David T. Doot
Secretary

March 31, 2017

VIA ELECTRONIC MAIL

TO: MEMBERS AND ALTERNATES OF THE NEPOOL PARTICIPANTS COMMITTEE

RE: Supplemental Notice of April 7, 2017 NEPOOL Participants Committee Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that a meeting of the NEPOOL Participants Committee **will be held on Friday, April 7, 2017, at 10:00 a.m.** at The Colonnade Hotel, 120 Huntington Avenue., Boston, MA. The Participants Committee meeting will be held in the Huntington Ballroom for the purposes set forth on the attached agenda and posted with the meeting materials at http://nepool.com/NPC_2017.php. For your information, this meeting is recorded, as are all the NEPOOL Participants Committee meetings.

The block of rooms at the Colonnade for the April 7 meeting is now full. Please contact the hotel directly (617-424-7000) and referencing the “NEPOOL Participants Committee” block of rooms to see if any rooms can be made available.

Looking ahead, please mark your calendars for the Participants Committee Summer Meeting to be held at The Chatham Bars Inn, Chatham, MA, on June 27-29, 2017 (http://www.chathambarsinn.com/). Please note that this year’s meeting will commence with NEPOOL general business on Tuesday, followed by a half day session on Wednesday, and conclude with Sector group meetings on Thursday. Detailed information regarding the Participants Committee Summer Meeting will be provided in future notices, including a link to the registration page and the reservations block, once the block is open.

Respectfully yours,

/s/
David T. Doot, Secretary

FINAL AGENDA

1. To approve the preliminary minutes of the Participants Committee teleconference meeting held on March 3, 2017. The draft minutes of the March 3 meeting, marked to show changes from the draft circulated with the initial notice, are included with this notice and posted with the meeting materials.

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

3. To receive an ISO Chief Executive Officer Report.

4. To receive an ISO Chief Operating Officer Report.

5. To receive an ISO update on the 2017/18 Work Plan.

6. To receive an ISO update on Operational Load Forecasting.

7. To consider and take action, as appropriate, on NEPOOL's Comments on FERC's Notice of Proposed Rulemaking regarding Generator Interconnection Procedures and Agreements. Background materials, including draft comments as proposed to be filed, and a draft resolution are included with this supplemental notice.

8. To consider and take action, as appropriate, on revisions to ISO Tariff Section II.44(1)(A) to align with Market Rule 1 moving the start of the Day-Ahead Energy Market. Background materials and a draft resolution are included with this supplemental notice.

9. To consider and take action, as appropriate, on balloting amendments to the NEPOOL Agreement and Participants Agreement to reflect:

   a. Clean-Up Changes to conform the Participants Agreement to the NEPOOL Agreement's currently effective Provisional Member arrangements and to make the application fee applicable to Data-Only Participants identical to their current annual fee amount; and

   b. the treatment of Small Standard Offer Service Providers as Provisional Members.

   Background materials and draft resolutions are included with this supplemental notice.

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

10A. To receive a report on status of GIS Agreement Working Group discussions concerning future GIS arrangements.

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

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

12. To receive a report on administrative matters.

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

PRELIMINARY

A meeting of the NEPOOL Participants Committee was held via teleconference beginning at 10:00 a.m. on Friday, March 3, 2017, pursuant to notice duly given. A quorum determined in accordance with the Second Restated NEPOOL Agreement was present and acting throughout the meeting. Attachment 1 identifies the members, alternates and temporary alternates who participated in the teleconference meeting.

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

APPROVAL OF FEBRUARY 3, 2017 MEETING MINUTES

Mr. Kaslow referred the Committee to the preliminary minutes for the February 3, 2017 meeting as circulated in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of the February 3 meeting were unanimously approved without change.

CONSENT AGENDA

There was no Consent Agenda for this meeting.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), referred the Committee to the summaries of the ISO Board and Board Committee meetings that had occurred since the February 3 meeting, which had been circulated and posted in advance of the meeting. There were no questions or comments on the summaries.

Mr. van Welie next reported that the FERC was arranging a technical conference on the issues currently under discussion concerning the tensions between public policies of the states and the organized markets. Notice of, and details concerning, that conference had not yet been announced.

ISO COO REPORT

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), reviewed highlights from the March COO report, which was circulated in advance of the meeting and posted on the NEPOOL and ISO websites. Focusing on report highlights, which he explained reflected data through February 22, 2017, he reported for February that: (i) Energy Market value was $266 million, down $190 million from January 2017 and down $59 million from February 2016; (ii) average natural gas prices were 19% lower than January 2017 average prices; (iii) average Real-Time Hub LMPs ($31.92/MWh) were 12.9% lower than January 2017 LMPs; (iv) average daily (peak hour) Day-Ahead cleared physical Energy, as a percent of forecasted load, was 96.7% in February, down from 98.3% in January; (v) daily Net Commitment Period Compensation (NCPC) for February totaled $6.7 million, up $2.2 million from January 2017 and up $3.9 million from February 2016; (vi) first contingency payments, totaling $3 million, were $525,000 lower than January's; (vii) second contingency payments totaled $3 million, up $2.1 million from January, almost all of which occurred in the Northeast Massachusetts and Boston Load Zone (NEMA); (viii) voltage support payments totaled $660,000, up $620,000 from January's; and (ix) NCPC payments were 2.5% of the total Energy Market value.

He reported that the March 1 implementation of sub-hourly settlement, fast-start pricing, and the Dispatchable Asset Related Demand (DARD) pump parameter enhancements had been relatively smooth to date. He explained that, following implementation, approximately 15-20 users who typically connect to eMarket continually had experienced browser-related connectivity problems for a couple hours. The ISO was able to identify the issue and help those users revise their browser setting and re-establish a connection to the upgraded eMarket system. Offer submission and the Day-Ahead Energy Market itself were not impacted by those issues. He said that the first run of statements reflecting sub-hourly settlements was scheduled to take place that evening. He noted that, looking back over the last 10 years, ~~this project~~the March 1 implementation of the projects was the second largest change in terms of scope and budget and third largest in terms of implementation, with the largest being the 2007-2008 changes to the Ancillary Services Market and the other comparable project being the 2014 implementation of hourly offers.

Dr. Chadalavada committed to have a report reflecting final February Winter Reliability Program data distributed when it became available. With respect to January, he addressed the January 10 Demand Response (DR) event needed to satisfy the morning pick-up ramp when loads came in higher than expected and there were several failed starts and unit reductions ~~on units~~.

Turning to FCA12, Dr. Chadalavada reported that ISO had notified existing resources of their qualification values. He reminded Market Participants that they needed to submit Retirement De-List Bids and Permanent De-List Bids on or before March 24 and that the Show of Interest window would be open April 14-28.

In response to questions concerning uplift incurred in NEMA, Dr. Chadalavada explained that loads were at the 17,000-18,000 MWh level at the time of generator outages in Southeast Massachusetts (SEMA). He referenced in response to questions on trends in winter ~~the~~ monthly recorded Net Energy for Load (NEL) and weather-normalized NEL, that low levels were the result of warmer weather and energy efficiency. He was asked about price fluctuations on March 2~~5~~, when prices were very low (negative for several hours) and cleared energy was very low relative to forecast following the evening ramp (by more than 1,000 MWhs). He explained that winds, and correspondingly wind-generation, were very high for part of the day but dropped very low when wind speeds got too high. He was not certain about the reason for the cleared energy under-forecast and committed to report back more broadly on load forecasting ~~that topic~~ in April.

FINANCIAL ASSURANCE POLICY – FCM CAPACITY CHARGE CALCULATION

Mr. Kenneth Dell Orto, Budget & Finance Subcommittee Chair, summarized for the Committee the materials posted in advance of the meeting concerning changes to the financial assurance calculations for the Forward Capacity Market (FCM) under the ISO Financial Assurance Policy (FAP). He explained how the changes would provide more rational determinations as to financial assurance for capacity obligations beginning with the eighth Capacity Commitment Period (CCP), avoiding the unintended overcapitalization that occurred with implementation of the seventh CCP.

He reported that the Budget & Finance Subcommittee discussed the proposed changes at its January 26 and February 10 teleconferences, and no objections were raised. He said that, since the February 10 teleconference, the ISO made clarifying revisions to the changes to the FAP and ISO Tariff, which he flagged for the members.

The following main motion was then duly made, seconded and unanimously approved:

> RESOLVED, that the Participants Committee supports the changes to the ISO Financial Assurance Policy and the ISO Transmission, Markets and Services Tariff relating to the financial assurance requirements for the Forward Capacity Market, as circulated to the Committee and discussed at this meeting, together with such further non-substantive changes as the Chief Financial Officer of ISO New England and the Chairman of the Budget & Finance Subcommittee may approve.

A member thanked the ISO for addressing the ~~prior~~ problems experienced by load serving entities with ~~the need for load to post~~ excessive capacity-related financial assurance requirements~~ experienced by load serving entities~~. The ISO reported that they planned to file the changes quickly and to request an effective date of June 1, 2017, the date that the eighth CCP would begin.

LITIGATION REPORT

Mr. Doot referred the Committee to the March 1 Litigation Report that had been circulated and posted in advance of the meeting. Mr. Doot highlighted the report by the settlement judge in the Peak Energy Rent (PER) complaint proceeding (EL16-120) initiated by the New England Power Generators Association (NEPGA), including next procedural steps.

COMMITTEE REPORTS

Transmission Committee. Mr. José Rotger reported that the Transmission Committee was scheduled to meet on March 28 to discuss and vote on NEPOOL's comments on the FERC's interconnection NOPR, which would be presented for consideration at the April Participants Committee meeting.

Markets Committee. Mr. William Fowler reported that the next Markets Committee meeting was scheduled for March 7 as a one-day meeting to be held in Milford, MA.

Reliability Committee. Mr. Robert Stein reported that the next three meetings of the Reliability Committee would cover changes to the Tariff and Market Rules to implement Price Responsive Demand. He said that notices had been sent recently to the Markets and Reliability Committees for the March 21 meeting agenda.

Membership Subcommittee. Mr. Kaslow reported that he had appointed Mr. Stacy Dimou to succeed Mr. Michael Lynch, who had recently retired, as chair of the Membership Subcommittee.

OTHER BUSINESS

Mr. Doot reported that the next Participants Committee meeting was scheduled for April 7, 2017 at the Colonnade Hotel in Boston, MA. Dr. Chadalavada indicated that he would provide an update to the 2017 Work Plan at that meeting. Mr. Kaslow indicated that, in light of the lack of FERC quorum and the continued light agenda items from the Technical Committees, the May meeting may be held via teleconference rather than in person.

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

Respectfully submitted,

David T. Doot, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN MARCH 3, 2017 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
American PowerNet Management	Supplier			Mary Smith
Ashburnham Municipal Light Plant	Publicly Owned			Brian Thomson
AVANGRID (CMP/UI)	Transmission			Paul Dumais
Boylston Municipal Light Department	Publicly Owned			Brian Thomson
BP Energy Company	Supplier			Nancy Chafetz
Calpine Energy Services, LP	Supplier		Brett Kruse	Bill~~William~~ Fowler
Chicopee Municipal Lighting Plant	Publicly Owned			Brian Thomson
Citigroup Energy Inc.	Supplier	Barry Trayers		
CLEAResult Consulting, Inc.	AR	Doug Hurley		
Competitive Energy Services, LLC	Supplier			Glenn Poole
Connecticut Municipal Electric Energy Coop.	Publicly Owned	Brian Forshaw		
Conservation Law Foundation	End User	Jerry Elmer		
Consolidated Edison Energy, Inc.	Supplier	Jeff Dannels		
Cross-Sound Cable	Supplier		Jose Rotger	
DC Energy, LLC	Supplier	Bruce Bleiweis		
Direct Energy Business, LLC	Supplier			Nancy Chafetz
Dominion Energy Marketing, Inc.	Generation	Jim Davis		
DTE Energy Trading, Inc.	Supplier			Nancy Chafetz
Dynegy Marketing and Trade, LLC	Supplier			William Fowler
Emera Maine/Emera Energy Services	Transmission		Sandi Hennequin	
Entergy Nuclear Power Marketing, LLC	Generation	Ken Dell Orto		Bill~~William~~ Fowler
EnerNOC, Inc.	AR	Sarah Griffiths		Doug Hurley
Essential Power, LLC	Generation		Bill~~William~~ Fowler	
Eversource Energy	Transmission	James Daly	Cal Bowie	
Exelon Generation Company	Supplier		Bill~~William~~ Fowler	
FirstLight Power Resources Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	Nancy Chafetz		
Generation Group Member	Generation		Abby Krich	Bob Stein
Groton Electric Light Department	Publicly Owned			Brian Thomson
H.Q. Energy Services (U.S.) Inc.	Supplier	Louis Guilbault	Bob Stein	Abby Krich
Harvard Dedicated Energy Limited	End User	Mary Smith		Doug Hurley
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Holden Municipal Light Department	Publicly Owned			Brian Thomson
Hull Municipal Lighting Plant	Publicly Owned			Brian Thomson
Industrial Energy Consumer Group	End User	Donald Sipe		
Ipswich Municipal Light Department	Publicly Owned			Brian Thomson
Long Island Lighting Company (LIPA)	Supplier		Bill Killgoar	
Maine Skiing, Inc.	End User	Donald Sipe		
Mansfield Municipal Electric Department	Publicly Owned			Brian Thomson
Marblehead Municipal Light Department	Publicly Owned			Brian Thomson
Massachusetts Attorney General's Office (MA AG)	End User	Fred Plett	Christina Belew	
Mass. Municipal Wholesale Electric Company (MMWEC)	Publicly Owned			Brian Thomson
Mercuria Energy America, Inc.	Supplier			Nancy Chafetz
Middleborough Gas and Electric Department	Publicly Owned			Brian Thomson
National Grid	Transmission	Tim~~othy~~ Brennan	Tim~~othy~~ Martin	
New Hampshire Electric Cooperative (NHEC)	Publicly Owned	Steve Kaminski		Brian Forshaw
NRG Power Marketing LLC	Generation	Dave Cavanaugh		
Paxton Municipal Light Department	Publicly Owned			Brian Thomson
Peabody Municipal Light Plant	Publicly Owned			Brian Thomson
Princeton Municipal Light Department	Publicly Owned			Brian Thomson
PSEG Energy Resources & Trade LLC	Supplier	Joel Gordon		

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
MARCH 3, 2017 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Reading Municipal Light Department	Publicly Owned			Brian Forshaw
Repsol Energy North America Company	Supplier		Nancy Chafetz	
Russell Municipal Light Department	Publicly Owned			Brian Thomson
Shrewsbury Electric & Cable Operations	Publicly Owned			Brian Thomson
Small Load Response Group Member	AR	Doug Hurley		
Small Renewable Generation Group	AR	Erik Abend		
South Hadley Electric Light Department	Publicly Owned			Brian Thomson
Sterling Municipal Electric Light Department	Publicly Owned			Brian Thomson
SunEdison companies	AR			Bob Stein, Abby Krich
Templeton Municipal Lighting Plant	Publicly Owned			Brian Thomson
The Energy Consortium	End User		Mary Smith	
Vermont Electric Power Company	Transmission	Frank Ettori		
Vermont Energy Investment Corporation	AR		Doug Hurley	
Verso Maine Energy LLC	Generation	Glenn Poole		
Vitol Inc.	Supplier	Jo~~s~~e~~ph~~ Wadsworth		
Wakefield Municipal Gas and Light Department	Publicly Owned			Brian Thomson
West Boylston Municipal Lighting Plant	Publicly Owned			Brian Thomson
Wheelabrator North Andover Inc.	AR	Bill ~~William~~ Fowler		

CONSENT AGENDA

From the notice of actions of the March 21, 2017 ***Reliability Committee***[1] meeting, dated March 23, 2017, which has been previously circulated:

1. ISO-NE/NYISO Coordination Agreement Revisions

Support revisions to the Coordination Agreement between ISO New England Inc. (ISO-NE) and the New York Independent System Operator, Inc. (NYISO), including revisions to the Emergency Energy pricing provisions to address sub-hourly settlements and to place a $0.00 floor on the price of Emergency Energy sold to New York, as well as a revision to the Agreement's definition of Transfer Limit, as recommended by the Reliability Committee at its March 21, 2017 meeting, with such further non-material changes as the Chair and Vice-Chair of the Reliability Committee may approve.

The motion to recommend Participants Committee support was approved unanimously.

2. Revisions to OP-18 and OP-18 Appendices C and D (Updates, Conforming and Clarifying Changes)

Support revisions to ISO-NE Operating Procedure (OP) No. 18 (Metering and Telemetering Criteria) and Appendices C (Minimum Accuracy Standards for New and Upgraded Metering, Recording and Telemetering Installations and for Calibration of Existing Equipment) and D (OP-18 Metering and Telemetering Diagrams), including the addition of transmission level HVDC metering specifications, clarification of communication data paths, addition of expanded record keeping instructions, and other updating, conforming and clarifying changes, all as recommended by the Reliability Committee at its March 21, 2017 meeting, with such further non-material changes as the Chair and Vice-Chair of the Reliability Committee may approve.

The motion to recommend Participants Committee support was approved unanimously.

3. Revisions to OP-11 and OP-11 Appendices D and F (Black Start DBR Start Capability Revisions)

Support revisions to OP-11 (Black Start Resource Administration) and OP-11 Appendices D (Application for Prospective Designated Blackstart Resources) and F (Instruction for Completing the Designated Blackstart Resource Test Log) to, among other things, remove the 90-minute start requirement and allow for each Designated Blackstart Resource (DBR) to provide their start capability in the DBR application process, as recommended by the Reliability Committee at its March 21, 2017 meeting, with such further non-material changes as the Chair and Vice-Chair of the Reliability Committee may approve.

The motion to recommend Participants Committee support was approved unanimously.

4. OP-1A Revisions (DBR Loss of Power Responsibilities, ISO Wind Forecasting Responsibilities, Biennial Review-Related Additions/Corrections)

Support revisions to OP-1A (Central Dispatch Responsibilities and Authority - Assignment of Responsibilities), including the addition of specific DBR responsibilities upon loss of power, the addition of wind power production forecasting to the ISO's System Load Forecasting responsibilities, and other biennial review-related additions and corrections, all as recommended by the Reliability Committee at its March 21, 2017 meeting, with such further non-material changes as the Chair and Vice-Chair of the Reliability Committee may approve.

The motion to recommend Participants Committee support was approved unanimously.

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

CONSENT AGENDA (cont.)

From the notice of actions of the March 7, 2017 ***Markets Committee***[2] meeting, dated March 8, 2017, which has been previously circulated:

5. Revisions to ISO-NE/NYISO Coordination Agreement and HQTE Emergency Pricing Letter (Conforming Revisions to Support Market Rule 1 Changes)

Support conforming revisions to the ISO-NE/NYISO Coordination Agreement and Hydro-Québec TransÉnergie (HQTE) Emergency Energy Pricing Letter (to reflect sub-hourly settlements, place a floor of $0.00 on prices for emergency energy sold to NYSIO and HQTE, and revise the definition of Transfer Limit in the ISO-NE/NYISO Coordination Agreement), as recommended by the Markets Committee at its March 7, 2017 meeting, with such further non-material changes as the Chair and Vice-Chair of the Markets Committee may approve.

The motion to recommend Participants Committee support was approved unanimously.

6. Manual M-11 Revisions (Resource Dispatchability Requirements Project Conforming Changes)

Support conforming changes to Manual M-11 (Market Operations) to support the Resource Dispatchability Requirements project and other clean-up changes, all as recommended by the Markets Committee at its March 7, 2017 meeting, with such further non-material changes as the Chair and Vice-Chair of the Markets Committee may approve.

The motion to recommend Participants Committee support was approved unanimously.

7. Market Rule 1 Revisions (Capping Adjusted Energy Offers for Use in Fast-Start Pricing)

Support revisions to Market Rule 1 to cap the adjusted energy offers of Rapid Response Pricing Assets under the Real-Time Fast-Start Pricing design at the Energy Offer Cap for purposes of pricing calculations for setting the Locational Marginal Price, as recommended by the Markets Committee at its March 7, 2017 meeting, with such further non-material changes as the Chair and Vice-Chair of the Markets Committee may approve.

