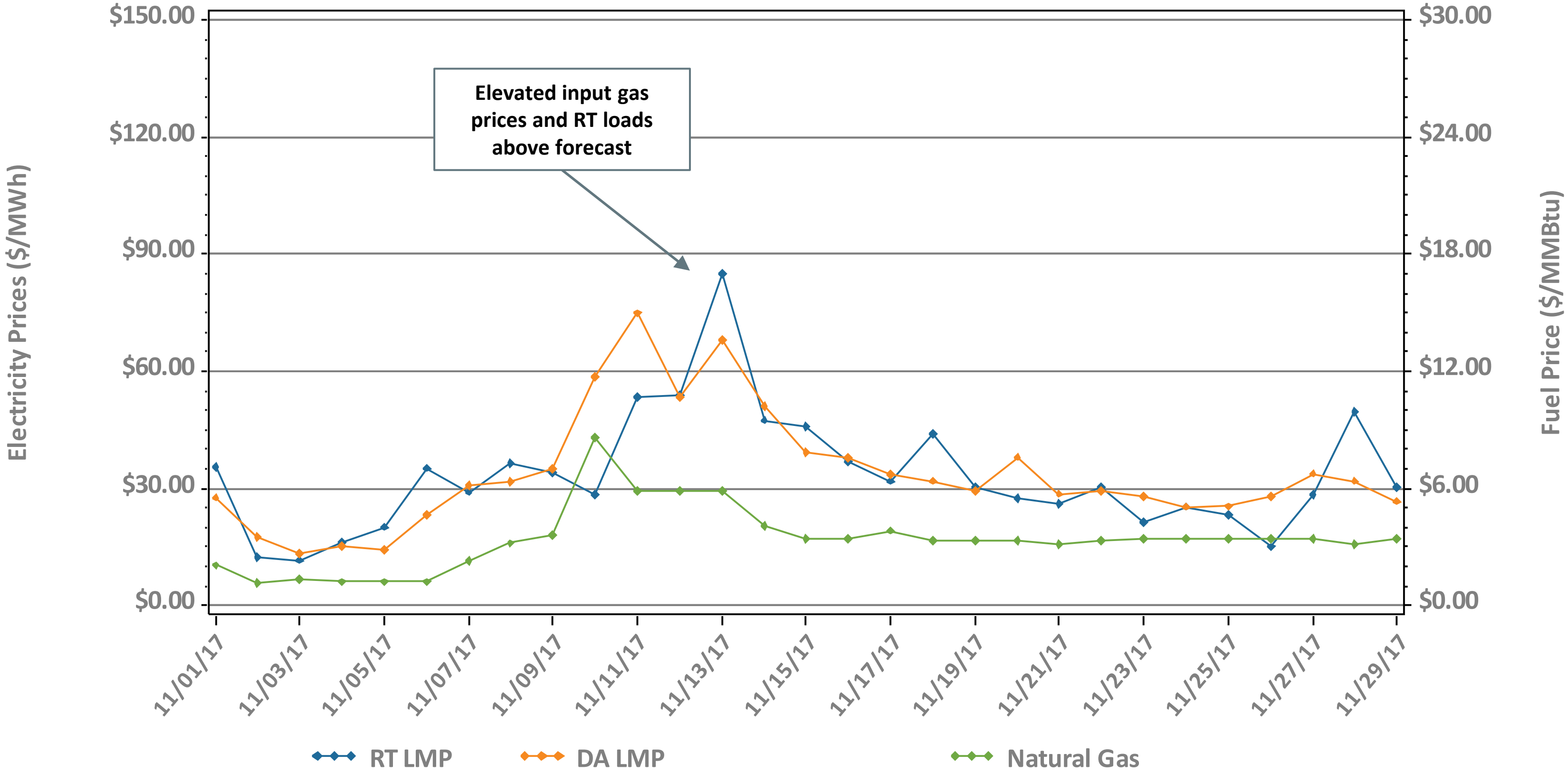
Dashboard Indicator



Ideally, MAE and Bias would be both equal to zero. Positive bias means less windpower was actually available compared to forecast. Negative bias means more windpower was actually available compared to forecast. Across all time frames, the ISO-NE/DNV-GL forecast compares well with industry standards, and monthly Bias is within yearly performance targets.

MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: November 1-29, 2017

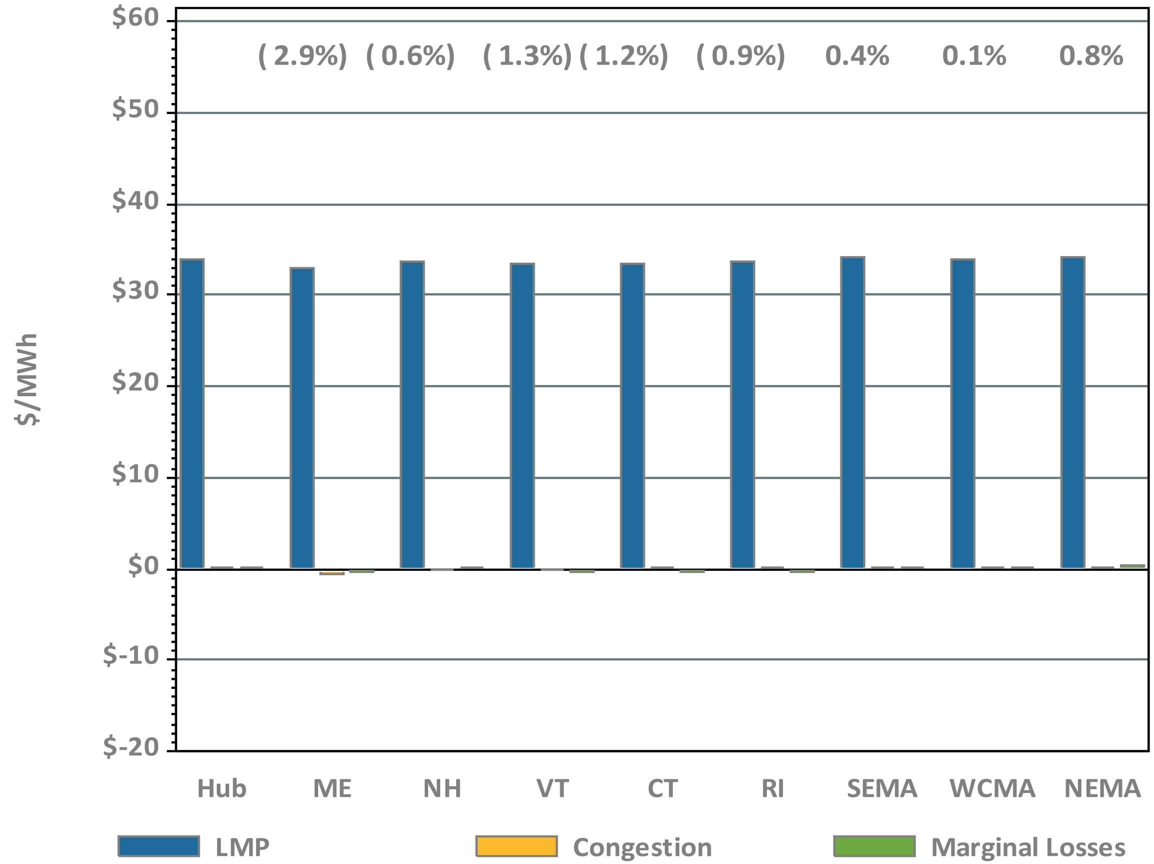


Underlying natural gas data furnished by:

ICE Global markets in clear view

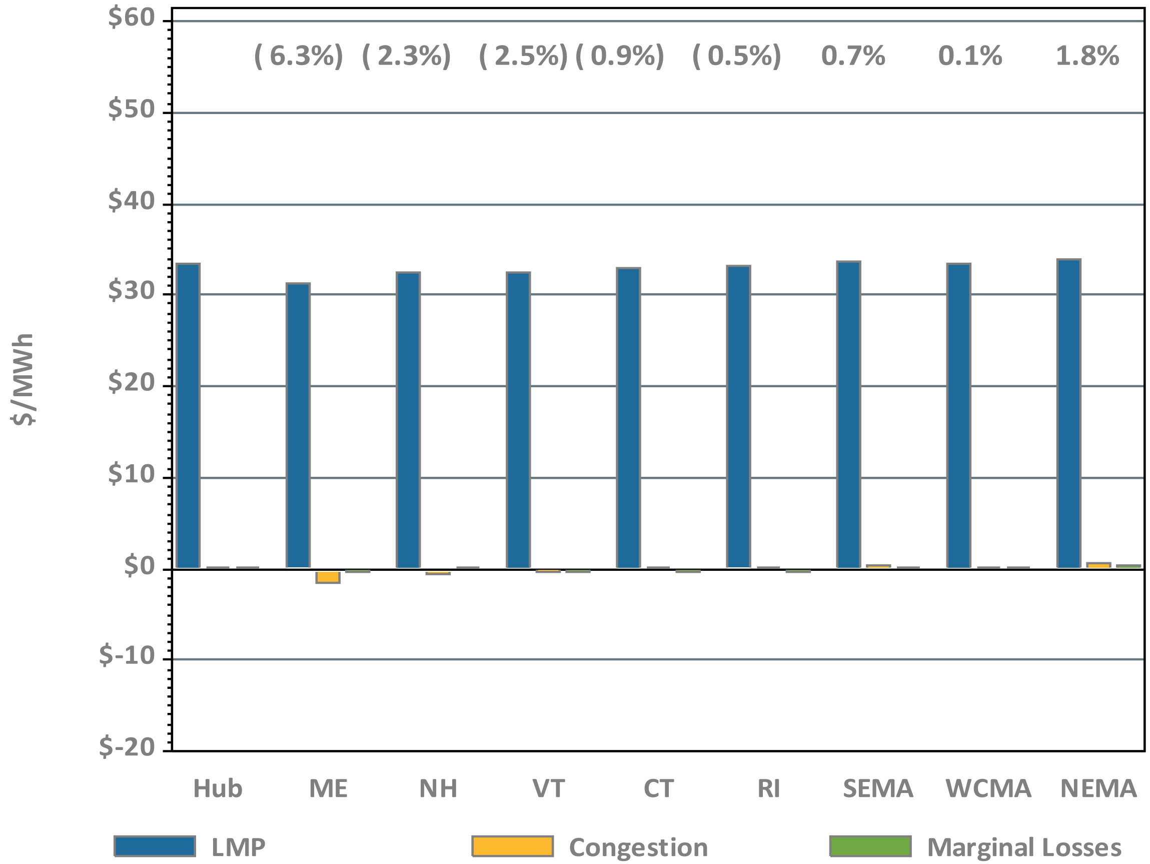
Average price difference over this period (DA-RT): $0.59
Average price difference over this period ABS(DA-RT): $6.86
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 21%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, November 2017



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

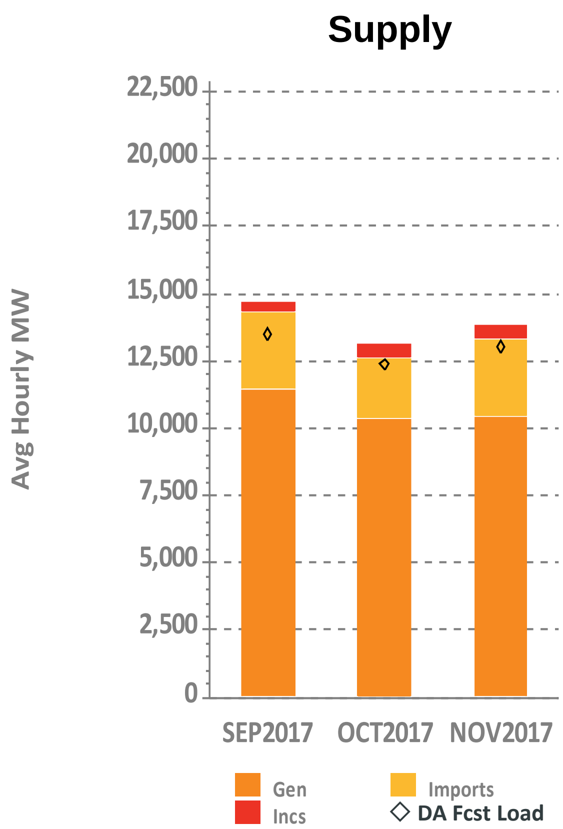
RT LMPs Average by Zone & Hub, November 2017



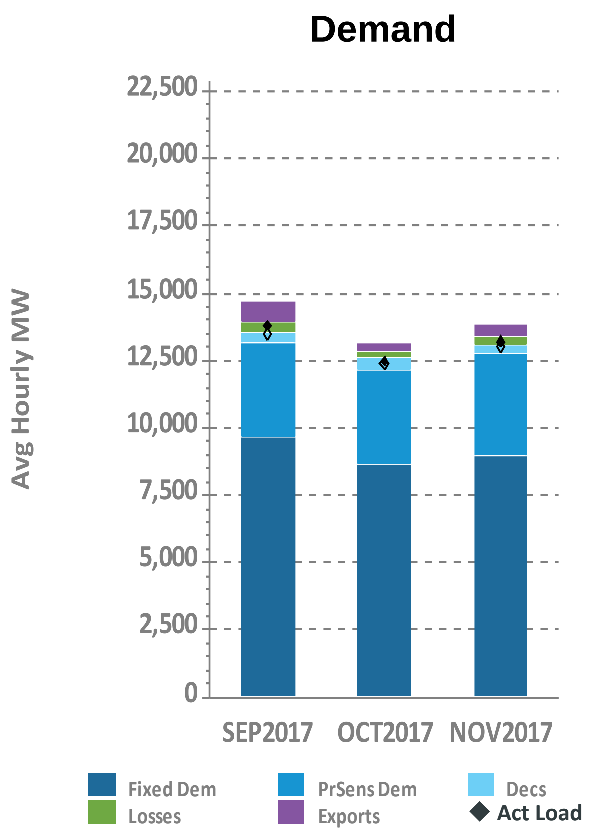
Definitions

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

Components of Cleared DA Supply and Demand – Last Three Months

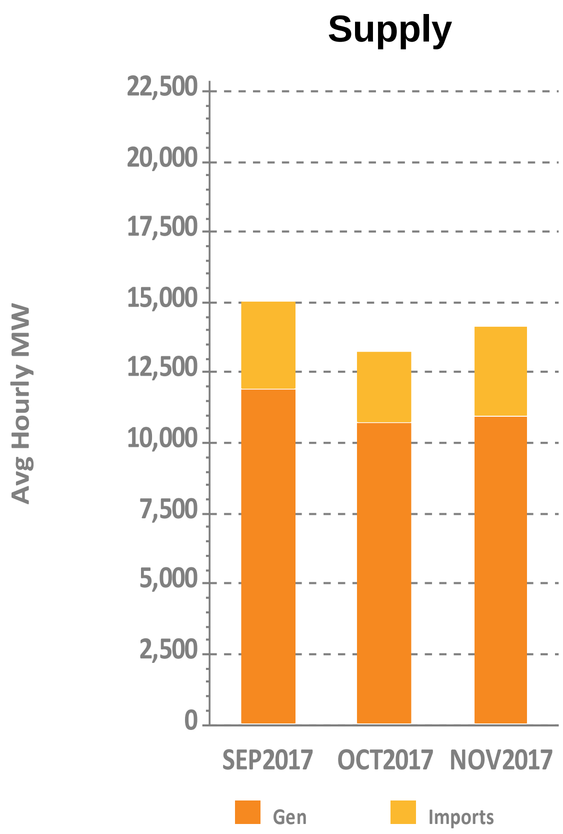


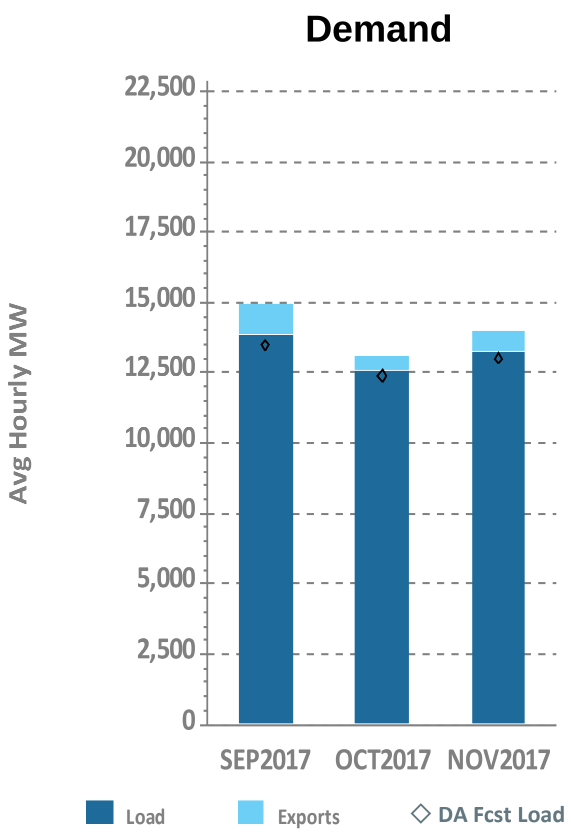
Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load



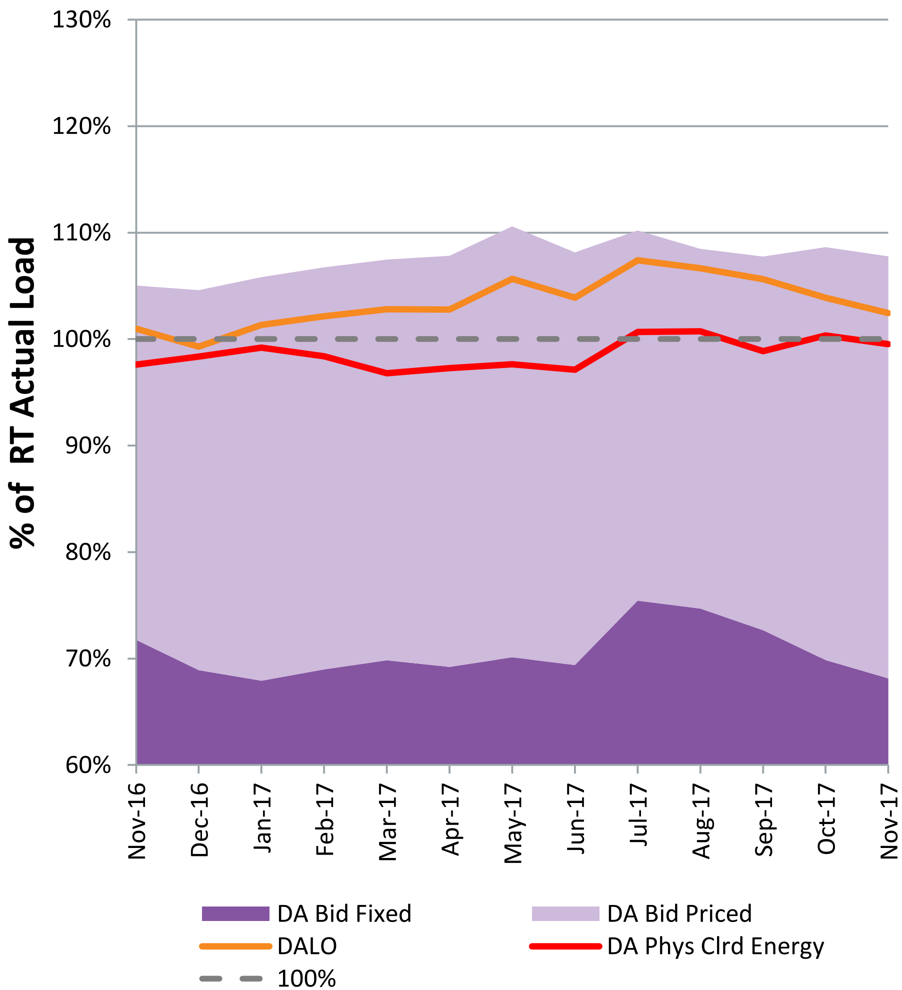
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

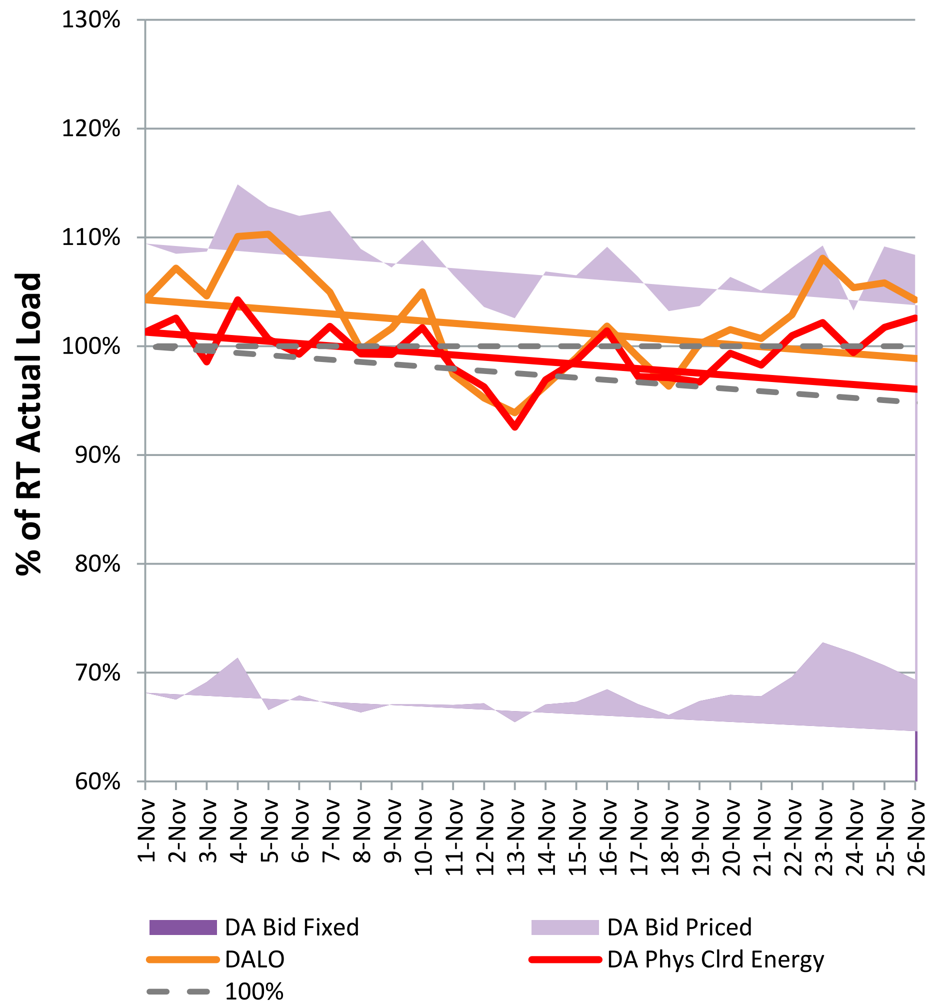
Components of RT Supply and Demand – Last Three Months





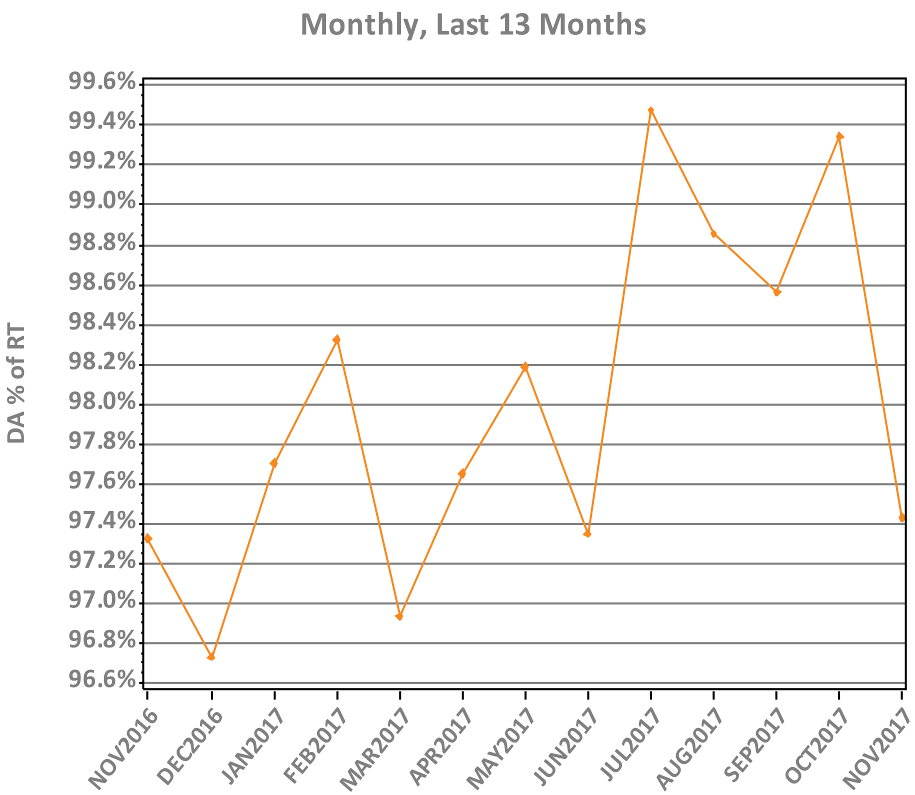
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

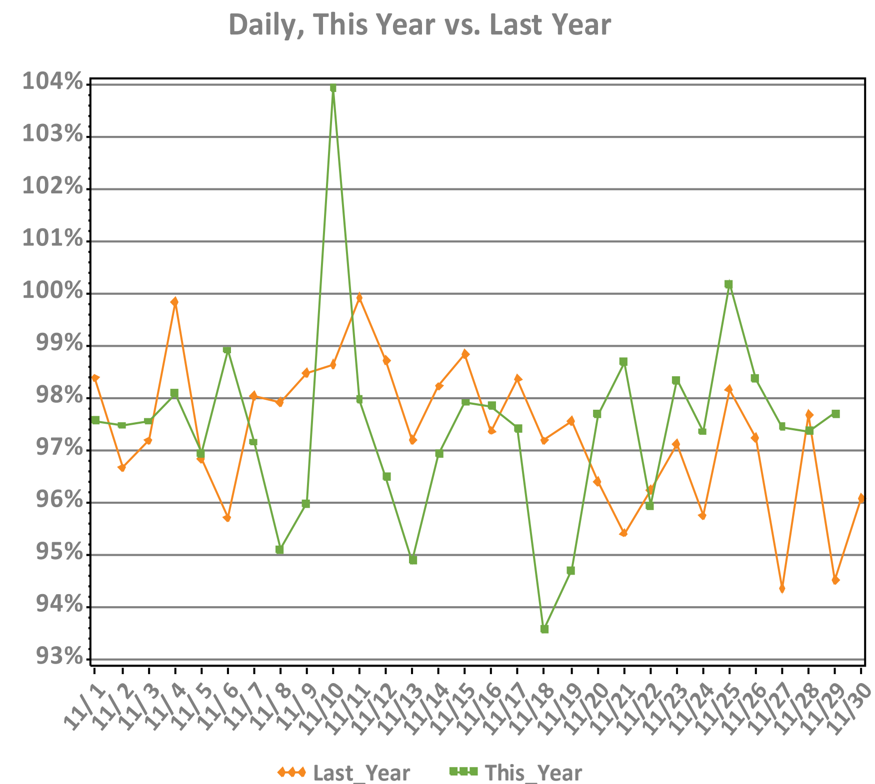




Note: Percentages were derived for the peak hour of each day (shown on right), then averaged over the month (shown on left). Values at hour of forecasted peak load. DA Bid categories reflect internal load asset bidding behavior (Virtual demand and export bid behavior not reflected).

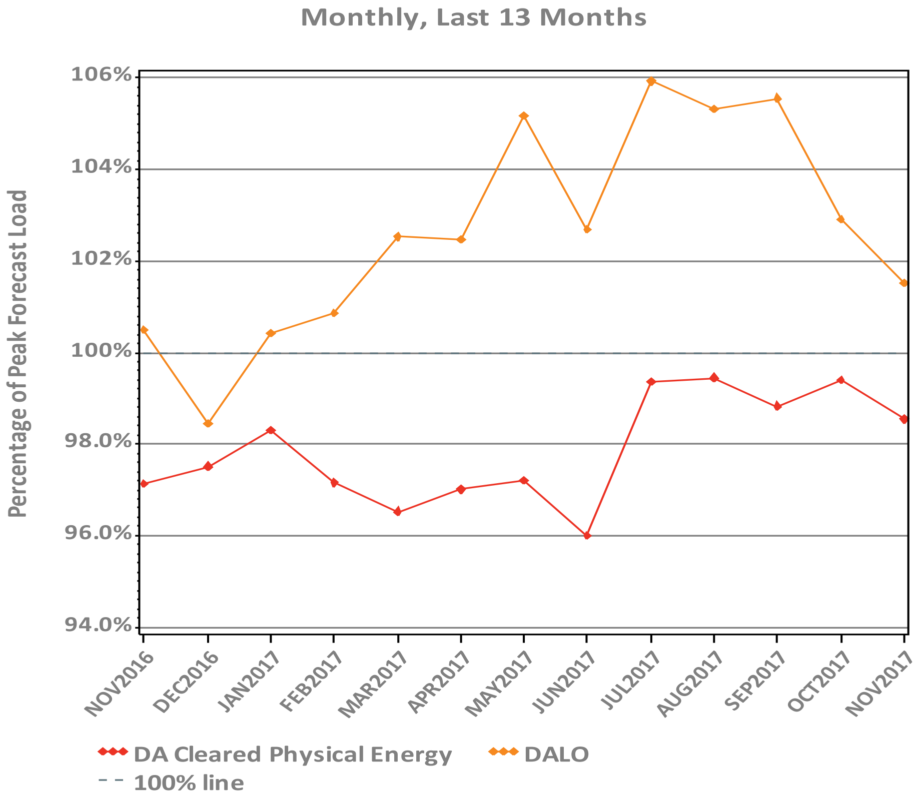
DA vs. RT Load Obligation: November, This Year vs. Last Year

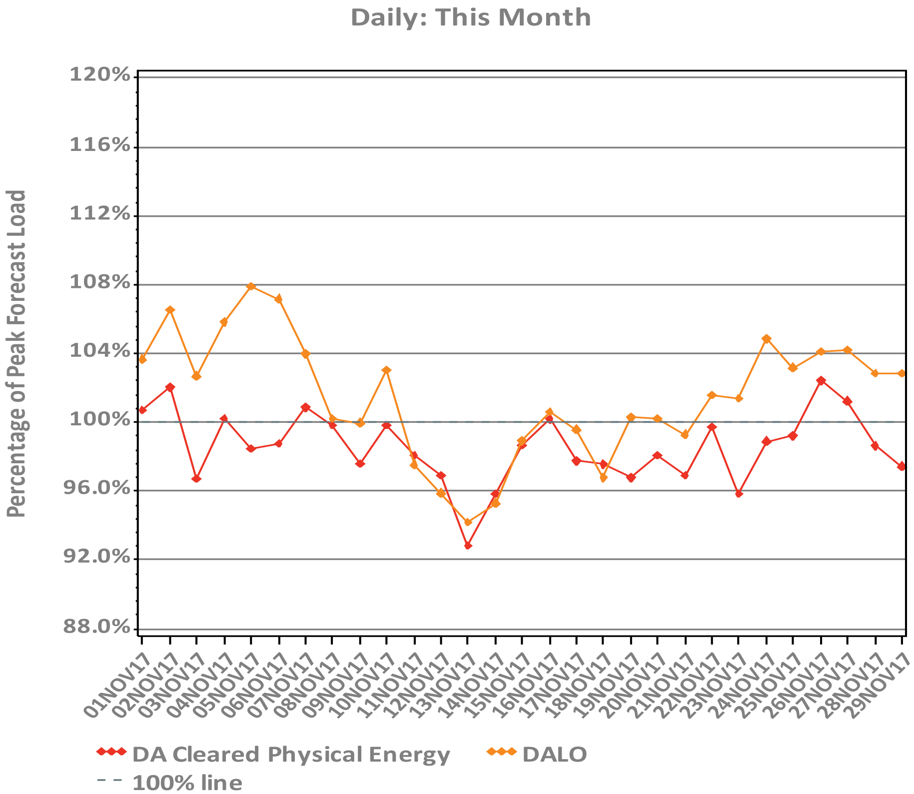




*Hourly average values

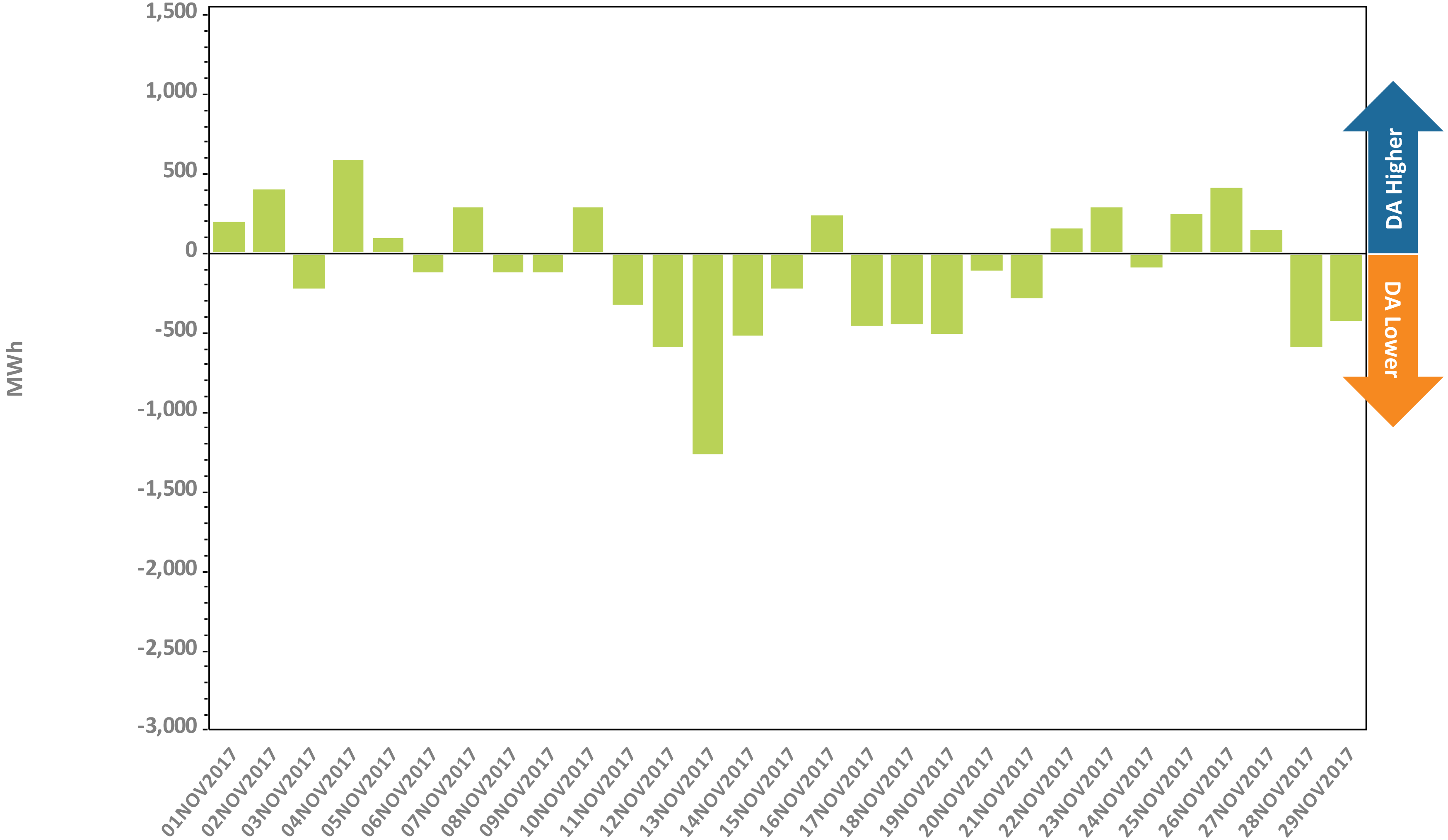
DA Volumes as % of Forecast in Peak Hour





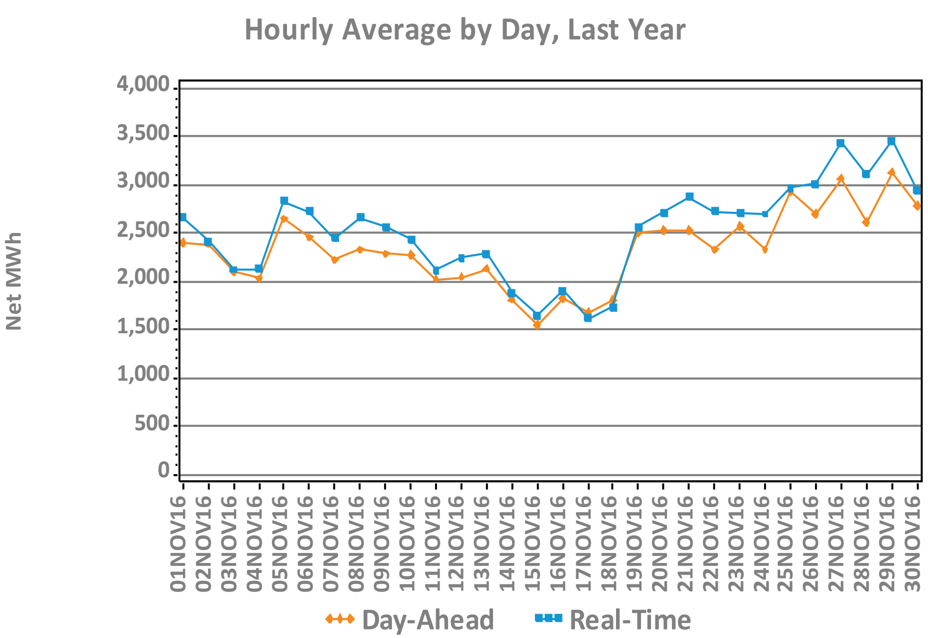
***There were 11 Supplemental commitment required for capacity during the Reserve Adequacy Assessment (RAA) process during November.**