The motion to recommend Participants Committee support was approved with one opposition (in the Supplier Sector) and 14 abstentions (8 Supplier Sector; 5 Generation Sector; and 1 AR Sector).

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

Summary of ISO New England Board and Committee Meetings

April 7, 2017 Participants Committee Meeting

Since the last update, the Audit and Finance Committee and the Nominating and Governance Committee both met in Boston on March 16.

The Audit and Finance Committee was presented with the Internal Audit Department's 2017 audit plan. The Committee discussed the major areas of coverage, including system development/implementation projects, NERC critical infrastructure protection, cyber security and change/configuration management, and local control center reviews. Next, the Committee received an update on current Internal Audit Department activities and the risk assessment process and audit planning cycle. Following this discussion, the Committee approved the 2017 audit plan. Next, the Committee met with representatives from KPMG and reviewed the work plan for the 2017 Service Organization Controls report. The Committee discussed the scope of the work, including objectives, audit team and methodology. KPMG and management reviewed the 2016 audited financial statements with the Committee and discussed disclosure controls. The Committee then held an executive session with KPMG. Following the executive session, the Committee voted to recommend the adoption of the audited financial statements by the Board of Directors. The Committee also received status updates on cyber security and on financial performance against the 2017 budget.

The Nominating and Governance Committee received a report on Joint Nominating Committee activities, and considered the 2017 evaluation process for the Board and Committees.

NEPOOL PARTICIPANTS COMMITTEE
04/07/17 MEETING, AGENDA ITEM #4

NEPOOL Participants Committee Report

April 2017

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

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Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Energy market value was $382M, up $78M from February and up $162M from March 2016
    - March natural gas prices over the period were 22% higher than February 2016 average values
    - Average RT Hub Locational Marginal Prices ($35.43/MWh) over the period were 26% higher than February 2016 averages
    - Average March 2017 natural gas prices and RT Hub LMPs over the period were up 142% and up 106%, respectively, from March 2016 averages
- Average DA cleared physical energy during the peak hours as percent of forecasted load was 96.4% during March, down from 97.2% during February*

Data are through March 29 (RT NCPC through March 28), 2017 unless otherwise noted.

Underlying natural gas data furnished by:

ICE Global markets in clear view

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

Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - March NCPC payments totaled $5.4M over the period, down $1.7M from February and up $1.3M from March 2016
    - First Contingency payments totaled $3.7M, up $273K from February
      - $3.4M paid to internal resources, down $9K from February
        - » $1.5M charged to DALO, $1.2M to RT Deviations, $631K* to RTLO
      - $285K paid to resources at external locations, up $282K from February
        - » $138K charged to DALO at external locations, $147K to RT Deviations
    - Second Contingency payments totaled $760K, down $2.3M from February
    - Voltage payments totaled $988K, up $282K from February
    - Distribution payments totaled $0, unchanged from February
  - NCPC payments over the period as percent of Energy Market value were 1.4%

*** NCPC types reflected in the Fist Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $331K; Rapid Response Pricing (RRP) Opportunity Cost - $222K; Posturing - $73K; Generator Performance Auditing (GPA) - $5K**

Highlights, cont.

- Power System Update during Spring Maintenance
  - During light loads in April and May, the ISO will require additional commitments to control high voltage on the New Hampshire 345 kV due to both a forced transmission outage and generator maintenance in NH
  - Connecticut will require additional generation commitments in April and May due to unplanned generation outages and ongoing transmission work
  - Currently scheduled NEMA/Boston upgrades are unlikely to require commitments in April and May
    - This could change in case of early hot weather or if other transmission lines and/or area generation resources are out of service due to unplanned outages

2016/17 Winter Reliability Program As of December 1

- **Oil Program**
  - As of December 1st, participation from 84 units for a total of 4.394 million barrels of oil
  - 3.052 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 $31.16M (@$10.21/barrel)
- **LNG Program**
  - As of December 1st, participation from 2 units, representing 171 thousand MMBTU
  - Total LNG program cost exposure is expected to be $291K (@$1.70/MMBTU)
- **DR Program**
  - As of December 1st, participation from 6 assets providing 23.0 MW of interruption capability
  - Total DR program cost exposure is anticipated to be $70.5K

2016/17 Winter Program Usage

- Winter Program Oil Inventory Changes:
  - Dec 2016: 76,967 BBLs
  - Jan 2017: 12,737 BBLs
  - Feb 2017: 18,663 BBLs
  - Mar 2017 : 5,643 BBLs
- Winter Program LNG usage:
  - Dec 2016: none
  - Jan 2017: none
  - Feb 2017: none
  - Mar 2017: none
- Winter Program DR Events:
  - Dec 2016: none
  - Jan 2017: 1 event; January 10th 6:39 AM – 9:04 AM, all assets dispatched
  - Feb 2017: none
  - Mar 2017: none
- Final Program Ending Oil Eligible Inventory
  - 3,034,668 BBLs

Winter Reliability Program Costs & Billing

- Expected Program Costs:
  - Oil: $30.9M ($23.4M collected; $7.5M outstanding)
  - LNG: $291K ($218K collected; $73K outstanding)
  - DR: $126K ($126K collected), includes energy payments for dispatch on January 10

- Billing/Payment Schedule:
  - Initial Billings were based on 75% of initial inventory
  - Trued-up charges for unused fuel will be issued on April 18, 2017
  - Payment to generators for unused fuel inventory will be in May 15, 2017 bill

Highlights, cont.

- 2016 Economic Study - NEPOOL Scenario Analysis
  - Phase I observations and key messages are complete, and the report is expected to be issued in the second quarter
  - Phase II is underway, reviewing certain market and operations impacts
- 2017 long-term load forecast, energy-efficiency forecast, and solar PV forecast are nearly complete. The overall trend is lower net energy and seasonal peak demand for New England
- Order 1000 Planning for Public Policy process is underway
  - Stakeholder input on state and federal policies was provided to NESCOE by the March 1 deadline
  - NESCOE input to the ISO is expected by May 1

Forward Capacity Market (FCM) Highlights

- CCP #8 (2017-2018)
  - Third and final reconfiguration auction is complete and results were posted on March 17
    - All transactions were approved for a total exchange of approximately 278 MW
  - As much as 700 MWs will not be commercial for June 1, 2017
  - These late new resources result in capacity margins being tight
    - Similar to Summer 2016, ISO System Operations has worked with local transmission owners to develop procedures to address potential reliability impacts

CCP – Capacity Commitment Period
RTEG – Real-Time Emergency Generation

FCM Highlights, cont.

- CCP #9 (2018-2019)
  - Second bilateral window will be May 1-5
  - Second reconfiguration auction will be August 1-3
  - Beginning with this CCP, RTEG will no longer be able to participate in the FCM. FERC issued this order on February 16.
- CCP #10 (2019-2020)
  - First bilateral transaction window will be April 3-7
  - First reconfiguration auction will be June 5-7
- CCP #11 (2020-2021)
  - First bilateral transaction window will be April 4-6, 2018
  - First reconfiguration auction will be June 1-5, 2018

FCM Highlights, cont.

- CCP #12 (2021-2022)
  - Retirement de-list bids and permanent de-list bids were due March 24 and approximately 521 MW chose to exit
    - Approximately 2 MW of permanent de-list bids
    - Approximately 499 MW of priced retirement de-list bids
    - IMM to make their cost determinations no later than June 22
    - Participant action to retire must be made no later than July 7
    - Reliability reviews to be completed by August 18
  - Show of Interest window will be April 14-28
  - The Renewable Technology Resource (RTR) election cap is approximately 514 MW

Highlights, cont.

- The lowest 50/50 and 90/10 Spring Operable Capacity Margins are projected for week beginning May 13, 2017.
- The lowest 50/50 and 90/10 Summer Operable Capacity Margins are projected for three consecutive weeks, weeks beginning June 3, 10, and 17, 2017.
- Forecasted summer outages/reductions:
  - Seasonal Claimed Capability (SCC) margins reflect generator retirements at Brayton Point and delays in commercial operation of new resources

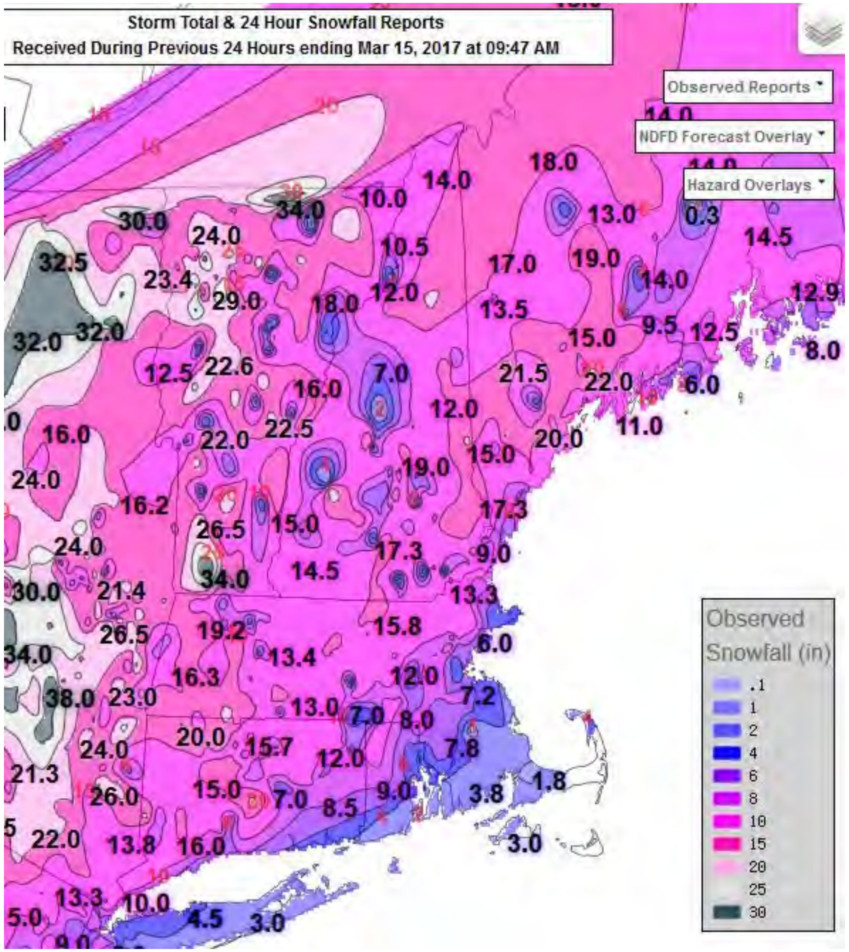
WINTER STORM – MARCH 14, 2017

Preparations Prior to Storm

- Recalled Transmission and Generation work
- NPCC plus PJM and MISO Conference Calls on readiness
- MLCC Heads Calls on Readiness
- NOAA Conference calls on storm situational awareness
- Calls with interstate Pipelines and data sharing on situational awareness

Final Snowfall Totals

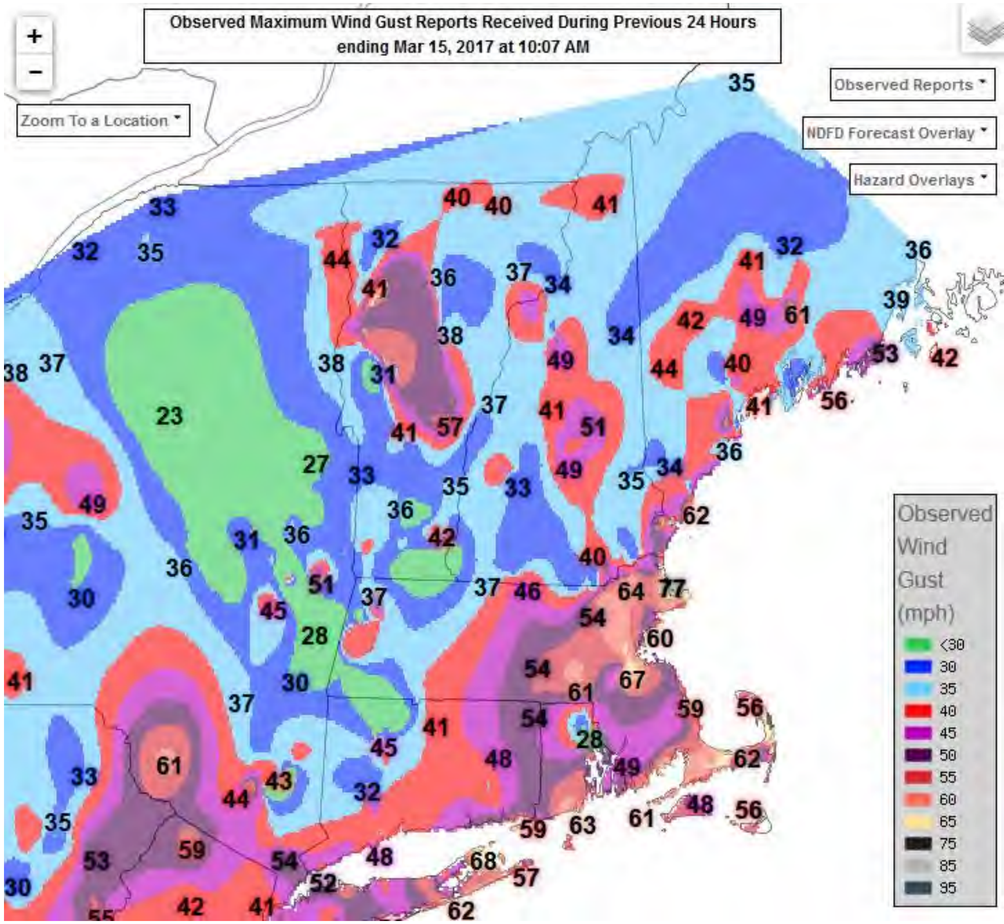
- Snow totals (inches)
  - Significant snow in NY
  - Greatest New England snowfall in southern VT
- Mixed precipitation in southeast New England



Wind Gusts

- Heaviest winds in southeast New England

- Near Blizzard conditions throughout the region



Observed Maximum Wind Gust Reports Received During Previous 24 Hours ending Mar 15, 2017 at 10:07 AM

Transmission Related Events

- Equipment failure at a major Eastern Massachusetts substation caused the loss of 5 major transmission elements at 12:09 on Tuesday during the storm
- The Transmission Owner was able to clear the damaged equipment at the substation during the storm and restoration of four of the five lines began at 14:30 with the last line restored 15:54
- At 13:04, a fault of a 23kV cable in the Boston Area resulted in the loss of one of the two feeders providing service to Distrigas
    - The Transmission Owner was able to restore the second feeder at approximately 14:15

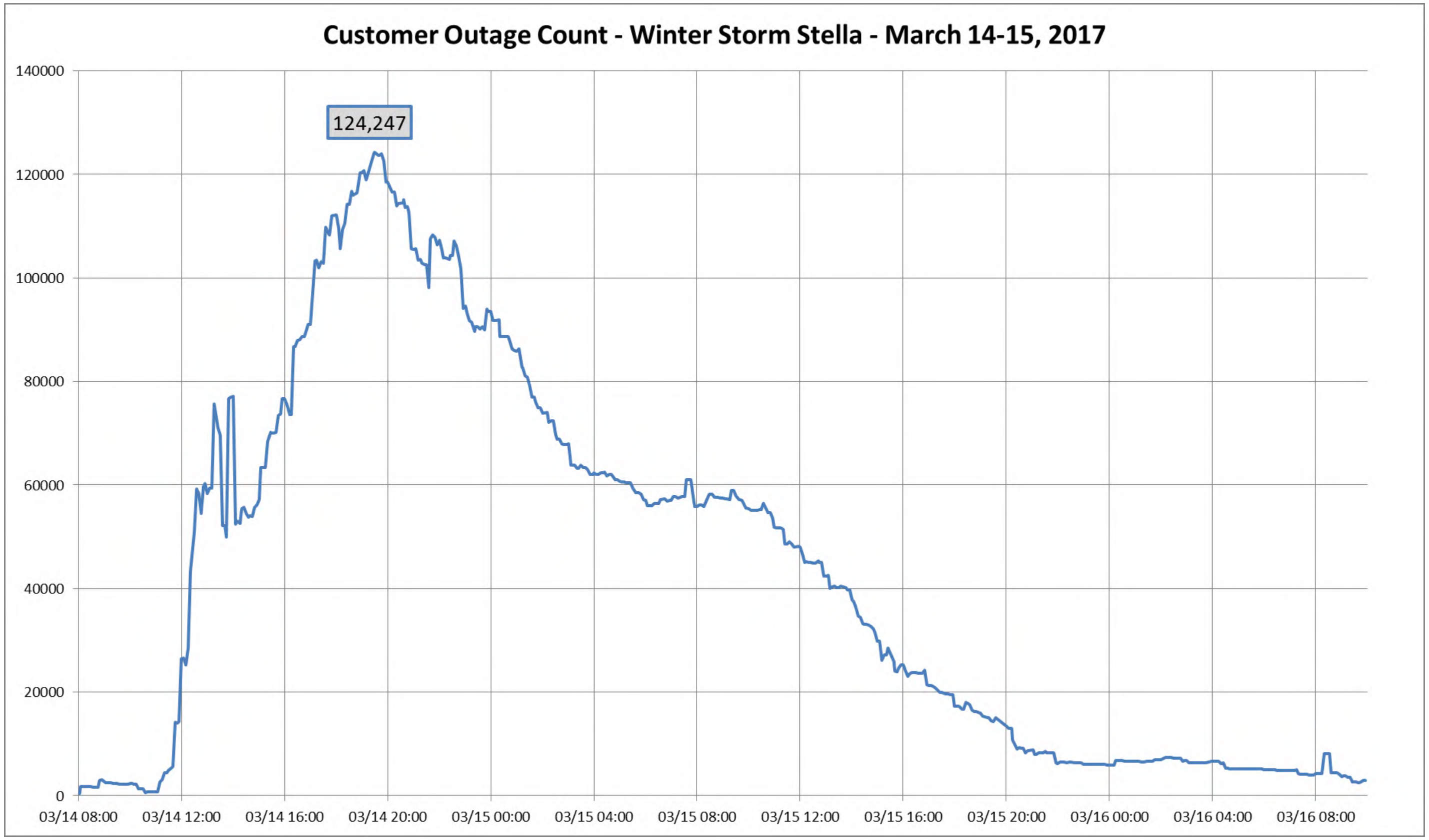
Supplemental Generation Commitment

- Due to the transmission event and subsequent ramp down of a major unit in SE Massachusetts on the day of the storm, additional units were committed in SE Massachusetts to secure the area

Customer Outages

(These are estimates)