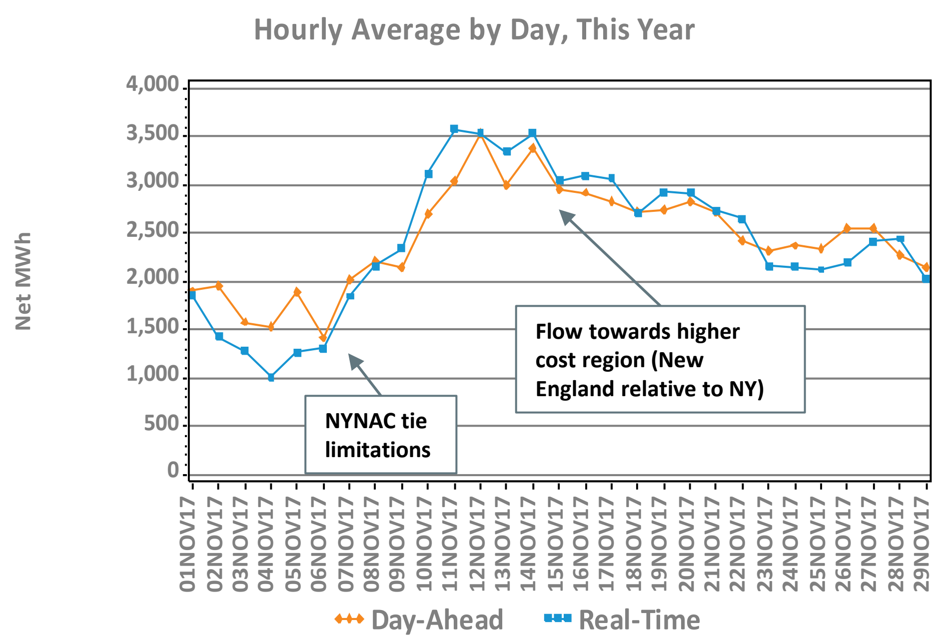
DA Cleared Physical Energy Difference from RT System Load at Peak Hour*



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

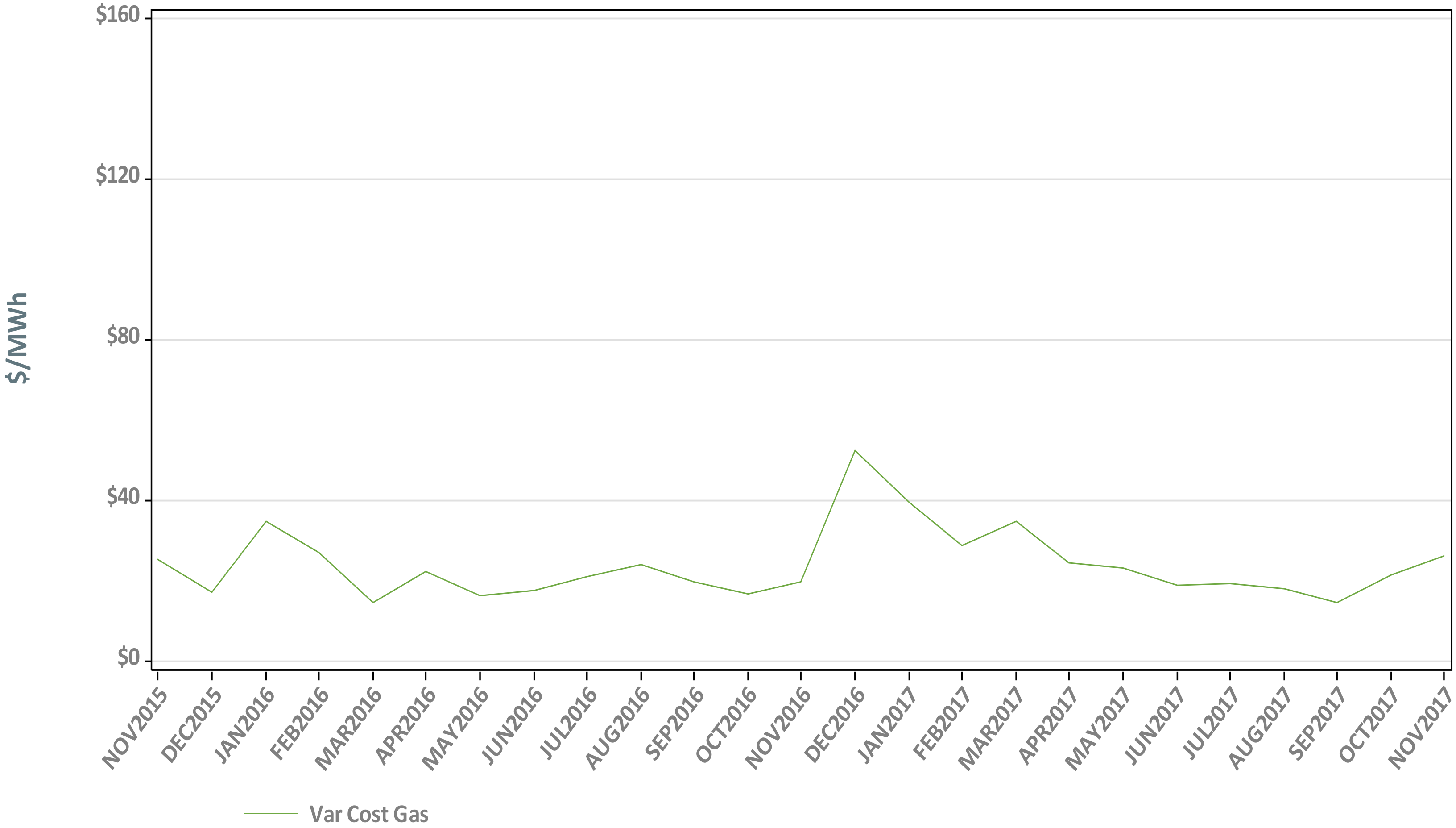
DA vs. RT Net Interchange November 2017 vs. November 2016





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

Variable Production Cost of Natural Gas: Monthly

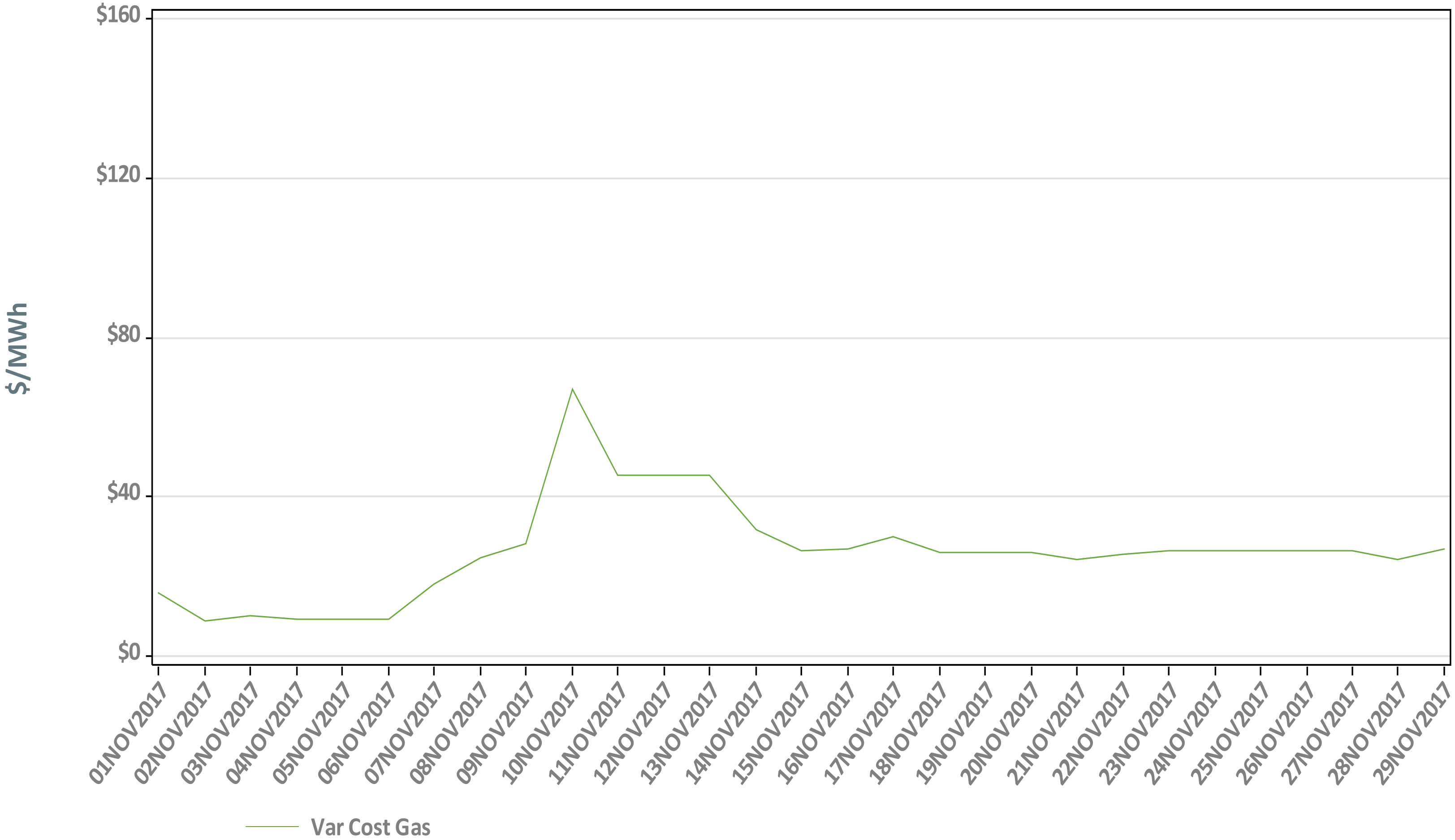


Underlying natural gas data furnished by:

ICE Global markets in clear view

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

Variable Production Cost of Natural Gas: Daily

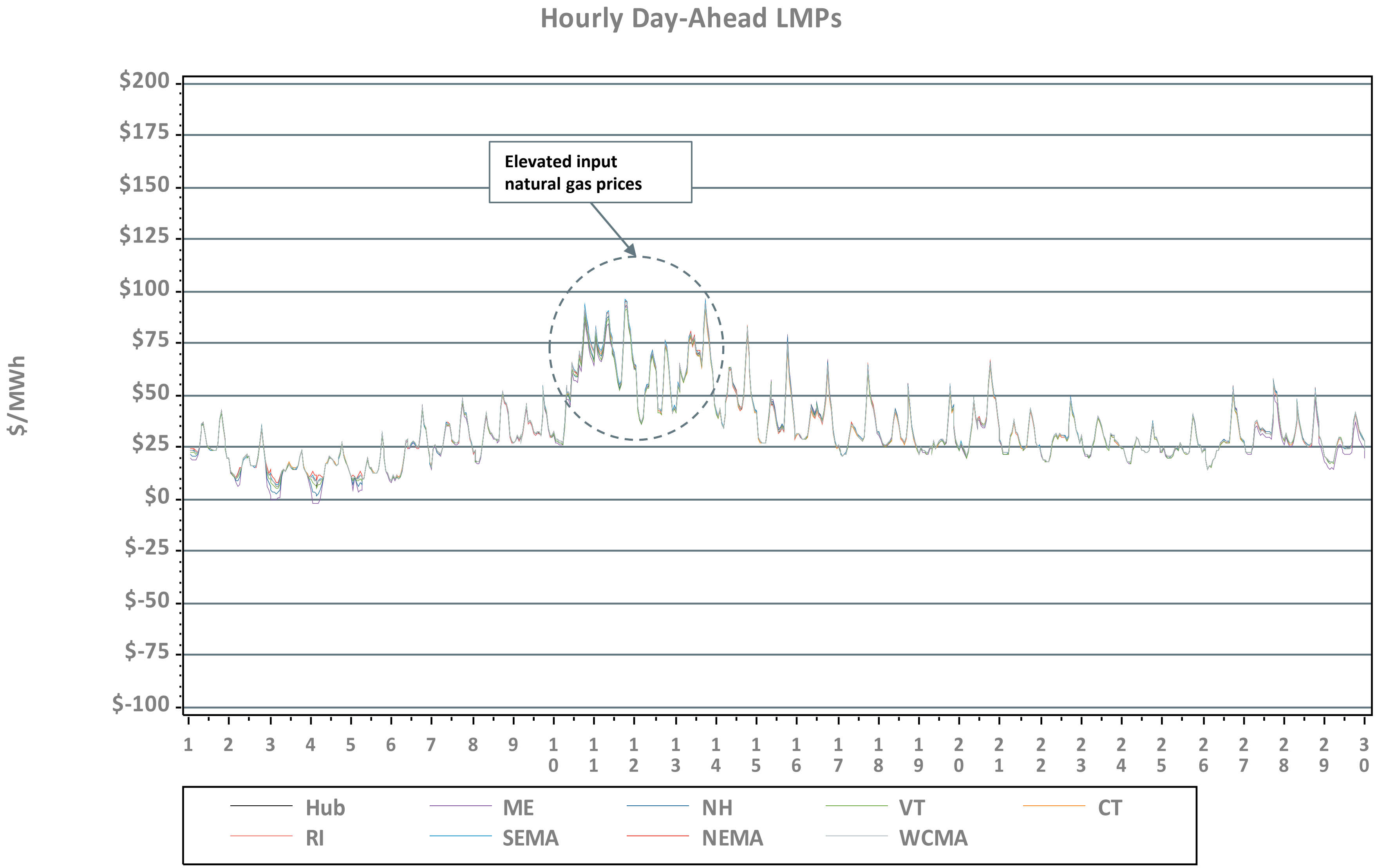


Underlying natural gas data furnished by:

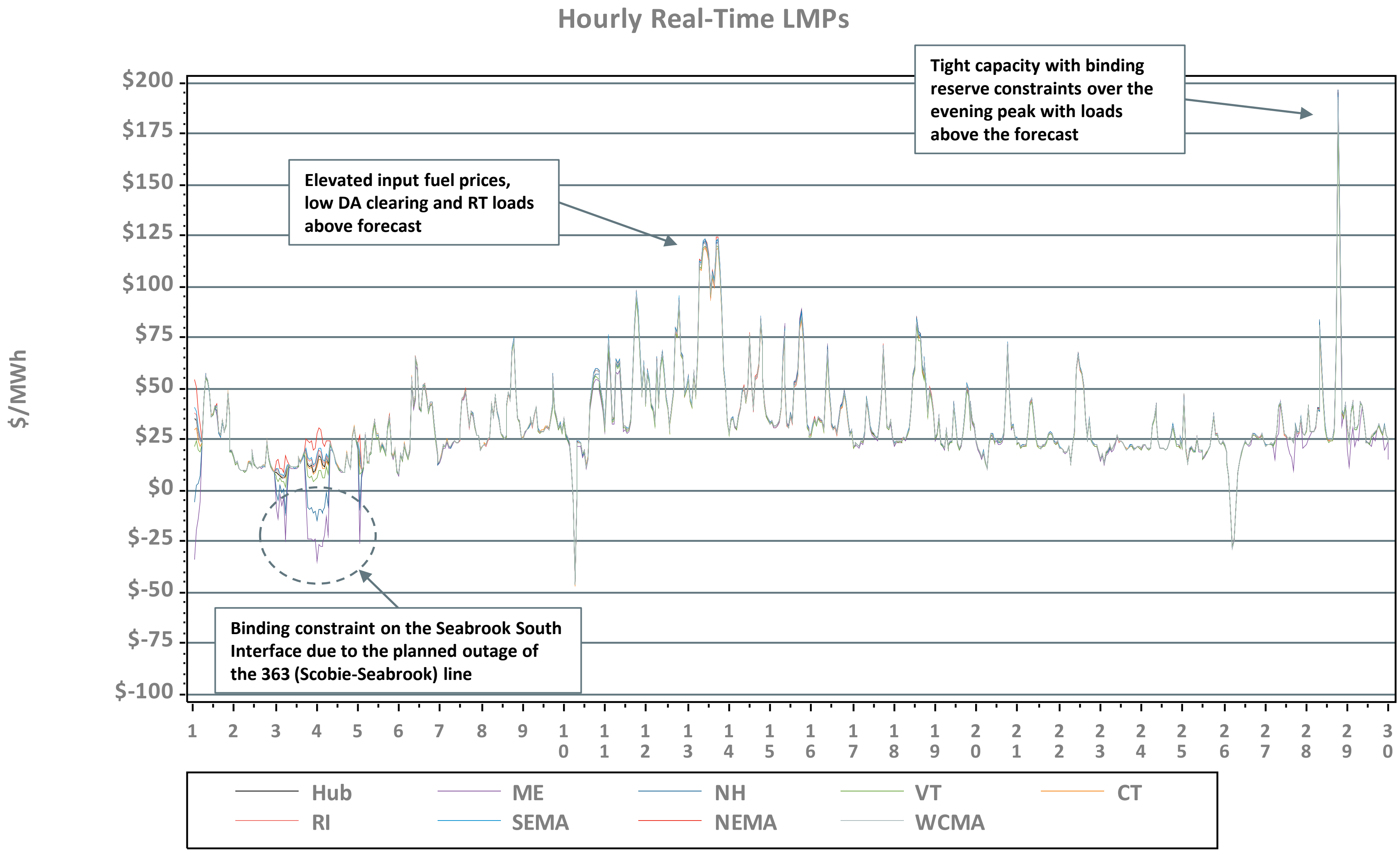
ice Global markets in clear view

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

Hourly DA LMPs, November 1-29, 2017

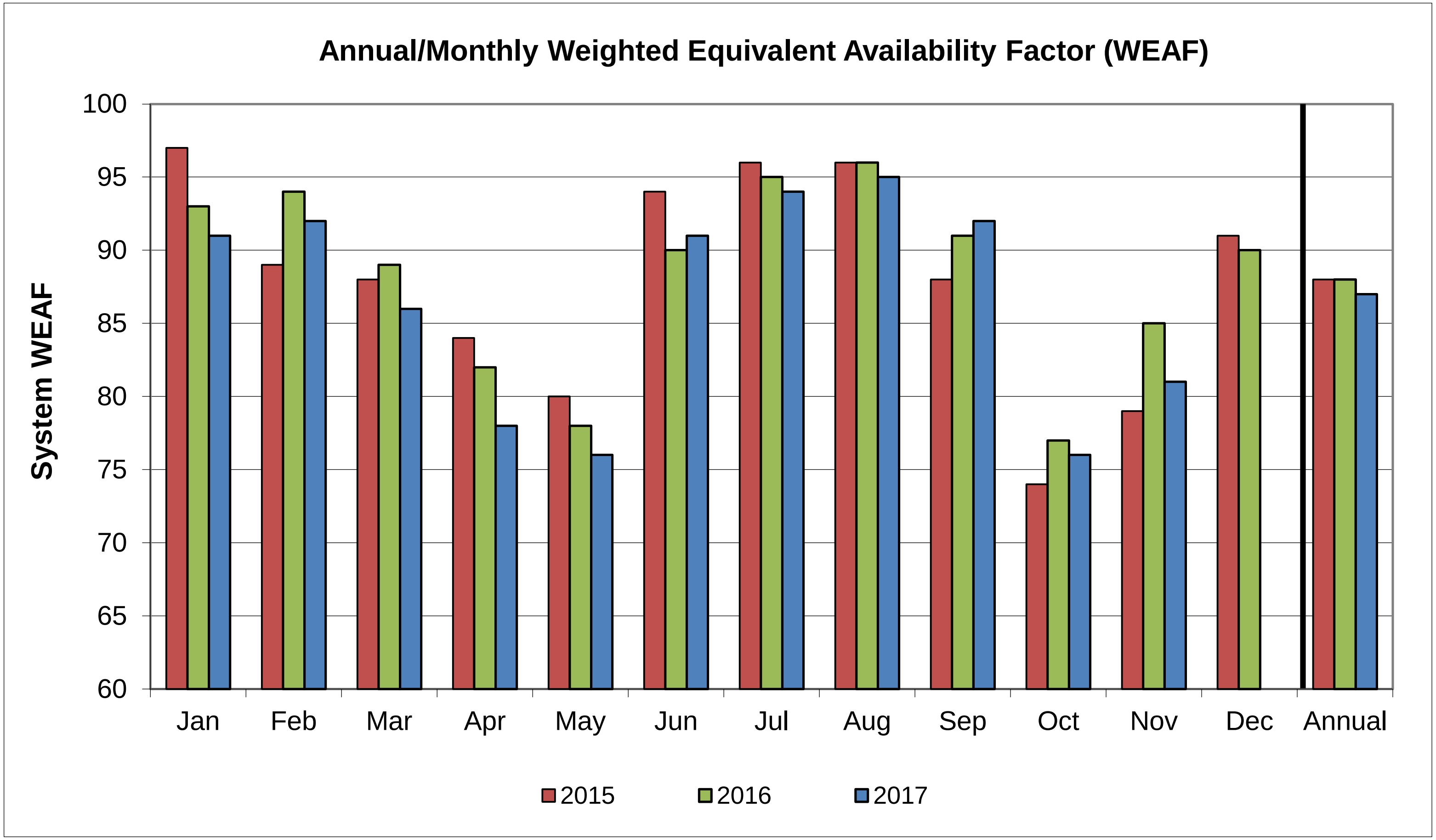


Hourly RT LMPs, November 1-29, 2017



* No Minimum Generation Emergencies were declared in November.

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2017	91	92	86	78	76	91	94	95	92	76	81		87
2016	93	94	89	82	78	90	95	96	91	77	85	90	88
2015	97	89	88	84	80	94	96	96	88	74	79	91	88

Data as of 11/30/17

BACK-UP DETAIL

LOAD RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for December 2017

Load Zone	RTDR*	RTEG**	On Peak	Seasonal Peak	Total
ME	119.5	0.0	163.0	0.0	282.5
NH	13.1	0.0	87.8	0.0	100.8
VT	27.4	0.0	133.2	0.0	160.6
CT	89.8	1.1	59.8	457.8	608.5
RI	13.8	0.0	208.0	0.0	221.8
SEMA	25.0	0.0	313.0	0.0	338.0
WCMA	39.6	0.0	288.0	49.0	376.6
NEMA	37.4	-0.2	587.3	0.0	624.4
Total	**365.5**	**0.8**	**1,840.0**	**506.8**	**2,713.3**

*** Real Time Demand Response**

**** Real Time Emergency Generation**

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

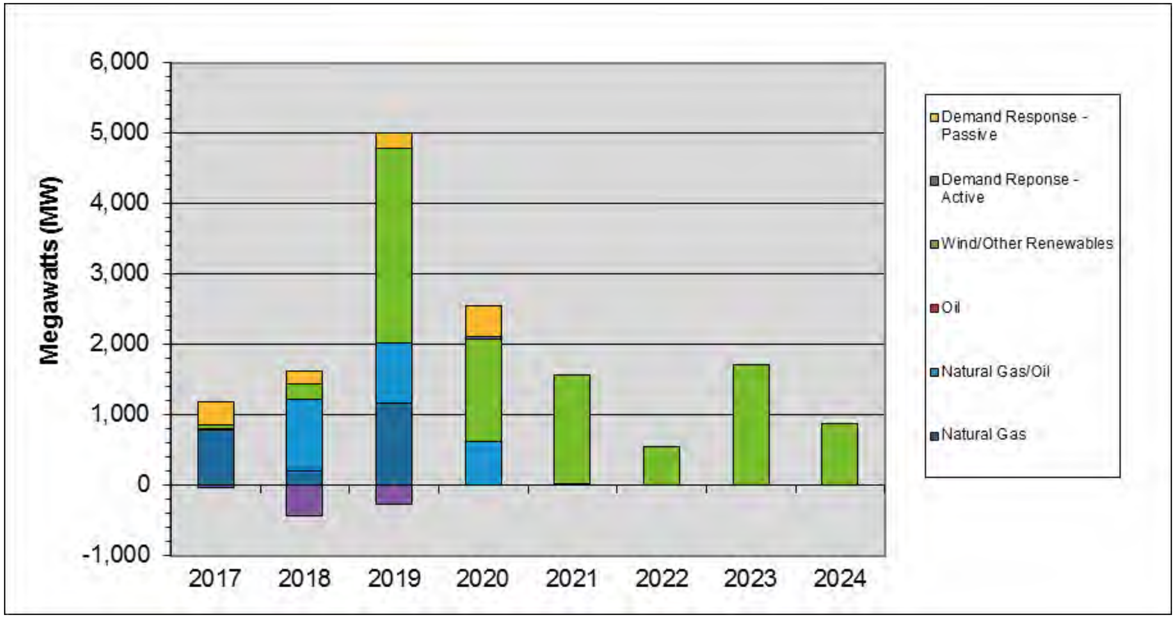
NEW GENERATION

New Generation Update
Based on Queue as of 11/30/17

- Ten new projects, with a total rating of 495 MW, have applied for interconnection study since the last update
  - 4 Battery Storage (400 MW Total) in MA COD 2022
  - 5 PV (75 MW Total) in RI COD 2019
  - 21 MW Wind in RI COD 2018
- Three withdrawals from the queue and one commercial, resulting in a net increase in new generation projects of 212 MW
- In total, 89 generation projects are currently being tracked by the ISO, totaling approximately 13,700 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



	2017	2018	2019	2020	2021	2022	2023	2024	Total MW	% of Total[1]
Demand Response - Passive	330	196	212	422	0	0	0	0	1,160	8.1
Demand Response - Active	-37	-433	-270	42	0	0	0	0	-697	-4.9
Wind & Other Renewables	47	213	2,774	1,454	1,537	550	1,718	880	9,173	64.0
Oil	0	0	0	0	0	0	0	0	0	0.0
Natural Gas/Oil[2]	14	1,009	844	625	23	0	0	0	2,515	17.6
Natural Gas	790	210	1,175	0	0	0	0	0	2,175	15.2
Totals	**1,144**	**1,195**	**4,736**	**2,544**	**1,560**	**550**	**1,718**	**880**	**14,326**	**100.0**

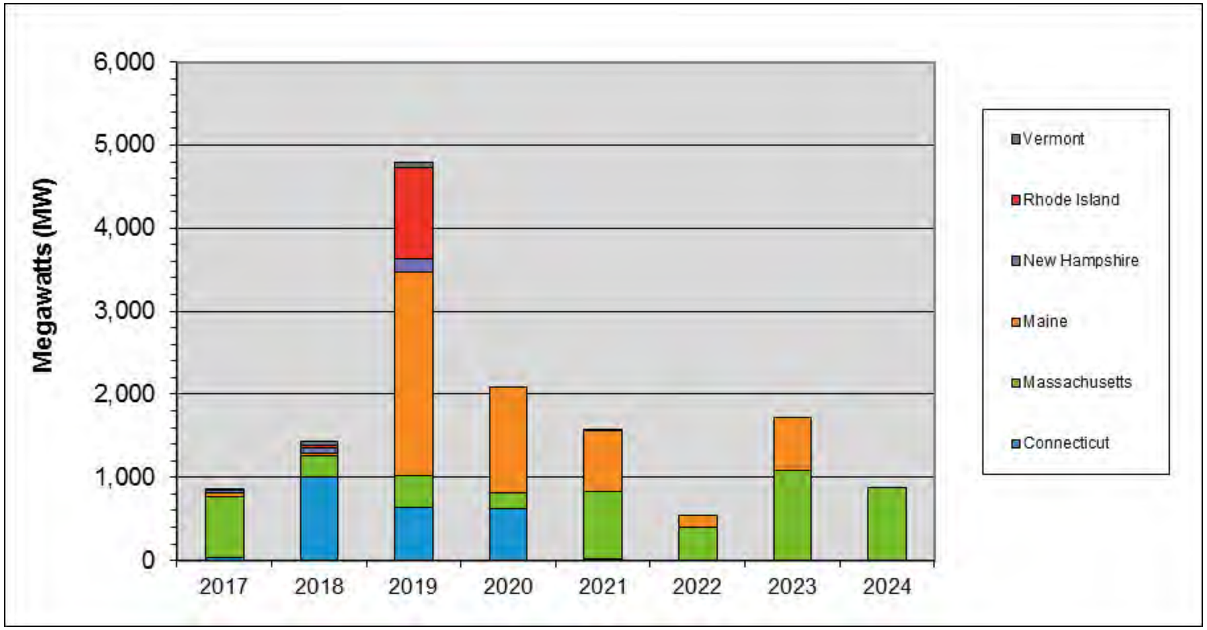
[1] Sum may not equal 100% due to rounding

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

- 2017 values include the 129 MW of generation that has gone commercial in 2017
- DR reflects changes from the initial FCM Capacity Supply Obligations in 2010-11

Actual and Projected Annual Generator Capacity Additions

By State



	2017	2018	2019	2020	2021	2022	2023	2024	Total MW	% of Total[1]
Vermont	2	50	60	0	0	0	0	0	112	0.8
Rhode Island	0	21	1,104	0	0	0	0	0	1,125	8.1
New Hampshire	41	65	158	0	5	0	0	0	269	1.9
Maine	39	33	2,457	1,268	732	150	630	0	5,309	38.3
Massachusetts	736	263	382	185	800	400	1,088	880	4,734	34.1
Connecticut	33	1,000	632	626	23	0	0	0	2,314	16.7
Totals	**851**	**1,432**	**4,793**	**2,079**	**1,560**	**550**	**1,718**	**880**	**13,863**	**100.0**

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

- 2017 values reflect the 129 MW of generation that has gone commercial in 2017

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	9	2,164	2	816	7	1,348
Natural Gas/Oil	8	2,501	2	1,009	6	1,492
Oil	0	0	0	0	0	0
Solar	29	1,142	0	0	29	1,142
Wind	33	7,314	0	0	33	7,314
Battery Storage	6	477	0	0	6	477
Total	89	13,734	4	1,825	85	11,909

- 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	2,513	2	308	40	2,205
Wind Turbine	33	7,314	0	0	33	7,314
Total	89	13,734	4	1,825	85	11,909

- 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	9	2,164	1	63	6	1,899	2	202	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	29	1,142	0	0	0	0	29	1,142	0	0
Wind	33	7,314	0	0	0	0	0	0	33	7,314
Battery Storage	6	477	0	0	0	0	6	477	0	0
Total	89	13,734	3	105	11	3,802	42	2,513	33	7,314

- 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 Month 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				
	Passive Demand	2,156.151	2,153.94	-2.211	2,150.196	-3.744	2,150.196	0	2,389.958	239.762				
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				
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				
	Intermittent	891.616	864.924	-26.692	872.425	7.501	853.414	-19.011	870.558	17.144				
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				
Import Total		**1,449**	**1,449**	**0**	**1,449**	**0**	**1,449**	**0**	**1,449**	0				
***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				
Net ICR (NICR)		**34,189**	**33,883**	**-306**	**33,883**	**0**	**33,421**	**-462**	**33,421**	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 Month 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.

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 Month 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.

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 Month 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.

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

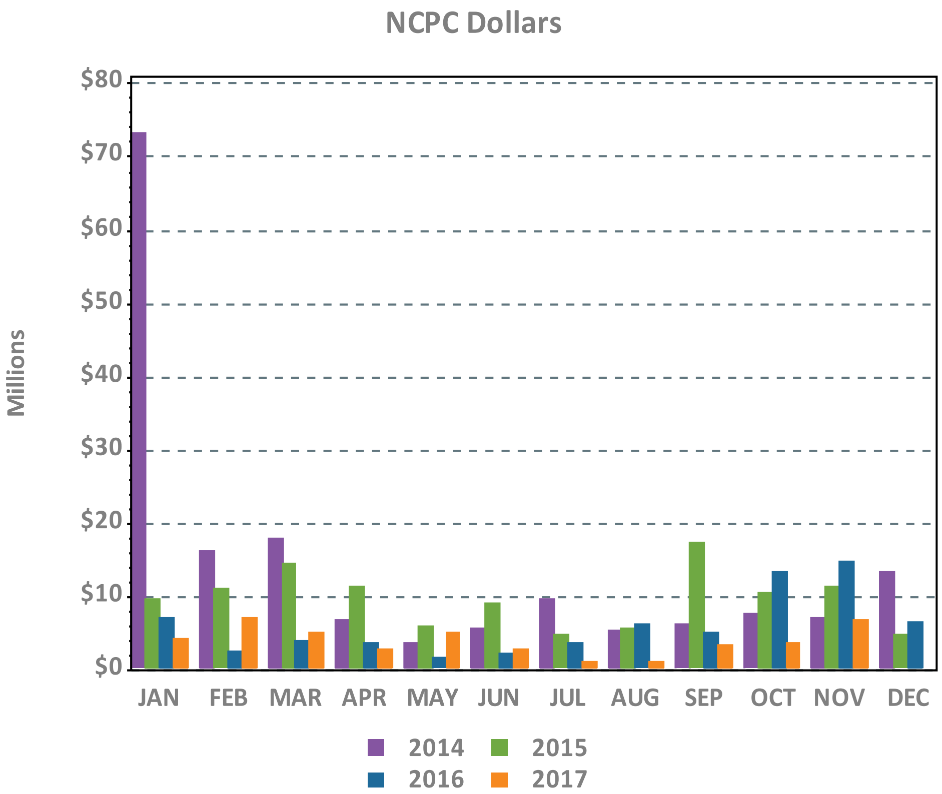
Definitions

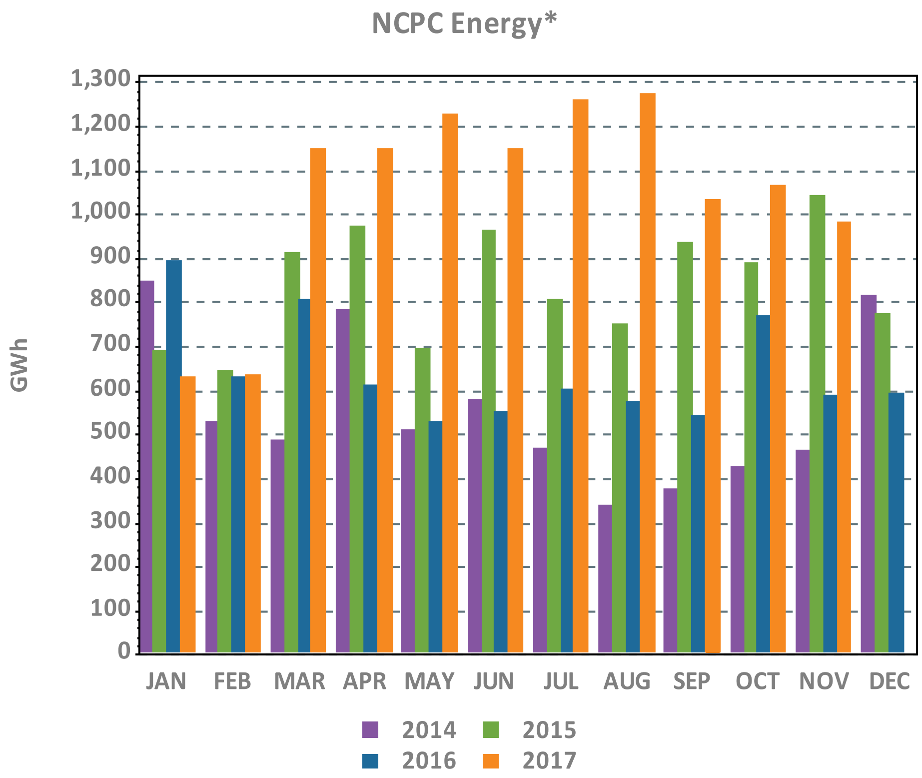
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing 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).