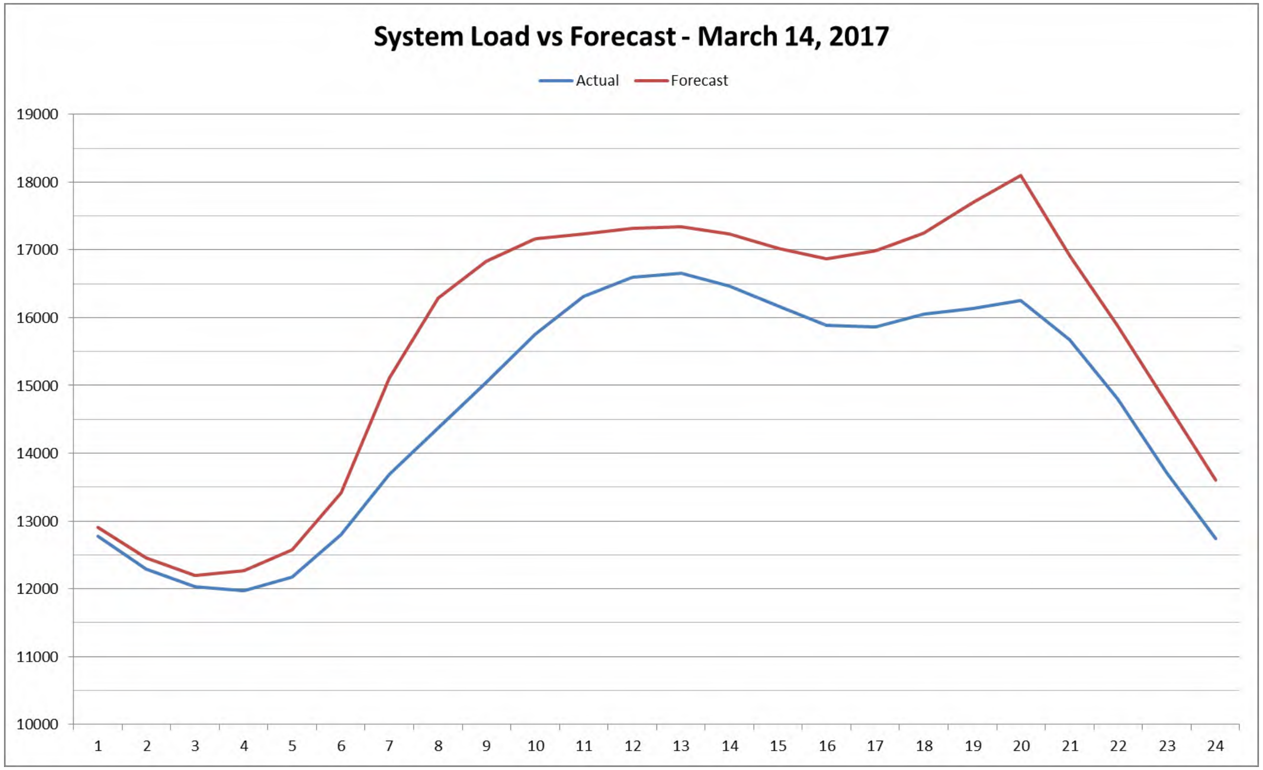
- Customer outages peaked at around 8 PM on 3/14



Data imported from utility company websites

Actual Load vs Forecast Load

- Day-ahead Load Forecast published prior to 10:00 am
- Load below Forecast for all 24 hours
  - Widespread closures of schools, businesses, and government offices



MARCH 2 PRICING

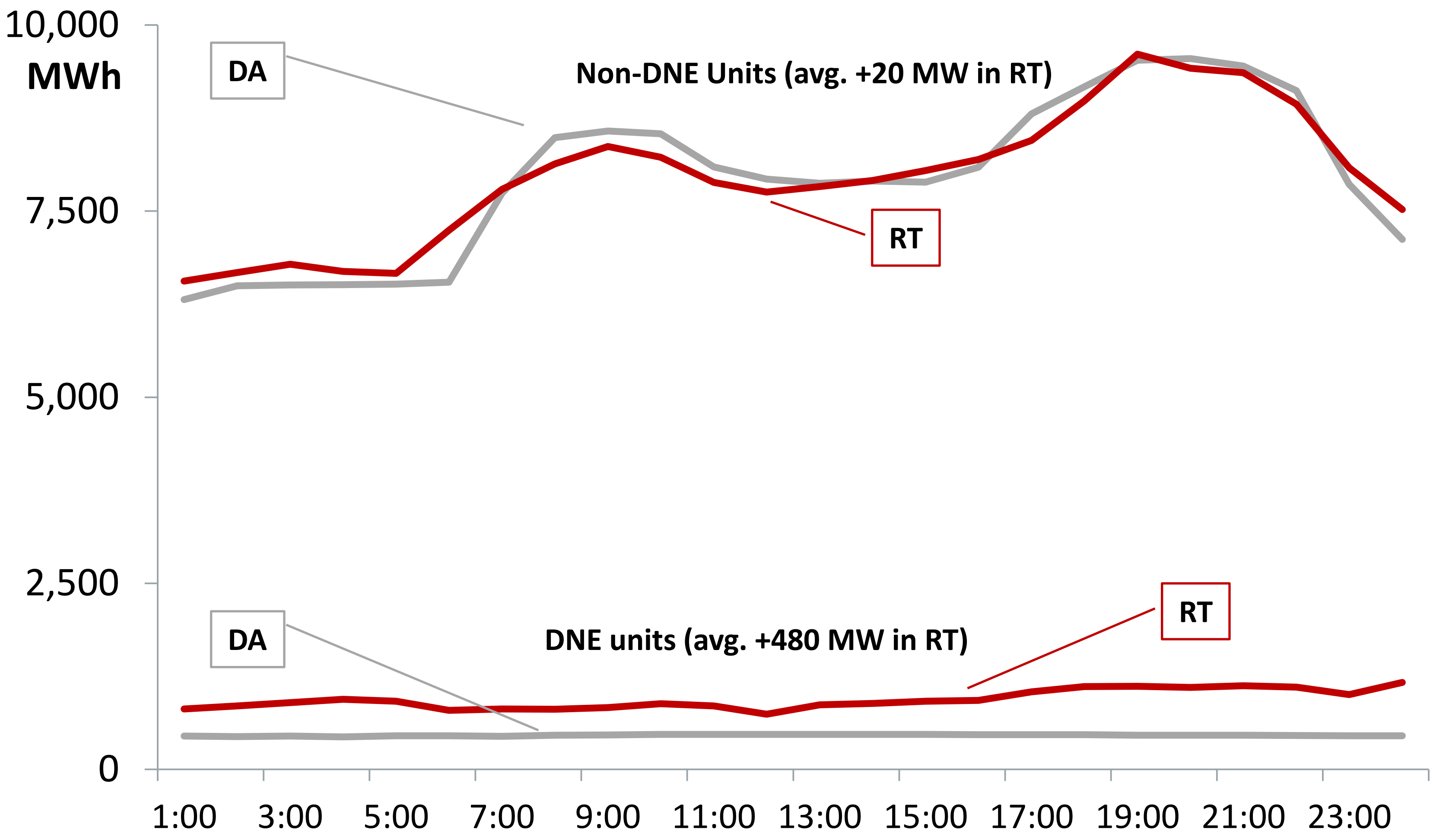
Pricing Assessment: March 2, 2017

- Negative pricing experienced at various times throughout the day; most notable around noon
- Binding reserve constraints during peak load hours
- Key drivers:
  - Real-Time generation supply above Day-Ahead cleared amounts
  - Loads under forecast early; Over the forecast during peak hours
  - Binding reserve constraint raises pricing over peak hours

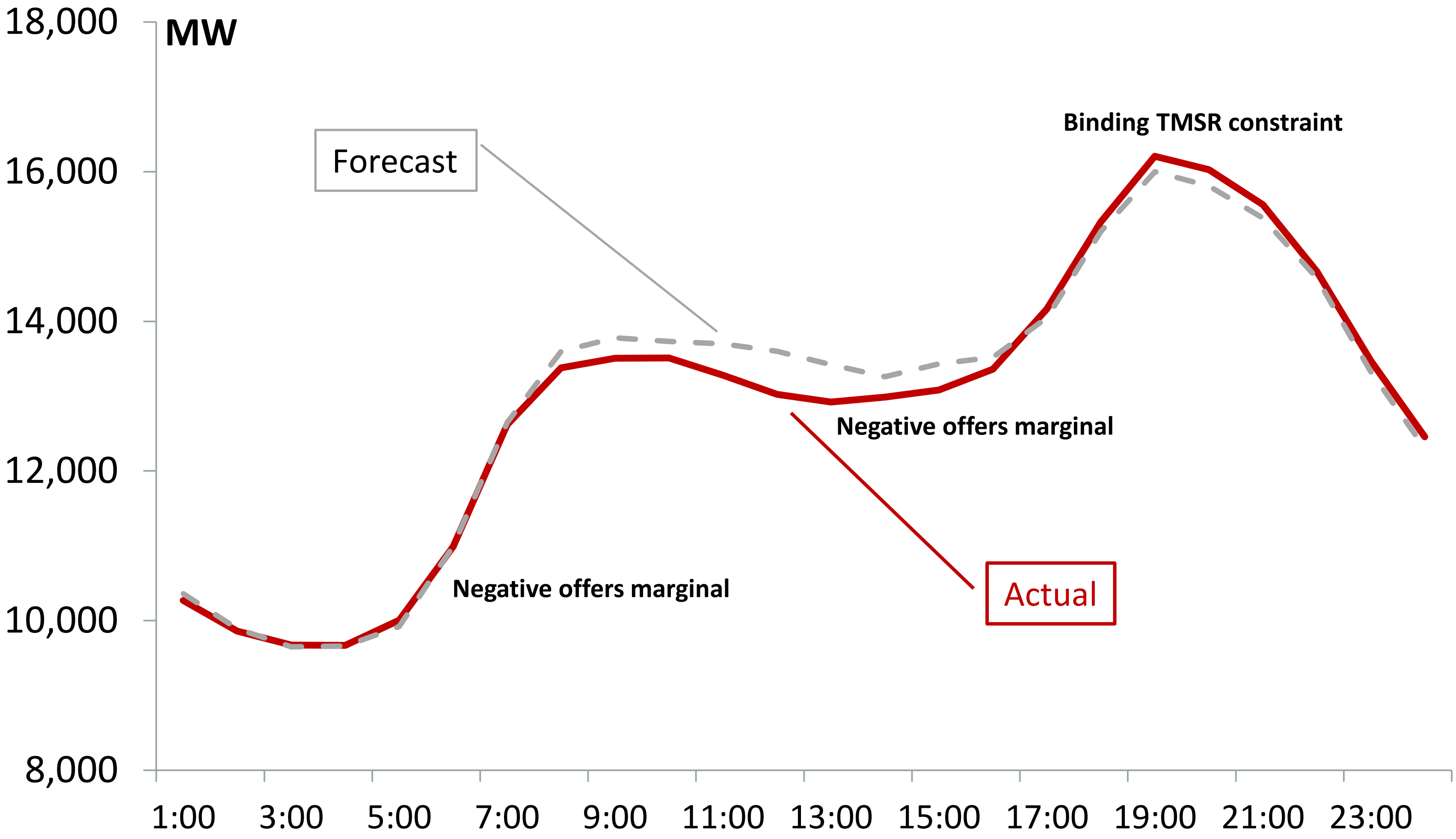
LMPs at Three Key Points During the Day

- **Around 6:00 a.m.**
  - ($28.26)/MWh
  - Negative offers become marginal
  - ~1,000 MWh offered economically below $0/MWh
- **12:00-1:00 p.m.**
  - ($49.58)/MWh
  - Mid-day loads at 13,000 MW (500 MW below forecast)
  - Negative offers become marginal
  - ~700 MWh offered economically below $0/MWh
- **7:00 p.m.**
  - $65.07/MWh
  - Load pick-up over peak hours caused binding TMSR constraint from 6:05 p.m. until 9:35 p.m.

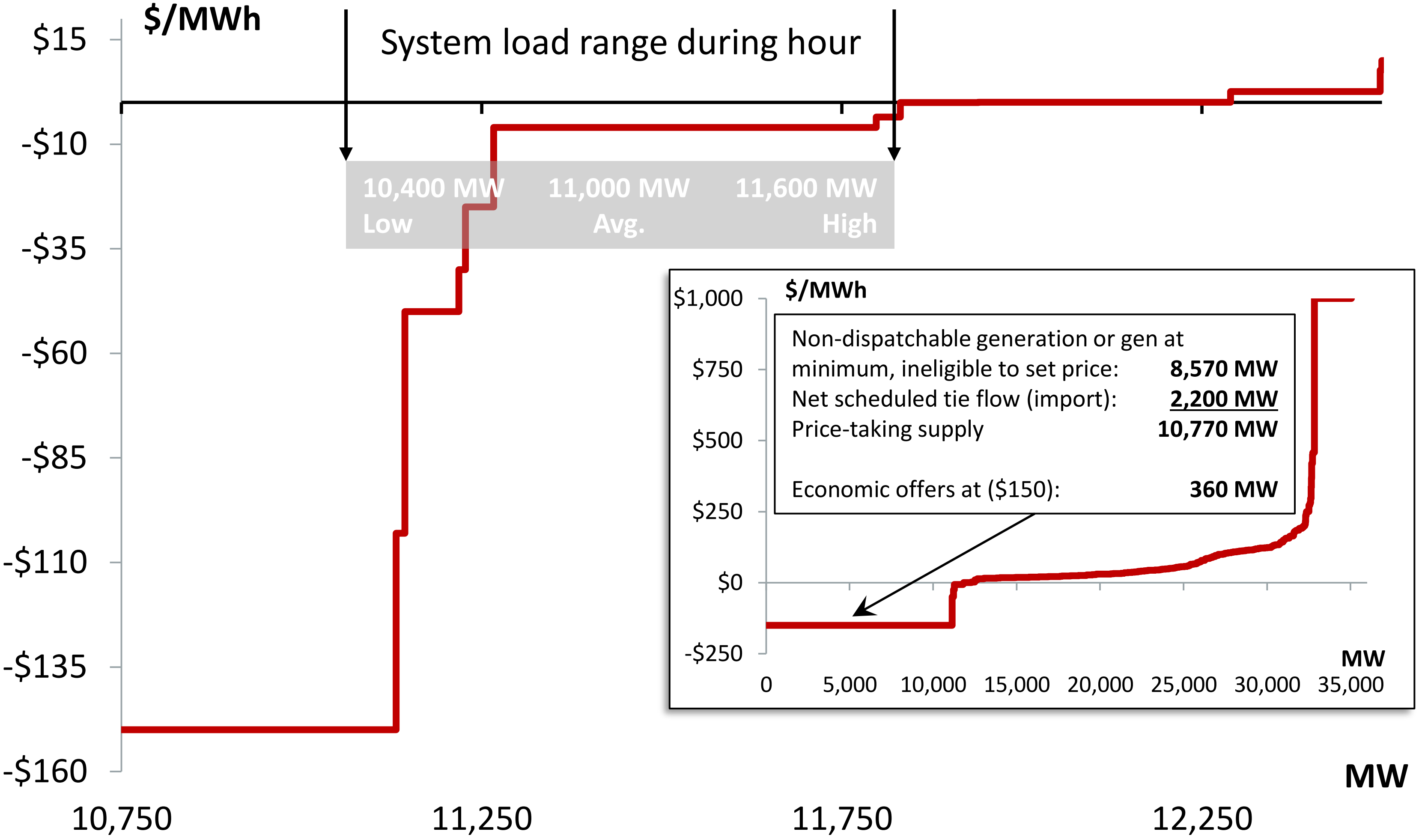
DA Cleared vs. RT Generation



Loads Below Forecast Midday; Above Forecast at Peak

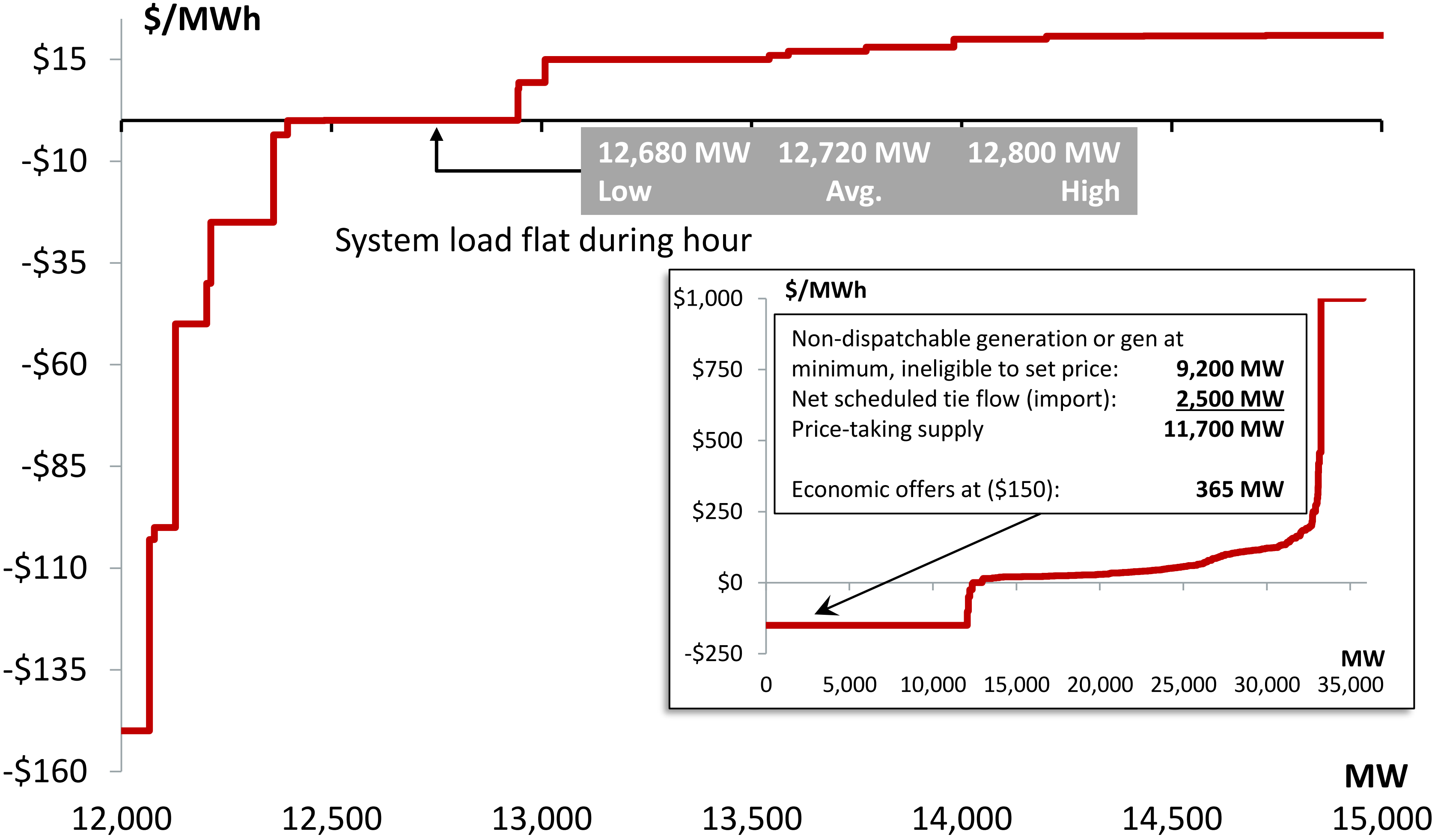


System Supply Curves: Hour Ending 6:00 a.m.



Non-dispatchable generation or gen at minimum, ineligible to set price:	**8,570 MW**
Net scheduled tie flow (import):	**2,200 MW**
Price-taking supply	**10,770 MW**
Economic offers at ($150):	**360 MW**

System Supply Curves: Hour Ending 1:00 p.m.



12,680 MW	12,720 MW	12,800 MW
Low	Avg.	High

System load flat during hour

Non-dispatchable generation or gen at minimum, ineligible to set price:	**9,200 MW**
Net scheduled tie flow (import):	**2,500 MW**
Price-taking supply	**11,700 MW**
Economic offers at ($150):	**365 MW**

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Below Normal (-5.2°F) Max: 63°F, Min: 9°F Precipitation: 3.05" – Below Normal Normal: 3.85" Snow: 9.02"	Hartford	Temperature: Below Normal (-5.7°F) Max: 61°F, Min: 7°F Precipitation: 4.79" – Above Normal Normal: 3.88" Snow: 18.78"

Peak Load:	17,454 MW	Mar 15, 2017	HE20

MLCC2: March 13/14, 2017	**Reason: Severe Weather**	**Declared: March 13, 2017 16:00** **Cancelled: March 14, 2017 23:00**
OP-4 : None		
NPCC Simultaneous Activation of Reserve Events:		
March 15, 2017	NE	540MW
March 16, 2017	IESO	825MW

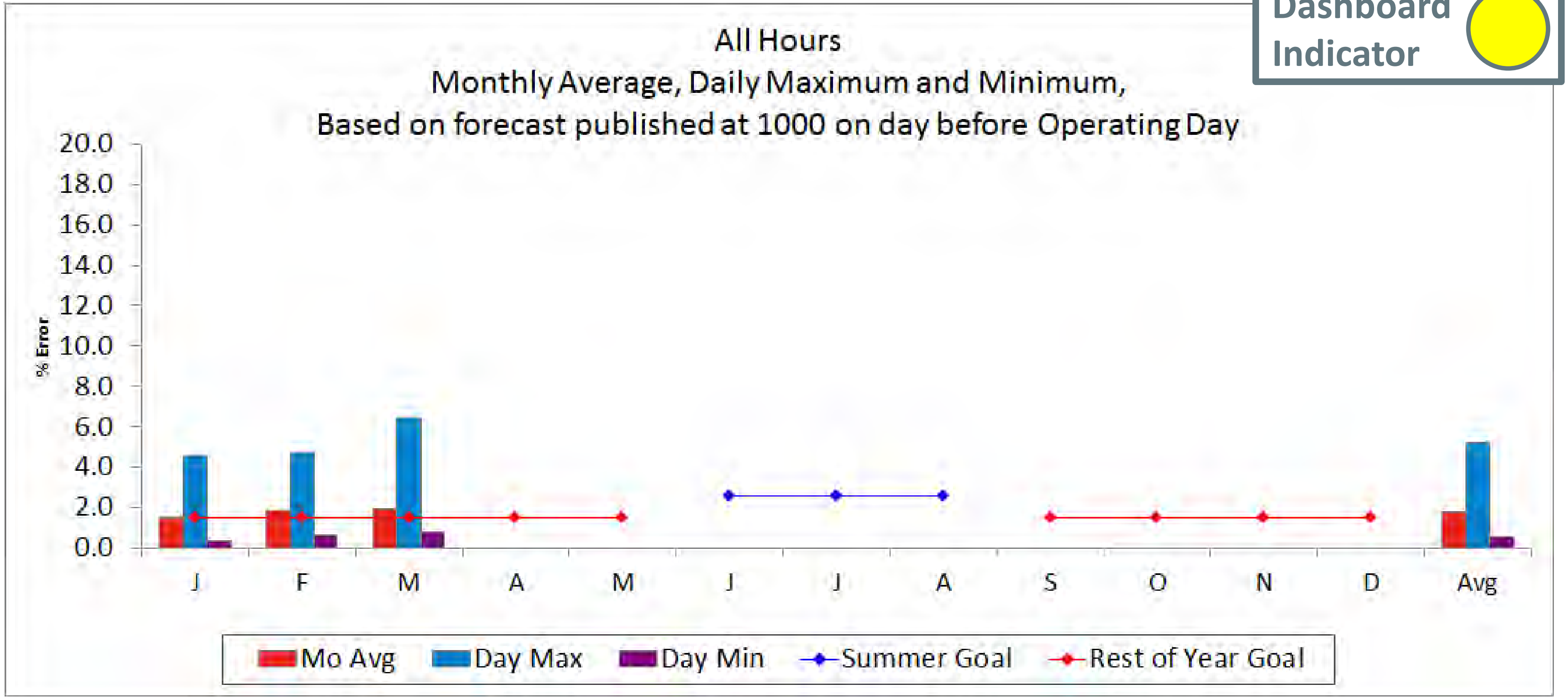
System Operations, cont.

Minimum Generation Warnings & Events:

Minimum Generation Warning	None	
Minimum Generation Emergency	None	

2017 System Operations - Load Forecast Accuracy

Dashboard Indicator ●

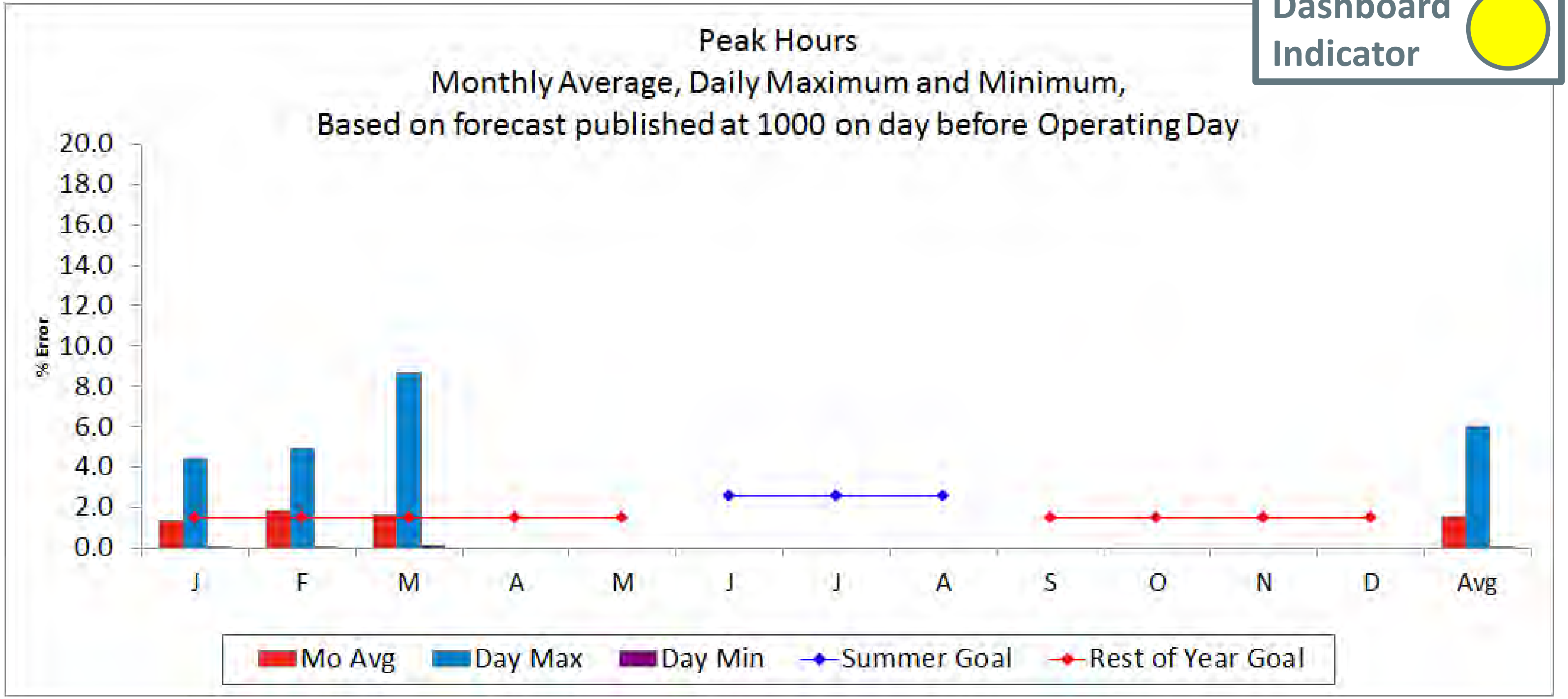


Month	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Mo Avg	1.51	1.84	1.95										1.76
Day Max	4.58	4.72	6.43										5.26
Day Min	0.33	0.62	0.77										0.57
Summer Goal						2.60	2.60	2.60					
Rest of Year Goal	1.50	1.50	1.50	1.50	1.50				1.50	1.50	1.50	1.50	
Rest of Year Actual	1.51	1.84	1.95										1.76
Summer Actual													

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

2017 System Operations - Load Forecast Accuracy, cont.

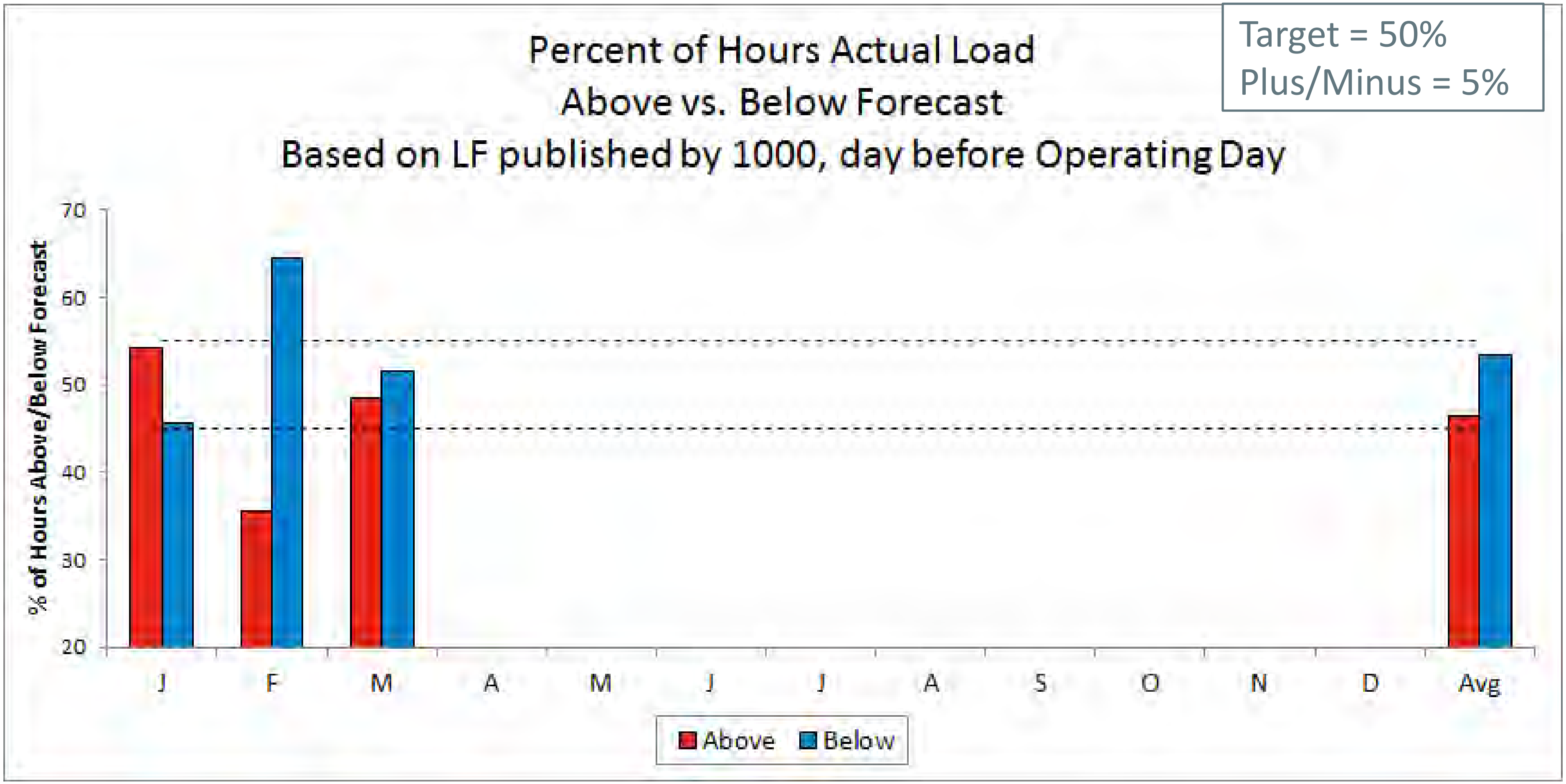
Dashboard Indicator 🟡



Month	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Mo Avg	1.38	1.83	1.63										1.61
Day Max	4.41	4.91	8.70										6.04
Day Min	0.01	0.05	0.14										0.07
Summer Goal						2.60	2.60	2.60					
Rest of Year Goal	1.50	1.50	1.50	1.50	1.50				1.50	1.50	1.50	1.50	
Rest of Year Actual	1.38	1.83	1.63										1.61
Summer Actual													

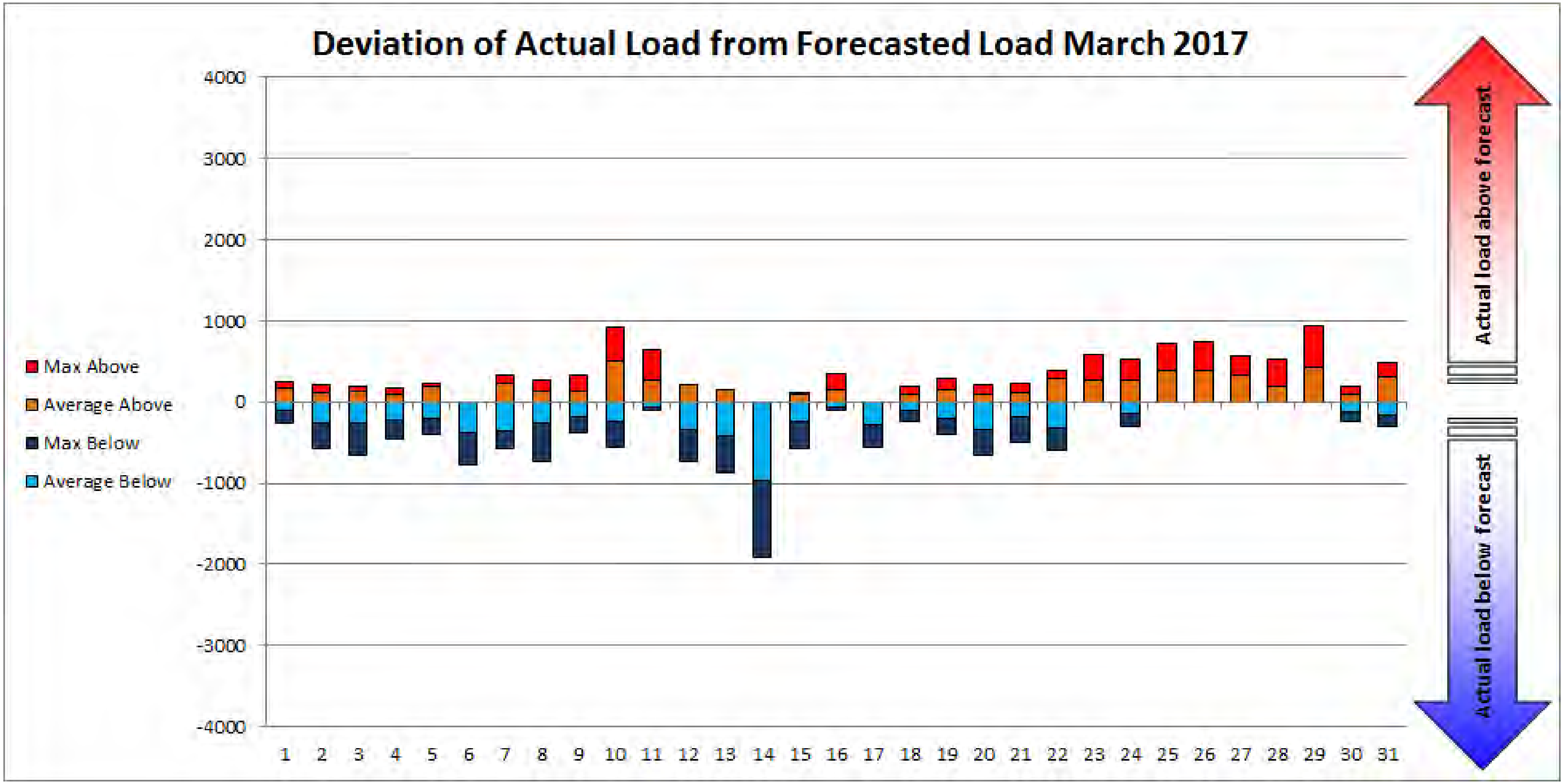
Rest of Year Goal < 1.5%
Summer Goal < 2.6%

2017 System Operations - Load Forecast Accuracy, cont.

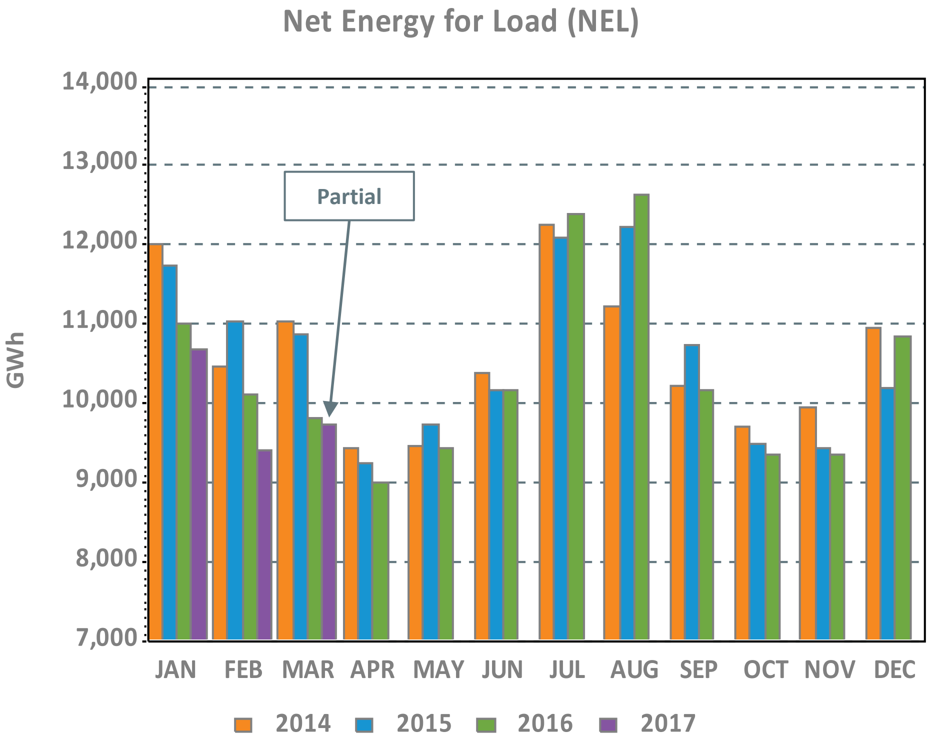


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	54.3	35.6	48.5										46
Below %	45.7	64.4	51.5										54
Avg Above	175.5	137.4	192.2										169
Avg Below	-174.1	-209.5	-206.6										-196
Avg All	20	-76	-32										-28

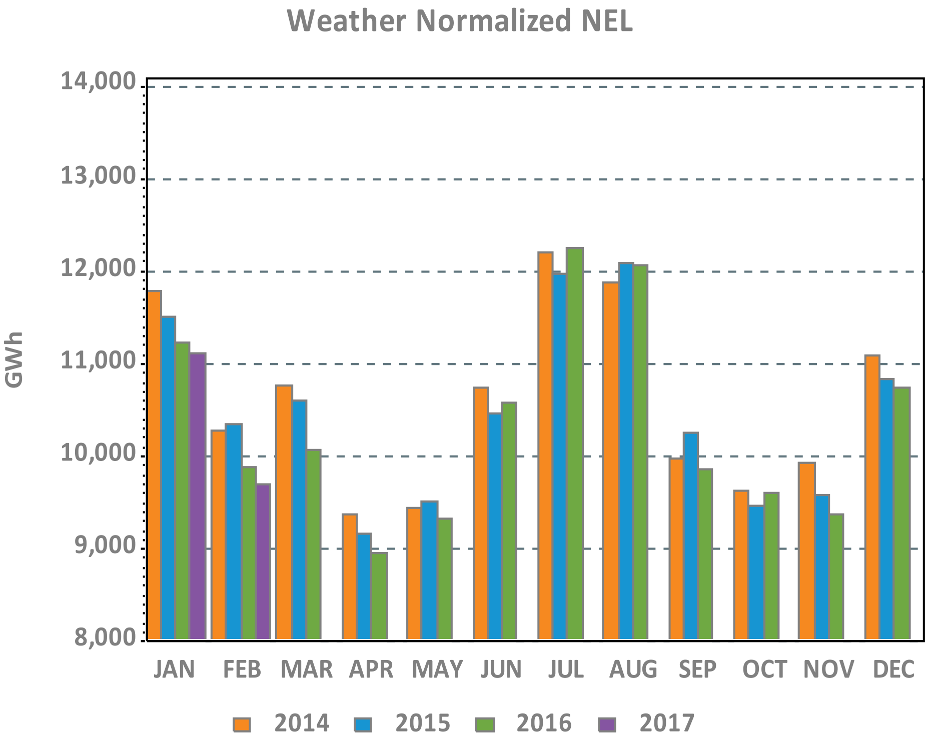
2017 System Operations - Load Forecast Accuracy, cont.