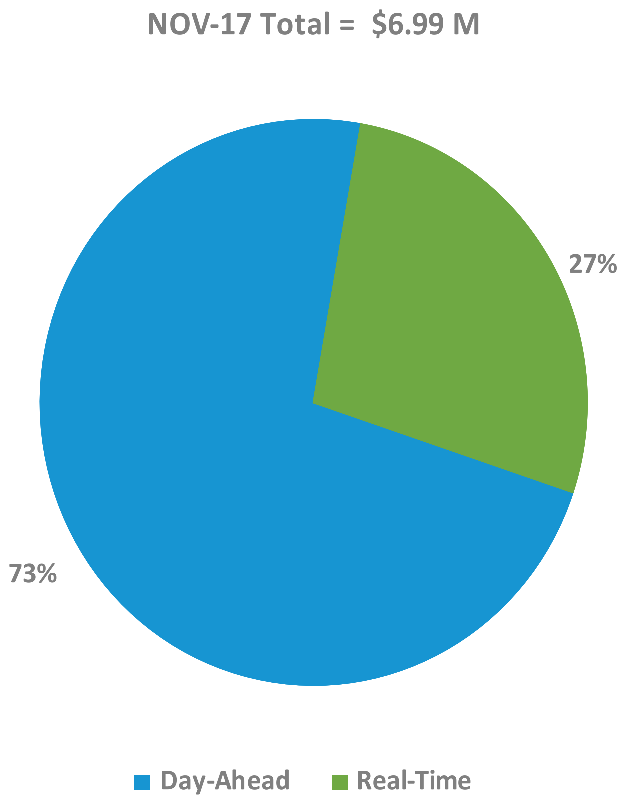
Year-Over-Year Total NCPC Dollars and Energy

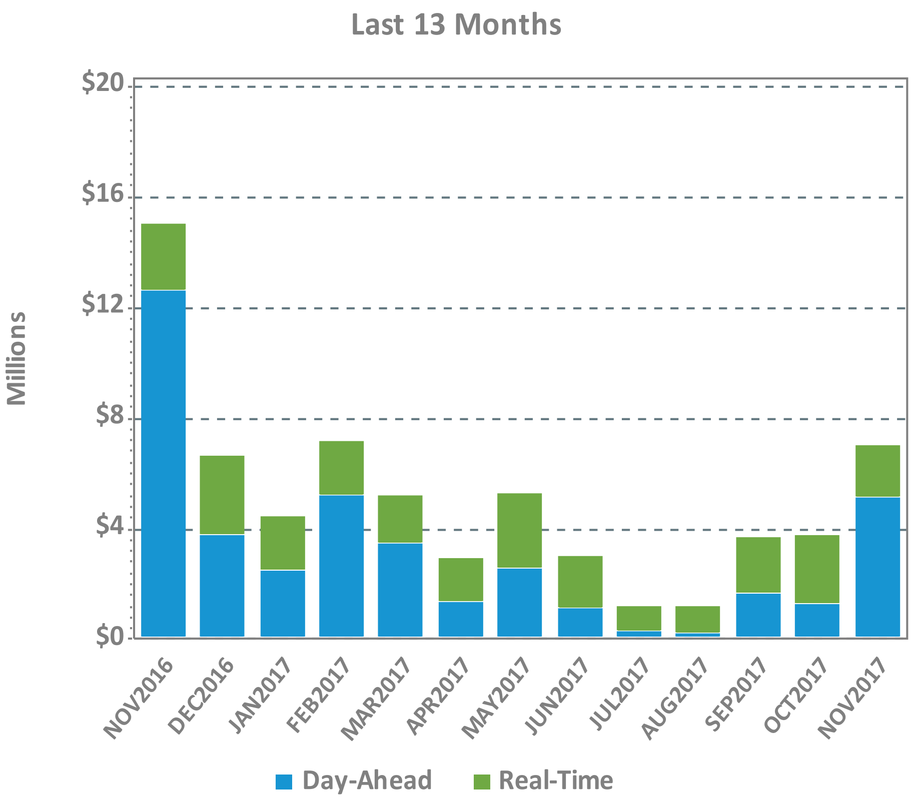




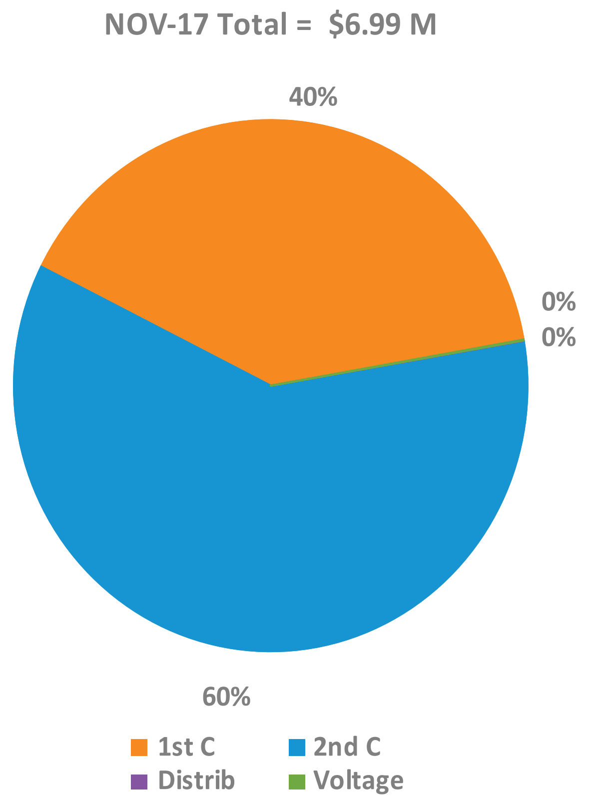
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

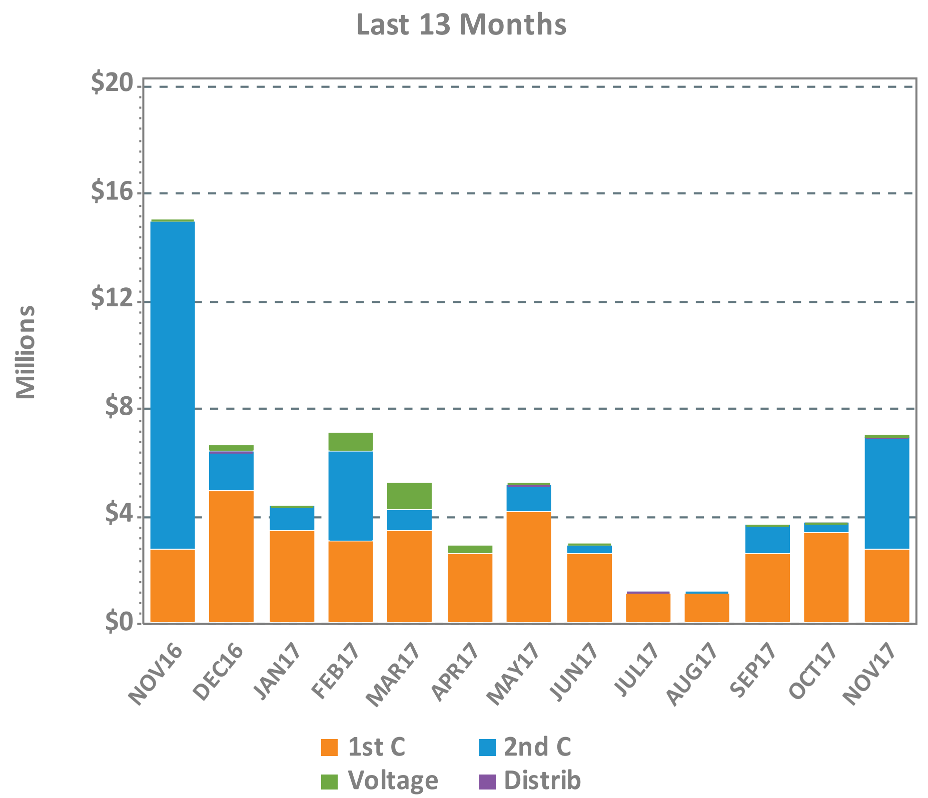
DA and RT NCPC Charges





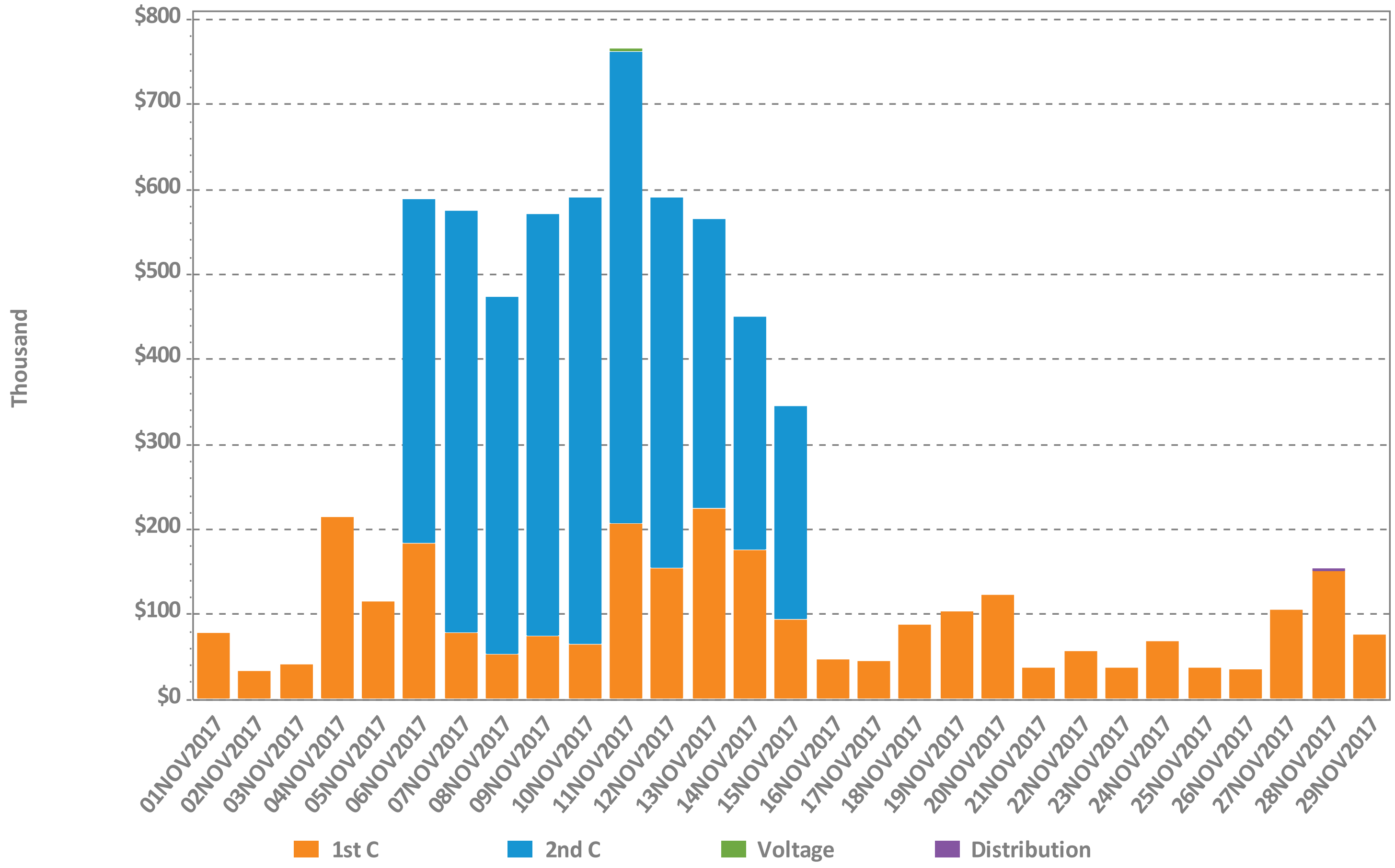
NCPC Charges by Type



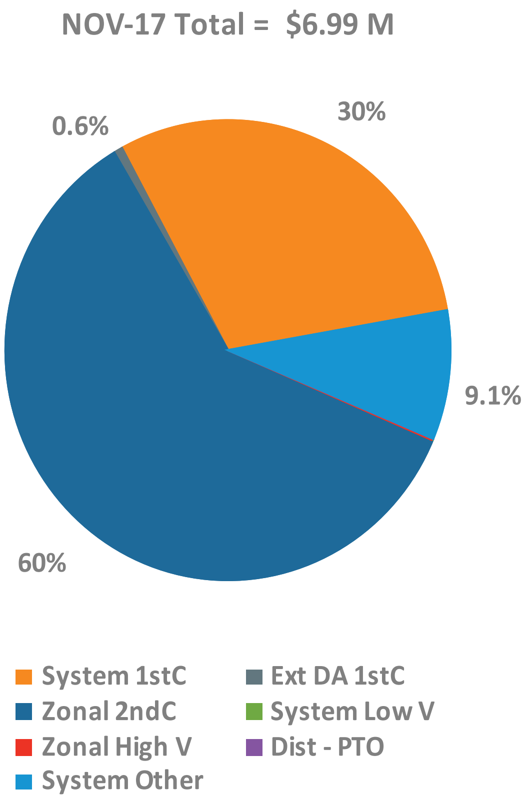


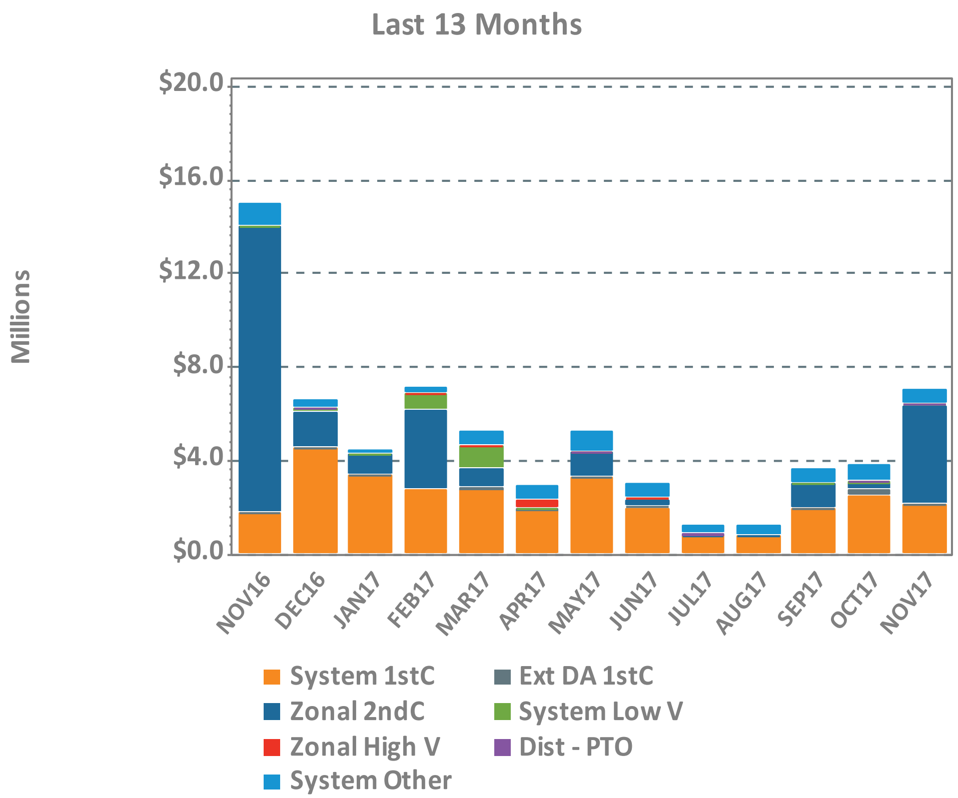
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



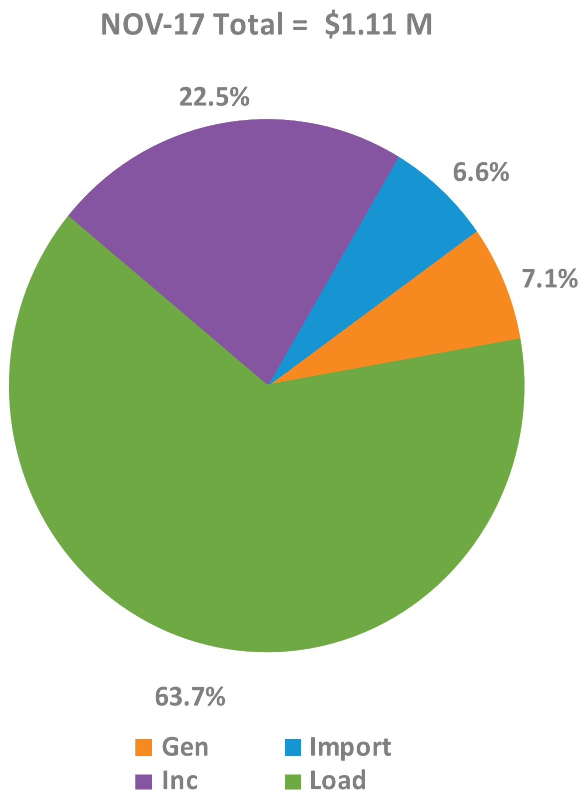
NCPC Charges by Allocation

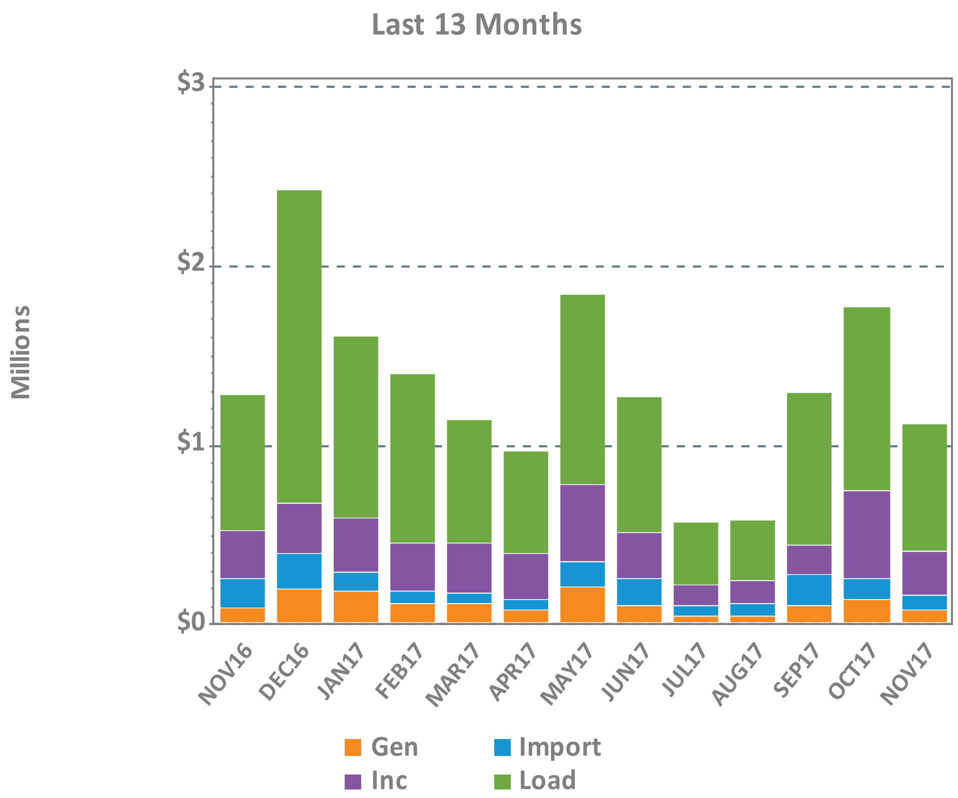




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

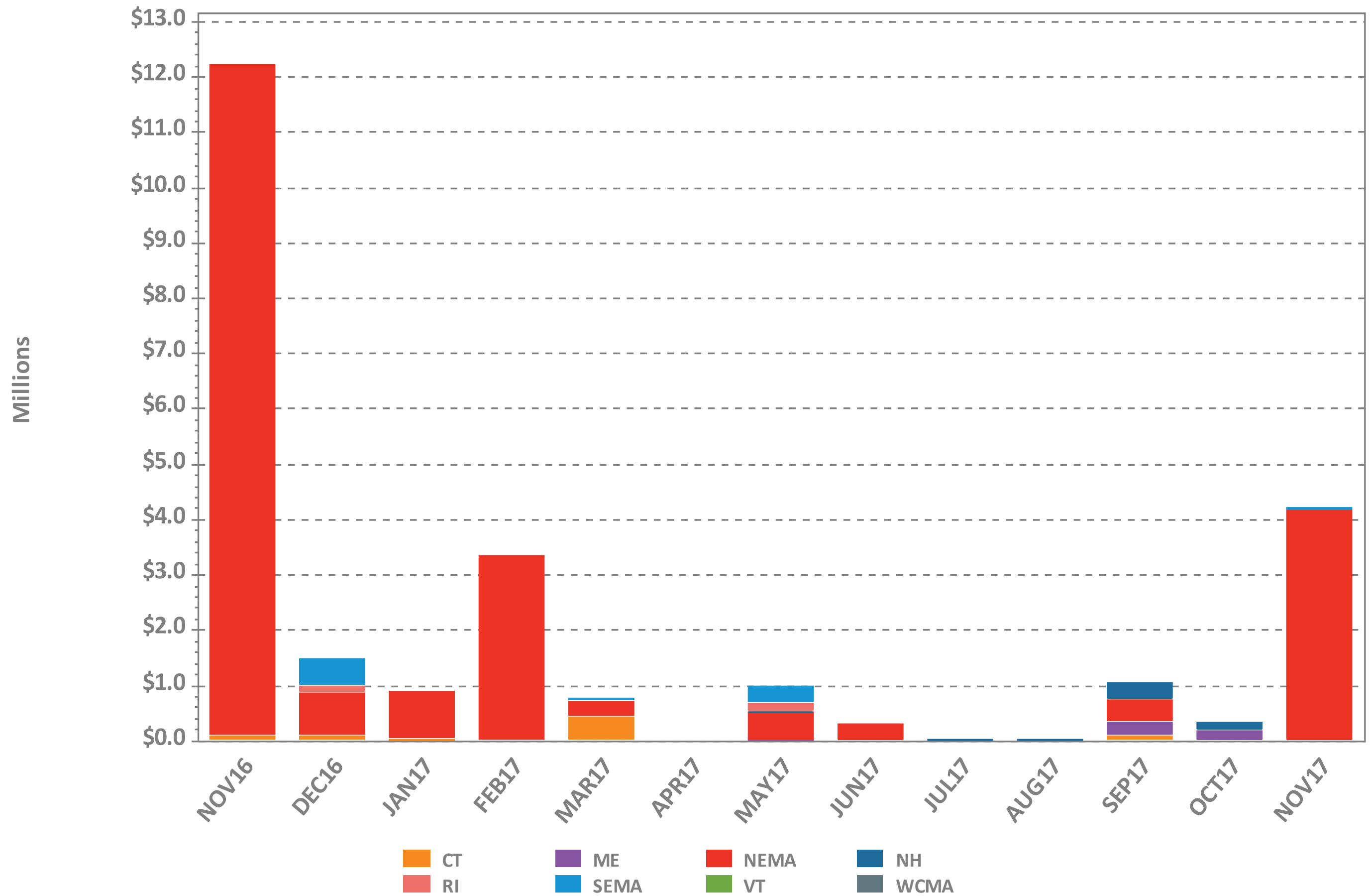
RT First Contingency Charges by Deviation Type





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

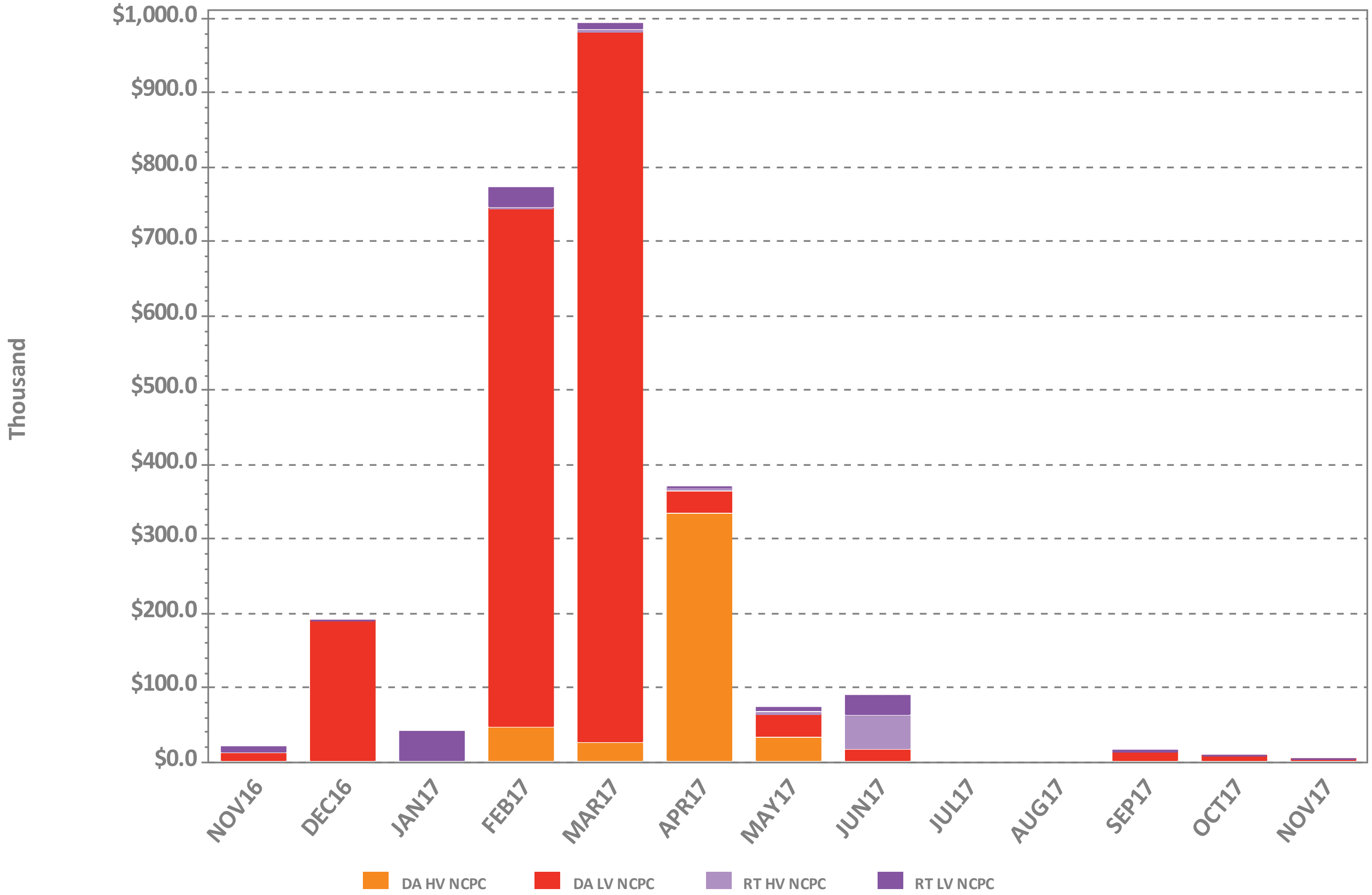
LSCPR Charges by Reliability Region



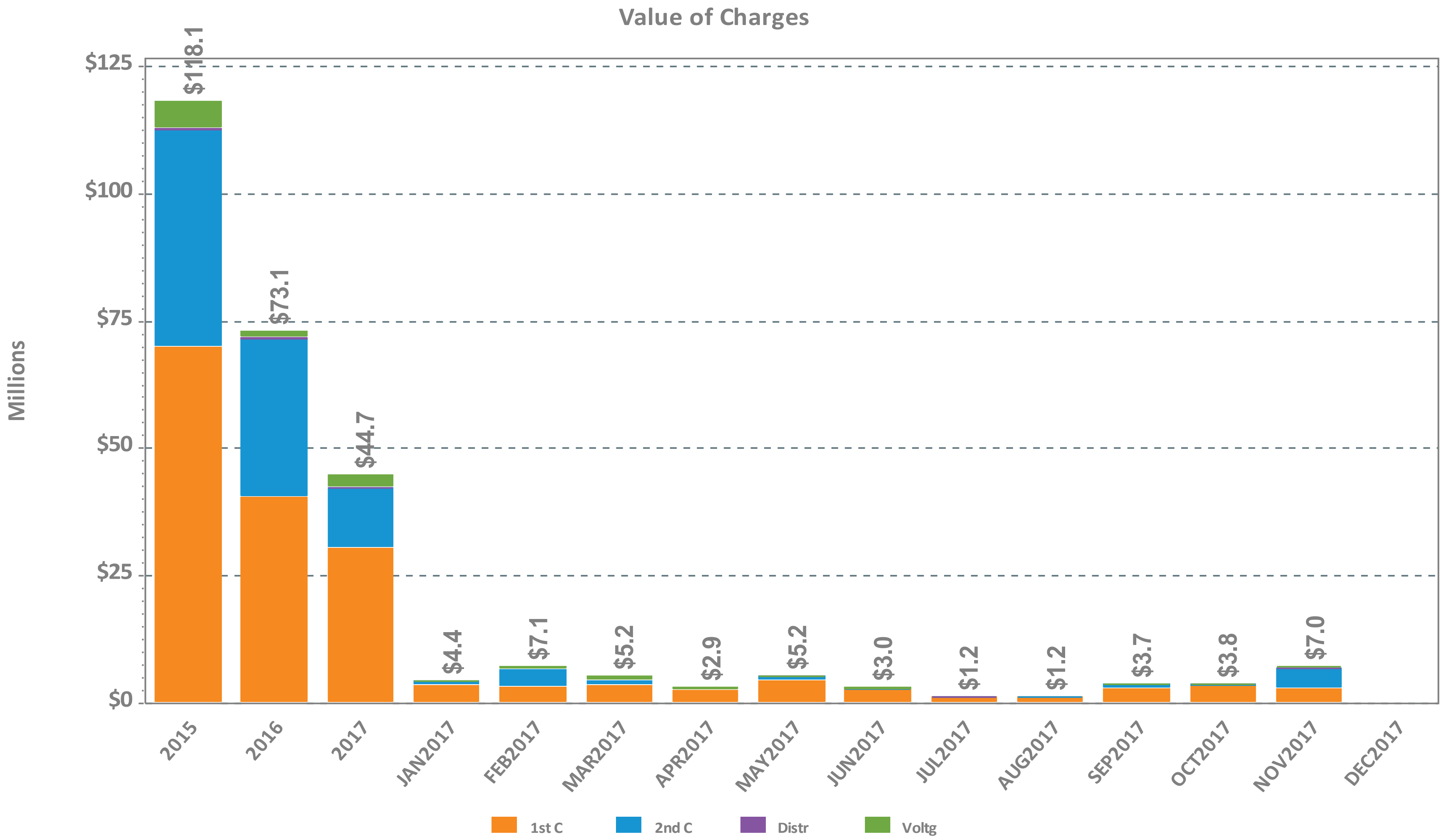
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

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

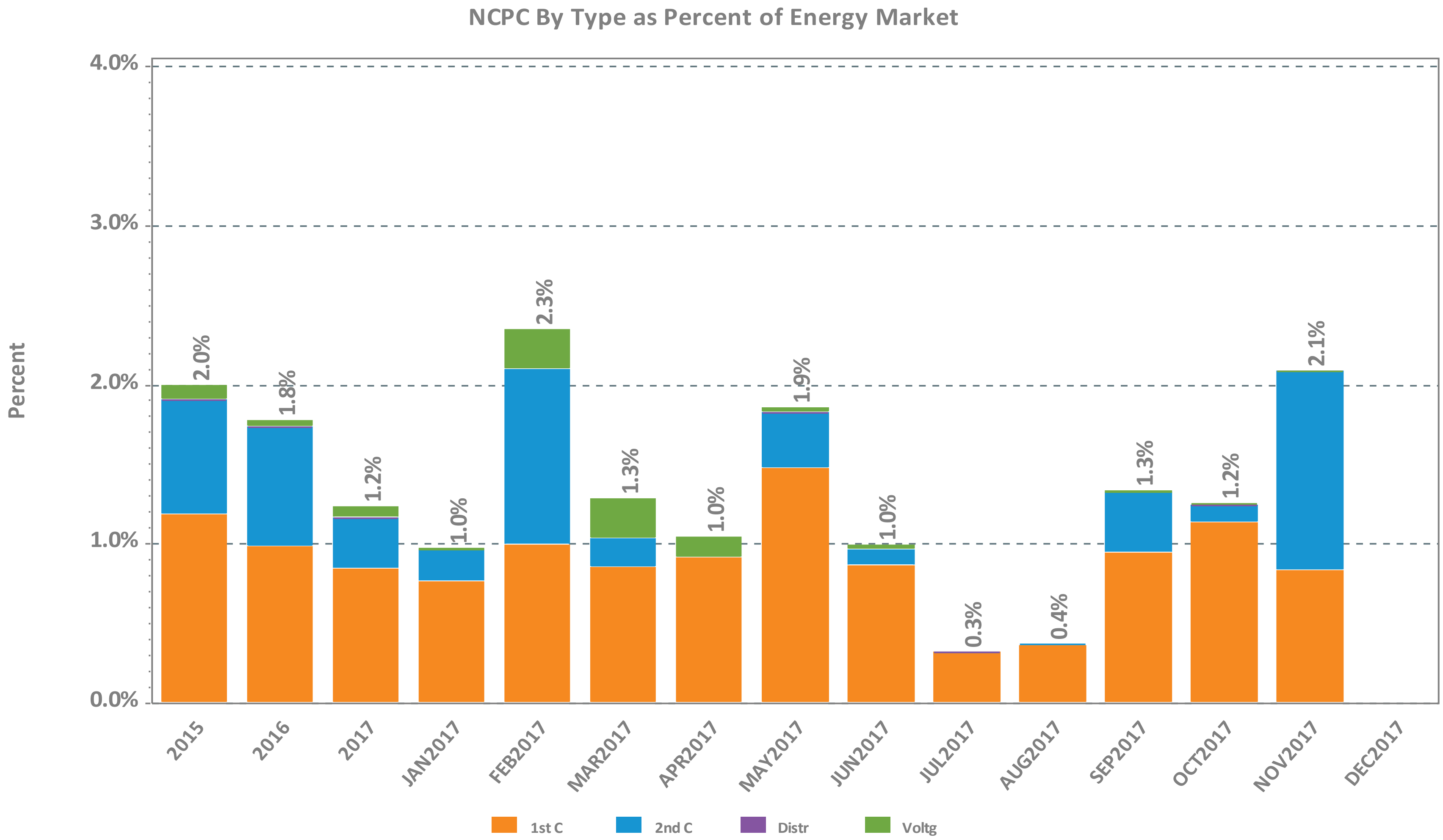
NCPC Charges for Voltage Support and High Voltage Control