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



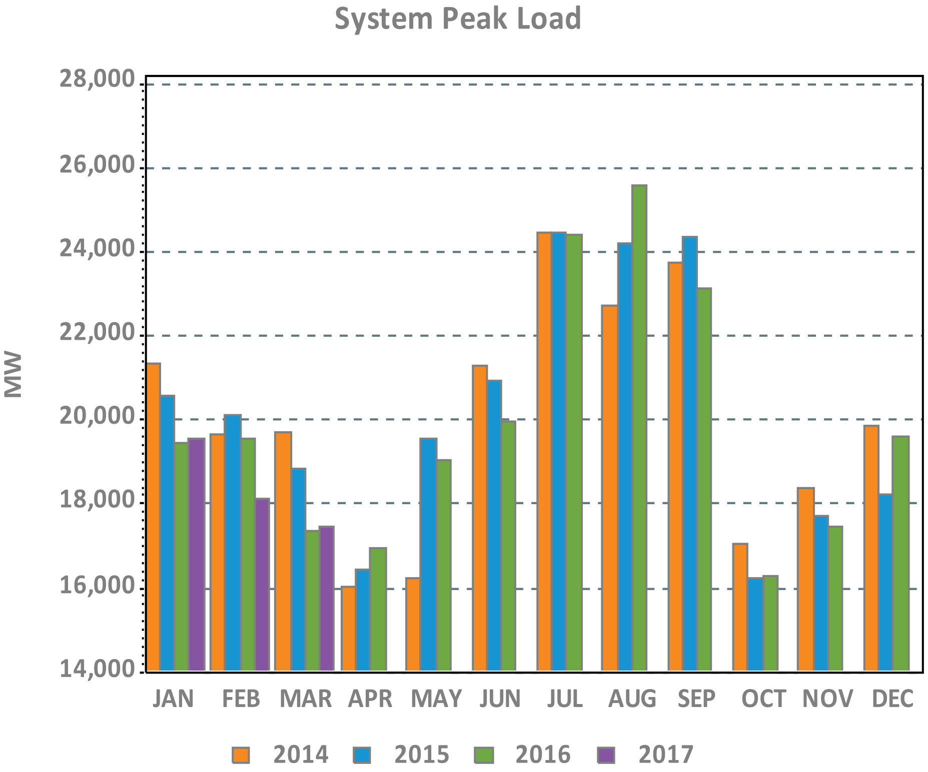
Ann Tot (TWh): 127.2 127.0 124.3 29.8



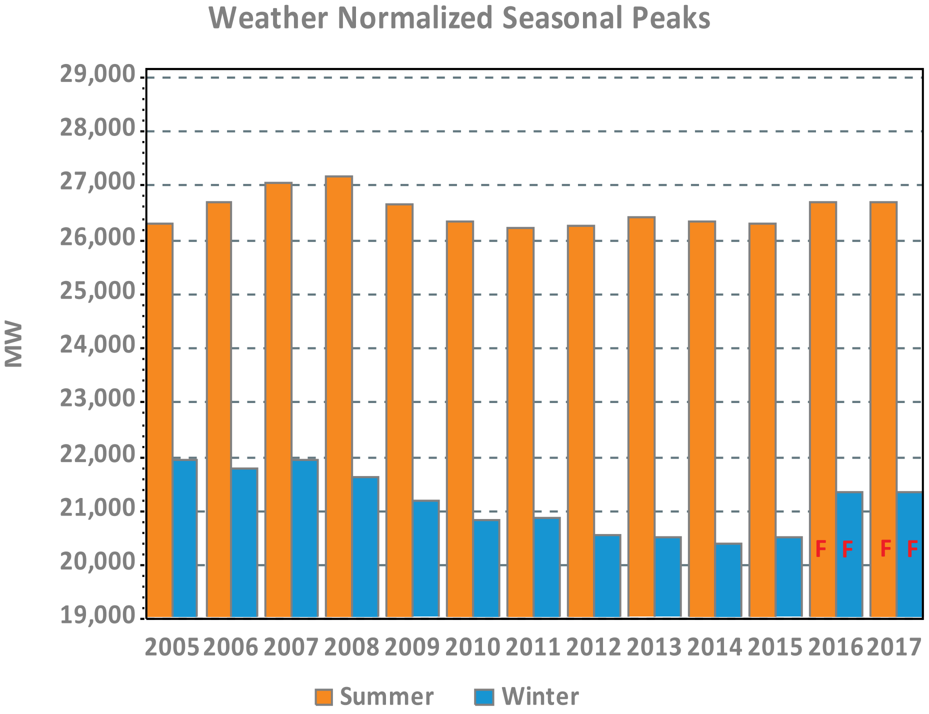
Ann Tot (TWh): 127.1 125.8 124.0 20.8

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

Monthly Peak Loads and Weather Normalized Seasonal Peak History



*Revenue quality metered value

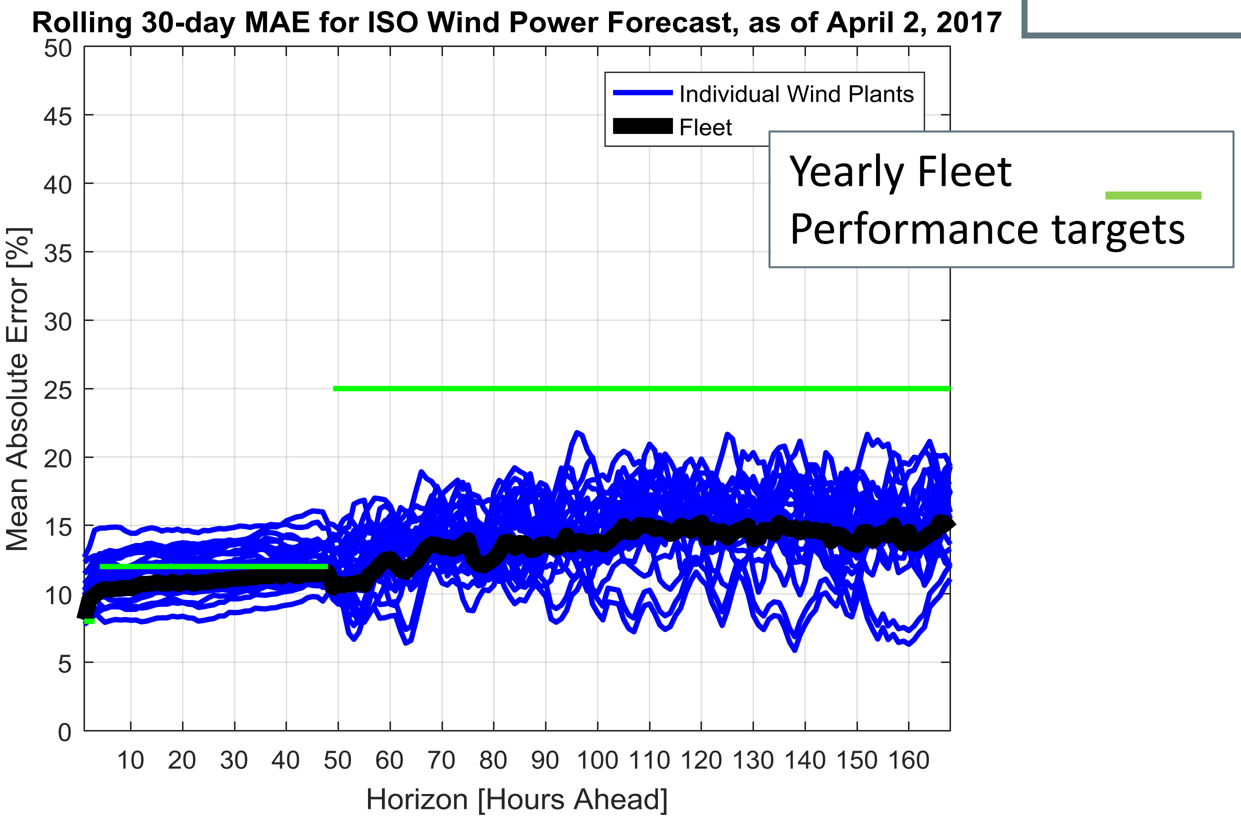


Winter beginning in year displayed

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

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

Dashboard Indicator ●

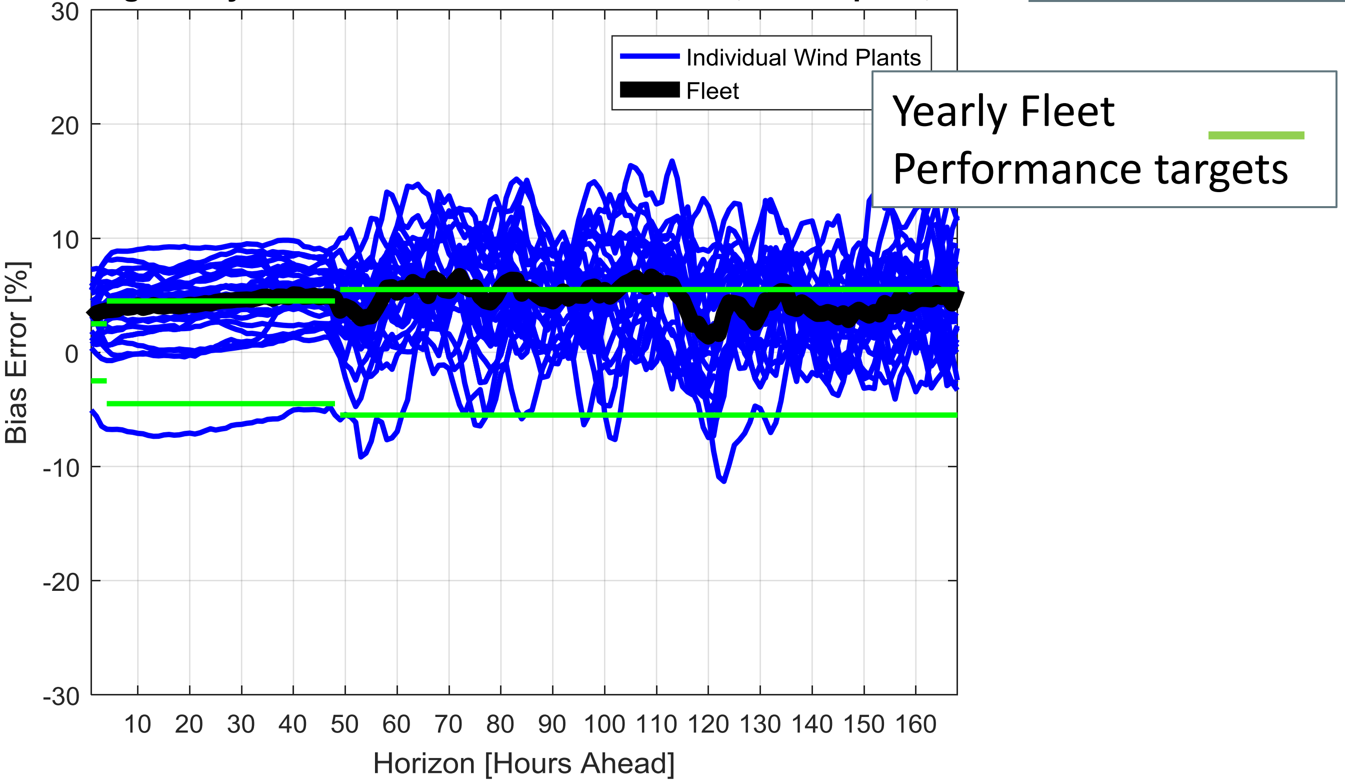


Ideally, MAE and Bias would be both equal to zero. As is typical, MAE increases with the forecast horizon. MAE and Bias for the fleet of wind power resources are less due to offsetting errors. Across all time frames, the ISO-NE/DNV-GL forecast is very good compared to industry standards, and monthly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

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

Dashboard Indicator ●

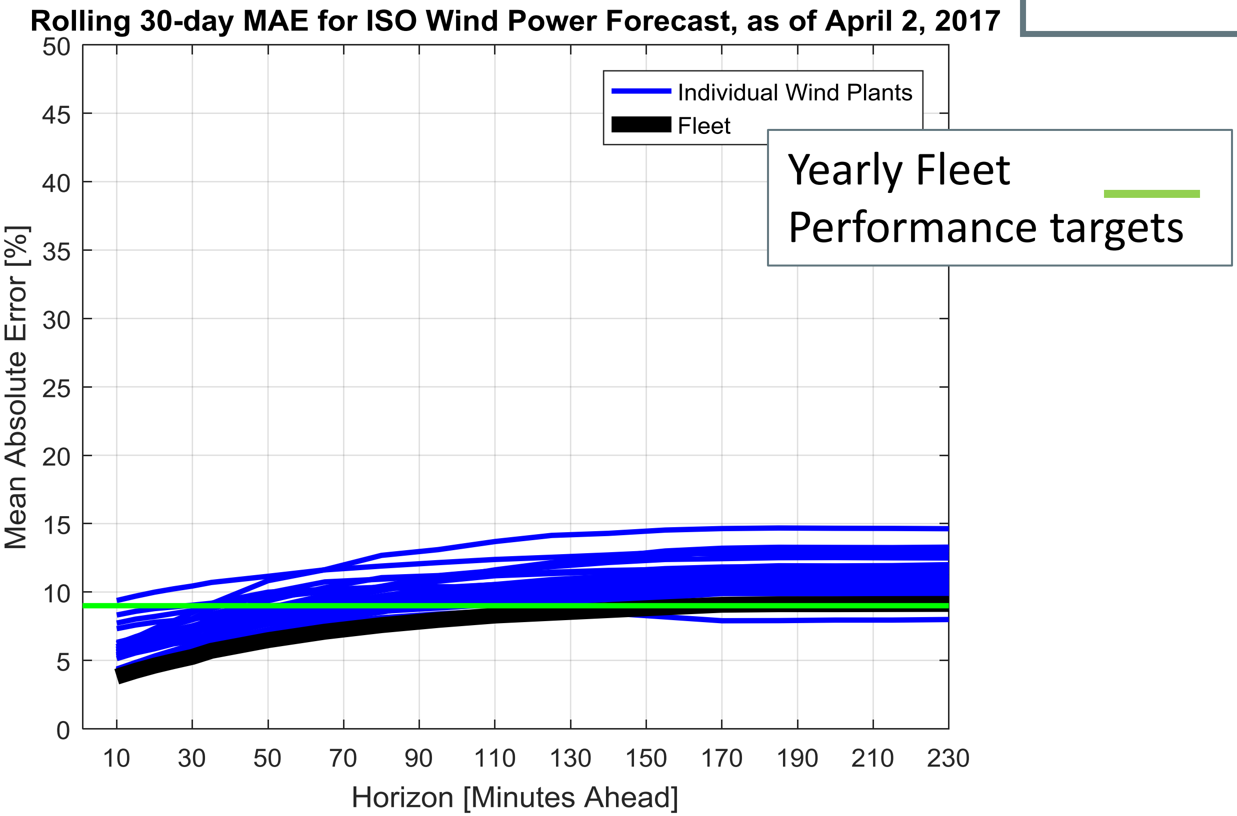
Rolling 30-day Bias for ISO Wind Power Forecast, as of April 2, 2017



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 mostly within yearly performance targets.

Wind Power Forecast Error Statistics: Short Term Forecast MAE

Dashboard Indicator ●

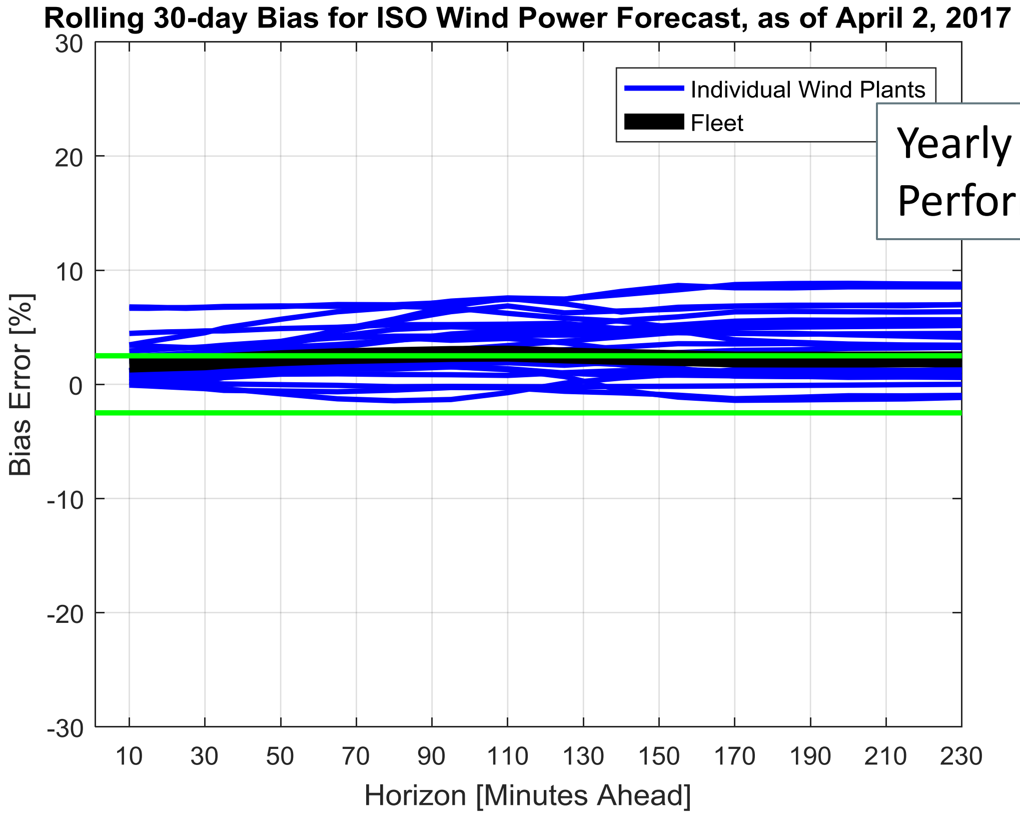


Yearly Fleet Performance targets

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 ●

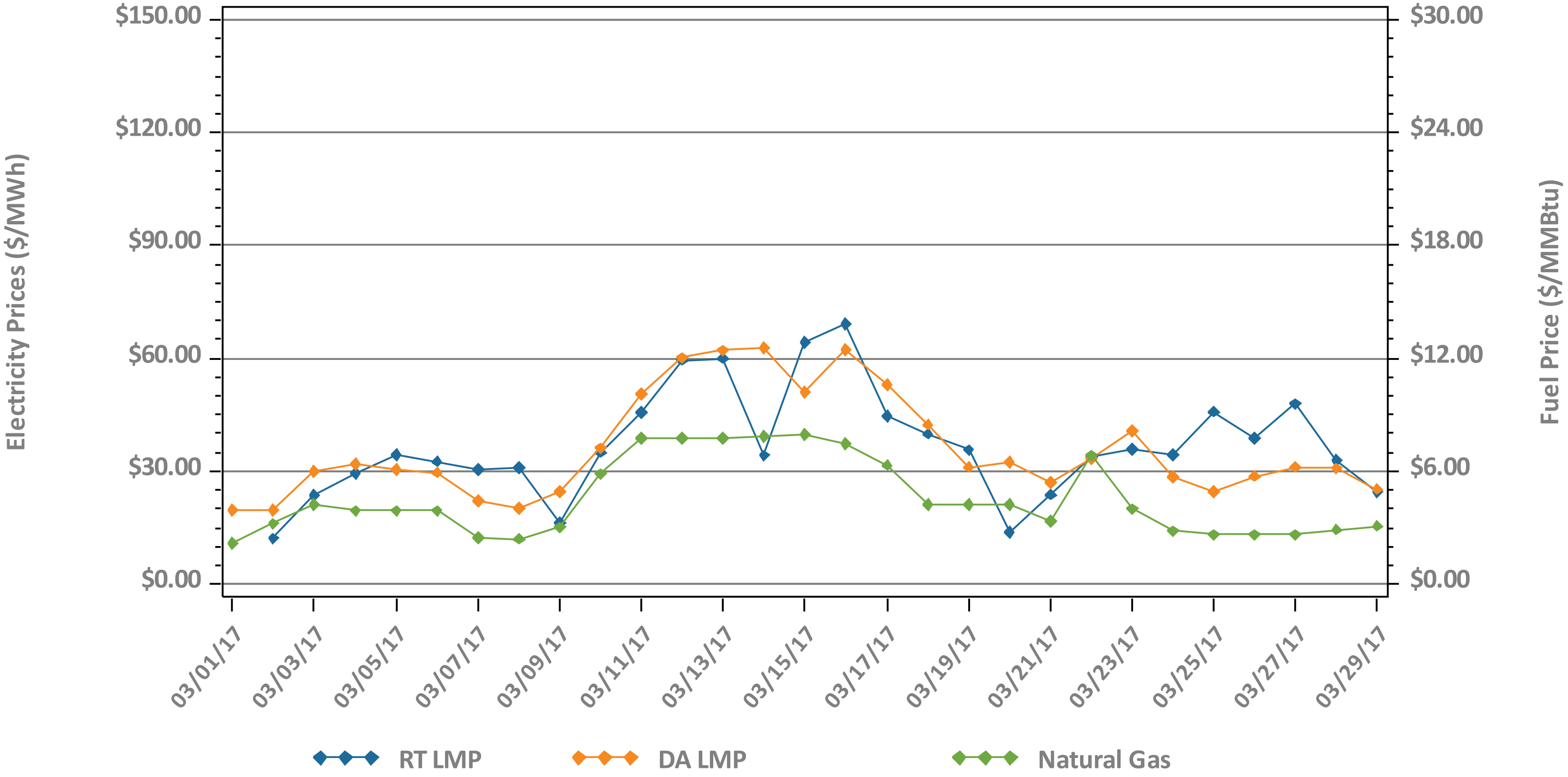


Yearly Fleet Performance targets 🟩

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: March 1-29, 2017

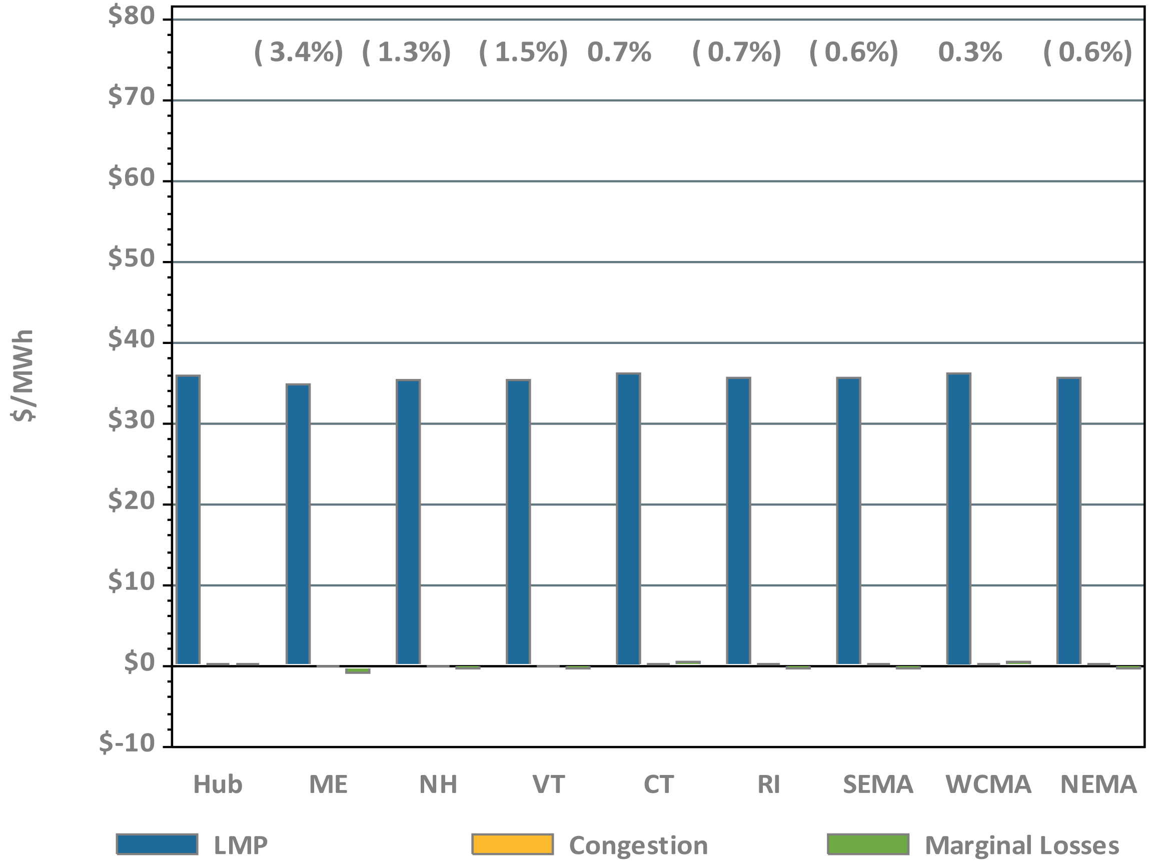


Underlying natural gas data furnished by:

ICE Global markets in clear view

Average price difference over this period (DA-RT): $0.48
Average price difference over this period ABS(DA-RT): $7.90
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 22%
Gas price is average of Massachusetts delivery points

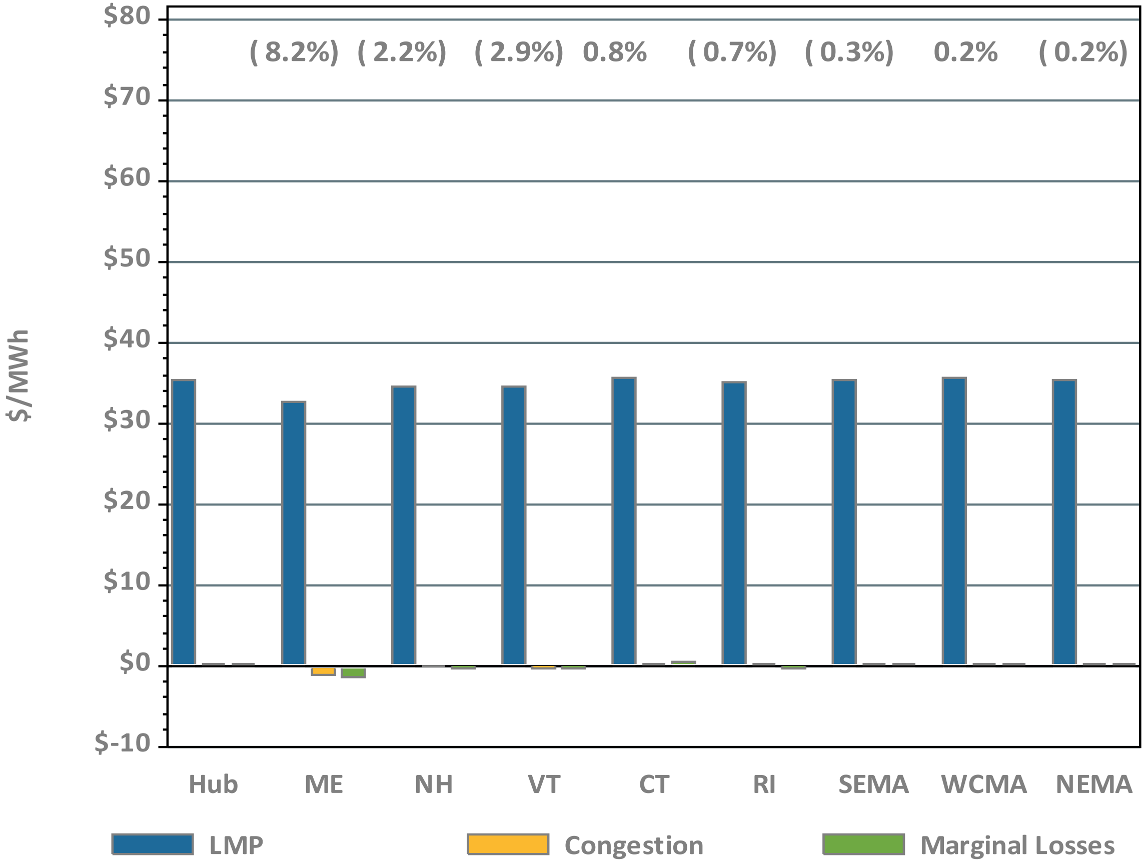
DA LMPs Average by Zone & Hub, March 2017



ME - Maine
NH – New Hampshire
VT – Vermont
CT – Connecticut

RI – Rhode Island
SEMA – Southeastern Massachusetts
WCMA – Western/Central Massachusetts
NEMA – Northeastern Massachusetts

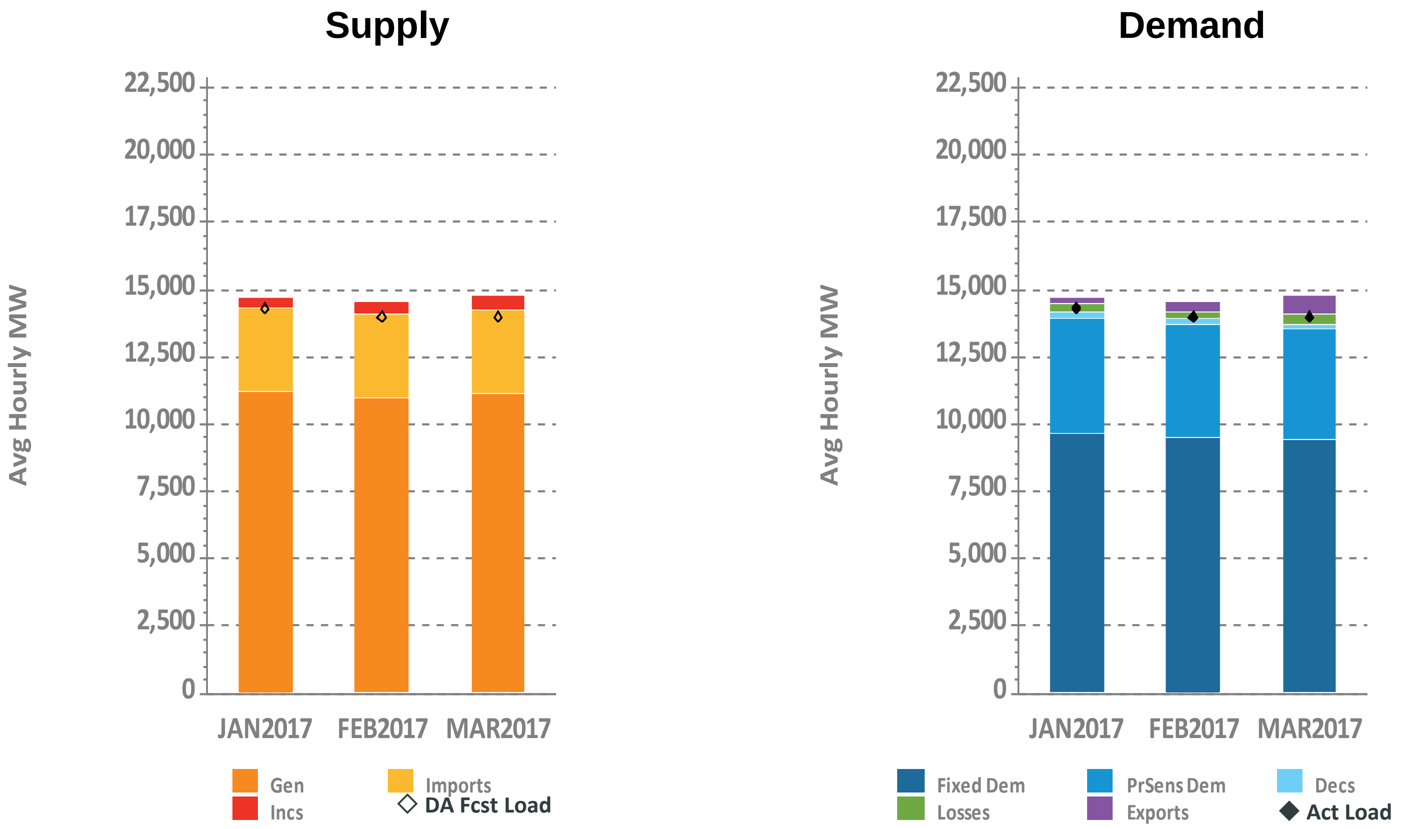
RT LMPs Average by Zone & Hub, March 2017



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

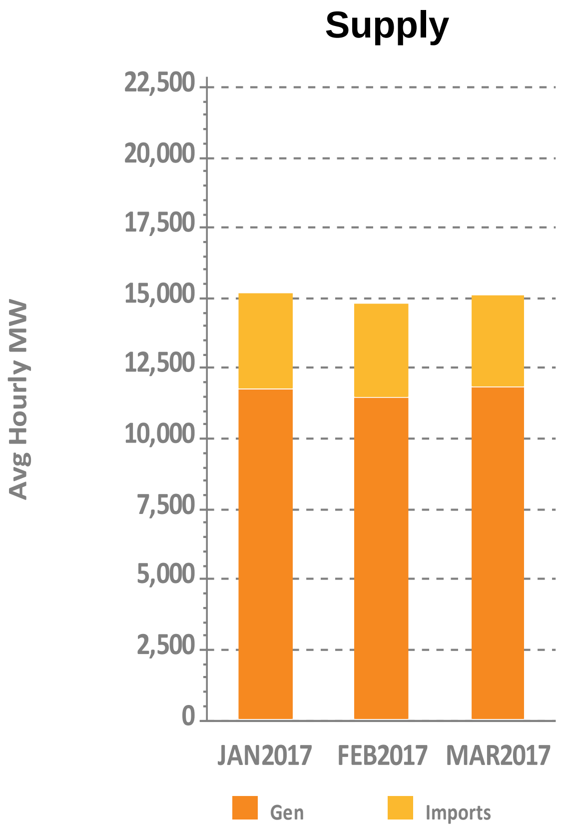
Components of Cleared DA Supply and Demand – Last Three Months

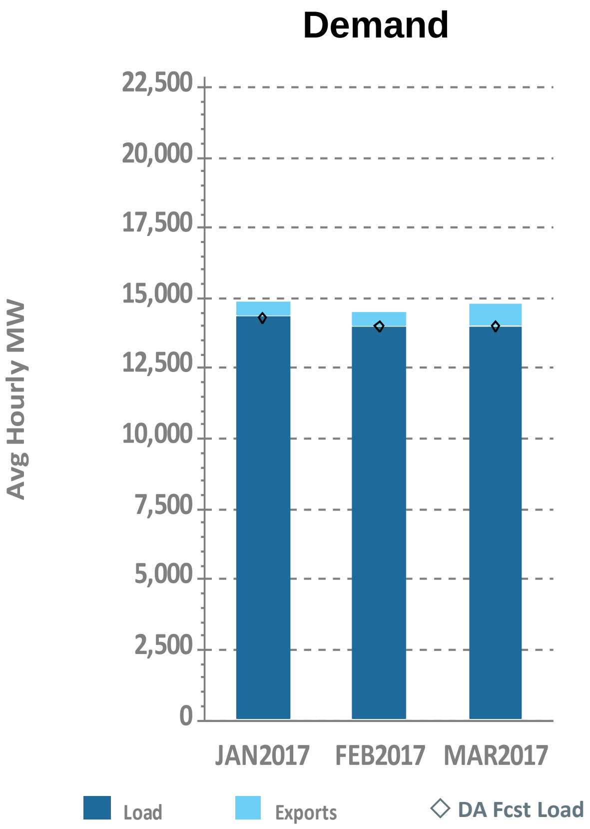


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load

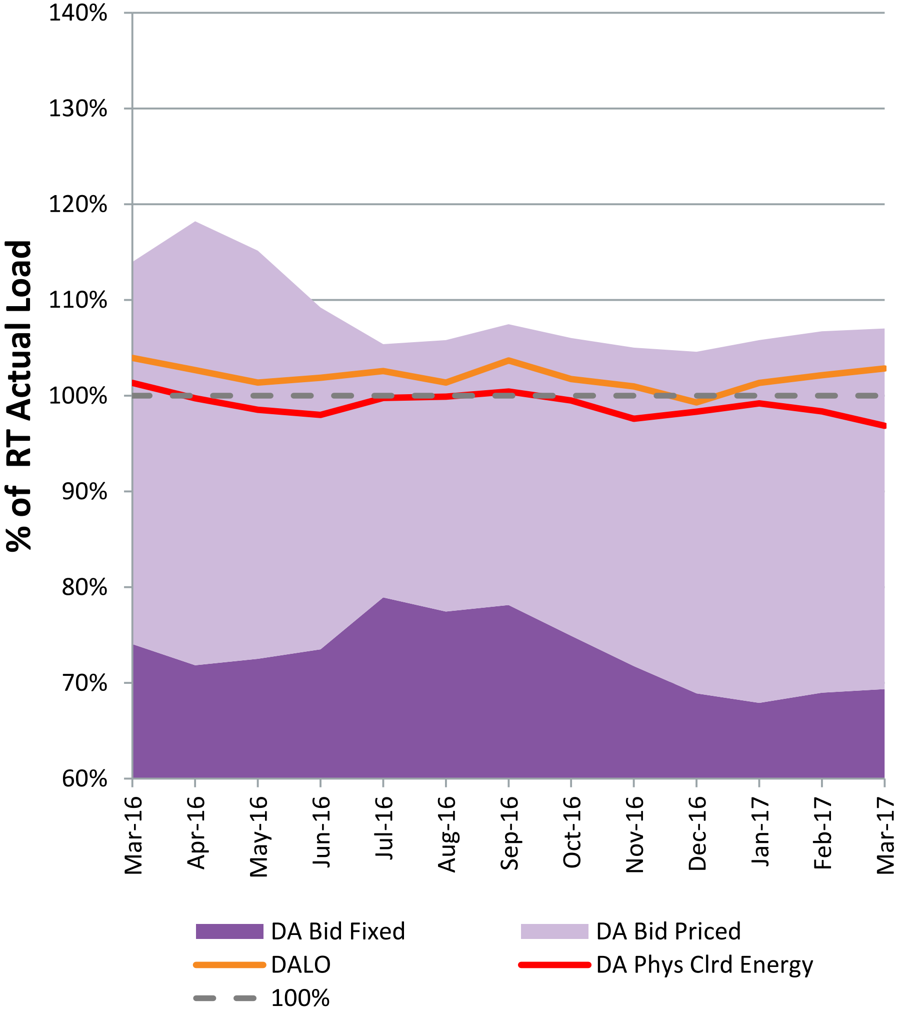
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