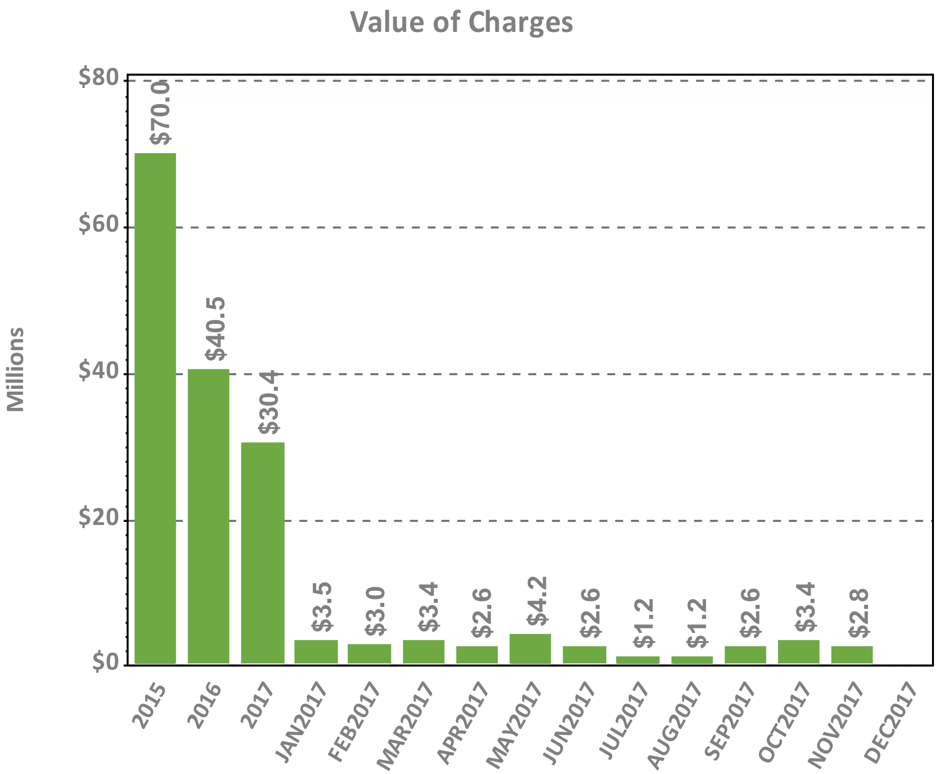
NCPC Charges by Type

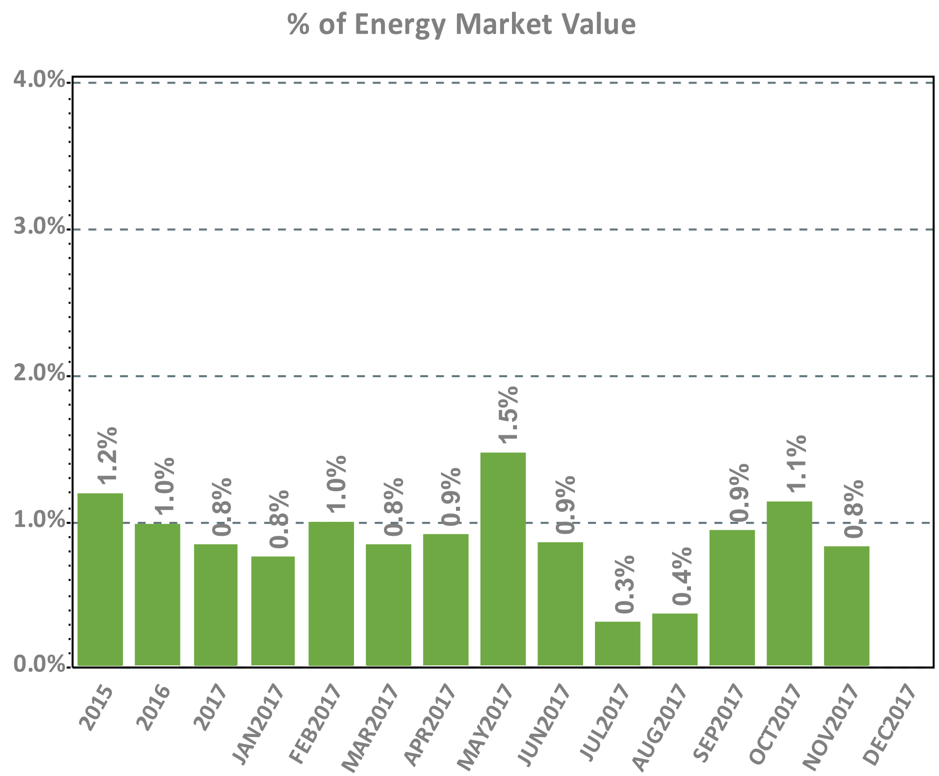


NCPC Charges as Percent of Energy Market



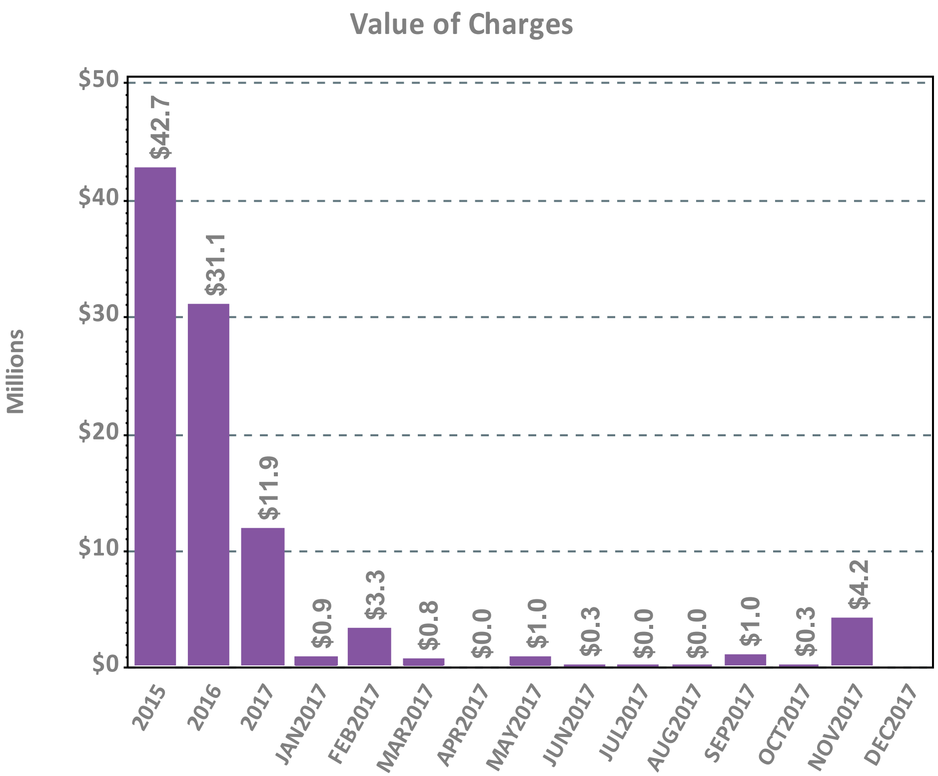
First Contingency NCPC Charges

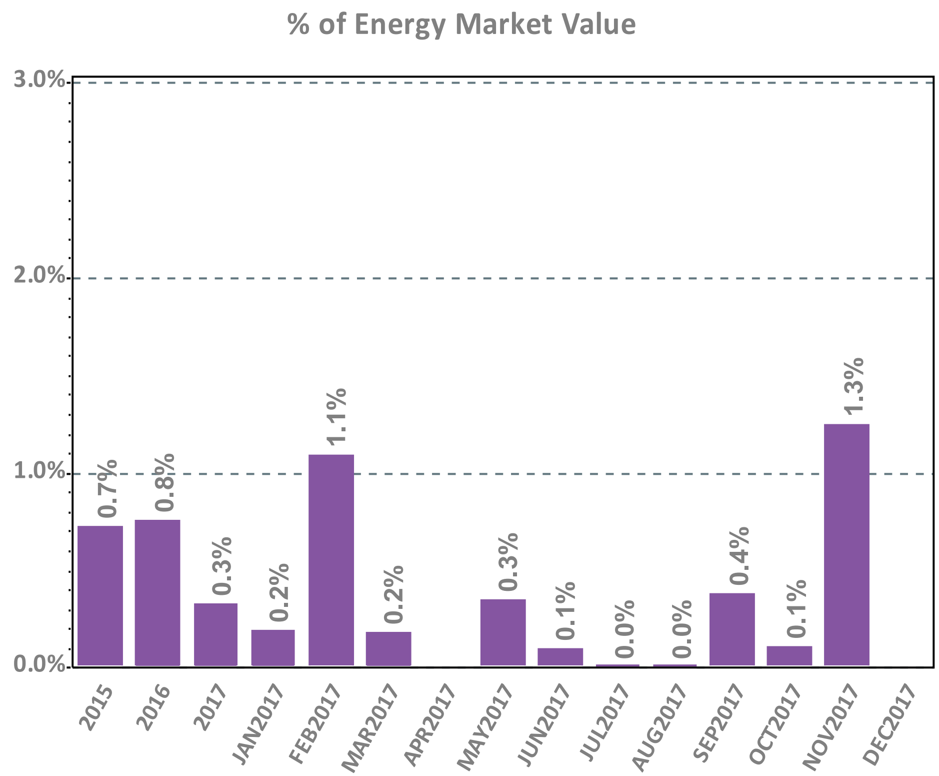




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

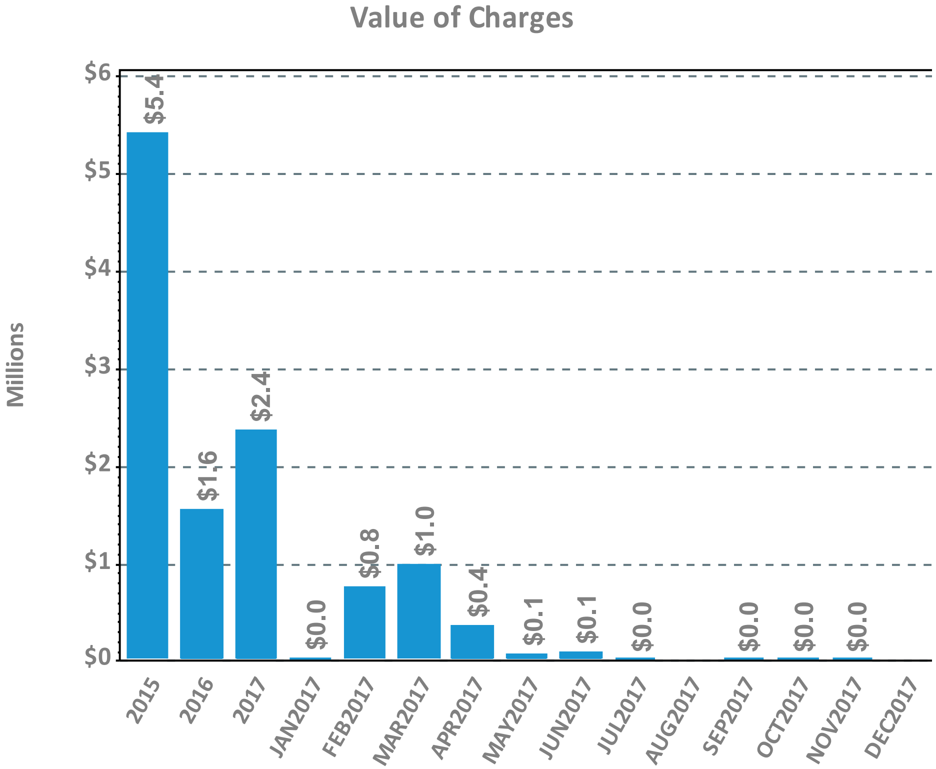
Second Contingency NCPC Charges

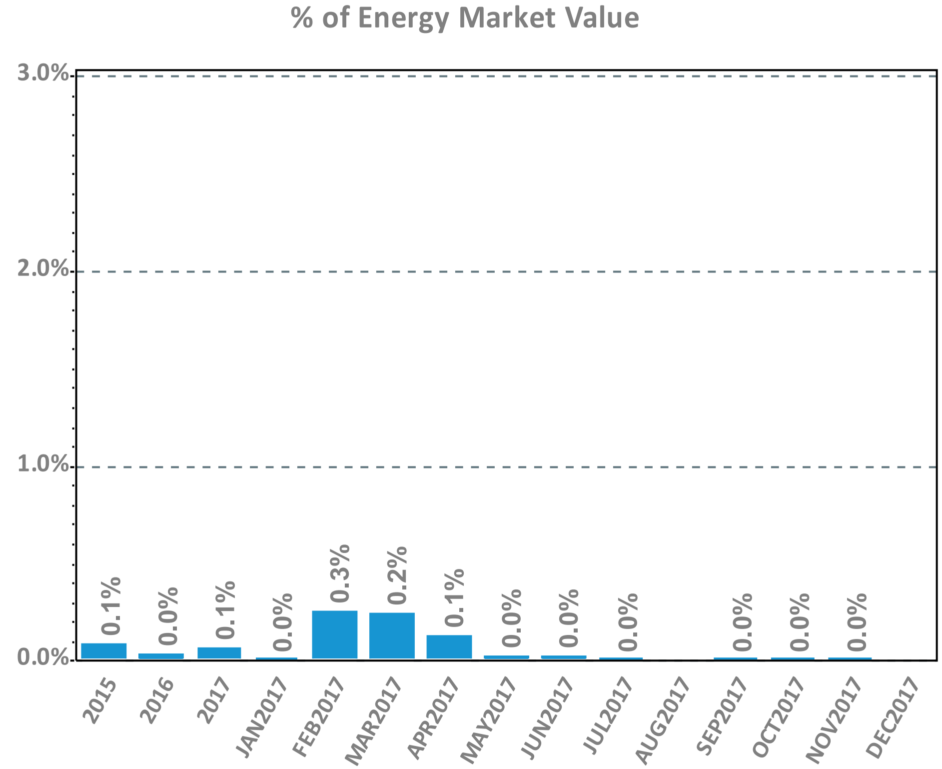




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

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

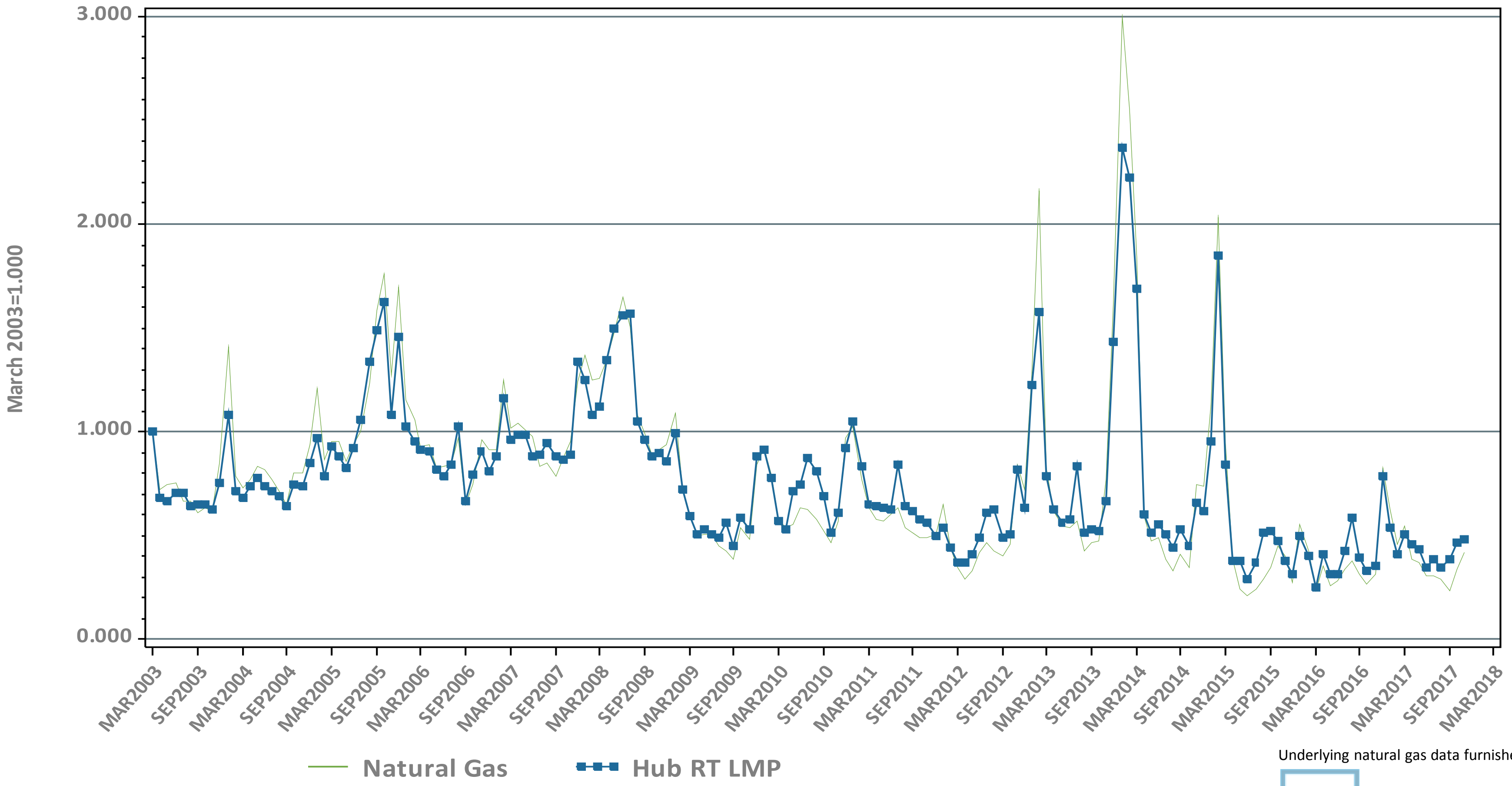
DA vs. RT LMPs ($/MWh)

Arithmetic Average

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

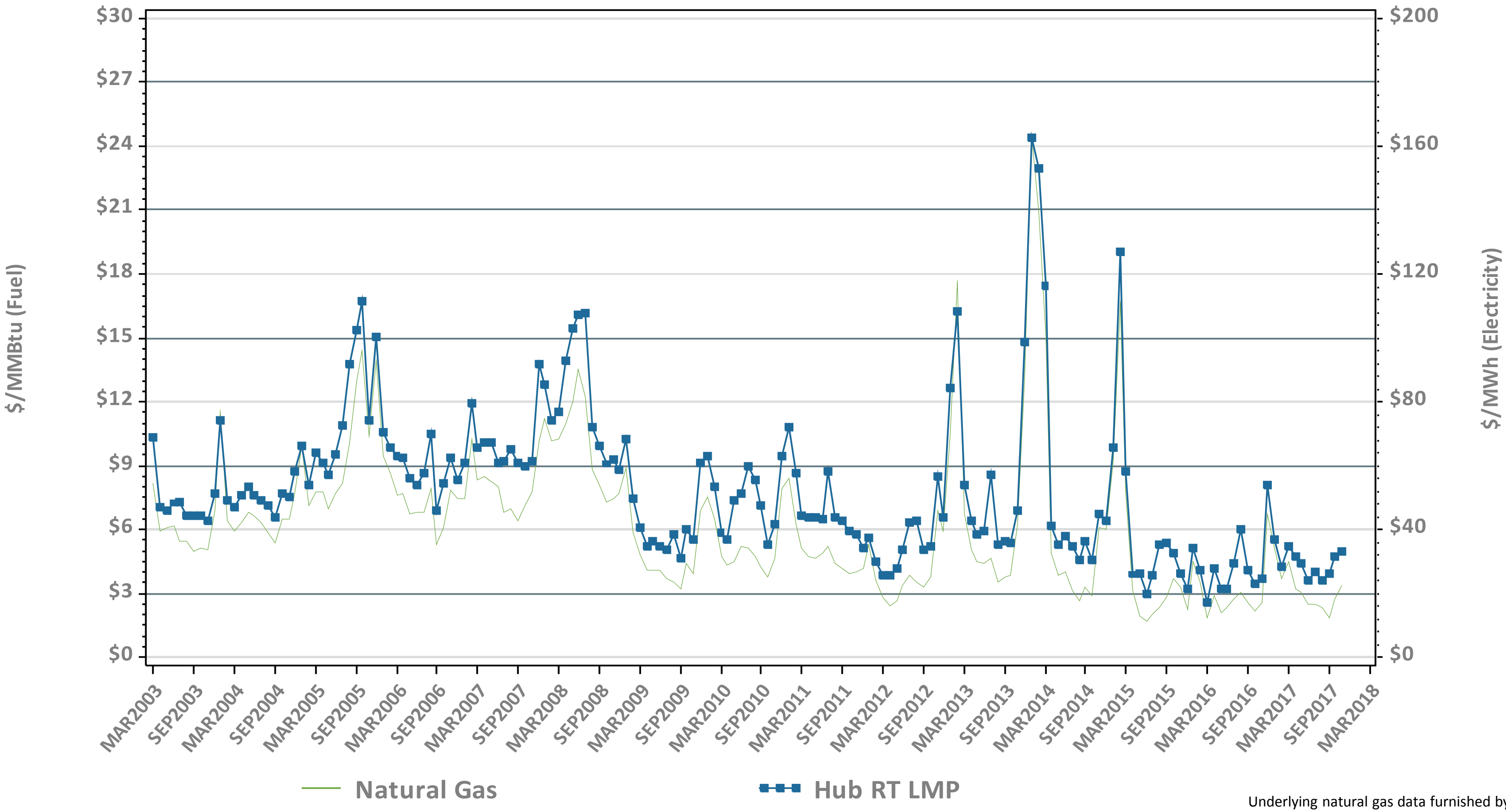
November-16	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$25.99	$24.83	$24.64	$24.90	$24.52	$24.87	$24.96	$25.04	$25.00
Real-Time	$24.74	$24.14	$23.64	$24.07	$23.58	$24.24	$24.36	$24.30	$24.31
RT Delta %	-4.8%	-2.8%	-4.1%	-3.3%	-3.8%	-2.5%	-2.4%	-3.0%	-2.7%
November-17	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$34.23	$33.56	$33.01	$33.79	$33.55	$33.68	$34.10	$34.01	$33.98
Real-Time	$33.90	$33.00	$31.03	$32.58	$32.45	$33.11	$33.53	$33.33	$33.30
RT Delta %	-1.0%	-1.7%	-6.0%	-3.6%	-3.3%	-1.7%	-1.7%	-2.0%	-2.0%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	31.7%	35.2%	34.0%	35.7%	36.8%	35.4%	36.6%	35.8%	35.9%
Yr over Yr RT	37.0%	36.7%	31.3%	35.4%	37.6%	36.6%	37.6%	37.2%	36.9%

Monthly Average Fuel Price and RT Hub LMP Indexes



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

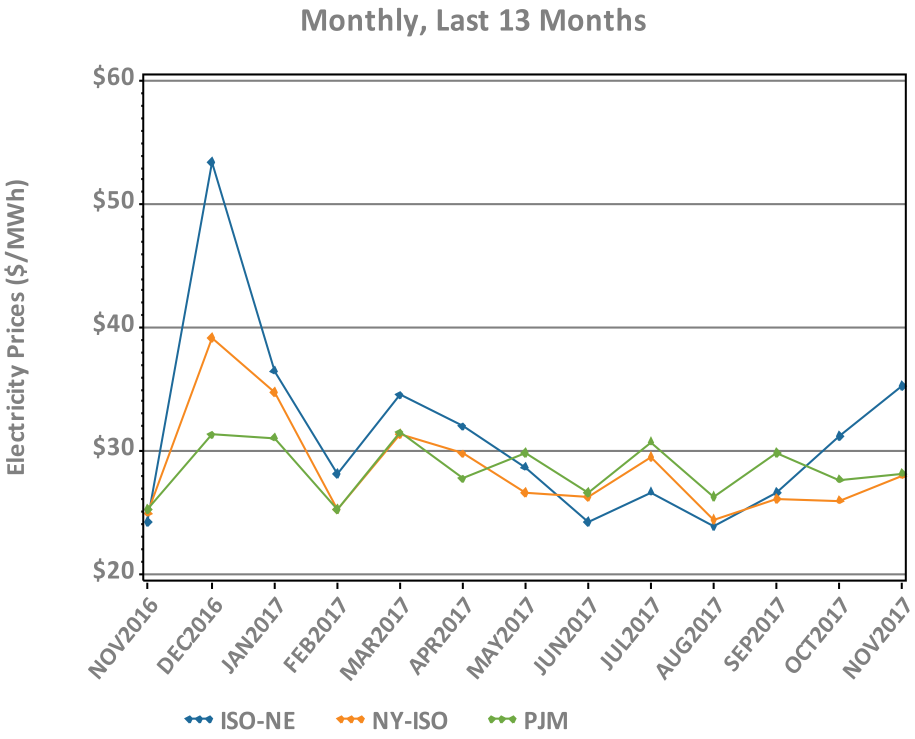
Monthly Average Fuel Price and RT Hub LMP



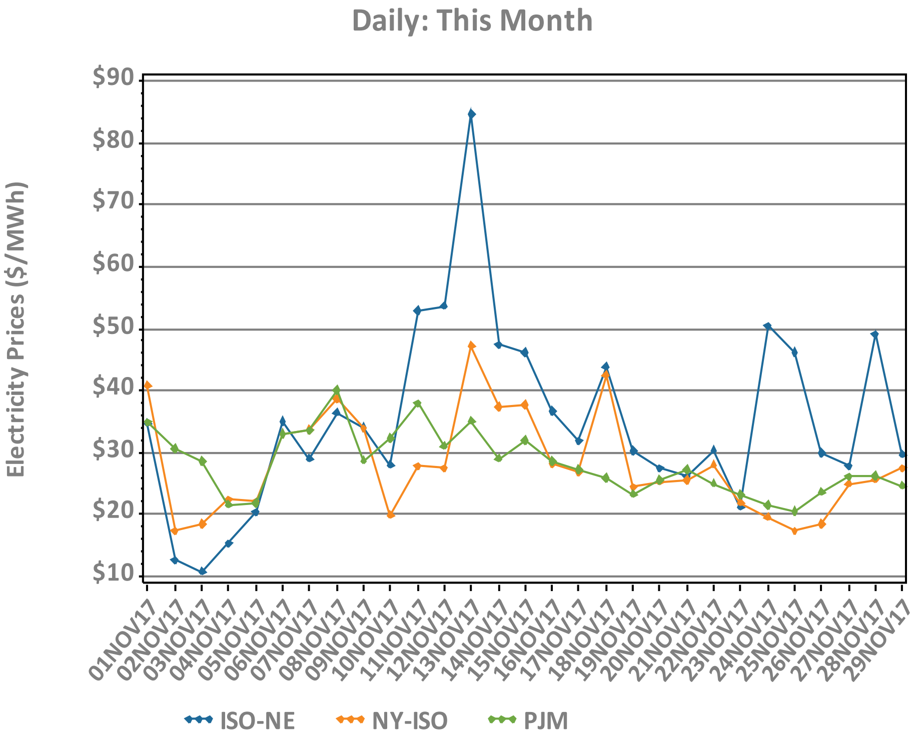
Underlying natural gas data furnished by:

ice Global markets in clear view

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

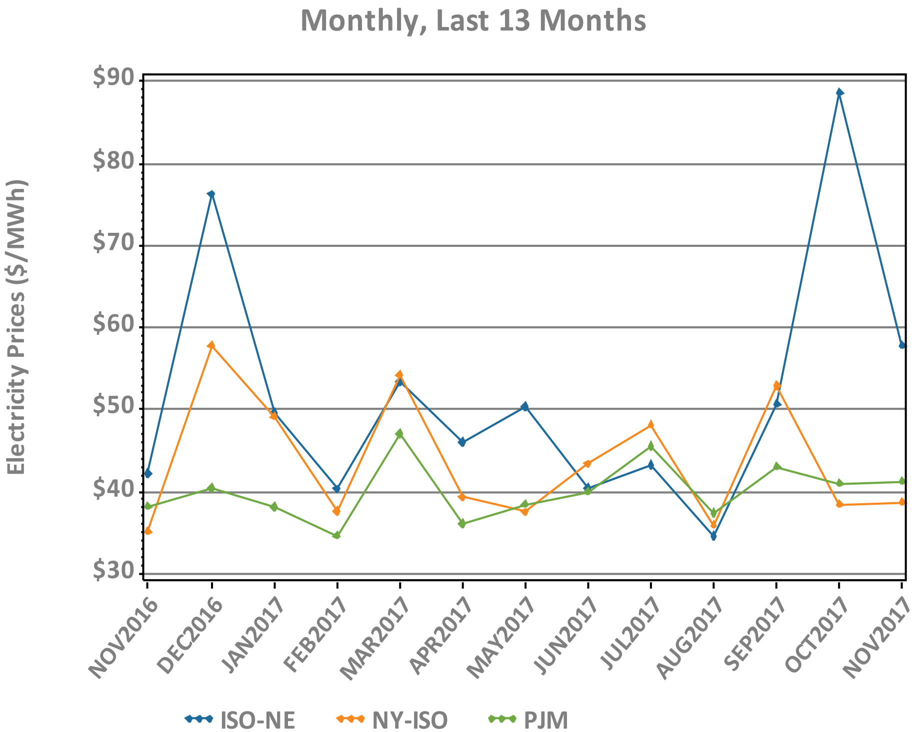


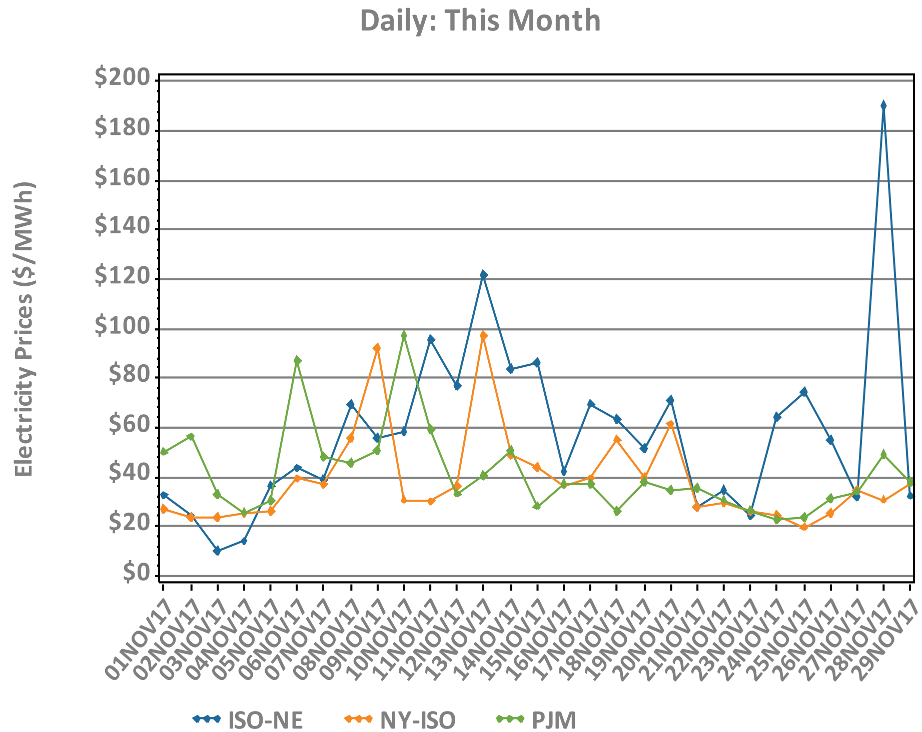
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





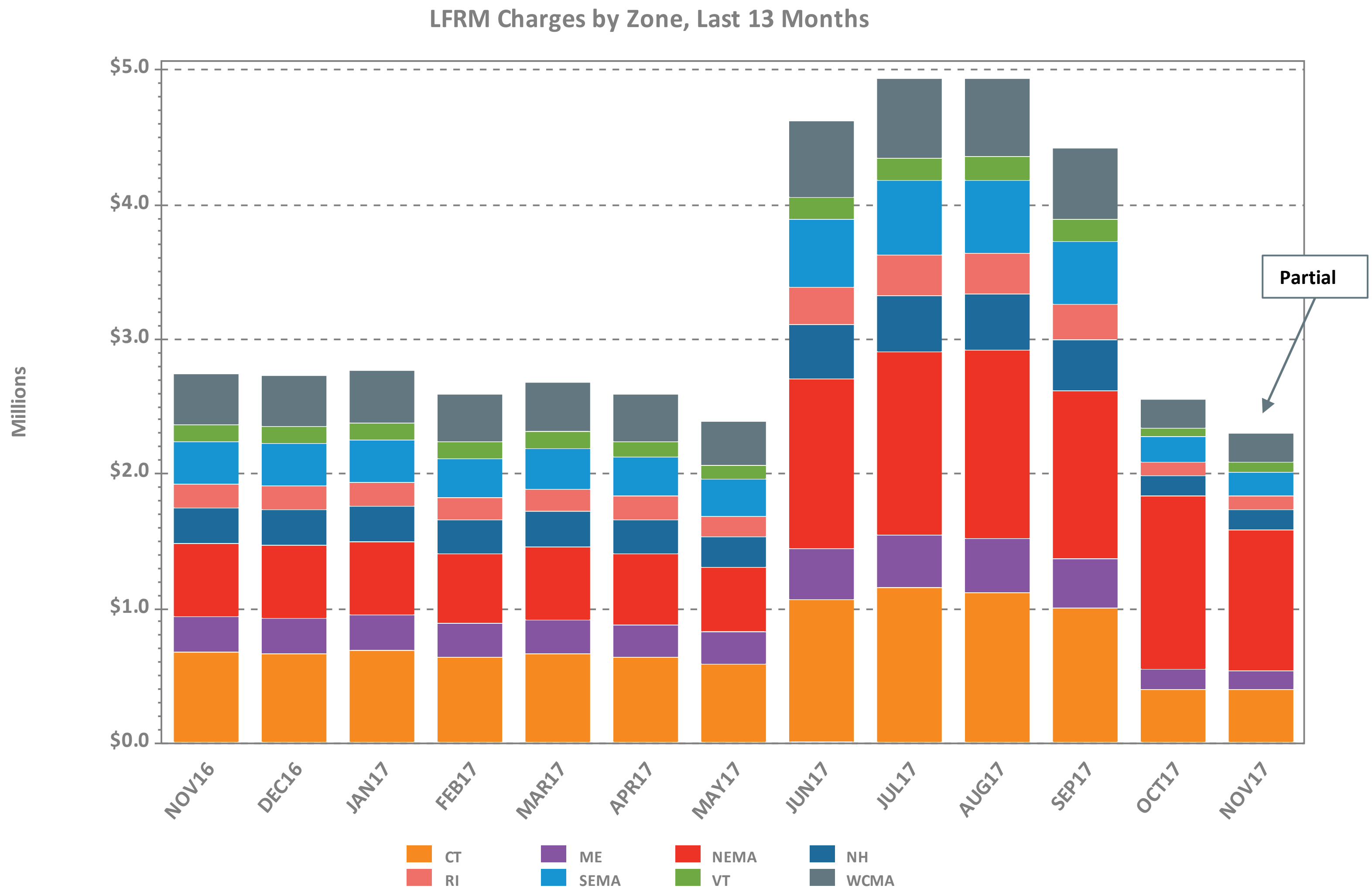
***Forecasted New England daily peak hours reflected**

Reserve Market Results – November 2017

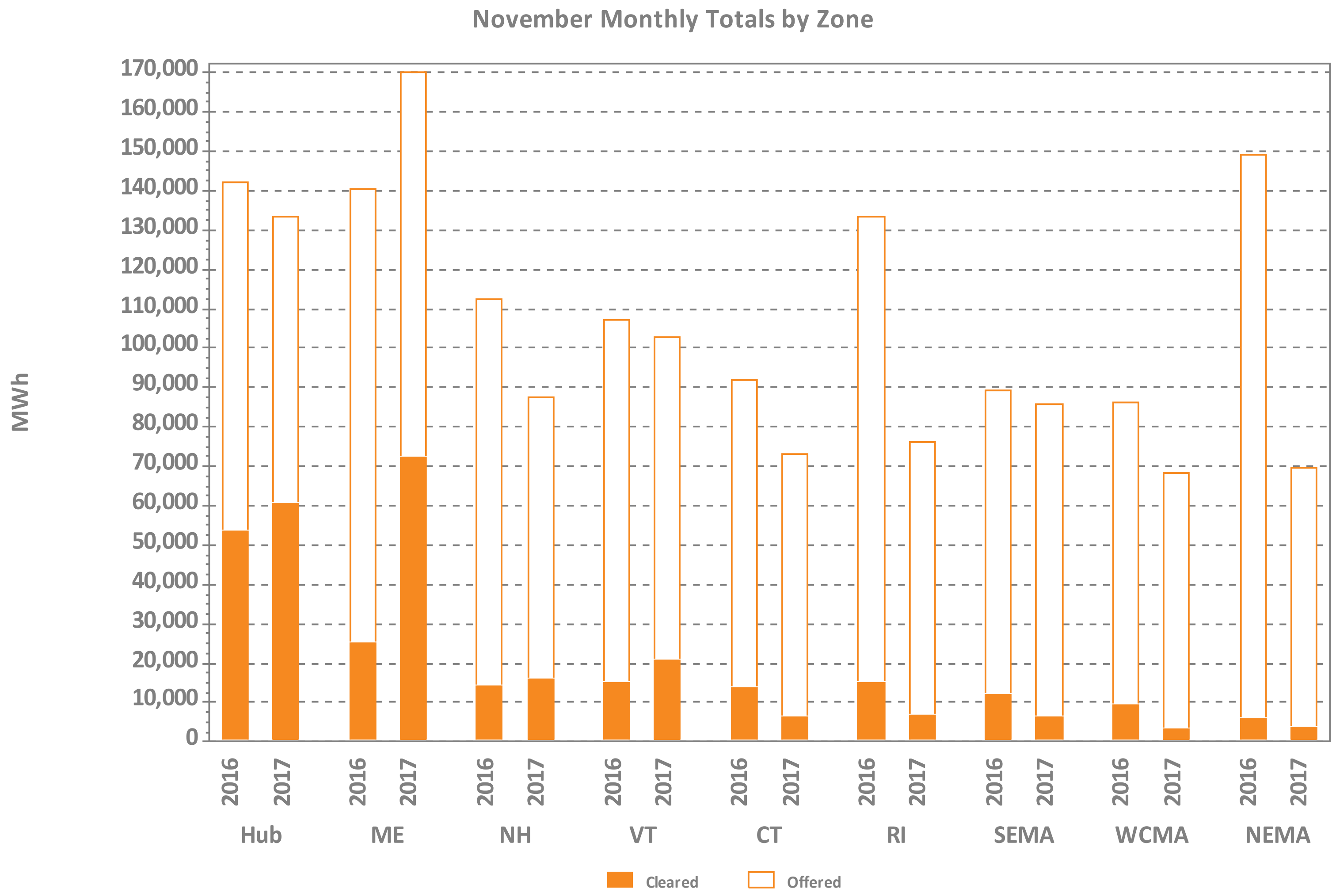
- Maximum potential Forward Reserve Market payments of $3.4M were reduced by credit reductions of $449K, failure-to-reserve penalties of $680K and failure-to-activate penalties of $120, resulting in a net payout of $2.3M or 67% of maximum
  - Rest of System: $1.16M/1.2M (97%)
  - Southwest Connecticut: $0.12M/0.15M (81%)
  - Connecticut: $0.5M/0.52M (97%)
  - NEMA: $0.5M/1.6M (33%)
- $1.7M total Real-Time credits were reduced by $276K in Forward Reserve Energy Obligation Charges for a net of $1.4M in Real-Time Reserve payments
  - Rest of System: 253 hours, $1,038K
  - Southwest Connecticut: 253 hours, $167K
  - Connecticut: 253 hours, $66K
  - NEMA: 254 hours, $113K