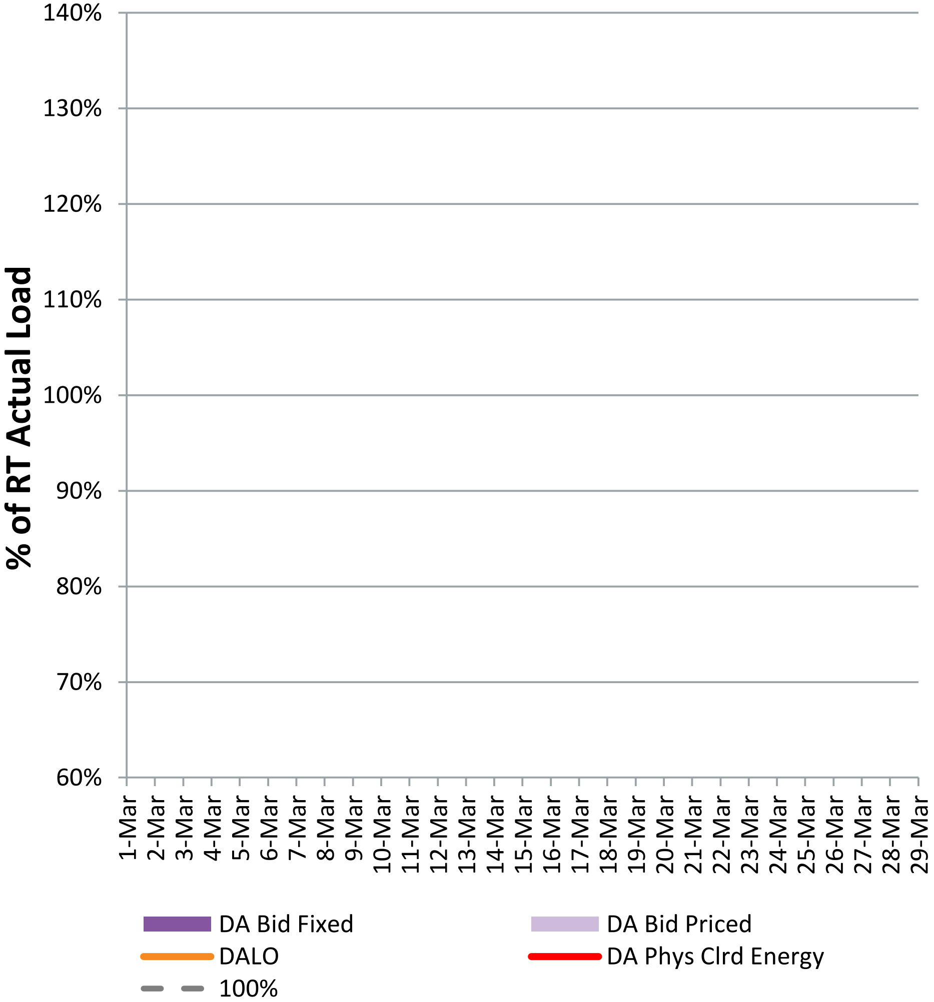
Components of RT Supply and Demand – Last Three Months





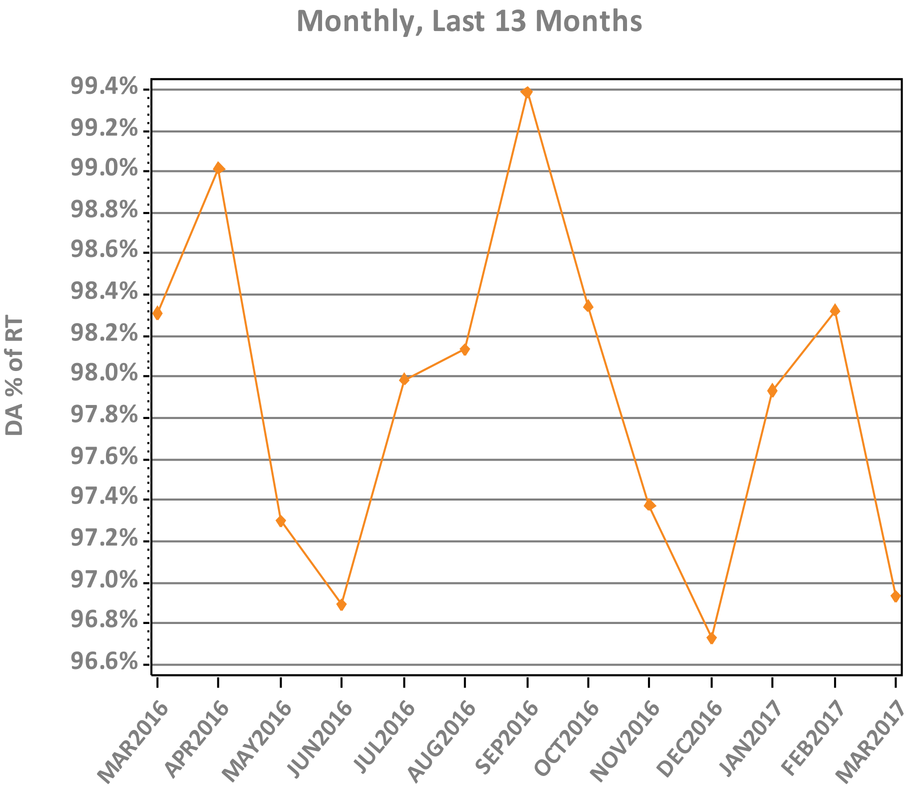
DAM Volumes as % of RT Actual Load (Peak Hour)

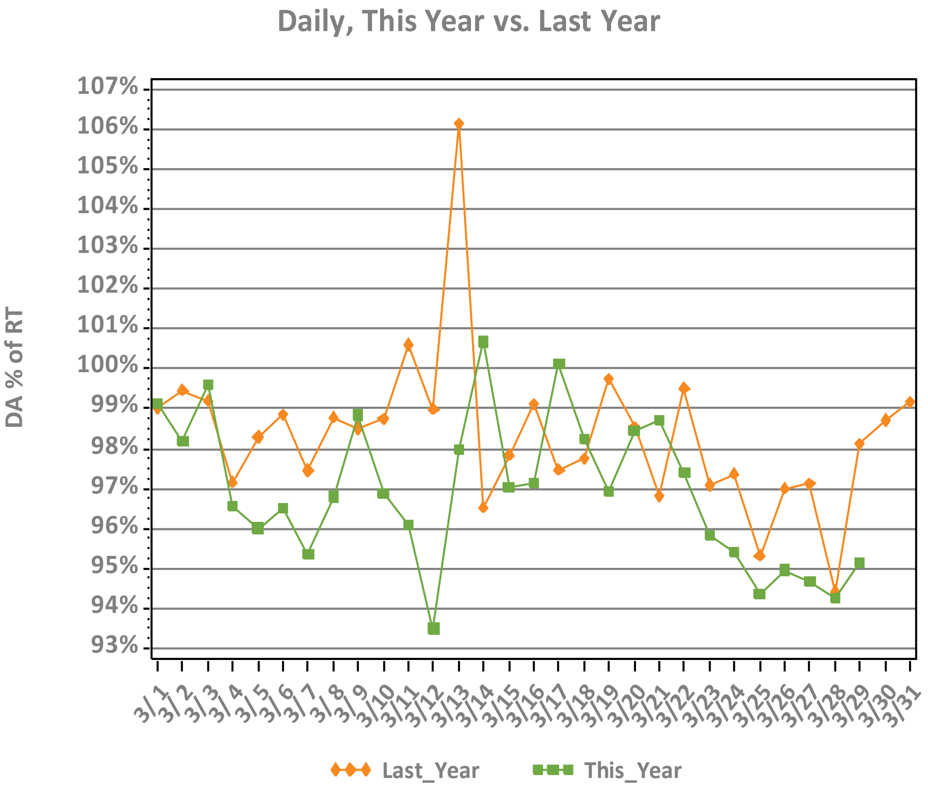




Note: Percentages were derived for the peak hour of each day (shown on right), then averaged over the month (shown on left). Values at hour of forecasted peak load. DA Bid categories reflect internal load asset bidding behavior (Dec and export bid behavior not reflected).

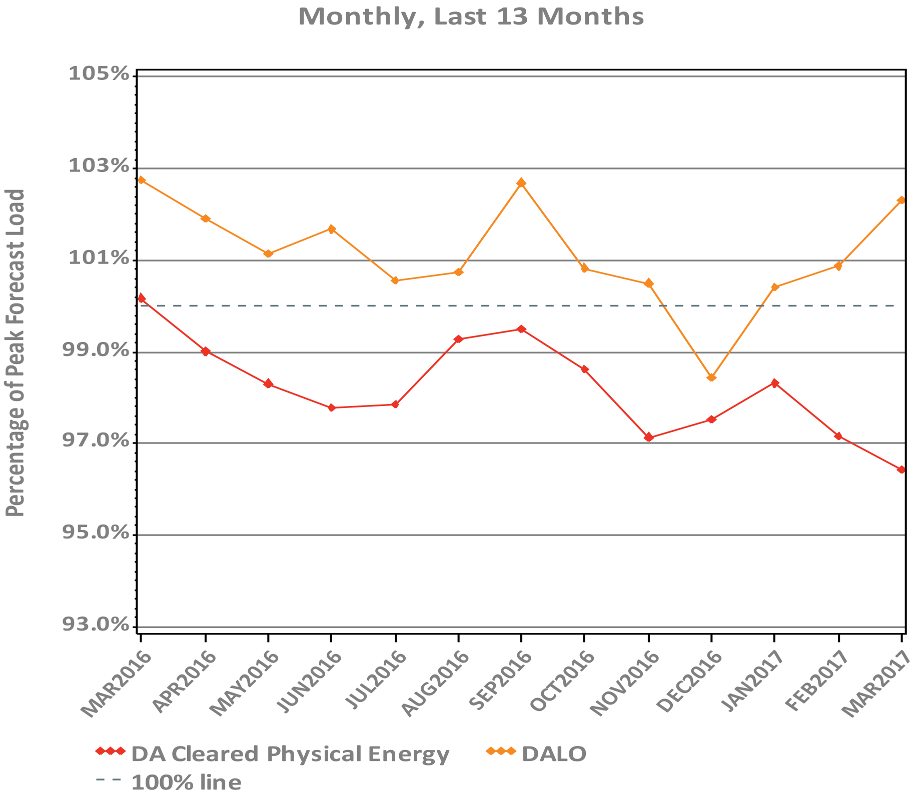
DA vs. RT Load Obligation: March, This Year vs. Last Year

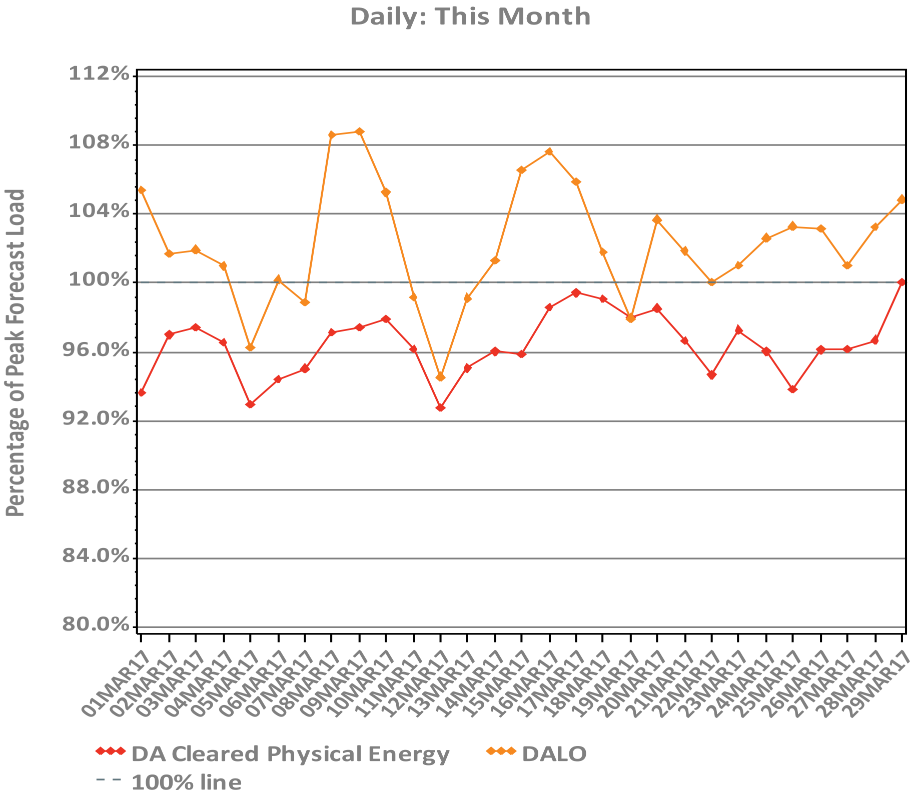




*Hourly average values

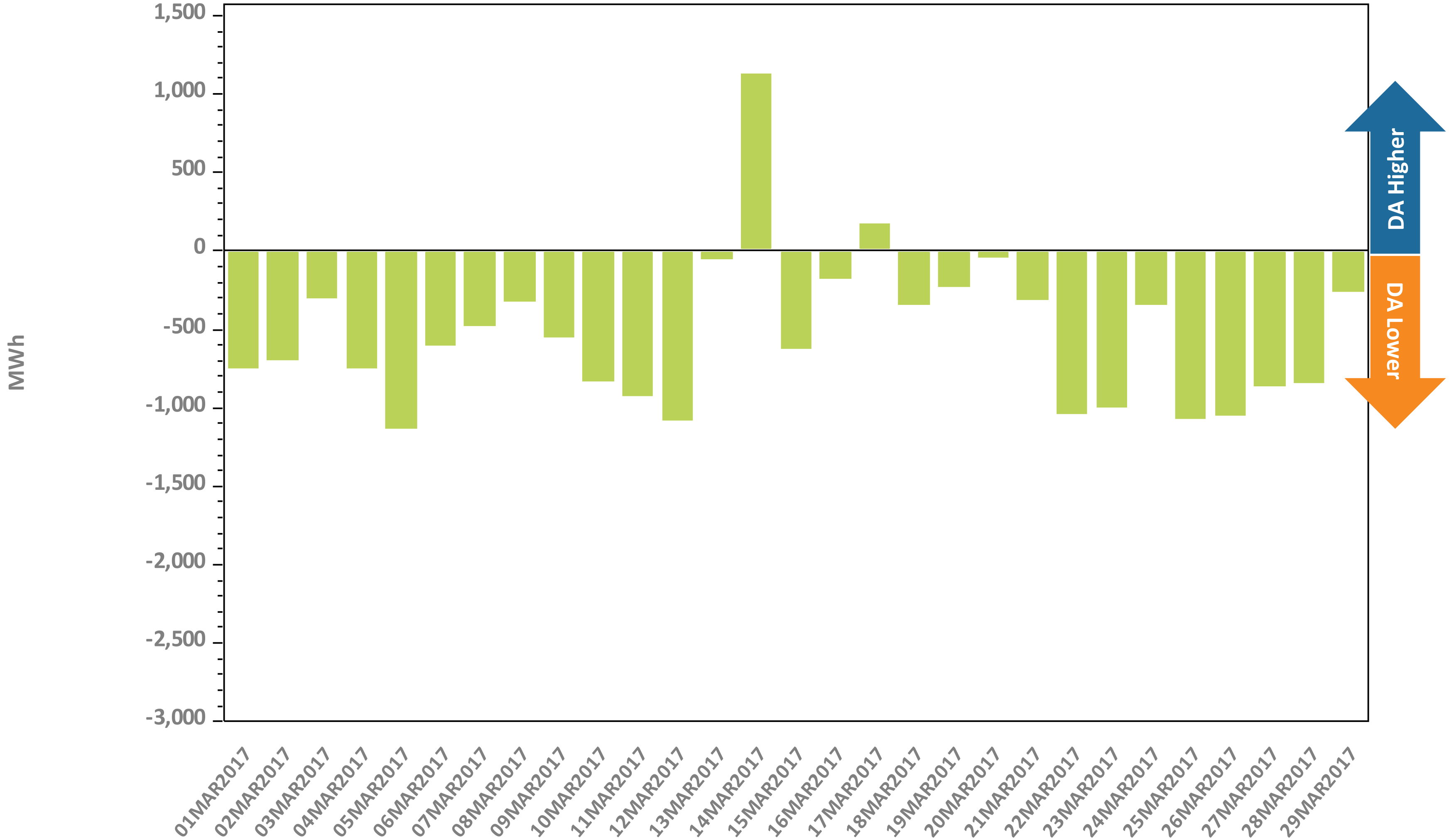
DA Volumes as % of Forecast (Peak Hour)





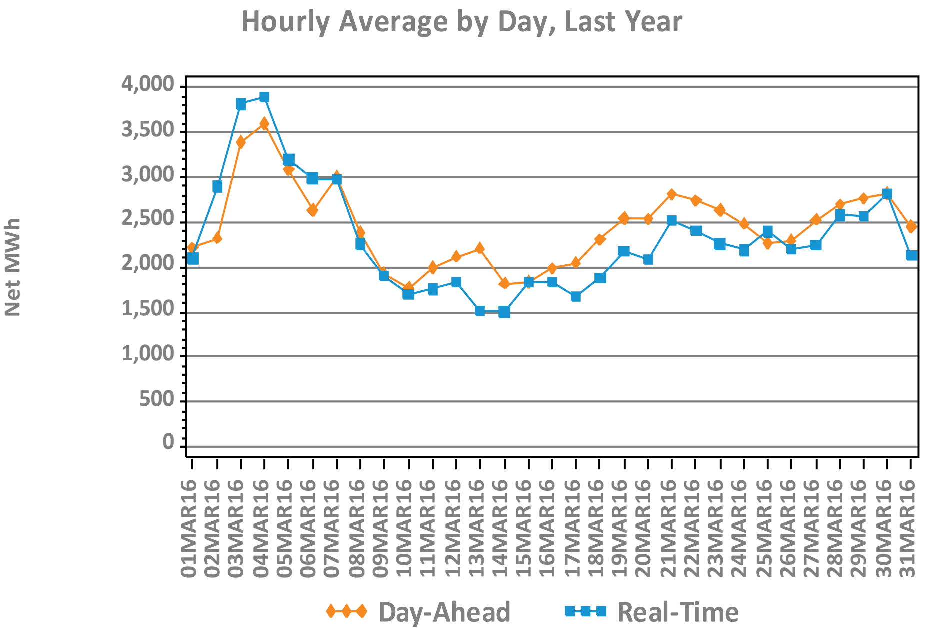
*Forecasted peak hour is reflected.