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

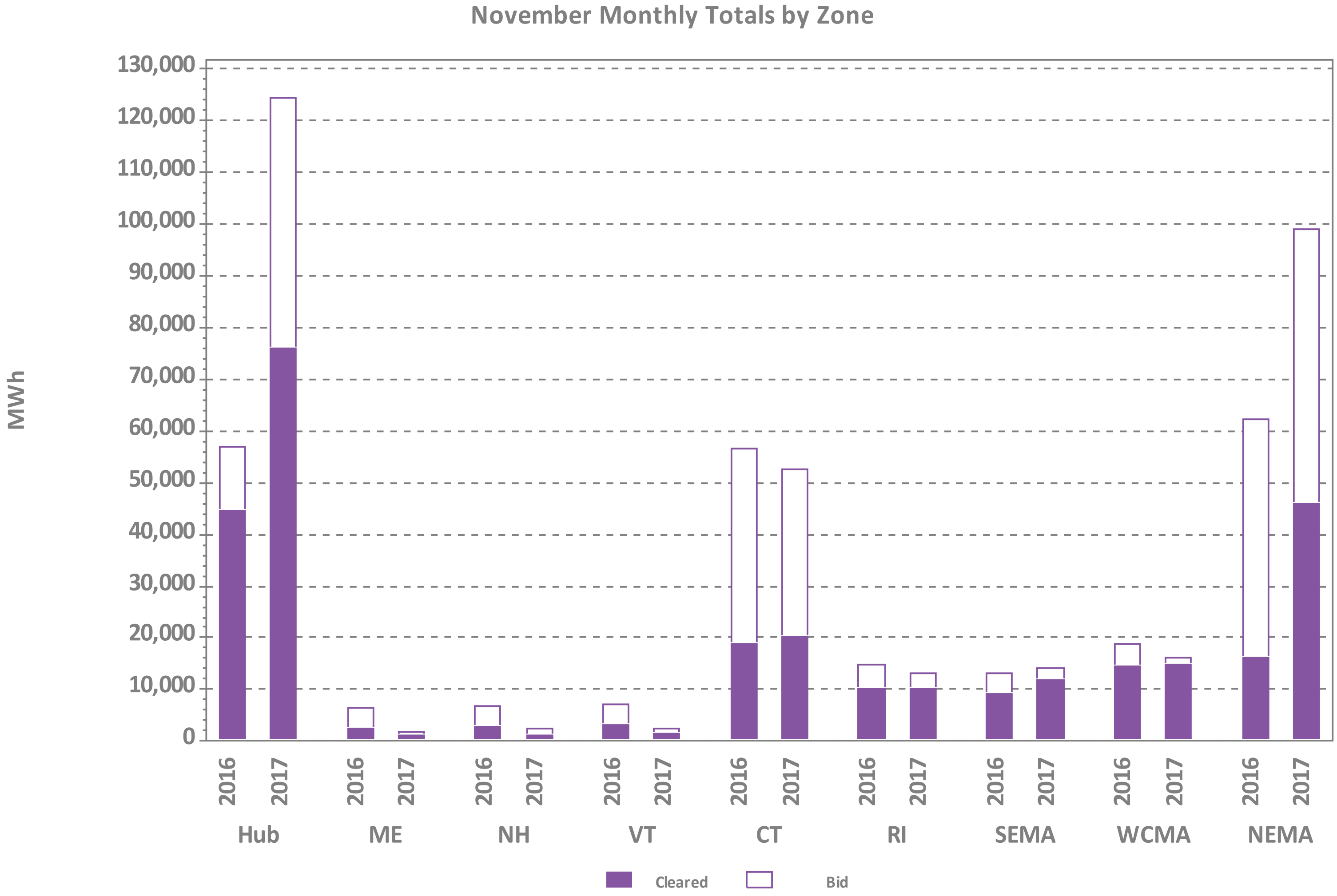
LFRM Charges to Load by Load Zone ($)



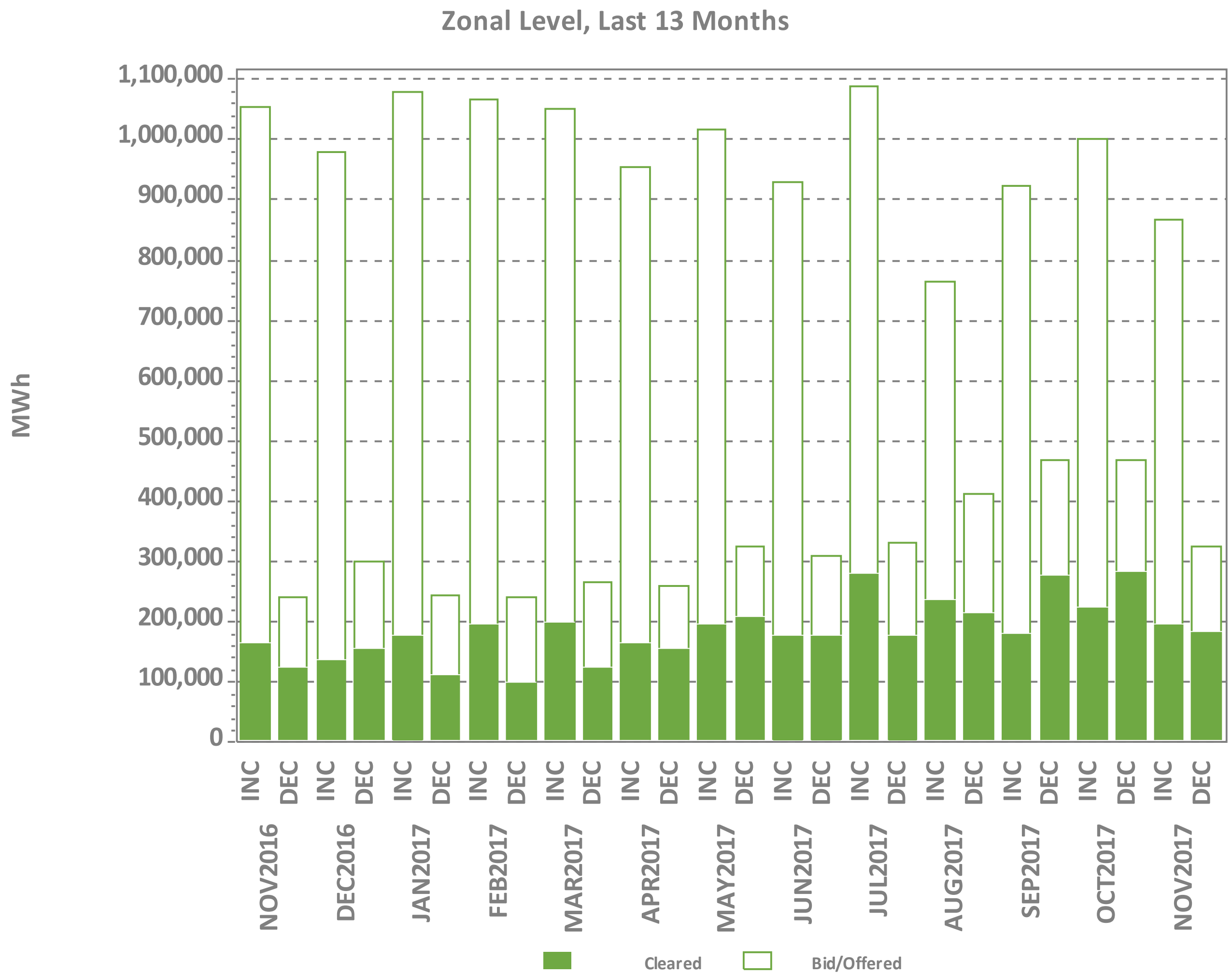
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

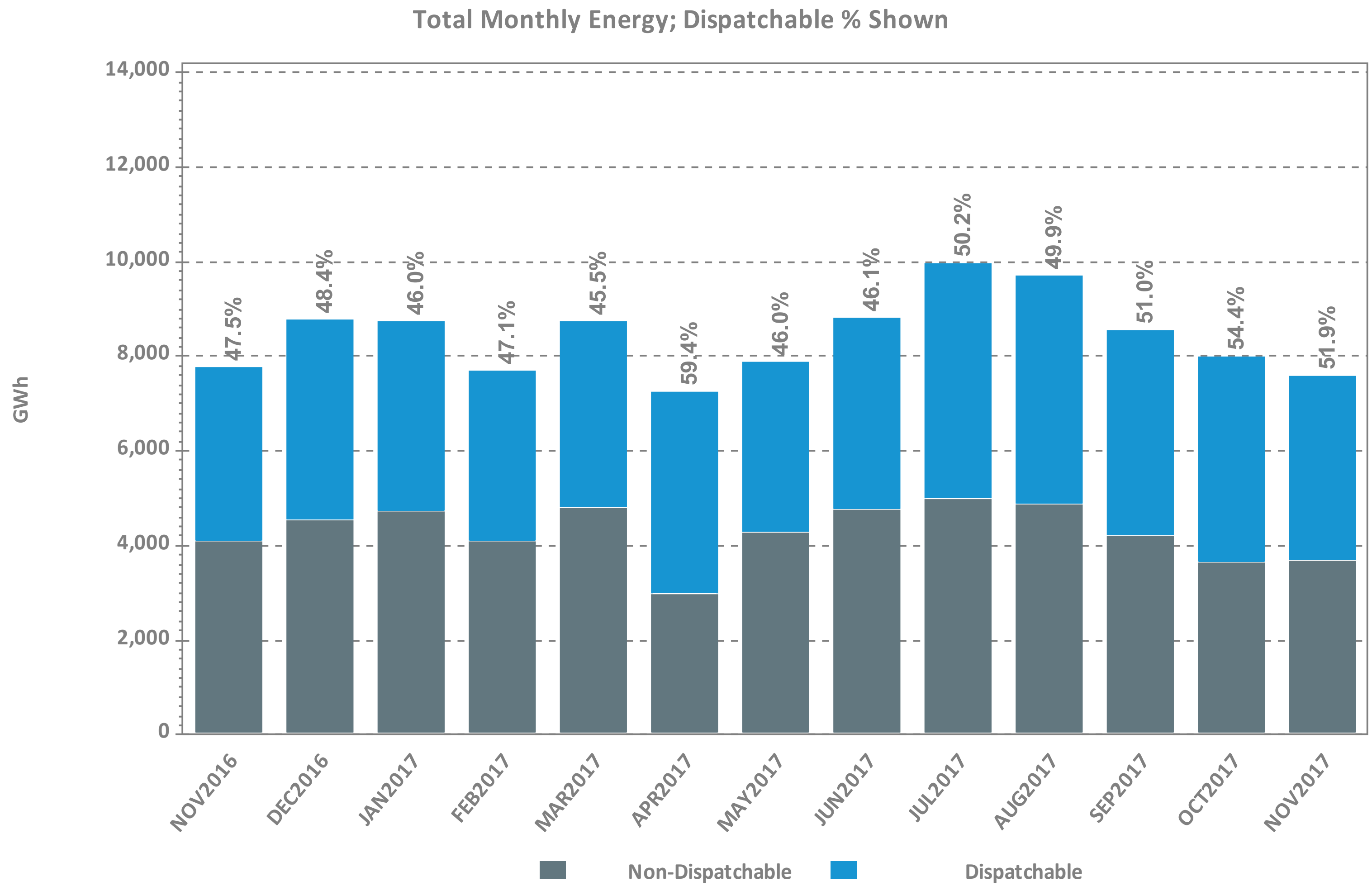


Total Increment Offers and Decrement Bids



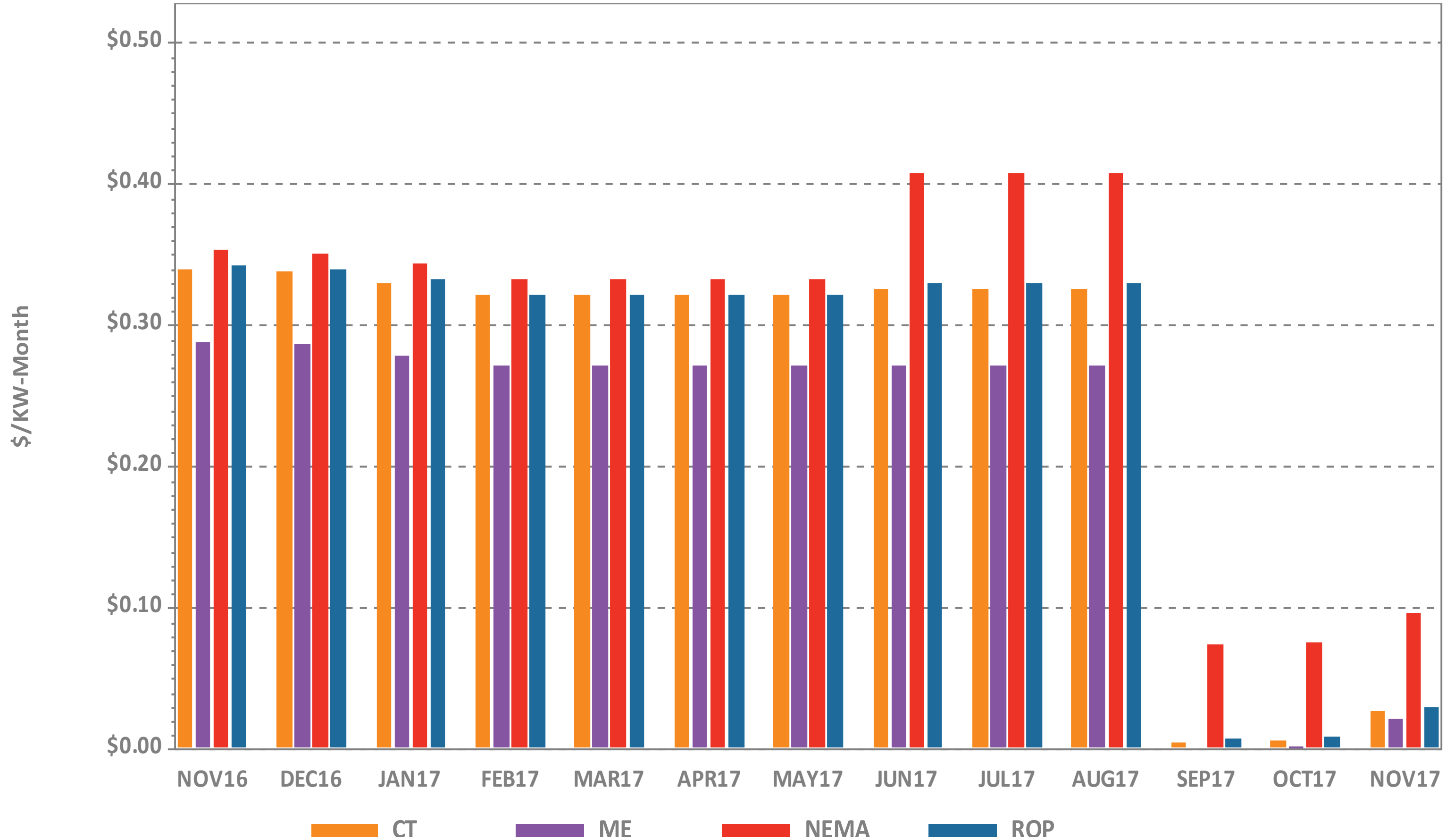
Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



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

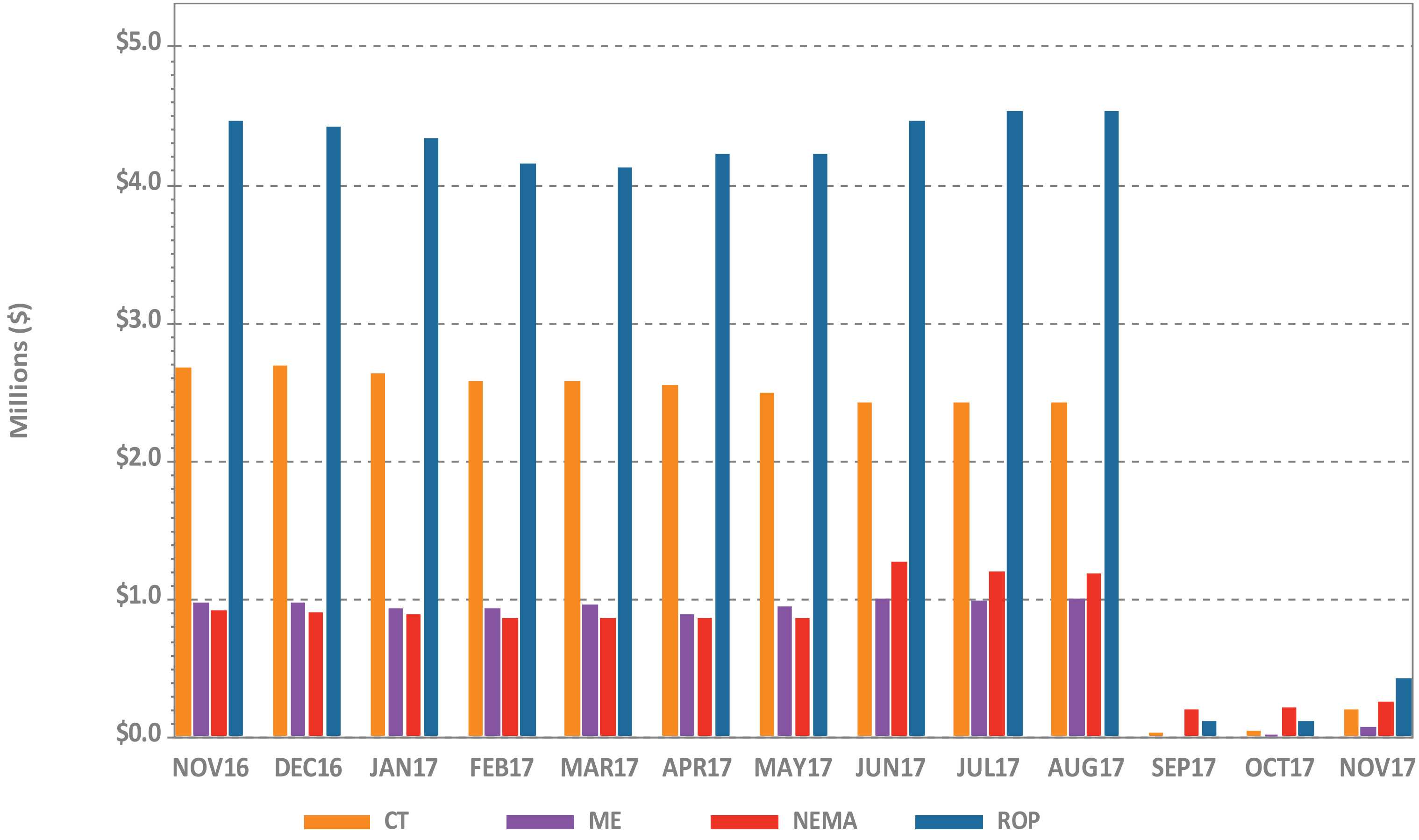
Rolling Average Peak Energy Rent (PER)



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

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

PER Adjustments



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

REGIONAL SYSTEM PLAN (RSP)

Planning Advisory Committee

- Final RSP17 report was posted on November 2
- December 20 PAC Meeting Agenda Topics*
  - 2017 ISO New England System Operational Analysis and Renewable Energy Integration Study (SOARES) Results
  - SEMA/RI 2027 Needs Assessment Scope of Work
  - Interregional Planning Update
  - Asset Condition Presentation Thresholds
  - National Grid Implementation Plan to Meet NPCC Directory 1 Update - Asset Condition
  - Eversource Connecticut and Western Massachusetts - Oil Circuit Breaker Replacement Projects - Asset Condition
  - Eversource Manchester (CT) Control House Expansion - Asset Condition
  - Eversource 345 kV Structure Replacement Projects - Asset Condition
  - Eversource Laminated Structure Replacement Projects - Asset Condition
  - Eversource Card 5X Autotransformer - Asset Condition

* 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 has commenced
- Load Forecast
  - Moody's presented their economic update to the PAC on November 16.
  - Next Load Forecast Committee meeting will be held on December 13.
  - Project to enhance information available on our website to be completed by Q1 2018.
- Energy-Efficiency (EE) Forecast
  - Efforts to benchmark the EE forecasts developed to date to actual reductions is nearly complete. Suggestions on how to improve the forecast of EE was rolled out to the EE Forecast Working Group on October 20.
  - Next EE Forecast Working Group meeting is scheduled for December 15.
- Photovoltaic (PV) Forecast
  - Efforts to improve the PV forecast continue including processes for the collection of interconnection data.
  - Distributed Generation Forecast Working Group meeting will be held on December 15 to discuss state policy updates and survey results.

Interregional Planning

- Interregional Planning Stakeholder Advisory Committee meeting is scheduled for December 11 from 9:00am-12:00pm
  – Discussions will include coordinated planning activities and identification of regional needs and solutions that will assist stakeholders with identifying possible interregional projects

Environmental Matters

- The ISO tracks environmental regulatory developments affecting new and existing generators and transmission infrastructure
  - Environmental Advisory Group will meet on December 12/12/17
    - 2016 system-wide emissions trends and other updates will be presented
  - EPA proposed repealing Clean Power Plan (CPP) on 10/16/17
    - No replacement proposed, comment period extended, litigation stayed
  - Massachusetts GWSA generator emission cap finalized on 8/11/17
    - Imposes declining CO_2 emissions cap of 9.8 million tons (beginning in 2018) on 21 power plants (between 2012-2016, emitted on average 9.2 million tons/year)
    - DEP stakeholder meeting on proposed auction design details (10/31/17)
    - ISO submitted general recommendations on auction design (10/16/17)
  - RGGI states proposing a 9-state regional CO_2 emissions cap reduction of 30% from 75 million tons (2021) to 54.6 million tons (2030), additional changes
    - Cap declines 2.275 million tons annually, for a 26 million ton reduction by 2030
    - 2016 RGGI CO_2 emissions were 80.8 million tons, 2018 cap set at 84.3 million tons
    - Virginia proposes rule joining RGGI in 2020 (11/16/17)

2016 Economic Study – NEPOOL Scenario Analysis

- NEPOOL Scenario Analysis Phase I final report was posted on November 20
- Work is proceeding on Phase II consistent with the scopes of work and are scheduled for completion by the end of 2017
  - Natural gas system capacity and energy analysis final presentation has been posted
  - FCA auction results final presentation has been posted
  - Analysis of regulation, ramping, and reserves is on schedule for discussion at the December 20 PAC meeting

2017 Economic Study

- 2017 Economic Study scope of work was discussed with the PAC on May 25
  - Work will proceed on a lower priority than the 2016 Economic Study Phase I and Phase II activities
  - Results scheduled for completion by 2Q 2018

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 12/4/17

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	Feb-18	3

New Hampshire/Vermont 10-Year Upgrades

Status as of 12/4/17

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-18	2
New 115 kV overhead line, Scobie Pond-Chester	Dec-15	4

New Hampshire/Vermont 10-Year Upgrades, cont.

Status as of 12/4/17

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 12/4/17

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 12/4/17

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 12/4/17

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	2
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	2

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 12/4/17

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	3
Separation of 115 kV DCT corresponding to the Bloomfield to North Bloomfield (1777) line and the North Bloomfield – Rood Avenue – Northwest Hartford (1751) line and add a breaker at North Bloomfield 115 kV substation	Dec-17	3
Install a 115 kV 3% reactor on the 115 kV line between South Meadow and Southwest Hartford (1704)	Dec-18	2
Replace the existing 3% series reactors on the 115 kV lines between Southington and Todd (1910) and between Southington and Canal (1950) with a 5% series reactors	Dec-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 12/4/17

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	Jun-18	3
Add a new 115 kV line from Frost Bridge to Campville	Jun-18	3
Separation of 115 kV DCT corresponding to the Frost Bridge to Campville (1191) line and the Thomaston to Campville (1921) line and add a breaker at Campville 115 kV substation	Dec-18	3
Upgrade the 115 kV line between Southington and Lake Avenue Junction (1810-1)	Dec-16	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 12/4/17

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	2
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	July-18	3
Replace two 115 kV circuit breakers at the Freight substation	Dec-15	4

Southwest Connecticut Projects, cont.

Status as of 12/4/17

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	3
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	Apr-18	3

Southwest Connecticut Projects, cont.

Status as of 12/4/17

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 12/4/17

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)	Dec-20	2

Southwest Connecticut Projects, cont.

Status as of 12/4/17

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 12/4/17

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	3
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 12/4/17

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	Apr-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	2
Install third 115 kV line from West Walpole to Holbrook	Sep-19	2
Install new 345 kV breaker in series with the 104 breaker at Stoughton	May-16	4
Install new 230/115 kV autotransformer at Sudbury and loop the 282-602 230 kV line in and out of the new 230 kV switchyard at Sudbury	Dec-17	3
Install a new 115 kV line from Sudbury to Hudson	Dec-19	1

Greater Boston Projects, cont.

Status as of 12/4/17

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	3
Upgrade 533-508 115 kV line from Lexington to Hartwell and associated work at the stations	Aug-16	4
Install a new 115 kV 54 MVAR capacitor bank at Newton	Dec-16	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 12/4/17

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.	Jun-18	3
Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard	Jun-18	2
Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-16	4

Greater Boston Projects, cont.

Status as of 12/4/17

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	3
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 12/4/17

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 12/4/17

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

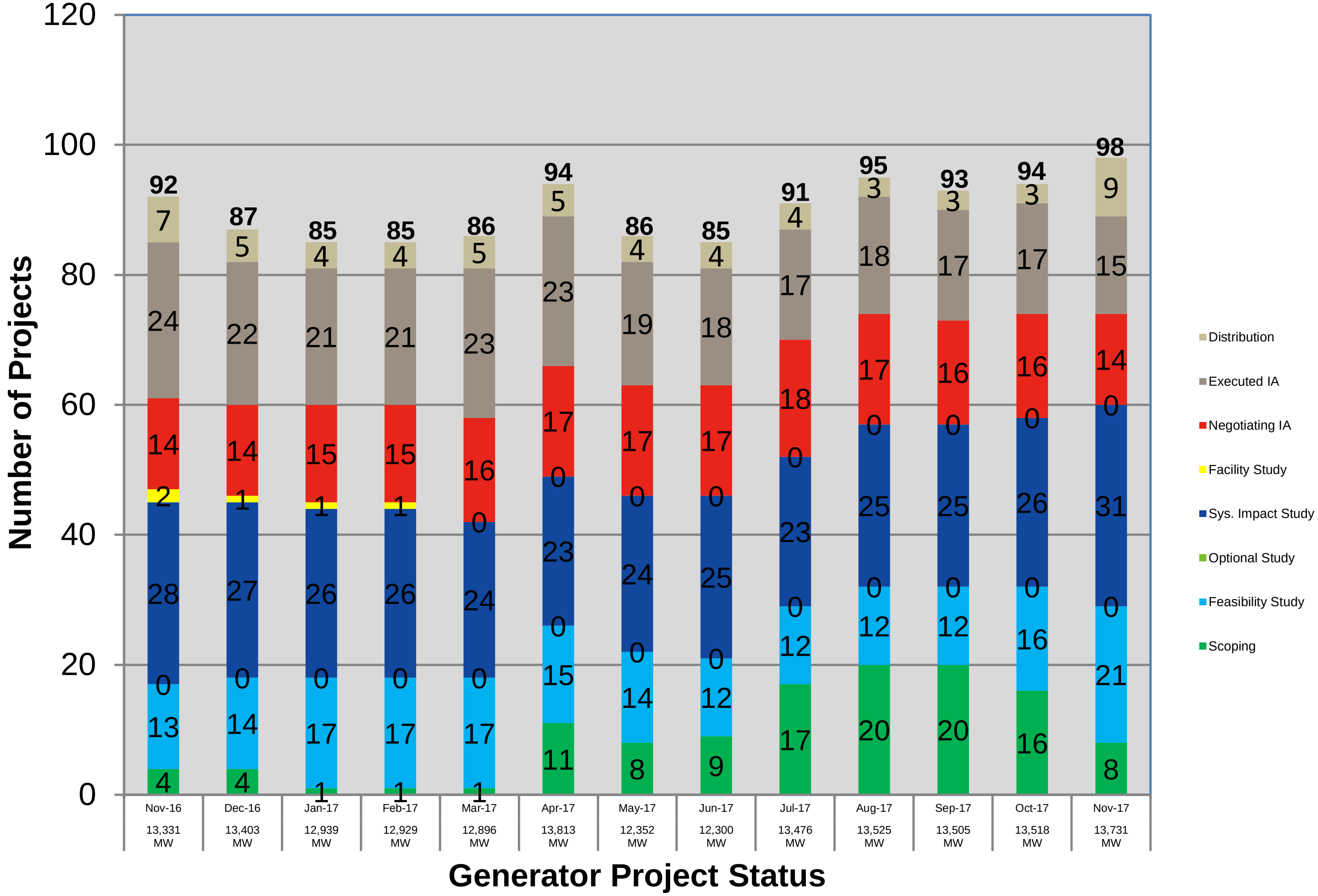
Pittsfield/Greenfield Projects, cont.

Status as of 12/4/17

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	3
Install a 75-150 MVAR variable reactor at Ludlow substation	Dec-17	3
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: As of November 2017, 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

Winter 2017/18

Winter 2017/18 Operable Capacity Analysis

50/50 Load Forecast (Reference)	January - 2017 CSO	January - 2017 SCC
Operable Capacity MW [1]	29,797	31,319
OP CAP From OP-4 RTDR (+)	387	387
OP CAP From OP-4 RTEG (+)	1	1
Operable Capacity with OP-4 DR and RTEG	30,185	31,707
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,202	1,202
Non Commercial Capacity (+)	0	0
Non Gas-fired Planned Outages/Reductions MW (-)	5	27
Gas Generator Outages/Reductions MW (-)	674	0
Allowance for Unplanned Outages (-) [5]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [4]	3,533	4,648
Net Capacity (NET OPCAP SUPPLY MW) [3]	24,375	25,434
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	21,197	21,197
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,502	23,502
Operable Capacity Margin [3]	873	1,932

[1] Operable Capacity is based on the Capacity Supply Obligation (CSO) and Seasonal Claimed Capability (SCC) data as of **November 9, 2017.** This does not include Capacity associated with Settlement Only Generators (SOG).

[2] Net load forecast assumes Peak Load Exposure (PLE) of 21,197 MW and represents the peak demand of week beginning **January 13, 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.

Winter 2017/18 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	January - 2017 CSO	January - 2017 SCC
Operable Capacity MW [1]	29,797	31,319
OP CAP From OP-4 RTDR (+)	387	387
OP CAP From OP-4 RTEG (+)	1	1
Operable Capacity with OP-4 DR and RTEG	30,185	31,707
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,202	1,202
Non Commercial Capacity (+)	0	0
Non Gas-fired Planned Outages/Reductions MW (-)	5	27
Gas Generator Outages/Reductions MW (-)	674	0
Allowance for Unplanned Outages (-) [5]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [4]	4,000	5,165
Net Capacity (NET OPCAP SUPPLY MW) [3]	23,908	24,917
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	21,895	21,895
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	24,200	24,200
Operable Capacity Margin [3]	-292	717

[1] Operable Capacity is based on the Capacity Supply Obligation (CSO) and Seasonal Claimed Capability (SCC) data as of **November 9, 2017.** This does not include Capacity associated with Settlement Only Generators (SOG).

[2] Net load forecast assumes Peak Load Exposure (PLE) of 21,895 MW and represents the peak demand of week beginning **January 13, 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.

Winter 2017/18 Operable Capacity Analysis (MW)
50/50 Forecast (Reference)

ISO-NE 2017/18 OPERABLE CAPACITY ANALYSIS

December 8, 2017 - 50/50 FORECAST using CSO values with RTDR and RTEG

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

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERATOR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW	OPCAP FROM OP4 REAL-TIME EMER. GEN MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
12/2/2017	29,933	1,034	0	1,519	877	3,200	1,781	23,590	19,935	2,305	22,240	1,350	366	1,716	1	1,717
12/9/2017	29,933	1,034	0	757	877	3,200	2,242	23,891	20,232	2,305	22,537	1,354	366	1,720	1	1,721
12/16/2017	29,933	1,034	0	36	17	3,200	3,284	24,430	20,244	2,305	22,549	1,881	366	2,247	1	2,248
12/23/2017	29,933	1,034	0	14	674	3,200	2,947	24,132	20,308	2,305	22,613	1,519	366	1,885	1	1,886
12/30/2017	29,797	1,202	0	14	674	2,800	3,293	24,218	20,715	2,305	23,020	1,198	387	1,585	1	1,586
1/6/2018	29,797	1,202	0	5	674	2,800	3,411	24,109	21,197	2,305	23,502	607	387	994	1	995
1/13/2018	**29,797**	**1,202**	**0**	**5**	**674**	**2,800**	**3,533**	**23,987**	**21,197**	**2,305**	**23,502**	**485**	**387**	**872**	**1**	**873**
1/20/2018	29,797	1,202	0	4	674	2,800	3,340	24,181	21,197	2,305	23,502	679	387	1,066	1	1,067
1/27/2018	29,797	1,202	0	4	674	3,100	3,063	24,158	20,966	2,305	23,271	887	387	1,274	1	1,275
2/3/2018	29,797	1,202	0	98	674	3,100	3,063	24,064	20,690	2,305	22,995	1,069	387	1,456	1	1,457
2/10/2018	29,797	1,202	0	106	674	3,100	2,648	24,471	20,660	2,305	22,965	1,506	387	1,893	1	1,894
2/17/2018	29,797	1,202	0	763	674	3,100	2,371	24,091	20,388	2,305	22,693	1,398	387	1,785	1	1,786
2/24/2018	29,797	1,202	0	1,672	674	3,100	1,818	23,735	19,366	2,305	21,671	2,064	387	2,451	1	2,452
3/3/2018	29,797	1,202	0	1,553	674	2,200	1,402	25,170	19,004	2,305	21,309	3,861	387	4,248	1	4,249
3/10/2018	29,797	1,202	0	1,955	674	2,200	1,264	24,906	18,802	2,305	21,107	3,799	387	4,186	1	4,187
3/17/2018	29,797	1,202	0	2,619	823	2,200	561	24,796	18,424	2,305	20,729	4,067	387	4,454	1	4,455
3/24/2018	29,797	1,202	0	3,788	1,067	2,200	0	23,944	17,839	2,305	20,144	3,800	387	4,187	1	4,188
3/31/2018	29,776	1,202	0	4,374	1,922	2,700	0	21,982	17,071	2,305	19,376	2,606	380	2,986	2	2,988

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 http://www.iso-ne.com/system-planning/system-plans-studies/celt
of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV)
10. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
11. Total Net Load Obligation per the formula(9 + 10 = 11)
12. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (8 - 11 = 12)
13. OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
14. OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (12 + 13 = 14)
15. OP 4 Action 6 Emergency Generation Response without the Voltage Reduction requiring > 10 Minutes based on OP4 Appendix A. Real Time Emergency Generation is capped at 600MW.
Reserve Margins and Distribution Loss Factor Gross Ups are Included.
16. OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (14 + 15 = 16)
This does not include Emergency Energy Transactions (EETs).

Winter 2017/18 Operable Capacity Analysis (MW)
90/10 Forecast (Extreme)

ISO-NE 2017/18 OPERABLE CAPACITY ANALYSIS

December 8, 2017 - 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]
12/2/2017	29,933	1,034	0	1,519	877	3,200	2,076	23,295	20,599	2,305	22,904	391	366	757	1	758
12/9/2017	29,933	1,034	0	757	877	3,200	2,588	23,545	20,906	2,305	23,211	334	366	700	1	701
12/16/2017	29,933	1,034	0	36	17	3,200	3,651	24,063	20,917	2,305	23,222	841	366	1,207	1	1,208
12/23/2017	29,933	1,034	0	14	17	3,200	4,006	23,730	20,983	2,305	23,288	442	366	808	1	809
12/30/2017	29,797	1,202	0	14	674	2,800	3,734	23,777	21,399	2,305	23,704	73	387	460	1	461
1/6/2018	29,797	1,202	0	5	674	2,800	3,865	23,655	21,895	2,305	24,200	(545)	387	(158)	1	(157)
1/13/2018	**29,797**	**1,202**	**0**	**5**	**674**	**2,800**	**4,000**	**23,520**	**21,895**	**2,305**	**24,200**	**(680)**	**387**	**(293)**	**1**	**(292)**
1/20/2018	29,797	1,202	0	4	674	2,800	3,786	23,735	21,895	2,305	24,200	(465)	387	(78)	1	(77)
1/27/2018	29,797	1,202	0	4	674	3,100	3,479	23,742	21,658	2,305	23,963	(221)	387	166	1	167
2/3/2018	29,797	1,202	0	98	674	3,100	3,479	23,648	21,373	2,305	23,678	(30)	387	357	1	358
2/10/2018	29,797	1,202	0	106	674	3,100	3,017	24,102	21,342	2,305	23,647	455	387	842	1	843
2/17/2018	29,797	1,202	0	763	674	3,100	2,710	23,752	21,062	2,305	23,367	385	387	772	1	773
2/24/2018	29,797	1,202	0	1,672	674	3,100	2,094	23,459	20,009	2,305	22,314	1,145	387	1,532	1	1,533
3/3/2018	29,797	1,202	0	1,553	674	2,200	1,633	24,939	19,636	2,305	21,941	2,998	387	3,385	1	3,386
3/10/2018	29,797	1,202	0	1,955	674	2,200	1,479	24,691	19,428	2,305	21,733	2,958	387	3,345	1	3,346
3/17/2018	29,797	1,202	0	2,619	823	2,200	715	24,642	19,038	2,305	21,343	3,299	387	3,686	1	3,687
3/24/2018	29,797	1,202	0	3,788	1,067	2,200	10	23,934	18,436	2,305	20,741	3,193	387	3,580	1	3,581
3/31/2018	29,776	1,202	0	4,374	1,922	2,700	0	21,982	17,652	2,305	19,957	2,025	380	2,405	2	2,407

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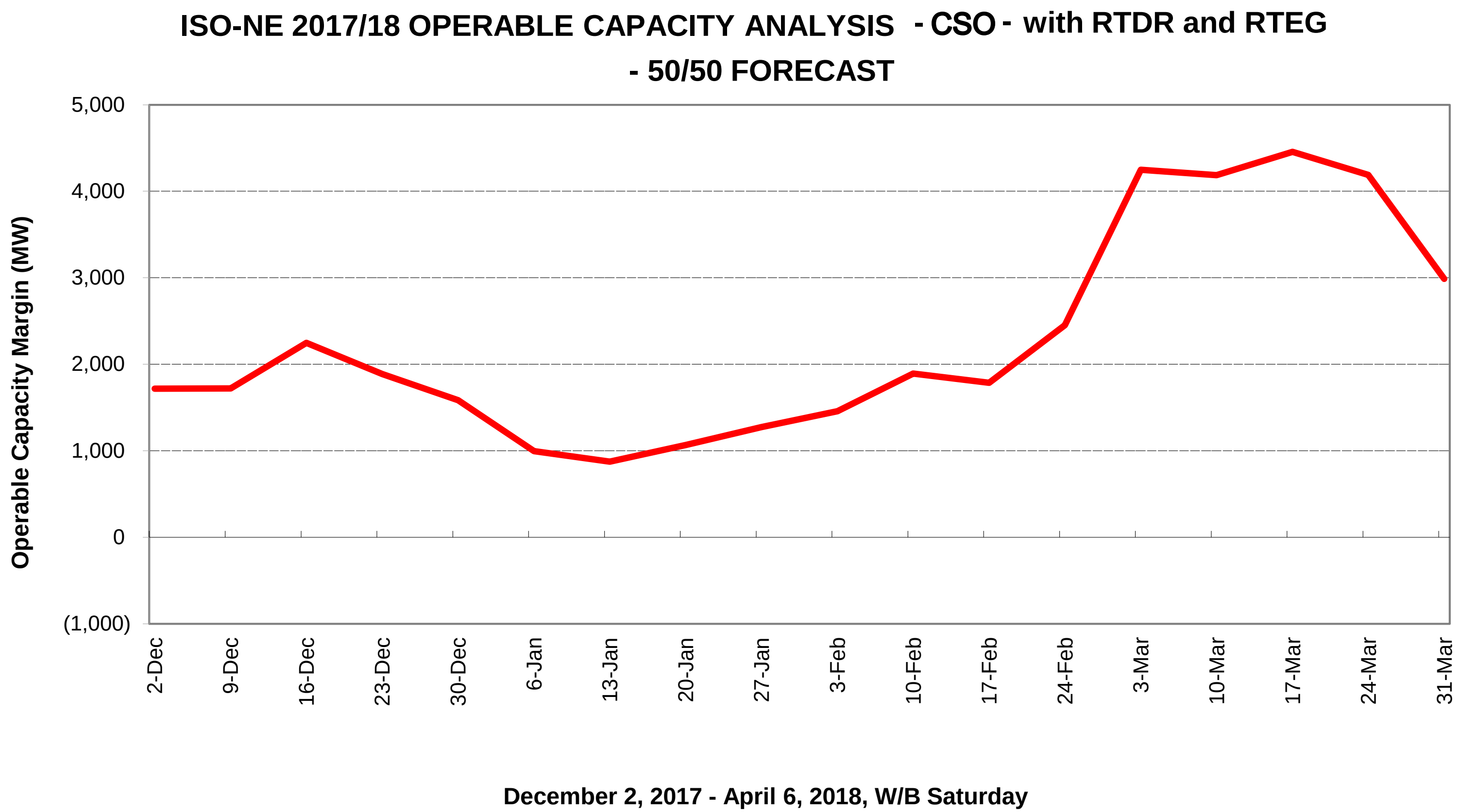
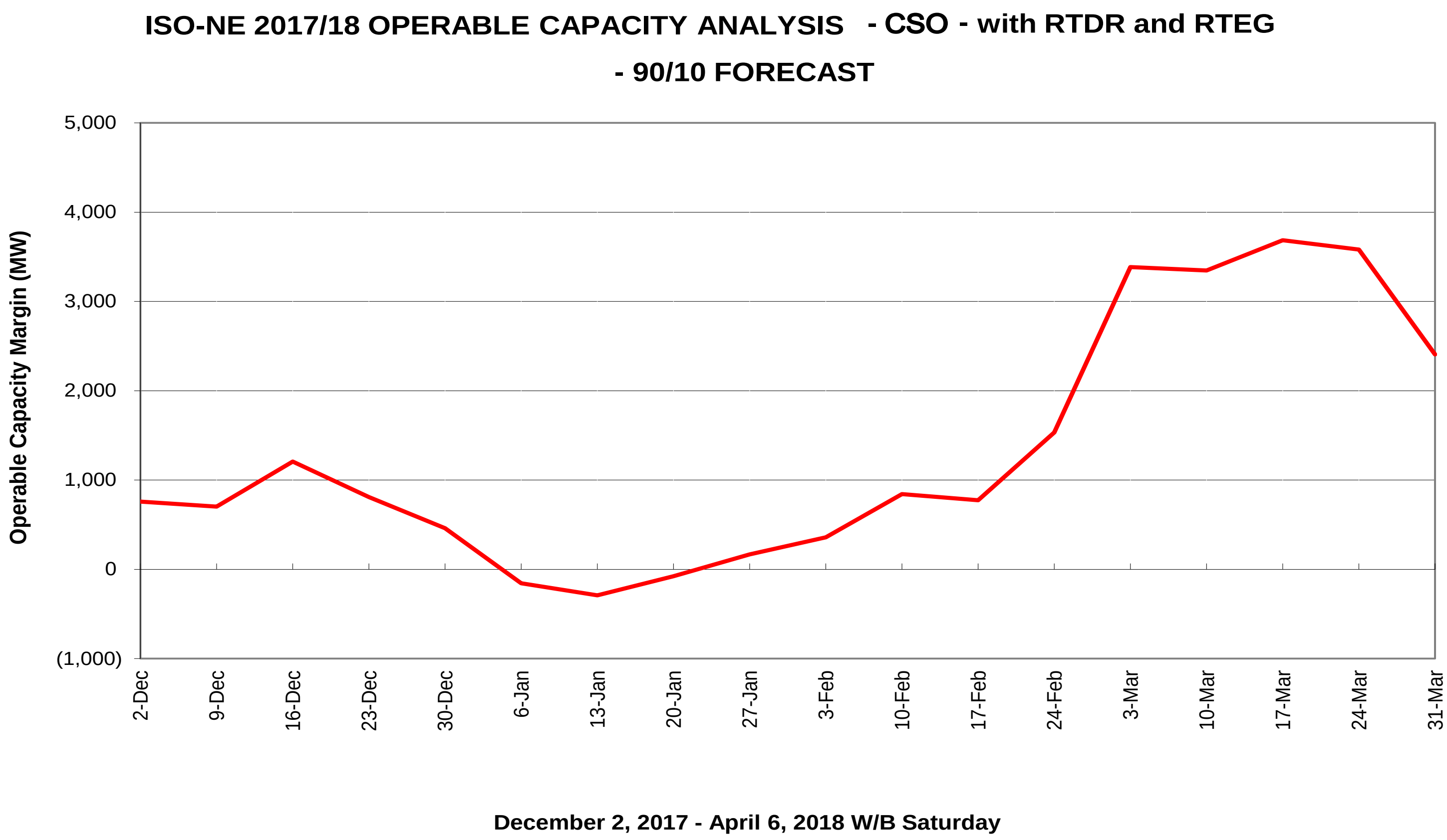
Winter 2017/18 Operable Capacity Analysis (MW)
50/50 Forecast (Reference)



Winter 2017/18 Operable Capacity Analysis (MW)
90/10 Forecast (Extreme)



OPERABLE CAPACITY ANALYSIS

Appendix

Possible Relief Under OP4: Appendix A

OP 4 Action Number	Page 1 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
1	Implement Power Caution and advise Resources with a CSO to prepare to provide capacity and notify "Settlement Only" generators with a CSO to monitor reserve pricing to meet those obligations. Begin to allow depletion of 30-minute reserve.	0 [1] 600
2	Dispatch real time Demand Resources.	**December 366 [3]** **January – March 387 [3]** **April 380 [3]**
3	Voluntary Load Curtailment of Market Participants' facilities.	40 [2]
4	Implement Power Watch	0
5	Schedule Emergency Energy Transactions and arrange to purchase Control Area-to-Control Area Emergency	1,000
6	Voltage Reduction requiring > 10 minutes Dispatch real time Emergency Generation	133 [4] **December – March 1 [3]** **April 2 [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 October 13, 2017.
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	265 [4]
9	Transmission Customer Generation Not Contractually Available to Market Participants during a Capacity Deficiency. Voluntary Load Curtailment by Large Industrial and Commercial Customers.	5 200 [2]
10	Radio and TV Appeals for Voluntary Load Curtailment Implement Power Warning	200 [2]
11	Request State Governors to Reinforce Power Warning Appeals.	100 [2]
Total		**December 2,910 [3]** **January – March 2,931 [3]** **April 2,925 [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 October 13, 2017.
4. The MW values are based on a 26,482 MW system load and the most recent voltage reduction test % achieved.

dcenergy

ISO-NE FTR Financial Assurance

DC Energy Comments and Proposed Modifications

December 2017

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Executive Summary

- **Credit requirements need to be both safe and fair**
  - It is easy to develop "very safe" collateral requirements
    - Extreme case: so onerous that no one participates, hence no default risk
  - Process needs to carefully balance conservatism and its impact on market liquidity and efficiency
- **ISO-NE's credit proposal for BoPP auction raises collateral unreasonably**
  - New proposal increases Hold collateral by 2X and Bid collateral 5X
  - This onerous increase in collateral due to the new methodology is unjustified and unwarranted
  - The new methodology (Standard Deviation approach) does not treat paths with a predominant direction of power-flow reasonably
    - Settlement distributions are inaccurately assumed to be symmetric from a settlement risk standpoint leading to a significant increase in collateral requirements of these paths
- **DC Energy recommends that ISO-NE continue to use the percentile approach to accurately capture the directionality of FTR paths**
  - DC Energy proposes raising the settlement percentile for collateral from 75% to 95% for LT auctions to address some of the concerns raised by ISO-NE
  - We agree with ISO-NE to apply the sun-of-squares approach to take into account temporal risk and propose the same approach to aggregate across months
- **DC Energy recommends a minimum collateral requirement**
  - In order to address the concern of $0 portfolio collateral, a minimum collateral floor that scales with the size of the portfolio (5c/MWh on a month-class portfolio basis) is proposed

Source: DC Energy

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ISO-NE proposal increases hold collateral significantly and bid collateral even more so

FTR Auctions – FA Result Comparison:
Current Method vs. Proposed Revised Method
Long Term Auctions for 2013 & 2016

Long-Term Auction Name	LT1 2013	LT2 2013	LT1 2016	LT2 2016
Total FTR Bid (MW)	130,652.2	199,821.6	126,644.4	118,870.4
Total FTR Award (MW)	15,960.6	17,268.8	22,211.7	23,062.9
Current Bidding FA ($)	$20,073,744	$31,877,209	$35,809,276	$35,773,348
Current Holding FA ($)	$6,950,492	$8,301,972	$8,441,482	$12,525,451
Proposed Bidding FA ($) *	$117,801,110	$169,088,808	$170,924,900	$151,442,926
Proposed Holding FA ($) *	$8,464,766	$9,617,820	$20,261,777	$23,567,516
Bidding FA Ratio (Proposed /Current)	5.87	5.30	4.77	4.23
Holding FA Ratio (Proposed/Current)	1.22	1.16	2.40	1.88

* FA figures are estimates based on the proposed methodology

Source: ISO-NE presentation to September 11, 2017 Budget and Finance Subcommittee

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DC Energy proposes modifying the standard deviation approach with a conservative percentile approach (95%-tile)

DC Energy Proposal

– LT and BoPP Credit Requirements –

Calculate 95%tile monthly risk outcome for each path

→ Aggregate linearly across portfolio to calculate portfolio risk by month-class

→ Use an average portfolio risk of 5c/MWh for a month-class , if average portfolio risk is lower than that

→ Aggregate on and off peak for each month using square root sum of squares

→ Aggregate months using square root sum of squares

→ Add the calculated portfolio risk to positive portfolio investment to calculate total hold collateral requirement

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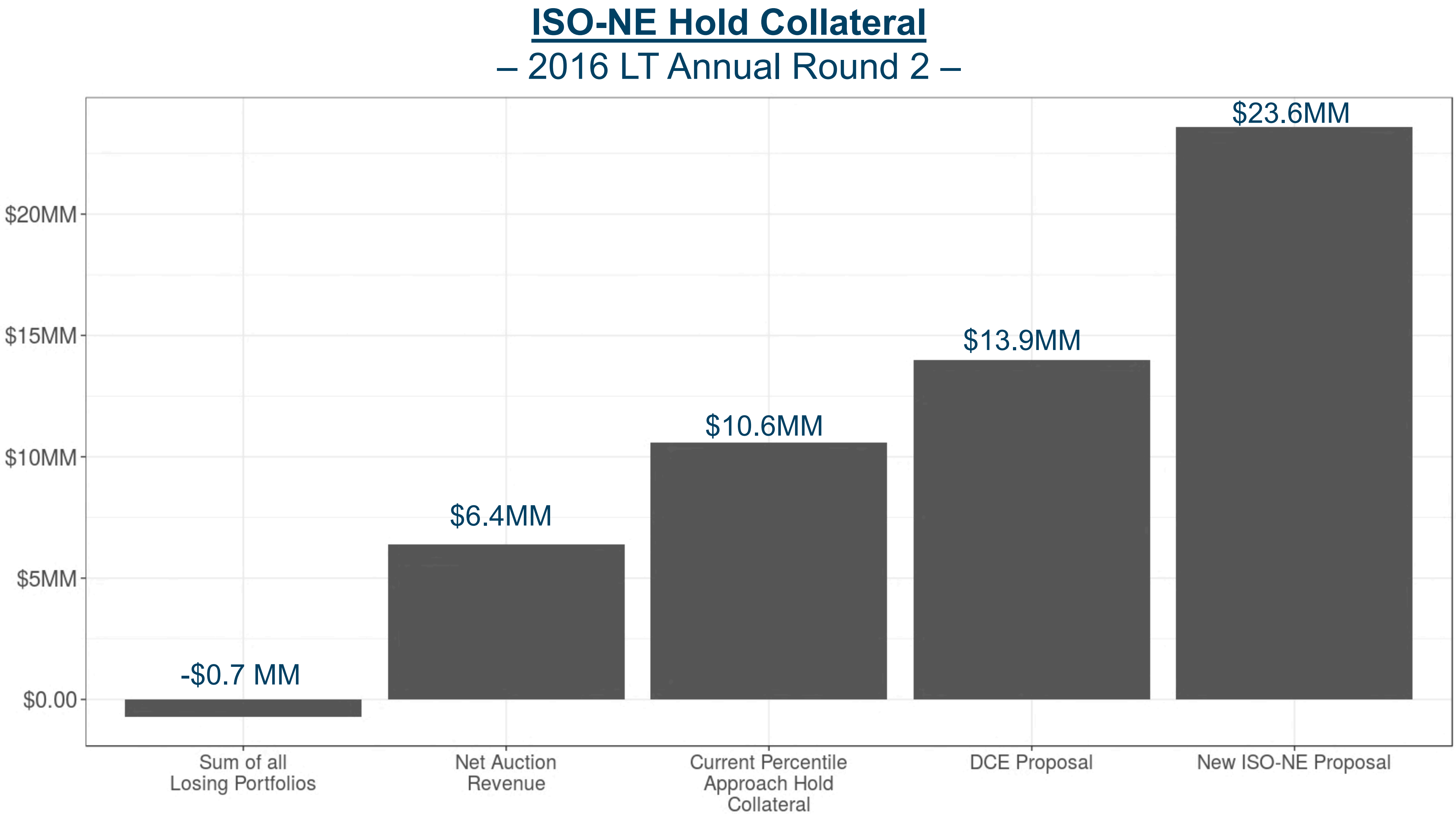
2016 LT Annual Round 2 hold collateral using the standard deviation approach is over 2X the current percentile approach



New ISO-NE Proposal is the proposed holding FA LT2 2016 given in the table on slide 4

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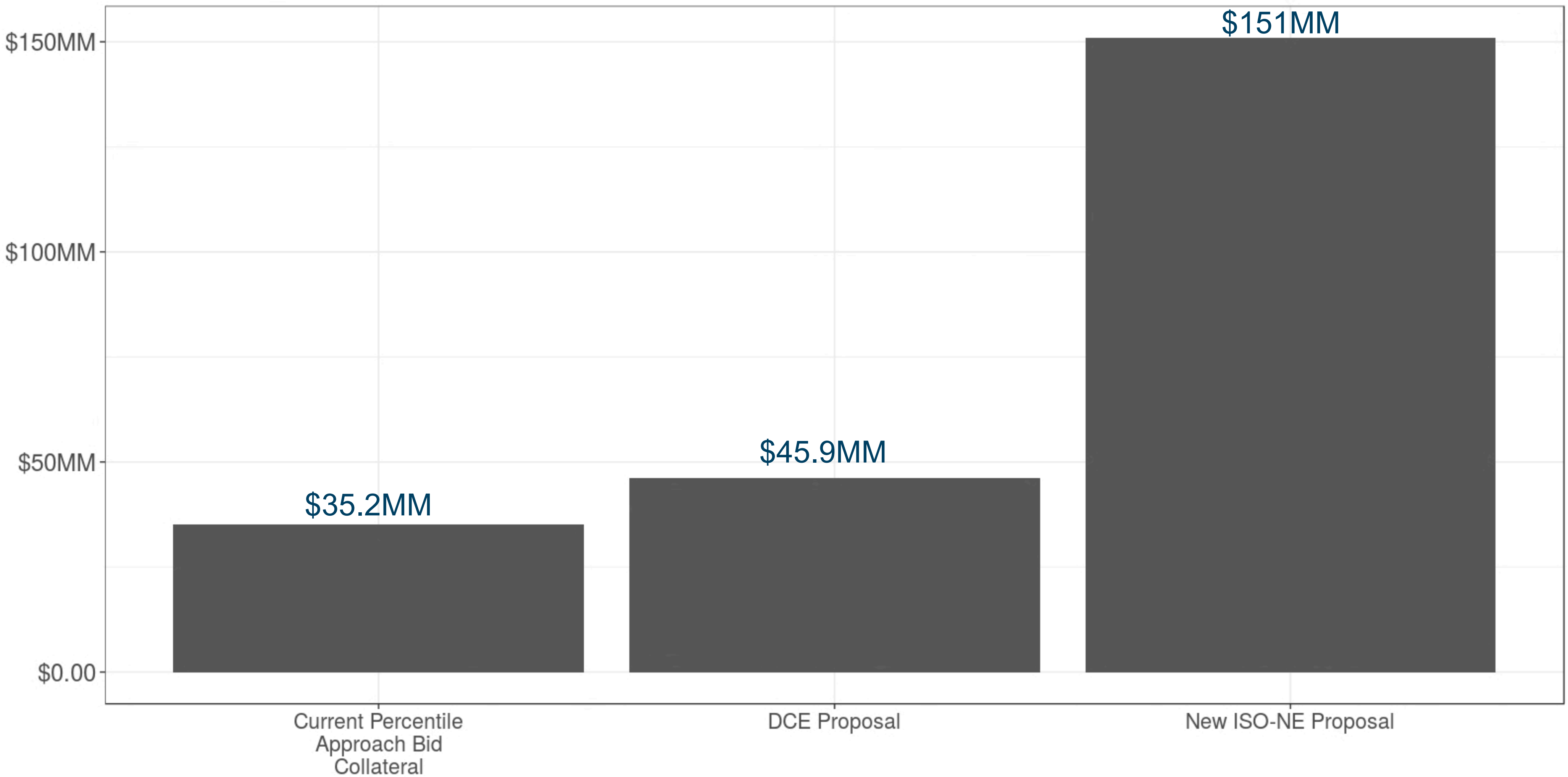
2016 LT Annual Round 2 bid collateral using the standard deviation approach is ~5X the current percentile approach

ISO-NE Bid Collateral
– 2016 LT Annual Round 2 –



Percentile-based bid collateral assumes a 3.3 multiplier on hold collateral based on DC Energy's hold to bid collateral ratio in 2016 Annual Round 2 auction.
New ISO-NE Proposal is the proposed bidding LT2 2016 FA given in the table on slide 4

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EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of December 6, 2017

The following activity, as more fully described in the attached litigation report, has occurred since the report dated November 1, 2017 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	Clear River Schedule 11 O&M Complaint (EL18-31)	Nov 17	Clear River Energy Center files complaint against ISO-NE, National Grid and the TOs; comment date Dec 7
			Nov 20-30	NEPOOL, NESCOE, NextEra, Dominion intervene
			Nov 29	ISO-NE moves for dismissal as a party and answers Complaint
			Dec 6; 5-6	NEPOOL submits protest and comments; NRG, Calpine, CMEEC, CT AG, CT OCC, CPV Towantic, MPUC intervene
	3	NEPGA PER Adjustment Complaint (EL16-120)	Nov 16	FERC denies NEPGA's request for clarification and/or rehearing of the *PER Complaint Order*
	4	Base ROE Complaint IV (2016) (EL16-64)	Nov 2	Trial Judge schedules Dec 8 Pre-Hearing IT meeting
			Nov 15	EMCOS file rebuttal testimony
			Nov 17	EMCOS move to file a summary of Dr. Lon L. Peters' Nov 15 prepared rebuttal testimony
			Nov 20	Presiding Judge Glazer grants EMCOS' motion to file a summary of Dr. Lon L. Peters' Nov 15 prepared rebuttal testimony
			Nov 21	EMCOS submit updated testimony and work papers of J. Lesser
			Nov 28	Parties submit joint statement of issues
			Dec 1	Parties submit pre-hearing briefs, joint witness list, statement of positions, index of exhibits; CAPS move to compel TOs' answers to data requests
			Dec 4	Trial Judge schedules Dec 11 oral argument on CAPS' Dec 1 motion
	5	206 Proceeding: RNS/LNS Rates and Rate Protocols (EL16-19)	Nov 13	Settlement conf. held; 11th settlement conf. scheduled for Jan 9
			Dec 5	Settlement Judge issues status report, recommending settlement judge procedures be continued

II. Rate, ICR, FCA, Cost Recovery Filings

*	7	ICR-Related Values and HQICCs – Annual Reconfiguration Auctions (ER18-371)	Dec 1	ISO-NE and NEPOOL jointly file ICR-Related Values and HQICCs for the 2018/19 ARA3, 2019/20 ARA2; and 2020/21 ARA1; comment date Dec 22
			Dec 5	NRG intervenes
*	7	FCA12 Qualification Informational Filing (ER18-264)	Nov 7	ISO-NE submits required FCA12 informational filing
			Nov 18-22	NEPOOL, Dominion, NRG, Eversource, NESCOE intervene
			Nov 22	Efficiency Maine Trust, CPower/Tesla protest their qualification determinations
*	8	ICR-Related Values and HQICCs – 2021-22 Capacity Commitment Period (ER18-263)	Nov 7	ISO-NE files ICR-Related Values for the 2021-22 Capacity Commitment Period
			Nov 18-28	Calpine, Dominion, Eversource, Exelon, FirstLight, NRG intervene
			Nov 28	NEPOOL, NEPGA, NESCOE submits comments
	8	Emera MPD OATT Attachment J Revision (ER18-210)	Nov 20	Maine PUC intervenes
			Nov 22	Maine Customer Group protests revisions

	9	2018 NESCOE Budget (ER18-85)	Nov 2-3 Dec 6	Eversource, NRG intervene FERC accepts Budget
	9	2018 ISO-NE Administrative Costs and Capital Budgets (ER18-77)	Nov 2-3 Dec 6	Eversource, NRG intervene FERC accepts 2018 ISO-NE Budgets
	10	Exelon Additional Cost Recovery Compliance Filing (ER17-933)	Nov 20	Exelon submits compliance filing detailing $97,188.90 in actual regulatory costs incurred and to be recovered; comment date Dec 11
	10	TOs' Opinion 531-A Compliance Filing Undo (ER15-414)	Nov 6 Dec 4	TOs request rehearing of Oct 6 *Order Rejecting Filing* FERC issues tolling order providing it additional time to consider the TOs' request for rehearing of the *Order Rejecting Filing*

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

	10	Waiver Request: 2017-18 Winter Rel. Program Participation Notice Deadline (Braintree) (EL18-5)	Nov 27	FERC grants Braintree's request for a limited waiver allowing ISO-NE to consider Braintree's offer to participate in the Program
	11	Waiver Request: DR Auditing Requirements (CPower) (ER18-185)	Nov 20	ISO-NE opposes waiver request; NEPOOL intervenes
	11	Small Generator Modeling Options Change (ER18-122)	Nov 2-9 Nov 22	Dominion, NRG, Eversource intervene FERC accepts changes, eff. Dec 20, 2017
	11	NCPC Calculation Changes for Ramp Constrained Down Resources (ER17-2569)	Nov 2	FERC accepts changes, eff. Dec 1, 2017
	12	*Order 831* (Modified Energy Market Offer Caps) Revisions (ER17-1565)	Nov 9	FERC accepts revisions, eff. Oct 1, 2019, as requested
	12	CONE & ORTP Updates (ER17-795)	Nov 6 Dec 4	NEPGA requests rehearing of the *CONE/ORTP Updates Order* FERC issues tolling order providing it additional time to consider NEPGA's request for rehearing of the *CONE/ORTP Updates Order*

IV. OATT Amendments / TOAs / Coordination Agreements

	14	Attachment K Revisions (ER17-2514)	Nov 13	FERC accepts updates to Appendix 3 QTPS list; eff. Nov 20

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes

*	15	Schedule 21-EM: Stored Solar J&WE LSA (ER18-387)	Dec 5	ISO-NE and CMP file Stored Solar J&WE LSA; comment date Dec 13
*	15	Schedule 22: Clear River LGIA (ER18-349)	Nov 29 Dec 5-6	ISO-NE, NEP file unexecuted Clear River LGIA; comment date Dec 20 NEPOOL, Dominion intervene
*	15	Schedule 21-NEP: NEP/Granite Reliable Power RFA (ER18-346)	Nov 29	NEP files agreement; comment date Dec 20
	15	Sched. 21-EM: Recovery of BHE/ MPS Merger-Related Costs (ER15-1434 et al.)	Nov 13 Nov 21	Emera Maine answers Oct 26 Responses Judge Dring issues status report recommending that settlement procedures (which are on-going) be continued

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

	17	Capital Projects Report - 2017 Q3 (ER18-81)	Nov 2-3 Dec 6	Eversource, NRG intervene FERC accepts 2017 Q3 Capital Projects Report
*	17	ISO-NE FERC Form 3Q (2017/Q3) (not docketed)	Nov 22	ISO submits quarterly financial report for 2017 Q3

IX. Membership Filings

*	18	December 2017 Membership Filing (ER18-353)	Nov 30	***New Members***: Fusion Solar Center, Josco Energy MA ***Name Change***: Summer Energy Northeast; comment date Dec 21
	18	November 2017 Membership Filing (ER18-186)	Nov 29	FERC accepts Yellow Jacket Energy, LLC membership, BNP Paribas termination
*	18	Lotus Danbury LMS100 Two Suspension Notice (not docketed)	Nov 2	ISO-NE files notice of suspension of Lotus Danbury LMS100 Two from New England Markets

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

	19	NOPR: Rev. Rel.: EOP-004-4, EOP-005-3, EOP-006-3, EOP-008-2 (RM17-12)	Nov 20-27	NERC, EEI, Magnum CAES file comments
	19	NOPR: New Reliability Standards: PRC-027-1 and PER-006-1 (RM16-22)	Nov 16	FERC issues NOPR proposing to approve Protection System Changes; comment date Jan 22, 2018
*	20	Rules of Procedure Changes (Appendix D) (RR18-1)	Nov 21	NERC files changes to Rules of Procedure registered ballot body criteria; comment date Dec 12
	21	Annual NERC CMEP Filing (RR15-2)	Nov 16	FERC accepts CMEP compliance filing, does not approve two proposed changes to CMEP, terminates annual reporting requirement

XI. Misc. - of Regional Interest

*	21	203 Application: Dynegy/Vistra (EC18-23)	Nov 22	Dynegy and Vistra request authorization for merger of Dynegy with and into Vistra; comment date Jan 22
	22	203 Application: Calpine/ECP (EC17-182)	Nov 13 Nov 14 Nov 20 Nov 24	Anaheim, Azusa, Banning, Colton, Pasadena, Riverside, CA intervene Public Citizen protests application Calpine answers Public Citizen protest Public Citizen answers Calpine Nov 20 answer
	22	203 Application: PSNH /FPL Wyman 4 (EC17-132)	Nov 6	NextEra submits notice that transaction was consummated Nov 1, 2017
*	23	NEP/HQUS Phase I/II HVDC-TF Service Agreement (ER18-388)	Dec 5	NEP files Agreement; comment date Dec 26
*	23	D&E Agreement Cancellation: NSTAR/Essential Power Newington (ER18-330)	Nov 27	NSTAR files cancellation notice; comment date Dec 18

*	24	IA: CL&P/Woods Hill Solar (ER18-316)	Nov 20	Eversource files IA; comment date Dec 11
	24	IA: NEP/Wheelabrator Millbury (ER17-2557)	Nov 17	FERC accepts LGIA, eff. Sep 26, 2017
	25	Emera MPD OATT Changes (ER15-1429; EL16-13, ER12-1650)	Nov 20	FERC approves Offer of Settlement
*	26	FERC Enforcement Action: Barclays Bank et al. (IN08-8)	Nov 7	FERC approves settlement resolving its investigation into (and subsequent litigation to obtain payments for) Barclays' Defendants violations of the FERC's Anti-Manipulation Rules – Barclays to pay a ***$70 million*** civil penalty and ***$30 million*** disgorgement

XII. Misc. - Administrative & Rulemaking Proceedings

28	DOE-Initiated Proposal: Grid Reliability & Resilience Pricing Rule (RM18-1)	Nov 7 Nov 20	ISO-NE and more than 100 parties file reply comments NEPOOL submits brief response to reply comments
32	*Order 831-A*: Price Caps in RTO/ISO Markets (RM16-5)	Nov 9	FERC issues grants in part and denies in part the requests for rehearing and clarification of *Order 831*; *Order 831* becomes eff. Jan 16, 2018

XIII. Natural Gas Proceedings

36	New England Pipeline Proceedings		
	• Atlantic Bridge Project (CP16-9)	Oct 27	FERC authorizes Algonquin to place into service 40,000/132,705 dth/day of incremental firm transportation service
		Oct 31	Algonquin requests authorization to begin construction of Stony Point Discharge Take-up and Relay
		Nov 1	Algonquin places 40k dth into service
		Nov 3	FERC authorizes construction of Stony Point facilities
	• Conn. Expansion Proj. (CP14-529)	Nov 1	Project facilities, other than Conn. Loop, placed in-service
		Nov 10	Conn. Loop placed in service
38	Non-NE Pipeline Proceedings Millennium Pipeline Valley Lateral Project (CP16-17)	Nov 15	FERC denies requests for rehearing, stay and rescission; challenge at 2d Circuit remains pending

XIV. State Proceedings & Federal Legislative Proceedings

40	Massachusetts Emissions Allowance Auctions: Stakeholder Input on Auction Design Parameters	Nov 15	Additional comments filed

XV. Federal Courts

41	Demand Curve Changes (17-1110**)	Nov 21	FERC files Respondent Brief
		Nov 28	NRDC/CLF request permission to file, and file, amicus curiae brief in support of the FERC
		Dec 5	Court grants NRDC/CLF motion for leave to participate as amici curiae; Clerk lodges Nov 28 (corrected) amicus curiae brief
42	Base ROE Complaints II & III (2012 & 2014) (15-1212)	Nov 13	Parties file 9th status report

M E M O R A N D U M

TO: NEPOOL Participants Committee Member and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: December 7, 2017

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 December 6, 2017. If you have questions, please contact us.

I. Complaints/Section 206 Proceedings

- **Clear River Schedule 11 O&M Complaint (EL18-31)**

On November 17, 2017, Clear River Energy Center LLC ("Clear River")[2] filed a complaint against ISO-NE, National Grid and the TOs (together, "Respondents") requesting that the FERC direct ISO-NE to modify Tariff Schedule 11 (and all other Tariff provisions that implement the Operating and Maintenance Cost ("O&M Costs") recovery provisions of Schedule 11) under which interconnection customers are or could be required to pay O&M Costs associated with the construction of Large Generator Interconnection Agreement ("LGIA")-required network upgrades, and to direct National Grid to modify its Schedule 21-NEP to conform with the changes made to Schedule 11. Clear River claims that National Grid's Direct Assignment Facilities Charge to Clear River of all costs associated with the Network Upgrades that National Grid will build to accommodate interconnection of the Clear River Project is inconsistent with Order 2003 and the charge, as well as the provisions of the ISO-NE Tariff that authorize such a charge, are unjust and unreasonable. Respondents' answer and all interventions or protests must be filed on or before December 7, 2017.

On November 29, ISO-NE asked the FERC to dismiss ISO-NE as a party to the Clear River Complaint proceeding, explaining that the Tariff provisions at issue are among those which the Participating Transmission Owners ("PTOs"), rather than ISO-NE, have the right to establish and modify under section 205 of the Federal Power Act ("FPA"), and that, with no financial interest in the matter, ISO-NE is not a necessary party. Alternatively, ISO-NE answered the Clear River Complaint (should the FERC decline to dismiss ISO-NE from the proceeding), taking no position on either the merits of Clear River's claims or on "the propriety of any relief Clear River requests".

In addition to ISO-NE's response, NEPOOL filed comments and a protest on December 6 requesting that the FERC deny the Clear River Complaint on its merits or, to the extent the FERC grants any part of the Clear River Complaint, send consideration of any necessary Tariff changes through the NEPOOL process for

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

[2] Clear River is an indirect, wholly-owned subsidiary of Invenergy Thermal Development LLC and thereby a Related Person to Generation Sector member Invenergy Energy Management LLC (collectively, "Invenergy"). Clear River is developing a 1,080 MW natural gas generation facility to be located in Burrillville, Rhode Island (the "Clear River Project"). The Project will interconnect to transmission facilities owned by National Grid and operated by ISO-NE. To provide service, National Grid will construct certain new network facilities, upgrade others and relocate an existing 345 kV network facility (collectively, the "NGrid Network Upgrades") at an estimated cost of about $60 million.

appropriate stakeholder input before they are filed. Doc-less interventions have thus far been filed by Calpine, CMEEC, CT AG, CT OCC, CPV Towantic, Dominion, MPUC, NESCOE, NextEra, and NRG. 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).

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

On November 16, the FERC denied[3] NEPGA's pending request for clarification and/or rehearing of the *PER Complaint Order*.[4] As previously reported, NEPGA asked for clarification that when the FERC "determines refunds [in this proceeding], it will direct the ISO to refund to capacity suppliers the difference between: (i) the PER Adjustment payments charged to capacity suppliers after the September 30, 2016 refund effective date, and (ii) the PER Adjustment payments that would have been charged to capacity suppliers if the PER Adjustment were calculated using a just and reasonable PER Strike Price." In declining to grant NEPGA's request for clarification and/or rehearing, the FERC stated that, "If in fact refunds are ordered (and we note that the Commission has not yet determined whether it will order refunds), NEPGA's understanding of the Commission's intended methodology is incorrect … the Commission 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. The order does not, nor did the Commission intend it to, provide for any change to the Monthly PER values that fall prior to the September 30, 2016 change in the methodology of calculating the strike price. FPA section 206 prevents such an outcome."[5] Any challenges to the FERC's *PER Complaint Order* and *PER Complaint Rehearing Order* must be filed in federal court on or before January 16, 2018.

- **NEPGA PER Adjustment Complaint Settlement Agreement (ER17-2153)**

The PER Settlement remains pending before the FERC. As previously reported, the Settling Parties[6] submitted, filed July 28, 2017,[7] an Offer of Settlement and settlement materials ("PER Settlement") to resolve the issue set for hearing and settlement judge procedures by the Commission in this proceeding.[8]

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[3] *New England Power Generators Assoc., Inc. v. ISO New England Inc.*, 161 FERC ¶ 61,193 (Nov. 16, 2017) *("PER Complaint Rehearing Order")*.

[4] *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).

[5] *PER Complaint Rehearing Order* at PP 11-12.

[6] 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: the ISO, PSEG, Consolidated Edison Energy, Inc. ("ConEd"), Verso Corp., GenOn Energy Management LLC, National Grid, NextEra, the New Hampshire Electric Coop. ("NHEC"), and Calpine.

[7] 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.

[8] *See New England Power Generators Assoc., Inc. v. ISO New England Inc.*, 158 FERC ¶ 61,034 (Jan. 19, 2017), *reh'g requested ("PER Complaint 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 the ISO 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." On February 15, NEPGA requested clarification of the PER

Under the PER Settlement, the ISO 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[9] 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. The PER Settlement does not resolve the issues of the applicability of the Strike Price methodology to FCA9 (which will be subject to comment in response to the PER Settlement Agreement) or whether capacity suppliers will receive any refunds for PER Events that occurred in August 2016 (currently the subject of, and to be decided through, a pending request for clarification and/or rehearing as noted below). Those issues remain to be resolved by the Commission when and as appropriate. The term sheet that formed the basis for the PER Settlement was supported by the Participants Committee at the June 27 session of the Summer Meeting. All parties in EL16-120 "are deemed to have intervened in Docket No. ER17-2153-000".[10]

In comments filed August 16, the ISO neither supported nor objected to the proposed PER strike price methodology and requested that the Commission resolve how the Average Monthly PER will be calculated on and after June 1, 2018. NEPOOL, NEPGA, NESCOE, and Eversource filed comments supporting the PER Settlement. Comments by FERC Trial Staff indicated that it did not oppose the PER Settlement. In reply comments, 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 the ISO to make a compliance filing, but decline to address NESCOE's request until some later date. Settlement Judge Young certified the uncontested settlement to the FERC on August 31, which remains pending before the Commission. If you have any questions concerning this matter, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com), Jamie Blackburn (202-218-3905; jblackburn@daypitney.com), or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Base ROE Complaint IV (2016) (EL16-64)**
  Hearings in this matter are scheduled to begin next Monday, December 11.

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'

Complaint Order with respect to the PER Adjustment payments charged to NEPGA's members on capacity invoices issued after the refund effective date. Specifically, NEPGA asked for clarification that when the FERC "determines refunds, it will direct the ISO to refund to capacity suppliers the difference between: (i) the PER Adjustment payments charged to capacity suppliers after the September 30, 2016 refund effective date, and (ii) the PER Adjustment payments that would have been charged to capacity suppliers if the PER Adjustment were calculated using a just and reasonable PER Strike Price." On Mar. 3, NESCOE and RESA answered NEPGA's rehearing request. NEPGA answered those answers on Mar. 17. The FERC issued a tolling order on Mar. 16, 2017, affording it additional time to consider NEPGA's request for rehearing, which remains pending.

[9] 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).

[10] Prior to Chief Judge Cintron's order, the following parties filed doc-less interventions in ER17-2153: Calpine, ConEd, Entergy, Eversource, Exelon, HQUS, NEPGA, NESCOE, NRG/GenOn, and RESA.

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

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 issued a tolling order on November 21, 2016, affording it additional time to consider the requests for rehearing, which remain pending.

Hearings. On December 21, 2016, in response to a request of the parties and supported by Settlement Judge Long, Chief Judge Cintron designated Steven A. Glazer as presiding judge for hearings in this matter, so that hearing procedures could proceed *concurrently* with settlement judge procedures (now terminated). Pursuant to a May 26, 2017 order of Chief Judge Cintron, hearings are now scheduled to be held December 11-15, 2017, with an initial decision to be issued on or before March 27, 2018.

There has been considerable activity since the last Report. Trial Judge Glazer scheduled a Pre-Hearing IT meeting for December 8 and oral argument for December 11 (just ahead of the commencement of hearings) on a December 1 motion by CAPS to compel TOs' answers to certain data requests. Submissions since the last report include EMCOS rebuttal testimony, including a late-filed summary of Dr. Peters' rebuttal testimony, EMCOS updated testimony and work papers of J. Lesser, pre-hearing briefs by CAPS, EMCOS, TOs and FERC Trial Staff (the "Parties"), and Parties' joint statement of issues, witness list, statement of positions, and index of exhibits. As noted above, hearings are scheduled to begin next Monday, December 11.

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 of all four ROE complaints (captioned above) in light of the *Emera Maine*[12] 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. These motions 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 Tariff is unjust, unreasonable, and unduly 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").[13] 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

[12] *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).

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

in an over-recovery of costs" due to the "the timing and synchronization of the RNS and LNS rates".[14] 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.[15] Hearings are being held in abeyance pending the outcome of settlement judge procedures underway.[16] The FERC-established refund date is January 4, 2016.[17]

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 have been held in 2017: April 5, May 9, July 7, and November 13, 2017. A tenth settlement conference has been scheduled for January 9, 2018. Judge Dring's most recent status report was issued on December 5, noting that the proceeding is taking longer than expected but that the parties are making progress toward settlement. Accordingly, he recommended that the settlement procedures be continued. 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)[18] and third (EL14-86)[19] 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;[20] the second, in EL14-86, was issued on November 24, 2014, established a 15-month refund period beginning July 31, 2014,[21] and, because of "common issues of law and fact", consolidated the two proceedings for purposes of hearing and decision, with the FERC finding it "appropriate for the parties to litigate a separate ROE for each refund period."[22] The TOs requested rehearing of both orders. On May 14, 2015, the FERC denied rehearing of both orders.[23] On

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[14] *Id.* at P 8.

[15] *Id.* at P 11.

[16] *Id.*

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

[18] 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%.

[19] 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.

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

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

[22] *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).

[23] *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).

July 13, 2015, the TOs appealed those orders to the DC Circuit Court of Appeals (*see* Section XIV below), and that appeal remains pending.

Hearings and Trial Judge Initial Decision. Initial hearings on these matters were completed on July 2, 2015. In mid-December 2015, Judge Sterner reopened the record for the limited purpose of having the 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.[24] The Decision also lowered the ROE ceilings. Judge Sterner's decision, if upheld by the FERC, would result in refunds totaling as much as $100 million, largely concentrated in the EL13-33 refund period. Briefs on exceptions were filed by the TOs, Complainant-Aligned Parties ("CAPs"), EMCOS, and FERC Trial Staff on April 21, 2016; briefs opposing exceptions, on May 20, 2016. Judge Sterner's findings and Initial Decision, and pleadings in response thereto, remain pending, and will be subject to challenge, before the FERC. The *2012/14 ROE Initial Decision* and its findings can be approved or rejected, in whole or in part.

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

II. Rate, ICR, FCA, Cost Recovery Filings

- **ICR-Related Values and HQICCs – Annual Reconfiguration Auctions (ER18-371)**

On December 1, 2017, ISO-NE and NEPOOL jointly filed materials that identify the Installed Capacity Requirement ("ICR"), Local Sourcing Requirements ("LSR"), Maximum Capacity Limits ("MCL"), Hydro Quebec Interconnection Capability Credits ("HQICCs"), and capacity requirement values for the System-Wide and Marginal Reliability Impact Capacity Demand Curves (collectively, the "ICR-Related Values") for the third annual reconfiguration auction ("ARA") for the 2018-19 Capability Year to be held March 1, 2018, the second ARA for the 2019-20 Capability Year to be held August 1, 2018, and the first ARA for the 2020-21 Capability Year to be held June 1, 2018. The ICR-Related Values were supported by the Participants Committee at its November 3, 2017 meeting. A January 30, 2018 effective date was requested. Comments on this filing are due December 22, 2017. Thus far, NRG has filed a doc-less intervention. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **FCA12 Qualification Informational Filing (ER18-264)**

On November 7, 2017, ISO-NE submitted its informational filing (the "FCA12 Informational Filing") for qualification in FCA12. ISO-NE is required under Market Rule Section 13.8.1 to submit an informational filing with the FERC containing the determinations made by ISO-NE for the upcoming Forward Capacity Auction ("FCA") at least 90 days prior to each auction. FCA12 is scheduled to begin February 5, 2018. The Informational Filing contained ISO-NE's determinations that the same three Capacity Zones that were modelled for FCA11 will be modelled for FCA12 -- Southeastern New England ("SENE"), Northern New England ("NNE") and Rest of Pool. SENE will again be modeled as import-constrained; NNE will be modeled as export-constrained. The Informational Filing reported that there will be 35,007 MW of existing capacity in FCA12 competing with 5,605 MW of new capacity under a Net ICR of 33,725 MW (ICR minus HQICCs). The ISO reported also that there were a total of 2,309 MW of Static, Export, and Administrative Export De-list bids. A summary of the De-list bids accepted and those rejected for reliability purposes was included in a privileged Attachment E.

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

Comments on the FCA12 Informational Filing were due November 22, 2017. There were two protests filed, one by Efficiency Maine Trust and the other jointly by Enerwise Global Technologies, Inc., d/b/a CPower and Tesla, Inc. (together, "CPower"). Efficiency Maine seeks modification of the determinations made for three of its energy efficiency ("EE") resources that it believes were unjustly decreased. Efficiency Maine also requests that FERC direct ISO-NE to continue to work cooperatively with Efficiency Maine to address the methodology issue that gave rise to the dispute and to correct that methodology in time for FCA13 so that it otherwise accounts for EE resource not accounted for in the FCA12 filing. For their part, CPower challenges ISO-NE's denial of CPower's Renewable Technology Resources ("RTR") status request for certain of its already qualified new On-Peak Demand Resources utilizing renewable technologies (i.e., solar and fuel cells/solar projects), including Tesla's renewable distributed resources. CPower asserts that ISO-NE has inconsistently interpreted Tariff Section III.13.1.1.1.7 to require a new On-Peak Demand Resource to demonstrate both that it currently *qualifies* under a state renewable or alternative energy portfolio standard ("RPS") and is currently *receiving* an out-of-market revenue source supported by such a program or a similar mechanism. CPower asks the FERC to direct ISO-NE to review RTR status for the New On-Peak Demand Resources consistent with the reality that new renewable resources are eligible to receive an out-of-market revenue source supported by an RPS program and, as a New Resource, will have a future in-service date given the anticipated Capacity Delivery Period. Doc-less interventions were filed by NEPOOL, Dominion, Eversource, NRG, and NESCOE. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **ICR-Related Values and HQICCs – 2021-22 Capacity Commitment Period (ER18-263)**

Also on November 7, 2017, ISO-NE filed ICR, LSR for SENE, MCL for NNE, HQICCs, and Marginal Reliability Impact ("MRI") Demand Curves (collectively, the "2021-22 ICR-Related Values") for the 2021-22 Capacity Commitment Year. The values will be used in FCA12 to be held in February 2018. With a 2021-22 ICR of 34,683 MW (reflecting tie benefits of 2,020 MW) and HQICCs of 958 MW/mo., the net amount of capacity to be purchased in FCA12 to meet the ICR will be 33,725 MW. The LSR for the SENE Capacity Zone is 10,018. The Participants Committee supported the 2021-22 ICR-Related Values at its October 13, 2017 meeting.

Comments on this filing were due November 28. Comments were filed NEPOOL, NEPGA, and NESCOE. NEPOOL's comments explained NEPOOL's processes and deliberations that preceded the November 7 filing and NEPOOL's support of the 2021-22 ICR-Related Values. NEPGA, while not contesting the November 7 filing, highlighted its concerns that ISO-NE's methodology for calculating ICR may overestimate the contribution of behind-the-meter photovoltaic ("BTM PV") resources to ISO-NE's resource adequacy needs and identified ISO-NE's commitment to work through the Participant Processes to address the concerns raised by NEPGA prior to FCA13 (and reserving NEPGA's right to later protest if corrections are not made). NESCOE supported the 2021-22 ICR-Related Values, agreeing that ISO-NE's incremental change to the PV Forecast was sound and necessary and, to the extent the FERC views as appropriate any additional guidance with respect to the development of the ICR, suggested that ISO-NE be encouraged "to work on further refinements to the load forecast to ensure that, as DG technologies are deployed in greater numbers and new data and modeling software become available, contributions from all DG resources are reflected in the ICR." Doc-less interventions were filed by Calpine, Dominion, Eversource, Exelon, FirstLight, and NRG. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

On November 1, Emera filed changes to Attachment J of the MPD OATT 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. Comments on this filing were due on or before November 22. A protest was filed by the Maine Customer Group

("MCG").[25] MCG identified a number of reasons why they asserted that the changes should be rejected, but their principal objection was the fact that "Emera already has a true-up mechanism in place under the MPD OATT to accommodate loss of Houlton load". No protests or comments were filed. This matter is pending before the FERC. If there are any questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **2018 NESCOE Budget (ER18-85)**

On December 6, the FERC accepted ISO-NE's October 17 filing of materials supporting the budget for and funding of NESCOE's 2018 operations. NESCOE's 2018 Operating Expense Budget is $2,282,317. The amount to be recovered reflects true-ups from 2016 overcollections of $752,672. The NESCOE budget will result in a charge of $0.00648 per kilowatt of Monthly Network Load. Unless the December 6 order is challenged, this proceeding will be concluded. If there are any questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **2018 ISO-NE Administrative Costs and Capital Budgets (ER18-77)**

The FERC also accepted on December 6 ISO-NE's October 16 filing for recovery of its 2018 administrative costs (the "2018 Revenue Requirement") and submission of its capital budget and supporting materials for calendar year 2018 ("2018 Capital Budget", and together with the 2018 Revenue Requirement, the "2018 ISO Budgets"). The 2018 ISO Budgets were filed together pursuant to the Settlement Agreement entered into to resolve challenges to the 2013 ISO Budgets. In the October 16 filing, the ISO reported that the 2018 Revenue Requirement, after true-up for 2016, is $195.5 million. Of that total, the ISO's administrative costs (i.e., the 2018 Core Operating Budget) comprise $164.2 million; depreciation and amortization of regulatory assets, $31 million; and 2016 true-up, that increases the 2018 Revenue Requirement by $400,000 as a result of a 2016 undercollection.

The ISO further reported that the 2018 Capital Budget, like the 2017 Capital Budget, is $28 million and is comprised of the following (with 2018 projected costs and target completion dates, if available, in parentheses):

Non-Project Capital Expenditures	($4 million)	2018 Issue Resolution Phase I (Jun 2018)	($800,000)
CASPR (Dec 2018)	($3 million)	2018 Issue Resolution Phase II (Dec 2018)	($700,000)
Other Emerging Work	($2.2 million)	FCM PFP (Jun 2018)	($600,000)
Price Responsive Demand (Q2 2018)	($2.1 million)	Enterprise Application Integration (Sep 2018)	($600,000)
FCA13 (Jun 2019)	($2 million)	Capitalized Interest	($500,000)
Storage Device Alternatives (Dec 2018)	($1.8 million)	FERC Form 1, 3-Q, 714 (Dec 2018)	($500,000)
nGem Software Development (Jun 2019)	($1.8 million)	Balance of Planning Period ("BoPP") FA Project (Dec 2018)	($400,000)
Operational Load Forecast: PV Integration (Dec 2018)	($1 million)	IMM Data Analysis Phase I (Apr 2018)	($400,000)
Energy Manag. Platform 3.2 Upgrade and Customs Reduction (Dec 2018)	($1 million)	FCM Improvements (Aug 2017)	($300,000)

[25] 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").

‣ Identity and Access Management (Sep 2018)	($800,000)	‣ Customer Contact Center Solution (Feb 2018)	($200,000)
		‣ CIMNET Simultaneous Feasibility Test w/ Data Transfer Enhancements (Dec 2018)	($200,000)

Unless the December 6 order is challenged, this proceeding will be concluded. If there are any questions on this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **Exelon Additional Cost Recovery Compliance Filing (ER17-933)**

As previously reported, the FERC granted Exelon Generation Company's ("Exelon's") request for additional fuel cost recovery for all mitigated days from October through November 2016, including the October 1, 3, and 4, 2016, operating days, in an amount totaling $1,554,854, as calculated by the IMM (slightly more than identified in the initial filing,[26] *plus* reasonable regulatory costs incurred in connection with the filing (subject to an Exelon compliance filing detailing the actual regulatory costs).[27] On November 20, Exelon submitted that compliance filing, detailing $97,188.90 in actual regulatory costs incurred and to be recovered in connection with its request for additional fuel cost recovery for Mystic Units 8 & 9. Comments on the compliance filing are due on or before December 11, 2017. If you have any questions concerning this mater, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

On October 6, 2017, the FERC rejected the TOs' June 5, 2017 filing in this proceeding,[28] which 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*[29] decision. The FERC required the TOs to continue collecting their ROEs currently on file, subject to a future FERC order.[30] 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.[31] On November 6, the TOs requested rehearing of the *Order Rejecting Filing*. On December 4, 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

- **Waiver Request: 2017/18 Winter Reliability Program Participation Notice Deadline (Braintree) (EL18-5)**

On November 27, the FERC granted Braintree's request for a limited waiver of the Notice Deadline for Participation in the 2017-18 Winter Reliability Program.[32] The Tariff deadline (set forth in Tariff Section III.K.1(e))

[26] *Exelon Generation Co., LLC*, 160 FERC ¶ 61,076 (Sep. 20, 2017) ("*Exelon Cost Recovery Order*").

[27] *Id.* at P 30.

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

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

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

[31] *Id.* at P 36.

[32] *Braintree Electric Light Department*, 161 FERC ¶ 61,224 (Nov. 27, 2017) ("*Braintree Waiver Order*").

was Sunday, October 1. Braintree submitted its notice before the start of the Business Day on Monday, October 2 (under the mistaken belief that the deadline would have been extended to the next Business Day given that the October 1 deadline fell on a weekend day), but its notice was rejected because the deadline had passed. No protests were filed in response to Braintree's waiver request. In granting the waiver, the FERC found that its conditions for granting waiver of tariff provisions were satisfied.[33] In light of the waiver, ISO-NE is allowed to consider Braintree's offer to participate in, but does not guarantee Braintree's acceptance into, the 2017-18 winter reliability program. If you have any questions concerning this mater, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Waiver Request: DR Auditing Requirements (CPower) (ER18-185)**

On October 30, 2017, Enerwise Global Technologies Inc. d/b/a CPower Corp. ("CPower") requested a one-time waiver of Tariff Sections III.13.6.1.5.4.1(c) and III.13.6.1.5.4.5 to allow the ISO to use July 26 Real-Time Demand Response ("RTDR") resource audit results as CPower's July 2017 Demand Reduction Value, rather than Jul 19 results which, because of a "communications software anomaly", produced "zero" reduction performance results. CPower explained that the communication software anomaly can be traced to an earlier July 12 outage at CPower's leased data center, following which CPower's Remote Terminal Unit ("RTU") communications service was not fully and properly restored, preventing a July 19, 2017 dispatch signal sent as part of an audit to not be received, ultimately producing "zero" reduction performance. Following full restoration of the RTU service, a subsequent audit was requested and performed on July 26. The requested waiver would permit the July 26 Audit results to replace the zero July 19 Audit results as the Demand Reduction Value (and mitigate the financial impacts of the July 19 results). Comments on CPower's waiver request were due on or before November 20. ISO-NE submitted comments opposing the waiver request (suggesting the request is not limited in scope, there is no concrete problem to be remedied and the likelihood that the waiver would result in unfavorable treatment to similarly-situated participants). NEPOOL submitted a doc-less intervention. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Small Generator Modeling Options Change (ER18-122)**

On November 22, the FERC accepted a change to provide an exception to the electronic dispatchability requirements for small generators that are currently modeled in the ISO's network model but are not capable of electronic dispatch (the "Small Generator Modeling Options Change"). The change was accepted effective as of December 20, 2017, as requested. Unless the November 22 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **NCPC Calculation Changes for Ramp Constrained Down Resources (ER17-2569)**

On November 2, the FERC accepted changes to the cost-related eligible quantity NCPC calculation provisions of the Tariff ("NCPC Calculation Changes"). The NCPC Calculation Changes were designed to avoid providing financial incentives for resources to deviate from dispatch instructions. The NCPC Calculation Changes were accepted effective as of December 1, 2017, as requested. The November 2 order was not is challenged, is final and unappealable, and this proceeding is concluded. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Waiver Request: Dispatchable Resources RTU Requirement (McCallum Enterprises) (ER17-1615)**

The May 9 request of McCallum Enterprises, owner of the 7 MW Derby Hydroelectric Project in Shelton and Derby, Connecticut, for a waiver of the portion of Market Rule Section 1.11.3 that requires McCallum to install a remote terminal unit ("RTU") and the necessary circuitry to make the Derby Project electronically dispatchable ("Waiver Request"), remains pending. McCallum asserts that, based on the specific facts related to the Derby Project, that it is both unreasonable and unnecessary for it to be required to incur the expenses

[33] *Braintree Waiver Order* at P 12.

associated with an RTU and 24x7x365 staff monitoring. McCallum asks that it be allowed to continue to utilize a telephone-based dispatch system. On May 31, the ISO opposed the Waiver Request. In opposing the request, the ISO asserted that McCallum has at least two other available options to meet the Resource Dispatchability Requirements, the Waiver Request is contrary to both the price formation and reliability objectives of the Resource Dispatchability Rules, would provide an unjustified preference over similarly situated resources, and would not be consistent with OP-14 requirements that a Designated Entity be available 24x7x365 to receive dispatch instructions. CL&P, which is the Lead Market Participant for the Project, intervened and asked that it "not be held liable for compliance with the market rule should the waiver request be declined." In a June 12 answer, the ISO opposed CL&P's request, noting that, "as the Lead Market Participant for the Derby Dam facility, and under the terms of the Market Participant Service Agreement executed by it, CL&P is responsible for compliance with all ISO-NE Tariff requirements applicable to the Derby Dam facility—including compliance with the new Resource Dispatchability rules." McCallum answered the ISO's protest on June 9, re-iterating its points made in the initial May 9 request, and the ISO's answer to CL&P's motion on June 22.

On September 7, the ISO withdrew its opposition to the McCallum Waiver Request. The ISO stated that, based on McCallum statements in its June 9 answer (which indicated that McCallum's generator does not have control over its output because its operation is wholly subject to the operation of an upstream dam facility), and after further investigation, the ISO has subsequently determined that the Derby Dam facility is improperly registered as a non-intermittent generator, and that it should instead be registered as an intermittent generator. If properly registered as an intermittent generator, the Derby Dam Facility would not in fact be subject to the Resource Dispatchability rules. The ISO added that it is undertaking efforts to require the resource to re-register as an intermittent generator, and to evaluate whether it should be subject to other dispatch rules when so registered. On October 11, McCallum requested the FERC delay action on its waiver request for 90 days so that it might have time to "provide FERC with relevant information required for the Commission's consideration regarding McCallum's request." As noted, McCallum's Waiver Request remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- ***Order 831* (Modified Energy Market Offer Caps) Revisions (ER17-1565)**

On November 9, the FERC accepted Tariff changes filed in response to the requirements of *Order 831* ("*Order 831* Revisions"). As previously reported, the *Order 831* Revisions cap incremental energy offers at the higher of $1,000/MWh or a resource's verified cost-based incremental energy offer (with a hard cap of $2,000/MWh on incremental energy offers used in pricing calculations), provide for make whole payments to recover costs that cannot be verified until after the offer clears and the resource is dispatched, and apply offer cap requirements on a resource-neutral basis. In addition, the *Order 831* Revisions include a number of ancillary changes required in order for the offer capping rules to function seamlessly within the market or that are needed because of their relationship to the offer capping rules. The *Order 831 Revisions* were accepted effective as of October 1, 2019, as requested (which the ISO stated accounts for the time required to design, develop, implement and test the software and process changes required to implement the *Order 831* Revisions and the need to complete other high-priority projects ahead of the development of *Order 831* Revision-implementing software changes). Unless the November 9 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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

Rehearing has been requested and is 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 the ISO in January.[34] In accepting the changes, the FERC disagreed with the challenges to ISO-NE's choice of reference

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

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, the FERC issued a tolling order providing it additional time to consider 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).

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

On October 30, the FERC denied[35] NEGPA, NextEra and Exelon's ("Petitioners") request for rehearing and clarification of the *Resource Retirement Reforms Order.*[36] As previously reported, the *Retirement Reforms Order* conditionally accepted, effective March 1, 2016, changes to the FCM rules for resource retirements proposed by the ISO and its Internal Market Monitor ("IMM") (the "ISO/IMM Proposal"). The FERC conditioned its acceptance of the ISO/IMM Proposal on the filing of Tariff revisions "establishing a materiality threshold for determining whether or not a particular proxy de-list bid will replace a Retirement Bid in an FCA,"[37] which were filed with and later accepted by the FERC.[38] Petitioners jointly requested rehearing of the *Resource Retirement Reforms Order*. In denying rehearing, the FERC explained, as it had in the *Resource Retirement Reforms Order*, that the "tariff changes add steps to the bid review process but do not fundamentally alter the process in a manner that infringes on Petitioners' rights to file rates under section 205 of the FPA."[39] The FERC rejected Petitioners' "implicit contention that [the ISO] does not provide a jurisdictional service and that the FCA is the suppliers', instead of [the ISO's], rate."[40] The FERC disagreed that its *Resource Retirement Reforms Order* described the IMM as possessing "unfettered license to review all bids" nor that the Tariff changes oblige the FERC to accept as just and reasonable an IMM-mitigated bid in lieu of a more accurate supplier-initiated bid.[41] The FERC disagreed that the two-run mechanism "unduly discriminates against suppliers who clear in the first and second round runs of the Forward Capacity Auction but are paid only the first round's clearing price", finding the mechanism "necessary to ensure that non-retiring suppliers themselves are not unduly discriminated against due to a retiring supplier's exercise of market power."[42] In addition, the FERC explained that it was persuaded of the need and reasonableness of addressing possible price distortion despite the risk of lower capacity prices resulting from possible over-mitigation.[43] Unless the *Resource Retirement Reforms Rehearing Order* is challenged on appeal in Federal Court, with any such challenge due on or before December 29, 2017, this matter will be concluded. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

[35] *ISO New England Inc.*, 161 FERC ¶ 61,115 (Oct. 30, 2017), *reh'g and clarif. denied* ("*Resource Retirement Reforms Rehearing Order*").

[36] *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). As previously reported, the ISO/IMM Proposal requires (i) that capacity suppliers with existing resources to submit a price for the retirement of a resource (to replace the existing Non-Price Retirement Request process), (ii) the use of a Proxy De-List Bid, and (iii) notice of the potential retirement and proposed retirement price to be submitted prior to the commencement of an FCA's qualification process for new resources. The ISO/IMM Proposal was considered but not supported by the Participants Committee at its Dec. 4, 2015 meeting.

[37] *Id.* at P 62.

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

[39] *Resource Retirement Reforms Rehearing Order* at P 15.

[40] *Id.* at P 17.

[41] *Id.* at P 18.

[42] *Id.* at P 22.

[43] *Id.* at P 25.

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

Still pending before the FERC is the ISO's compliance filing in response to the FERC's August 8, 2016 remand order.[44] In the *2013/14 Winter Reliability Program Remand Order*, the FERC directed the ISO to request from Program participants the basis for their bids, including the process used to formulate the bids, and to file with the FERC 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.[45] The ISO 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, the ISO 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 the ISO'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, the ISO answered the TransCanada and MA AG protests. On March 10, TransCanada answered the ISO's February 28 answer. This matter is again 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

- **Attachment K Revisions (Updates to Appendix 3 List of QTPS) (ER17-2514)**

On November 13, the FERC accepted revisions to Appendix 3 to Attachment K that update the list of Qualified Transmission Project Sponsors ("QTPS") to add: Belmont, Holyoke, CTMEEC, Grid America Holdings, Hudson, Middleborough, Norwood, and Taunton. The changes were accepted effective as of November 20, 2017, as requested. Unless the November 13 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Clustering Revisions (ER17-2421)**

On October 31, the FERC accepted, without change or condition, the "Clustering Revisions" (changes to the ISO Tariff to incorporate a cluster-based methodology for considering Interconnection Requests and allocating interconnection upgrade costs when a specified set of conditions are present in the interconnection queue).[46] The Clustering Revisions were accepted effective as of November 1, 2017, as requested. The *Clustering Revisions Order* was not challenged, is final and unappealable and this proceeding is concluded. If you have any questions concerning this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

[44] *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).

[45] *2013/14 Winter Reliability Program Remand Order* at P 17.

[46] *ISO New England Inc.*, 161 FERC ¶ 61,123 (Oct. 31, 2017) ("*Clustering Revisions Order*").

VI. Schedule 20/21/22/23 Changes

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

On December 5, Emera Maine and ISO-NE filed a Local Service Agreement ("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 LSA extends the same discounted service rate to Stored Solar that was offered to its predecessors, Indeck Maine and Covanta Maine. A January 1, 2016 effective date (the date Stored Solar acquired the Jonesboro facility) was requested. Comments on the LSA are due on or before December 26, 2017. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 22: Clear River LGIA (ER18-349)**

On November 29, ISO-NE and NEP filed an unexecuted Large Generator Interconnection Agreement ("LGIA") by and among ISO-NE, NEP and Clear River to govern the interconnection of Clear River's proposed new Large Generating Facility to be located in Burrillville, Rhode Island (the "Clear River Project"). ISO-NE reports that the Clear River LGIA is being filed unexecuted because Clear River disagrees with various aspects of the Clear River LGIA, including Clear River's challenges regarding cost responsibility for upgrades and the post-FCA restudy. (*See also* Clear River Schedule 11 O&M Complaint, EL18-31, Section I above). A November 30, 2017 effective date was requested (to coincide with the date on which interconnection activities under the LGIA are expected to commence). Comments on the LGIA are due on or before December 20, 2017. Thus far, doc-less interventions have been filed by NEPOOL and Dominion. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Schedule 21-NEP: NEP/Graite Reliable Power RFA (ER18-346)**

On November 29, 2017, New England Power ("NEP") filed a Related Facilities Agreement ("RFA") with Granite Reliable Power, LLC ("Granite Reliable Power") to address costs associated with upgrades to NEP's equipment at the Moore Generating Station and modifications to NEP's protection system in connection with the Dummer, New Hampshire interconnection of Granite Reliable Power's 99 MW wind generation facility. A November 1, 2017 effective date was requested. Comments on this filing are due on or before December 20, 2017. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Eversource Reorganization Tariff Changes (ER18-132)**

On October 23, 2017, Eversource filed tariff revisions to the following portions of Section II of the ISO Tariff to reflect the new references to NSTAR Electric (East) and NSTAR Electric (West), which will be used to refer to the transmission services and rates previously provided separately by NSTAR Electric and WMECO, that will continue to be provided as if NSTAR Electric and WMECO were separate legal entities, until such future time as a filing can be made to allow for one set of books and records and to adjust rates as may be necessary: Schedules 21-NSTAR and 21-ES, Schedules 20A-NSTAR and 20A-ES, and the Attachment F and Schedule 1 Implementation Rules. Comments on this filing were due on or before November 13; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **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

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

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]

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 November 21 status report, Judge Dring found that that the parties are making 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).

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48 *Id.* at P 24.

49 *Id.* at PP 25-26.

50 *Id.* at P 27.

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

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

- **Capital Projects Report - 2017 Q3 (ER18-81)**

On December 6, the FERC accepted ISO-NE's October 16 Capital Projects Report and Unamortized Cost Schedule covering the third quarter ("Q3") of calendar year 2017 (the "Report"). Report highlights included the following new projects: (i) Customer Contact Center Solution ($694,600); and (ii) Regulation Sub-Hourly Settlements ($440,000). Projects with a significant changes were (i) BoPP FAP (2017 Budget decrease of $387,700, reallocation to 2018, with total project costs remaining at $658,500); (ii) Transmart Technical Architecture Update (2017 Budget decrease of $372,700 with a total project cost of $50,000); (iii) IMM Data Analysis Phase I (2017 Budget decrease of $126,900, for total project costs of $1.16 million); and (iv) IT Asset Workflow (2017 Budget increase of $150,000, for a total project cost of $944,500). Unless the December 6 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

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

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 the ISO 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).

- **ISO-NE FERC Form 3Q (2017/Q3) (not docketed)**

On November 22, the ISO submitted its 2017/Q3 FERC Form 3Q (quarterly financial report of electric utilities, licensees, and natural gas companies). FERC Form 3-Q is a quarterly regulatory requirement which supplements the annual FERC Form 1 financial reporting requirement. These filings are not noticed for comment.

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

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

IX. Membership Filings

- **December 2017 Membership Filing (ER18-353)**

On November 30, NEPOOL requested that the FERC accept (i) the memberships of Fusion Solar Center (Related Person to Deepwater Wind Rhode Island (AR Sector) and Josco Energy MA (Supplier Sector); and (ii) the name change of Supplier Sector member Summer Energy Northeast (f/k/a REP Energy). Comments on the December Membership filing are due on or before December 21.

- **November 2017 Membership Filing (ER18-186)**

On November 29, the FERC accepted (i) the membership of Yellow Jacket Energy, LLC (Related Person to Bloom Energy (AR Sector)); and (ii) the termination of the Participant status of BNP Paribas Energy Trading.

- **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 Participant was 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***
Oct 31 / Nov 2	Lotus Danbury LMS100 Two, LLC ("Lotus Danbury Two")

As of the date of this report, Lotus Danbury Two is suspended from the Markets. 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).

- **FERC Staff Report on CIP v5 Reliability Standards Audits (not docketed)**

On October 6, 2017, FERC Staff issued a report offering recommendations to help those subject to the Critical Infrastructure Protection ("CIP") Reliability Standards to assess their risk, compliance with those standards and their overall cyber security. The report describes the lessons learned from FERC-led audits completed in fiscal years 2016 and 2017, including insights into the cyber security and CIP compliance issues encountered by the audited entities. Among staff's recommendations:

- Ensure that all shared facility categorizations are coordinated between the owners of the shared facility through clearly defined and documented responsibilities for CIP reliability standards compliance;
- Ensure that policies and testing procedures for all electronic communications protocols are afforded the same rigor; and
- For each remote cyber asset conducting Interactive Remote Access, disable all other network access outside of the connection to the bulk electric system cyber system that is being remotely accessed, unless there is a documented business or operational need.

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

On September 26, 2017, NERC filed 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) (together, the "Supply Chain Cybersecurity Risk Management Changes"). In addition, the FERC proposed to approve the associated VRFs, VSLs, implementation plans, effective dates, and retirements of the applicable currently-effective versions of the Standards immediately prior to the effective dates of the new Standards. 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*. NERC proposes that the Supply Chain Cybersecurity Risk Management Changes become effective on the first day of the first calendar quarter that is 18 calendar months after the effective date of the Commission's order approving the Changes. As of the date of this Report, the Supply Chain Cybersecurity Risk Management Changes have not been noticed for public comment.

- **NOPR: Revised Reliability Standards: EOP-004-4, EOP-005-3, EOP-006-3, EOP-008-2 (RM17-12)**

On September 20, 2017, the FERC issued a NOPR proposing to approve Emergency Preparedness and Operations ("EOP") Reliability Standards EOP-004-4 (Event Reporting), EOP-005-3 (System Restoration from Blackstart Resources), EOP-006-3 (System Restoration Coordination), and EOP-008-2 (Loss of Control Center Functionality) (together, the "EOP Changes").[54] In addition, the FERC proposed to approve the associated VRFs, VSLs, implementation plans, effective dates, and retirements of the currently-effective versions of the Standards immediately prior to the effective dates of the new Standards. The EOP Changes are designed to incorporate several recommendations resulting from a periodic review of the Standards, changes to eliminate inaccurate or duplicate reporting of events identified in the Department of Energy's ("DOE") Electric Emergency Incident and Disturbance Report (OE-417) and Attachment 1 to EOP-004, and to improve the Standards by enhancing the requirements for emergency operations, including the communication and coordination amongst reporting entities. Comments on the *EOP NOPR* were due on or before November 27, 2017[55] and were filed by NERC, EEI, and Magnum CAES

- **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").[56] 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* are due on or before December 26, 2017.[57]

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

On November 16, 2017 the FERC issued a NOPR proposing to (i) two new Reliability Standards -- PRC-027-1 (Coordination of Protection Systems for Performance During Faults) and PER-006-1 (Specific Training for

[54] *Emergency Preparedness and Ops. Rel. Standards*, 160 FERC ¶ 61,072 (Sep. 20, 2017) ("*EOP NOPR*").

[55] The *EOP NOPR* was published in the Fed. Reg. on Sep. 26, 2017 (Vol. 82, No. 185) pp. 44,746-44,750.

[56] *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*").

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

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 proposes 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* are due on or before January 22, 2018.[58]

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

The *ATC NOPR* remains pending before the FERC. As previously reported, the FERC's June 19, 2014, NOPR[59] proposed to approve changes to MOD-001-2 (Modeling, Data, and Analysis - Available Transmission System Capability) to replace, consolidate and improve upon the Existing MOD Standards in addressing the reliability issues associated with determinations of Available Transfer Capability ("ATC") and Available Flowgate Capability ("AFC"). MOD-001-2 will replace the six Existing MOD Standards[60] to exclusively focus on the reliability aspects of ATC and AFC determinations. NERC requested that the revised MOD Standard be approved, and the Existing MOD Standards be retired, effective on the first day of the first calendar quarter that is 18 months after the date that the proposed Reliability Standard is approved by the FERC. NERC explained that the implementation period is intended to provide NAESB sufficient time to include in its WEQ Standards, prior to MOD-001-2's effective date, those elements from the Existing MOD Standards, if any, that relate to commercial or business practices and are not included in proposed MOD-001-2. The FERC sought comment from NAESB and others whether 18 months would provide adequate time for NAESB to develop related business practices associated with ATC calculations or whether additional time may be appropriate to better assure synchronization of the effective dates for the proposed Reliability Standard and related NAESB practices. The FERC also sought further elaboration on specific actions NERC could take to assure synchronization of the effective dates. Comments on this NOPR were due August 25, 2014,[61] and were filed by NERC, Bonneville, Duke, MISO, and NAESB. On December 19, 2014, NAESB supplemented its comments with a report on its efforts to develop WEQ Business Practice Standards that will support and coordinate with the MOD Standards proposed in this proceeding. NASEB issued a report on September 25, 2015, informing the FERC that the NAESB standards development process has been completed and NAESB will file the new suite of business practice standards as part of Version 003.1 of the NAESB WEQ Business Practice Standards in October 2015. As noted above, the *ATC NOPR* remains pending before the FERC.

- **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 are due on or before December 12, 2017.

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

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

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

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

- **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.

- **Annual NERC CMEP Filing (RR15-2)**

On November 16, the FERC accepted NERC's February 22, 2017 compliance filing reviewing the progress of its risk-based Compliance Monitoring and Enforcement Program ("CMEP") program, but did not approve NERC's two proposed enhancements to the risk-based CMEP (eliminating the public posting of compliance exceptions identified through self-logging and expanding the use of compliance exceptions to include certain moderate risk noncompliance), because, in most situations, information on NERC's resolution of compliance and enforcement matters should be transparent and publicly available and processing of noncompliance should reflect the relative risk level of the violation.[62] Nonetheless, the FERC continues to support the general direction of NERC's compliance program towards a focus on risk-based compliance and concluded that its holding was consistent with that approach.[63] In addition, the FERC terminated the annual informational filing requirement that precipitated the filing in this proceeding.[64]

XI. Misc. - of Regional Interest

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

On November 22, Dynegy and Vistra Energy Corp. ("Vistra") requested authorization for a proposed transaction pursuant to which Dynegy will merge with and into Vistra, with Vistra being the surviving corporation (the "VistraTransaction"). Applicants requested an order authorizing the Vistra Transaction on or before March 15, 2018. Comments on the application are due on or before January 22, 2018.

- **203 Application: PSNH/Granite Shore (EC18-12)**

On October 27, PSNH and Granite Shore Power LLC ("Granite Shore")[65] requested authorization for a proposed transaction pursuant to which Granite Shore will acquire PSNH's portfolio of generation assets (the "Granite Shore Transaction").[66] Applicants requested an order authorizing the Granite Shore Transaction on or before December 22, 2017. Comments on the application are due on or before December 11, 2017.

[62] *N. Am. Elec. Rel. Corp.*, 161 FERC ¶ 61,187 (Nov. 16, 2017).

[63] *Id.* at P 37.

[64] *Id.* at P 22.

[65] Granite Shore is a Related Person to Supplier Sector members Castleton Commodities Merchant Trading LP, Rensselaer Generating LLC, and Roseton Generating LLC.

[66] PSNH's generation portfolio (1,130 MW) includes the following facilities: Merrimack, Schiller, Newington, White Lake, and Lost Nation.

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

On September 15, Calpine Corporation ("Calpine") requested authorization for a proposed transaction pursuant to which it will become an indirect, wholly-controlled subsidiary of ECP Control Co, LLC ("ECP") (the "Calpine/ECP Transaction"). Applicants requested an order authorizing the Calpine/ECP Transaction on or before January 15, 2018. Comments on the application are due on or before November 14, 2017. A protest was filed by Public Citizen, which asserted that, because the application failed to include Dynegy's merchant generation assets in the market power analysis (in which it believes Capital Partners has a significant financial interest), the application was incomplete. Calpine answered the Public Citizen protest, refuting its assertions and arguments. Public Citizen answered Calpine's answer, again asserting that the application be considered incomplete until ECP fully divests all Dynegy ownership or redoes the Competitive Analysis Screen to include ECP's ownership of Dynegy. This matter is pending before the FERC.

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

On October 31, the FERC approved certain conversions of GenOn notes into common equity of, and corporate structure changes that will result in, a "reorganized GenOn".[67] 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: PSNH /FPL Wyman 4 (EC17-132)**

On August 28, the FERC authorized the sale of Public Service Company of New Hampshire d/b/a Eversource Energy's ("PSNH" or "Seller") 3.14% ownership interest in W.F. Wyman Station – Unit 4 ("Wyman 4") and associated jurisdictional facilities to FPL Energy Wyman IV LLC (the "Transaction").[68] Among other conditions, the order required notice within 10 days of the consummation of the transaction. NextEra submitted that notice on November 6, reporting that the transaction was consummated on November 1, 2017 and concluding this proceeding.

- **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.[69] 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.

- **203 Application: WMECO /NSTAR Merger (EC17-62)**

On March 2, 2017, the FERC authorized Eversource's internal reorganization under which Western Massachusetts Electric Company ("WMECO") will merge with and into NSTAR Electric Company ("NSTAR"), with NSTAR as the surviving entity.[70] Applicants committed to hold harmless transmission and wholesale customers from transaction-related costs for five years to the extent that such costs exceed savings related to the merger. Among other conditions, the *NSTAR/WMECO Merger Order* required Eversource to notify the FERC within 10 days of the consummation of the merger, which was expected to occur on January 1, 2018. Since the last Report, Eversource submitted an informational filing notifying the FERC that, while there will be no rate changes

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

[68] *Public Service Co. of NH and FPL Energy Wyman IV LLC*, 160 FERC ¶ 62,186 (Aug. 28, 2017).

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

[70] *NSTAR Elec. Co. and W. Mass. Elec. Co.,* 158 FERC ¶ 62,155 (Mar. 2, 2017) ("*NSTAR/WMECO Merger Order*").

filed to accomplish the merger, NSTAR will temporarily keep separate books and records for transmission service and ratemaking purposes, and will continue to provide transmission service and charge customers rates as if the transmission assets were owned by legally separate entities, until it makes an application with the FERC to consolidate rates. Until that time, NSTAR Electric will use "NSTAR Electric (East)" and "NSTAR Electric (West)" to refer to the transmission services and rates previously provided separately by NSTAR Electric and WMECO, respectively.

- **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).

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

On December 5, NEP filed a new Phase I/II HVDC-TF Service Agreement with HQUS to allow the continuation without interruption of service provided pursuant to an existing agreement between NEP and HQUS that 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 is being 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). A January 1, 2018 effective date was requested. Comments, if any, on this filing are due on or before December 26. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement Cancellation: NSTAR/Essential Power Newington (ER18-330)**

On November 27, NSTAR filed a notice of cancellation of the Design and Engineering Agreement ("D&E Agreement") between NSTAR and Essential Power Newington (designated as service agreement IA-NSTAR-34). The D&E Agreement set forth the terms and conditions under which NSTAR undertook certain design and engineering activities on its transmission system[71] in connection with Essential Power Newington's FCA11 New Capacity Qualification Determination Notification. With the work completed, the

[71] Specifically, NSTAR has agreed to make changes to the Zone 2 timer on both primary (P1) and backup (P2) relays at its Mystic Substation that are associated with NSTAR Line 423-515.

D&E Agreement is now terminated. A November 27, 2017 effective date was requested. Comments, if any, on this filing are due on or before December 18. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **IA: CL&P/Woods Hill Solar (ER18-316)**

On November 20, 2017, Eversource, on behalf of CL&P, filed a two-party IA between CL&P and Woods Hill Solar to govern the interconnection of a 20 MW photovoltaic ("PV") generating facility to be located in Pomfret, CT. A November 30, 2017 effective date was requested. Comments on this filing are due on or before December 11, 2017. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement: Pootatuck Ring Bus Expansion (ER18-111)**

On October 19, The United Illuminating Company ("UI") filed a D&E Agreement between UI and Eversource for the planned Pootatuck Substation Ring Bus Expansion. The "Ring Bus Expansion" (relocation of the existing line structure and reconfiguration of the Pootatuck Substation into a four-breaker "ring" bus expansion) is designed to address conditions created under certain contingencies in which UI transmission loads could be subject to overloads or voltage collapse conditions. An October 20, 2017 effective date was requested. Comments on this filing were due on or before November 9; none were filed. A doc-less intervention was filed by Eversource. 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).

- **IA: New England Power/Wheelabrator Millbury (ER17-2557)**

On November 17, the FERC accepted a two-party LGIA between NEP and Wheelabrator Millbury, which replaces an expiring agreement governing, and to provide for continuing interconnection service to, Wheelabrator's 45.24 MW generation facility located in Millbury, Massachusetts. The LGIA is consistent with the ISO Tariff's Schedule 22 *pro forma* LGIA, other than changes to reflect the 2-party nature of the Agreement. The LGIA was accepted effective as of September 26, 2017, as requested (the previous interconnection agreement expired on September 25, 2017). Unless the November 17 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).

- **IA: PSNH/Pontook (ER17-2449)**

On September 7, 2017, as amended on October 31, 2017, Eversource, on behalf of PSNH, filed a two-party IA between PSNH and Pontook for the continued provision of interconnection service to Pontook's existing 3-unit, 9.6 MW hydro-electric facility located on the Androscoggin River in Dummer, New Hampshire. The facility has been connected to PSNH distribution system since 1986, Pontook makes use of PSNH's distribution system and the New England transmission system to market the output of the facility, and the IA replaces a 1985 Agreement whose initial 3-year term has expired. Because there was no modification to the facility or to the interconnection facilities, a three-way IA between PSNH, Pontook and ISO-NE under Schedule 23 of the ISO-NE OATT was not required. A December 16, 2016 effective date was requested. The October 31 amendment clarified that the IA will not be designated under Schedule 21-ES. Comments on the amendment filing were due on or before November 21, 2017; 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).

- **Maine Power Express Negotiated Rates Determination Request (ER16-1619)**

On May 26, Maine Power Express LLC ("MPX") filed a motion asking the FERC to determine that its July 1, 2016 order,[72] authorizing MPX to sell transmission rights at negotiated rates, permits MPX to sell the

[72] *Maine Power Express*, 156 FERC ¶61,002 (July 1, 2016).

Maine Power Express merchant transmission project's[73] capacity pursuant to the March 30, 2017 Massachusetts RFP. MPX requested expedited treatment of and a shortened comment period for its request, given the July 27 RFP bid deadline (which has since passed). As of the date of this Report, a comment date has still not yet been set. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

As previously reported, the FERC conditionally accepted, on December 7, 2015, changes to the Maine Public District ("MPD") Open Access Transmission Tariff ("MPD OATT"), including to the rates, terms, and conditions set forth in MPD OATT Attachment J.[74] However, the FERC found, ultimately, that the changes to the MPD OATT had not been shown to be just and reasonable, may be unjust and unreasonable, instituted a Section 206 proceeding (in EL16-13) to examine the provisions, and set the matter for a trial-type evidentiary hearing, to be held in abeyance pending the outcome of settlement judge procedures (*see* below).

Hearing and Settlement Judge Procedures. The FERC encouraged the parties to make every effort to settle their disputes before hearing procedures were commenced, and held hearings in abeyance pending the outcome of settlement judge procedures.

Settlement Agreement (-006). On June 22, Emera Maine submitted an uncontested Joint Offer of Settlement ("Offer of Settlement") between itself, Houlton Water Company, Van Buren Light and Power District, Eastern Maine Electric Coop., ReEnergy Biomass Operations, the MPUC, and Maine OPA (collectively, the "Settling Intervenors"). That Offer of Settlement, which resolved all issues pending in these proceedings, was approved on November 20.[75] This settlement does not, however, resolve the matters set for hearing and settlement judge procedures in *Emera Maine and BHE Holdings*, (2016). (*See* ER15-1434 in Section VI above.)

If you have any questions concerning these matters, 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.

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[73] The Maine Power Express project is a proposed 315-mile, 1,000 MW HVDC completely underground merchant transmission project that will originate in Haynesville, Maine, and terminate at a new DC/AC converter station in Boston connected with the Eversource transmission system. MPX anticipates that the Project will be operational in 2021.

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

[75] *Emera Maine*, 161 FERC ¶ 61,206 (Nov. 20, 2017).

- **FERC Enforcement Action: Barclays Bank et al. (IN08-8)**

On November 7, the FERC approved a Stipulation and Consent Agreement[76] that resolves its claims (and subsequent litigation in the US District Court for the Eastern District of California[77]) against Defendants for violations of section 222 of the Federal Power Act ("FPA") and the FERC's Anti-Market Manipulation Rules.[78] Under the Settlement, in which Defendants neither admited nor denied the alleged violations, Barclays agreed to pay a significantly smaller amount, ***$105 million*** -- a ***$70 million penalty*** and ***$35 million in disgorgement***, $20 million of which will be set aside to pay people or entities that claim to have been harmed because of Barclay's alleged misconduct. The FERC directed that the $15 million Disgorgement Payment owed to the FERC, as well as any amount of the $20 million Disgorgement Payment that is not used for remediation, shall go to the Low Income Home Energy Assistance Program (LIHEAP) of the states of Arizona, California, Oregon and Washington for the benefit of their respective electric energy customers. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

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

XII. Misc. - Administrative & Rulemaking Proceedings

- **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) 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 tech conference's calendar entry. Those interested were invited to submit post-conference comments on or before June 22. 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.

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[76] *Barclays Bank PLC, Daniel Brin, Scott Connelly, and Karen Levine*, 161 FERC ¶ 61,147 (Nov. 9, 2017).

[77] *FERC v. Barclays Bank PLC et al.*, No. 2:13-cv-02093-TLN-DB (E.D. Cal.).

[78] As previously reported, the FERC found that Barclays Bank PLC ("Barclays"), Daniel Brin, Scott Connelly, Karen Levine, and Ryan Smith ("Individual Traders", and collectively with Barclays, "Defendants") violated the FERC's Anti-Manipulation Rule by engaging over a two-year period in a deliberate and coordinated strategy of trading physical electricity at an economic loss at four trading points in the Western United States in order to boost Barclays' financial positions at those same trading points. FERC found that Defendants' conduct resulted in an estimated $139 million in financial losses to other market participants with positions settling off of the allegedly manipulated trading points. Accordingly, the FERC assessed a record amount of civil penalties -- $435 million against Barclays (plus disgorgement of $34.9 million, plus interest), $15 million against Connelly, and $1 million against each of Brin, Levine, and Smith. *Barclays Bank PLC*, 144 FERC ¶ 61,041 (2013).

- **BPS Reliability Technical Conference (AD17-8)**

On June 22, the FERC held a technical conference that discussed policy issues related to the reliability of the Bulk-Power System ("BPS"). Panel presentations covered the following topics: (i) an overview on the state of reliability; (ii) international perspectives; (iii) the potential for long-term and large-scale disruptions to the BPS; and (iv) grid security. Written comments were filed ahead of the conference by the Chairman of the Ohio Public Utilities Commission and by a representative of the Large Public Power Council. Speaker materials, as well as a transcript of the technical conference, are posted on the FERC's eLibrary. Since the last report, on June 20, Environmental Defense Fund filed post-technical conference comments. This matter is pending before the FERC.

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

As previously reported, the FERC held a technical conference on November 9, 2016 to discuss the utilization of electric storage resources as transmission assets compensated through RTO/ISO transmission rates, for grid support services that are compensated in other ways, and for multiple services. On November 14, the FERC invited all those interested to file, on or before December 14, 2016, post-technical conference comments on the topics discussed in the November 1 Supplemental Notice of Technical Conference. Comments were filed by over 45 parties, including Avangrid, Brookfield, EEI, Energy Storage Association, Exelon, FirstLight, NEPGA, NextEra, PSEG, Solar City/Tesla, and UCS. This matter is pending before the FERC.

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

The FERC held a technical conference on a June 27-28, 2016 to discuss competitive transmission development process-related issues, including use of cost containment provisions, the relationship of competitive transmission development to transmission incentives, and other ratemaking issues. In addition, participants had the opportunity to discuss issues relating to interregional transmission coordination, regional transmission planning and other transmission development issues. Pre-technical conference comments were filed by over 20 parties, including by NESCOE, BHE US Transmission, LSPower, and NextEra Energy Transmission. Technical conference materials are available on the FERC's e-Library. Post-technical conference comments were filed by over 60 parties, including: NEPOOL, ISO-NE, Avangrid, AWEA, BHE US Transmission, EDF Renewables, EEI, ELCON, Eversource, Exelon, LSP Transmission Holdings, MMWEC, National Grid, NESCOE, NextEra, and PSEG. This matter remains pending before the FERC.

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

A workshop to discuss compensation for Reactive Supply and Voltage Control (Reactive Supply) in RTO/ISO markets was held on June 30, 2016. The workshop explored the types of costs incurred by generators for providing Reactive Supply capability and service; whether those costs are being recovered solely as compensation for Reactive Supply or whether recovery is also through compensation for other services; and different methods by which generators receive compensation for Reactive Supply (e.g., FERC-approved revenue requirements, market-wide rates, etc.). The workshop also explored potential adjustments in compensation based on changes in Reactive Supply capability and potential mechanisms to prevent overcompensation for Reactive Supply. Technical conference materials are available on the FERC's e-Library. Written comments were filed by, among others, NYISO, PJM, the PJM IMM, AWEA, EEI, EPSA, EDF Renewables, Talen, Essential Power, and Exelon. EDF Renewables filed reply comments on August 19; the PJM IMM on August 21. This matter remains pending before the FERC.

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

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

Xcel Energy Services filed supplemental comments addressing the reasons why RTO energy market prices can be negative and the implications to wholesale and retail customers if QFs were required to be compensated at long-term fixed prices during periods when market prices are negative. In addition, the written testimony of the following individuals who appeared before the House Subcommittee on Energy on September 6, addressing "Powering America: Reevaluating PURPA's Objectives and its Effects on Today's Consumers" is posted in eLibrary: S. Thomas, PE (for the Industrial Energy Consumers of America); T. Kouba (for Alliant Energy Corporate Services); and F. Prager (for Xcel Energy Services).

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

As previously reported, the FERC directed each RTO/ISO to publicly provide, and the RTO/ISO's provided, information related to five price formation issues:[79] (1) pricing of fast-start resources; (2) commitments to manage multiple contingencies; (3) look-ahead modeling; (4) uplift allocation; and (5) transparency. The FERC indicated it would use the reports and comments filed in response thereto to determine what further action is appropriate. NOPRs addressing fast-start pricing (RM17-3) and uplift allocation and transparency (RM17-2) have already been issued.

- **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.[80] The NOI followed the D.C. Circuit's *United Airlines*[81] 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".[82] Comments and reply comments were submitted by over 25 and 18 parties, respectively. This matter is pending before the FERC.

- **DOE-Initiated Proposal: Grid Reliability & Resilience Pricing Rule (RM18-1)**

On September 28, exercising rarely-used authority under §403(a) of the Department of Energy ("DOE") Organization Act, Secretary of Energy Rick Perry sent to the FERC a proposal in the form of a NOPR that would, if adopted by the FERC, require 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. Secretary Perry established an aggressive 60-day timeframe for FERC action on the NOPR, with the aim of having new compensation mechanisms in place by winter.

On October 2, the FERC issued a notice inviting initial comments on the DOE proposal to be submitted by October 23, with reply comments due November 7. On October 4, the Director of the Office of Energy Policy and Innovation issued a list of questions to be addressed (to assist FERC Staff in its understanding of the

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

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

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

[82] *Id.* at 137.

implications of the proposed rule) related to the need for reform, eligibility, implementation, rates, and other. A number of requests to extend the proposed deadlines were filed, but denied.

More than 450 comments were submitted by October 23 in response to the DOE NOPR. Those filings raise and discuss an exceptionally broad spectrum of process, legal, and substantive arguments. NEPOOL's comments made the following three requests of FERC in considering its response to the DOE NOPR: (1) if FERC is inclined to issue a rule in response to the DOE NOPR, FERC should provide adequate time and process for meaningful stakeholder consideration and input on a FERC proposed rule before finalizing that rule; (2) if FERC concludes that changes to organized markets are needed, FERC should not mandate a single solution, but instead should allow sufficient flexibility, both procedurally and substantively, for each region with an organized market to address the concerns raised in the DOE NOPR with reference to the specific and unique circumstances of that region; and (3) FERC should ensure that there is adequate time for compliance with any final rule that might apply to New England so that New England can follow its FERC-approved stakeholder process in designing and finalizing any such compliance. A summary of the initial comments filed was circulated under separate cover and can be found with the posted materials for the November 3 meeting. Reply comments were due November 7 and were filed by over 100 parties, including ISO-NE. On November 20, NEPOOL filed a brief response to arguments made in certain reply comments, requesting that the FERC (i) reject any arguments that a one-size-fits-all solution should be implemented, without following applicable stakeholder processes, in response to the DOE NOPR, and (ii) respect regional differences and priorities, and to provide flexibility, both procedurally and substantively, for each region to satisfy its unique needs using its stakeholder processes in a time frame that allows for full and informed consideration of the market changes and is compatible with its priorities.

DOE set out a very expedited timeline final FERC action on the proposal and for ISOs/RTOs to implement the new requirements. DOE directed the FERC to take final action on the proposal within 60 days from the NOPR's publication[83] (or, alternatively, to issue the proposal as an interim final rule effective immediately). Under DOE's proposed schedule, the final rule would take effect within 30 days of publication of the final rule in the Federal Register, and the ISOs/RTOs would have to make compliance filings within 15 days of the effective date. The NOPR further proposed that compliance filings take effect 15 days after they are due and that RTO/ISOs would have to implement the NOPR by late January 2018.

- **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

[83] The DOE NOPR was published in the Fed. Reg. on Oct. 10, 2017 (Vol. 82, No. 194) pp. 46,940-46,948.

[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

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. This matter is pending before the FERC.

- **NOPR: Fast-Start Pricing in RTO/ISO Markets (RM17-3)**

On December 15, the FERC issued a NOPR proposing to require each RTO and ISO to incorporate market rules that meet certain requirements when pricing fast-start resources.[89] The FERC stated that the reforms should lead to prices that more transparently reflect the marginal cost of serving load, which would reduce uplift costs and thereby improve price signals to support efficient investments. Specifically, the FERC proposes to require that each RTO/ISO incorporate the following five requirements for its fast-start pricing:

1. an RTO/ISO must apply fast-start pricing to any resource committed by the RTO/ISO that is able to start up within 10 minutes or less, has a minimum run time of one hour or less, and that submits economic energy offers to the market;
2. when an RTO/ISO makes a decision to commit a fast-start resource, it should incorporate commitment costs, i.e., start-up and no-load costs, of fast-start resources in energy and operating reserve prices, but must do so only during the fast-start resource's minimum run time;
3. an RTO/ISO must modify its fast-start pricing to relax the economic minimum operating limit of fast-start resources and treat them as dispatchable from zero to the economic maximum operating limit for the purpose of calculating prices;
4. if an RTO/ISO allows off-line fast-start resources to set prices for addressing certain system needs, the resource must be feasible and economic; and
5. an RTO/ISO must incorporate fast-start pricing in both the Day-Ahead and Real-Time markets.

Comments on the *Fast-Start Pricing NOPR* were filed by numerous parties, including NEPOOL, ISO-NE and EEI. Reply comments were filed by MISO and the PJM IMM. On August 18, the CAISO filed supplemental comments (providing additional information identifying challenges facing CAISO and the adverse impacts it believes the NOPR rules would have on its markets). The *Fast-Start Pricing NOPR* remains pending before the FERC.

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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] *Fast-Start Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 157 FERC ¶ 61,213 (Dec. 15, 2016) ("*Fast-Start Pricing NOPR*").

- **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.[90] 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, Direct, Exelon, Potomac Economics, Saracen, EEI, APPA/NRECA, Appian Way Energy Partners, AWEA, ELCON, EPSA, Financial Marketers Coalition, and the IRC. This matter is pending before the FERC.

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

The FERC's *Storage NOPR* remains pending. As previously reported, on November 23, 2016, the FERC issued the *Storage NOPR* proposing to require each RTO and ISO to revise its tariff "to (1) establish a participation model consisting of market rules that, recognizing the physical and operational characteristics of electric storage resources, accommodates their participation in the organized wholesale electric markets and (2) define distributed energy resource aggregators as a type of market participant that can participate in the organized wholesale electric markets under the participation model that best accommodates the physical and operational characteristics of its distributed energy resource aggregation."[91] Comments on the *Storage NOPR* were filed by over 100 parties, including: NEPOOL, ISO-NE, APPA/ NRECA, Avangrid, AWEA, Brookfield, CT DEEP, CT PURA, Dominion, DTE, EEI, ELCON, EPSA, EPRI, ESA, Exelon, FirstLight, Genbright, Harvard Environmental Policy Initiative, IPKeys, MA DPU, MIT, MMWEC, NARUC, NERC, NESCOE, NextEra, NRG, SEIA, UCS. Since the last Report, supplemental comments were filed by the Advanced Energy Management Alliance. In addition, on September 22, a number of US Senators[92] requested that this rulemaking proceed towards completion as quickly as possible. Chairman Chatterjee responded to each on October 5, noting that the comments received are being reviewed and relaying his personal commitment to address the issues raised in the NOPR as the rulemaking proceeds forward. This matter remains pending before the FERC.

- **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.[93] 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

[90] *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*").

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

[92] Senators Whitehouse (RI), Booker (NJ), Markey (MA), Wyden (OR), Warren (MA), and Sanders (VT).

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

proposes to eliminate MBR sellers' corporate organizational chart submission requirement adopted in *Order 816*. Comments on the *Data Collection NOPR* were due on or before September 19, 2016[94] 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*[95] 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.[96] On December 19, 2016, EEI requested rehearing of *Order 833*. The FERC issued a tolling order on January 17, affording it additional time to consider the EEI request for rehearing, which remains pending.

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

The *Primary Frequency Response NOPR*[97] remains pending. The *Primary Frequency Response NOPR*, issued on November 17, 2016, proposes to require all newly interconnecting large and small generating facilities, both synchronous and non-synchronous, to install and enable primary frequency response capability as a condition of interconnection. To implement these requirements, the Commission proposes to revise the *pro forma* LGIA and the *pro forma* SGIA. The *Primary Frequency Response NOPR* follows the FERC's *Frequency Response NOI*[98] from early 2016. Comments on the *Primary Frequency Response NOPR* were filed by over 30 parties, including AWEA, EEI, ELCON, EPSA, ESA, First Solar, the IRC, NRECA, and UCS. Supplemental comments were filed by ELCON. On August 18, 2017, the FERC issued a request for supplemental comments related to whether and when electric storage resources should be required to provide primary frequency response, and the costs associated with primary frequency response capabilities for small generating facilities.[99] Supplemental comments were filed by over 20 parties, including the AES Companies, NERC, Western Interconnection Advisory Body, Magnum CAES, NRECA, Arizona Public Service, Tri-State Generation, and North American Generator Forum, Independent Transmission Company ("ITC"), the IRC, NYTOs, SoCal Edison, San Diego Gas & Electric, and the Energy Storage Association ("ESA").

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

On November 9, in *Order 831-A*,[100] the FERC granted in part and denied in part the requests for rehearing and clarification of *Order 831.*[101] *Order 831* required each RTO/ISO: (i) to cap each resource's

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

[95] *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*").

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

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

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

[99] Notice of the Request for Supplemental Comments was published in the Fed. Reg. on Aug. 24, 2017 (Vol. 82, No. 163) pp. 40,081-40,085.

[100] *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 831-A, 161 FERC ¶ 61,156 (Nov. 9, 2017) ("*Order 831-A*").

[101] *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 831, 157 FERC ¶ 61,115 (Nov. 17, 2016) ("*Order 831*"), *reh'g and clarif. granted in part and denied in part*, 161 FERC ¶ 61,156 (Nov. 9, 2017).

incremental energy offer at the higher of $1,000/MWh or that resource's verified cost-based incremental energy offer; and (ii) cap verified cost-based incremental energy offers at $2,000/MWh when calculating locational marginal prices ("LMP"). In addition, *Order 831* clarified that the verification process for cost-based incremental offers above $1,000/MWh should ensure that a resource's cost-based incremental energy offer reasonably reflects that resource's actual or expected costs. *Order 831* modified the FERC's *Offer Cap NOPR* by including a $2,000/MWh hard cap for the purposes of calculating LMPs. *Order 831* became effective February 21, 2017.[102] On December 19, 2017, American Municipal Power Inc. ("AMP") and APPA, Exelon, NYISO, and TAPS requested rehearing and/or clarification of *Order 831*.

In *Order 831-A*, in response to NYISO Concerns, the FERC clarified that *Order 831* did not require cost-based incremental energy offers above $2,000/MWh to be used to determine economic merit-order dispatch.[103] The FERC also clarified that application of the offer cap and verification requirement adopted in *Order 831* to minimum generation offers, as NYISO requested, is appropriate.[104] With respect to the verification requirement, the FERC granted Exelon's request to amend the regulatory text, by adding the words "actual or expected", to clearly state the FERC's intention that *both* actual and expected costs over $1,000/MWh may be submitted for verification. The FERC granted NYISO's request for clarification regarding the calculation of uplift payments, clarifying (i) that if a resource avails itself of an RTO's/ISO's current rules to allow a resource to include opportunity costs in its cost-based incremental energy offer, then that RTO/ISO must give that resource an opportunity to recover those opportunity costs through an uplift payment, subject to verification, (ii) that a resource may not receive uplift payments for incremental energy costs in excess of the costs included in its verified incremental energy offer, and (iii) after-the-fact uplift payments may not include any adders above cost, including risk related adders, because actual costs are known after-the-fact.[105] All other requests for rehearing and clarification were denied. *Order 831* becomes effective January 16, 2018.[106]

New England's Tariff revisions in response to requirements of *Order 831,* the *Order 831 Revisions,* were accepted on November 9, effective as of October 1, 2019, as requested (*see* ER17-1565, Section III above).

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).

- **Technical Conference: Natural Gas Index Liquidity, Price Discovery & Price Formation (AD17-12)**

The FERC held a technical conference on June 29 on developments in natural gas index liquidity and transparency. The purpose of the technical conference was to understand the state of liquidity in the physical natural gas markets, to explore current trends in physical natural gas trading and price reporting and how the use of natural gas indices have evolved over time, to obtain industry's views on the current level of confidence in natural gas indices and price formation, and finally, to consider whether there is a need to improve natural gas market liquidity and price reporting and, if so, how. Post-technical conference comments were filed on July 31 by AGA, INGAA, the PJM IMM, Rice Energy Marketing, Tenaska Marketing

[102] *Order 831* was published in the *Fed. Reg.* on Dec. 5, 2016 (Vol. 81, No. 233) pp. 87,770-87,800.

[103] *Order 831-A* at P 16.

[104] *Id.* at P 17.

[105] *Id.* at PP 39-40.

[106] *Order 831-A* was published in the *Fed. Reg.* on Nov. 16, 2017 (Vol. 82, No. 220) pp. 53,403-53,411.

Ventures and others. A transcript of the technical conference is available on the FERC's eLibrary. This matter is pending before the FERC.

- **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.[107] 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.[108] 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.[109] 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.[110] 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.[111] 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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[107] *Algonquin Gas Transmission, LLC*, 154 FERC ¶ 61,269 (Mar. 31, 2016).

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

[109] *Id.* at P 27.

[110] *Id*. at P 34.

[111] *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*[112] 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").[113] 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."[114] 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.[115] 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.[116]

Total Gas & Power North America, Inc. et al. (IN12-17). On April 28, 2016, the FERC issued a show cause order[117] in which it directed Total Gas & Power North America, Inc. ("TGPNA") and its West Desk traders and supervisors, Therese Tran f/k/a Nguyen ("Tran") and Aaron Hall (collectively, "Respondents") to show cause why Respondents should not be found to have violated NGA Section 4A and the FERC's Anti-Manipulation Rule through a scheme to manipulate the price of natural gas at four locations in the southwest United States between June 2009 and June 2012.[118]

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

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

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

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

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

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

[118] 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

The FERC also directed TGPNA to show cause why it should not be required to disgorge unjust profits of ***$9.18 million***, plus interest; TGPNA, Tran and Hall to show cause why they should not be assessed civil penalties (TGPNA - ***$213.6 million***; Hall - ***$1 million*** (jointly and severally with TGPNA); and Tran - ***$2 million*** (jointly and severally with TGPNA)). In addition, the FERC directed TGPNA's parent company, Total, S.A. ("Total"), and TGPNA's affiliate, Total Gas & Power, Ltd. ("TGPL"), to show cause why they should not be held liable for TGPNA's, Hall's, and Tran's conduct, and be held jointly and severally liable for their disgorgement and civil penalties based on Total's and TGPL's significant control and authority over TGPNA's daily operations. Respondents field their answer on July 12, 2016. OE Staff replied to Respondents' answer on September 23, 2016. 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.[119] 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.
    - 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.

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.

[119] *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).

- Certificate of public convenience and necessity granted Jan. 25, 2017.[120]
- Certain facilities,[121] 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.[122] 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.

- ***Connecticut Expansion Project (CP14-529)***
  - Tennessee Gas Pipeline filed for Section 7(c) certificate July 31, 2014.
  - 72,100 Dth/d of firm capacity.
  - 13.26 miles of three looping segments & facility upgrades/modifications in NY, MA & CT.
  - Three firm shippers: Conn. Natural Gas, Southern Conn. Gas, and Yankee Gas.
  - Environmental Assessment (EA) issued on Oct. 23, 2015.
  - Certificate of public convenience and necessity granted Mar. 11, 2016.[123]
  - Construction began 4th Quarter 2016; now completed.
  - Facilities placed in-service – All project facilities, other than the Connecticut Loop, on November 1, 2017; Connecticut Loop, on November 10, 2017.

- ***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

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[120] Order Issuing Certificate and Authorizing Abandonment, *Algonquin Gas Transmission LLC and Maritimes & Northeast Pipeline, LLC*, 158 FERC ¶ 61,061 (Jan. 25, 2017), *reh'g denied,* 160 FERC ¶ 61,016 (Aug. 21, 2017) ("*Atlantic Bridge Project Order*").

[121] 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).

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

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

decision; and (2) the NY DEC acted within its statutory authority in denying the certification, and its denial was not arbitrary or capricious.

- 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.[124]
    - 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 generation.[125]
    - 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.

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

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

        - 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.[126] 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.[127]
    - 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.
    - 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.[128]

- ***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,

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

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

[128] 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.

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.

- **NAESB WGQ Version 3.1 Standards (RM96-1)**

On September 29, the North American Energy Standards Board ("NAESB") submitted an informational status report summarizing the development and summary of the changes that resulted in the issuance of Version 3.1 of the NAESB Wholesale Gas Quadrant ("WGQ") Standards. This report will not be noticed for public comment.

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[129] 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.

The MA Executive Office of Energy and Environmental Affairs ("EEA") and the MassDEP are seeking stakeholder input on implementation of emissions allowance auctions under Section 7.74, and have posed the following questions:

- Are there additional special considerations that should be taken into account for an auction of this type occurring in a single state?
- When and how often should allowance auctions occur?
- Other than regulated power plants, should any other entities be allowed to purchase allowances?
- Should there be a minimum reserve price, and, if so, what should it be?
- What limits should there be on the number of allowances that can be purchased by a single bidder?
- Is there a need to protect certain information about auction bids or results from public release?

[129] 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.

- Are there any particular design elements that should be considered because of the number of regulated facilities and facility owners?

To provide input on the auction design parameters, interested stakeholders may, *by November 15, 2017*, provide additional input by submitting written comments to climate.strategies@state.ma.us. This input will be used to inform auction design activities planned for 2018. Additional opportunities to provide input may be provided.

To receive further emails about this stakeholder process, including meeting announcements, go to https://www.surveymonkey.com/r/C22Z6YR to provide your contact information.

- **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 Lebous 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).

- **Demand Curve Changes (17-1110**)**
Underlying FERC Proceedings: ER14-1639[130]
Petitioners: NextEra, NRG, PSEG

On April 3, 2017, NextEra, NRG and PSEG ("Petitioners") again petitioned the DC Circuit Court of Appeals 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. Petitioners' statement of issues and other initial procedural submissions, as well as the FERC's initial submissions, were filed May 8. The Clerk granted on June 2 the interventions filed by NEPOOL, NESCOE, CT PURA, and CPV. Petitioner's Brief was filed on September 8, and corrected on September 18 (for compliance with the Court's rules on acronyms and abbreviations). Respondent FERC's Brief was filed on 11/21/2017; Intervenors for Respondent Brief(s) is to be filed 12/12/2017; Petitioner Reply Brief, 1/11/2018; Deferred Appendix, 01/25/2018; and Final Briefs, 2/01/2018. On November 28, NRDC and CLF jointly moved for leave to participate as amici curiae and filed an amicus curiae brief in support of the FERC On December 5, the Court granted NRDC/CLF leave to participate as amici curiae and the Clerk lodged the Nov 28 amicus curiae brief. As noted herein, Intervenors for Respondent Briefs are due December 12.

[130] 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*).

- **FCA10 Results (16-1408) and FCA9 Results (16-1068)**
  Underlying FERC Proceedings: ER16-1041[131] ER15-1137[132]
  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. With Final Briefs submitted on June 26, 2017, all briefing is complete and this matter is before the Court.

- **NEPGA PER Complaint and FCM Jump Ball and Compliance Proceedings (16-1023/1024)**
  Underlying FERC Proceeding: ER14-1050;[133] EL14-52;134 EL15-25[135]
  Petitioner: NEPGA

As previously reported, NEPGA filed, on January 19, 2016, a petition for review of the FERC's orders on NEPGA's first PER Complaint. 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, Sentelle and Randolph. This matter is now pending before the Court.

- **Base ROE Complaints II & III (2012 & 2014) (15-1212)**
  Underlying FERC Proceedings: EL13-33; EL14-86[136]
  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 ninth such report filed, was filed on November 13, 2017. 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.

- **FCM Pricing Rules Complaints (15-1071**, 16-1042) (consol.)**
  Underlying FERC Proceeding: EL14-7,[137] EL15-23[138]
  Petitioners: NEPGA, Exelon

On March 31, 2015, NEPGA filed a petition for review of the FERC's orders on NEPGA's FCM Administrative Pricing Rules Complaint. Following briefing, oral argument was held October 6, 2017 before Judges Srinivasan, Wilkins and Sentelle. This matter is now pending before the Court.

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[131] 155 FERC ¶ 61,273 (June 16, 2016); 157 FERC ¶ 61,060 (Oct. 27, 2016).

[132] 153 FERC ¶ 61,378 (Dec. 30, 2015); 151 FERC ¶ 61,226 (June 18, 2015).

[133] 153 FERC ¶ 61,224 (Nov. 19, 2015); 153 FERC ¶ 61,223 (Nov. 19, 2015); 147 FERC ¶ 61,172 (May 30, 2014).

[134] 153 FERC ¶ 61,222 (Nov. 19, 2015); 150 FERC ¶ 61,053 (Jan. 30, 2015).

[135] 153 FERC ¶ 61,222 (Nov. 19, 2015); 150 FERC ¶ 61,053 (Jan. 30, 2015).

[136] 147 FERC ¶ 61,235 (June 19, 2014); 149 FERC ¶ 61,156 (Nov. 24, 2014); 151 FERC ¶ 61,125 (May 14, 2015).

[137] 150 FERC ¶ 61,064 (Jan. 30, 2015); 146 FERC ¶ 61,039 (Jan. 24, 2014).

[138] 154 FERC ¶ 61,005 (Jan. 7, 2016); 150 FERC ¶ 61,067 (Jan. 30, 2015).

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