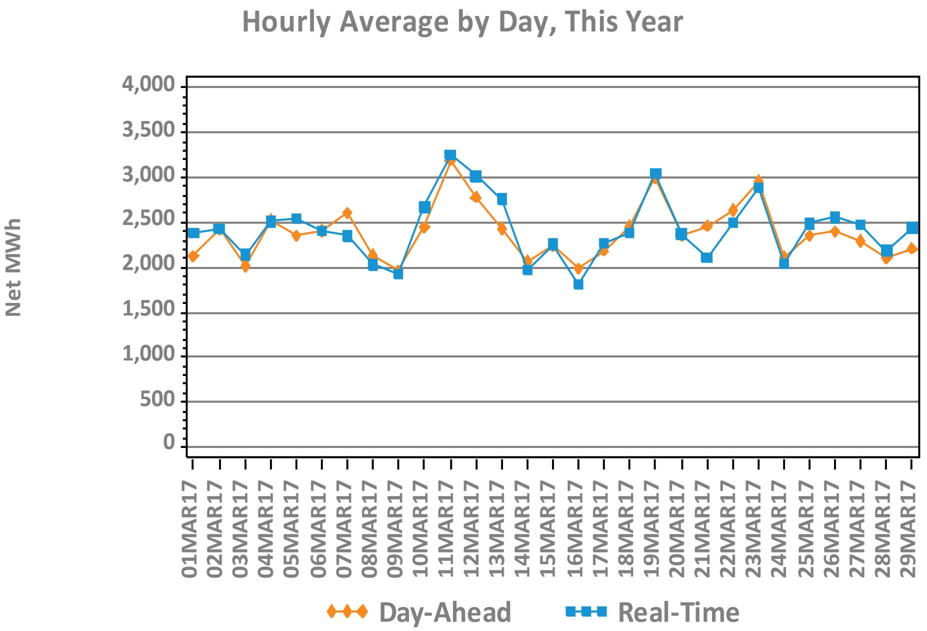
DA Cleared Physical Energy Difference from RT System Load at Peak Hour*



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

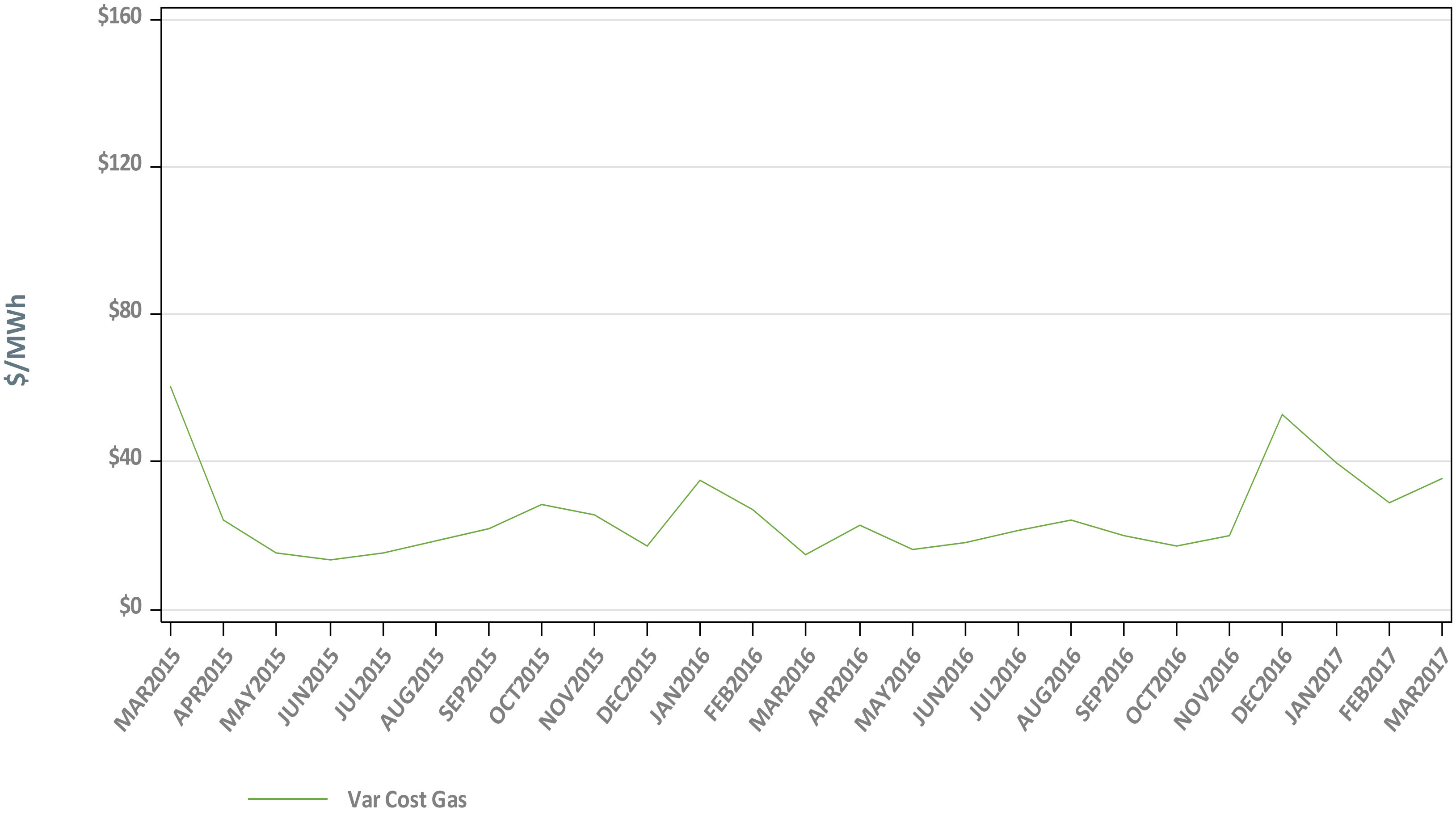
DA vs. RT Net Interchange March 2017 vs. March 2016





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

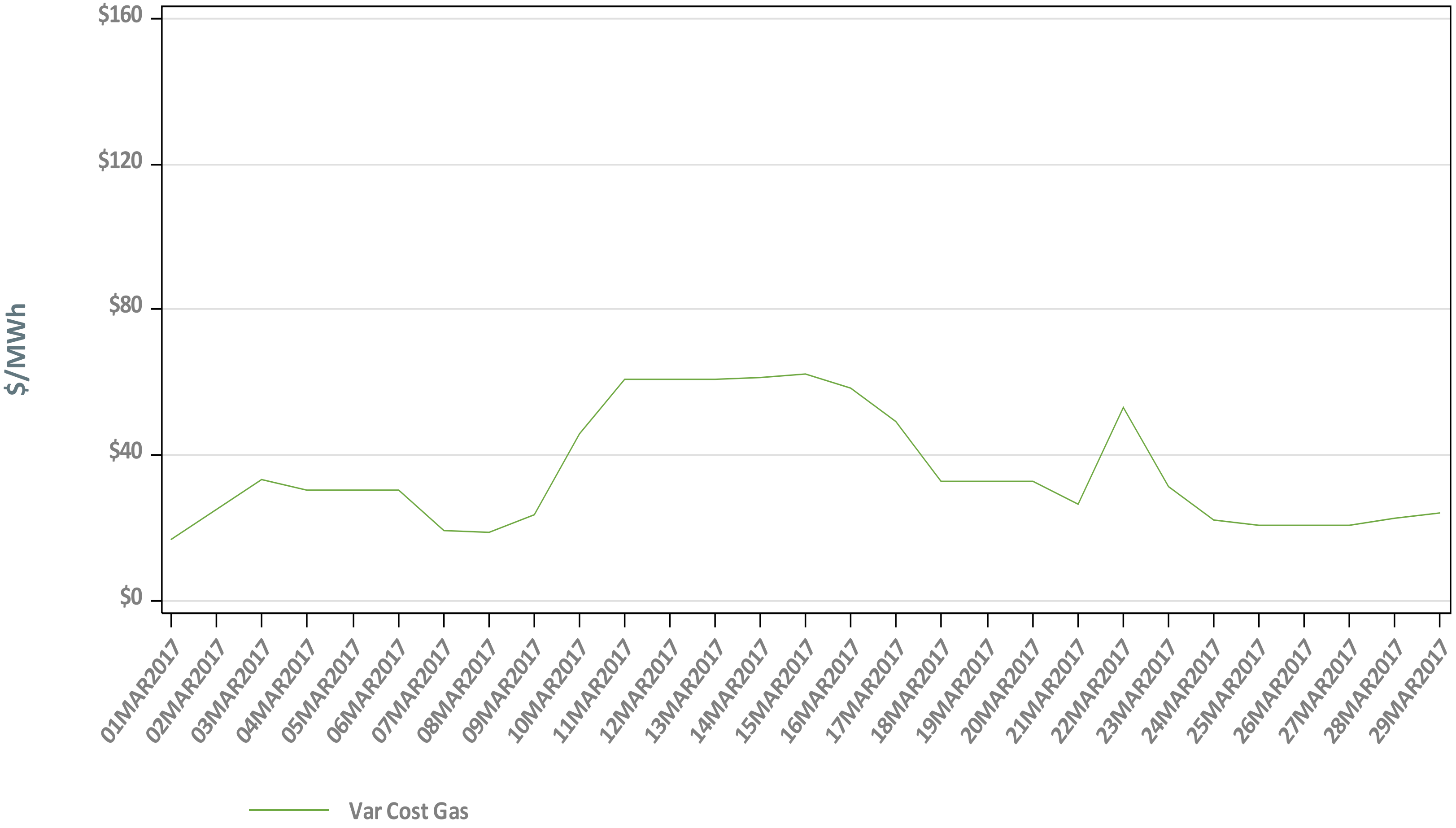


Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

Underlying natural gas data furnished by:

ice Global markets in clear view

Variable Production Cost of Natural Gas: Daily

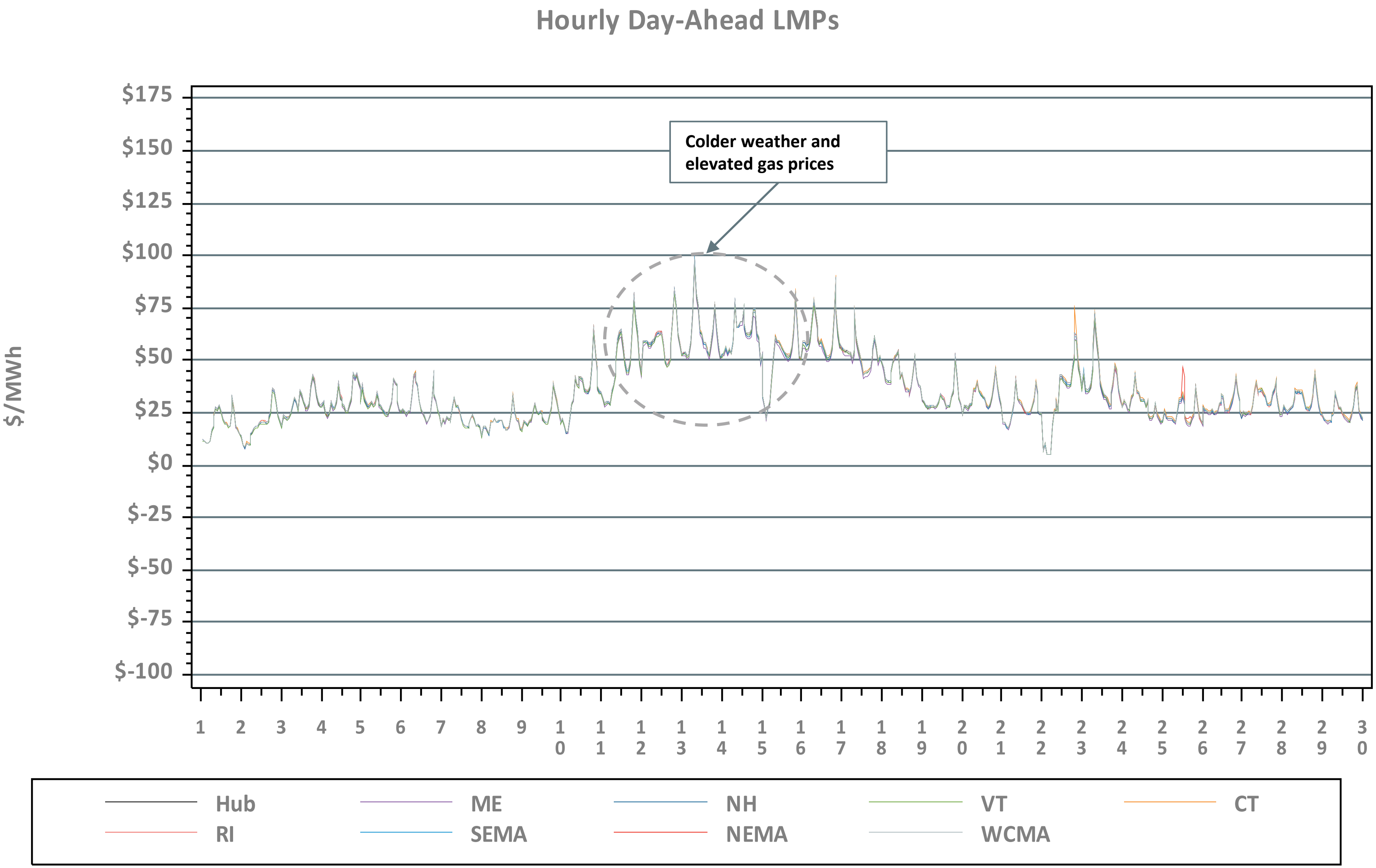


Underlying natural gas data furnished by:

ice Global markets in clear view

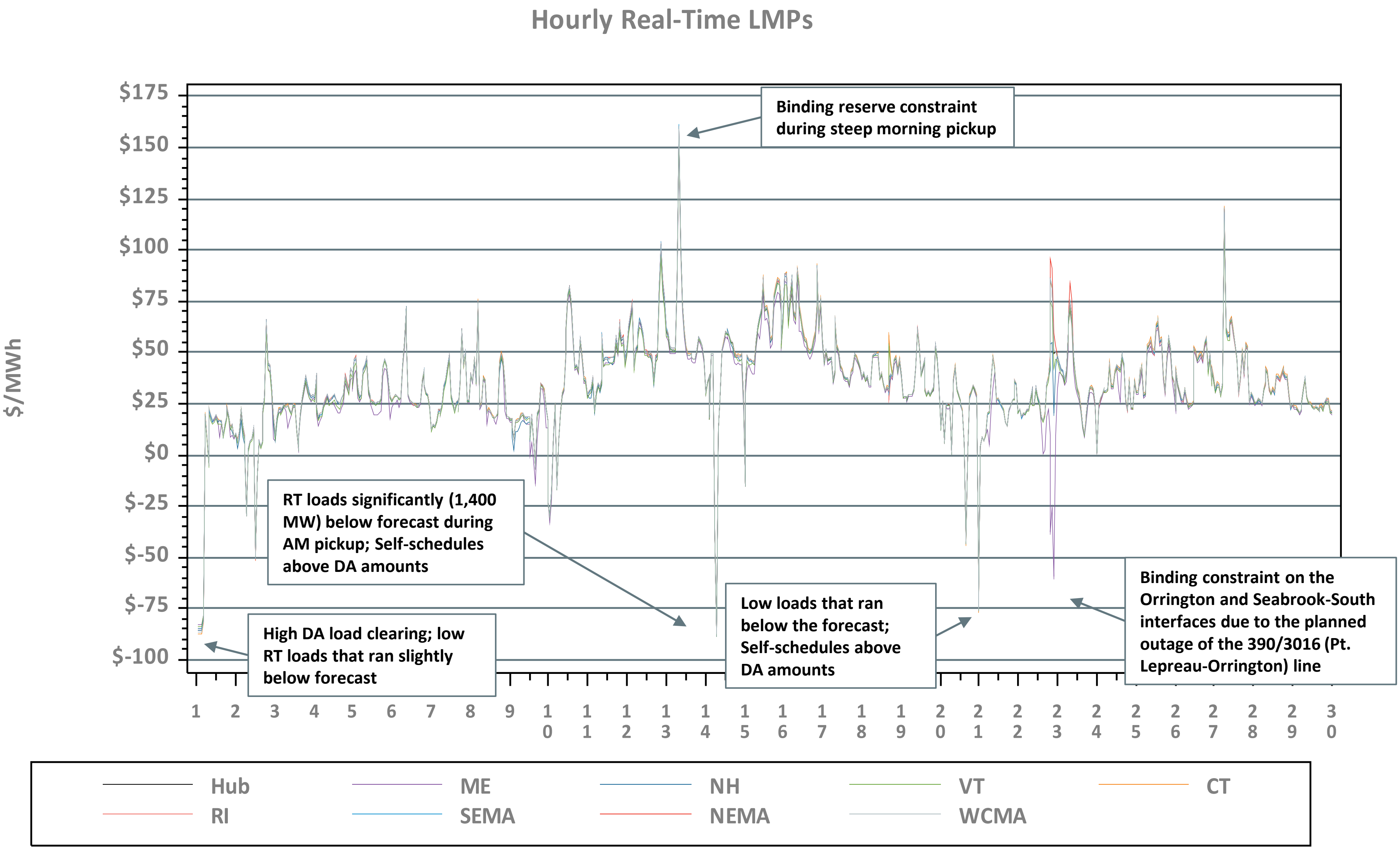
Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

Hourly DA LMPs, March 1-29, 2017



Colder weather and elevated gas prices

Hourly RT LMPs, March 1-29, 2017



Binding reserve constraint during steep morning pickup

RT loads significantly (1,400 MW) below forecast during AM pickup; Self-schedules above DA amounts

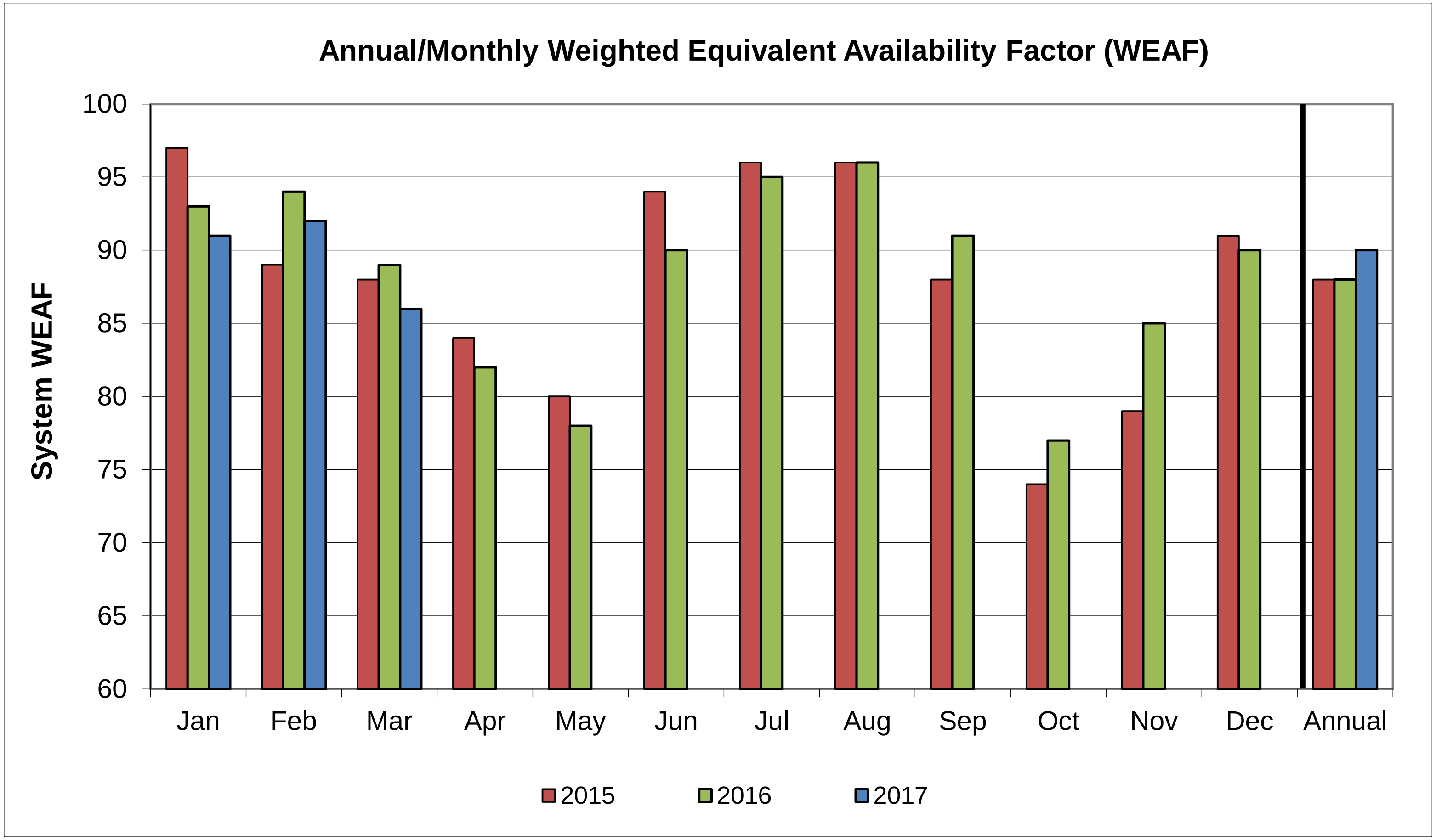
High DA load clearing; low RT loads that ran slightly below forecast

Low loads that ran below the forecast; Self-schedules above DA amounts

Binding constraint on the Orrington and Seabrook-South interfaces due to the planned outage of the 390/3016 (Pt. Lepreau-Orrington) line

* No Minimum Generation Emergencies were declared in March.

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2017	91	92	86										90
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 4/3/17

BACK-UP DETAIL

LOAD RESPONSE

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

Load Zone	RTDR*	RTEG**	On Peak	Seasonal Peak	Total
ME	77.2	0.0	133.3	0.0	210.6
NH	10.5	0.0	81.1	0.0	91.6
VT	25.0	0.0	104.7	0.0	129.8
CT	57.2	1.5	58.9	355.4	473.0
RI	11.2	0.0	177.0	0.0	188.2
SEMA	10.8	0.0	246.7	0.0	257.4
WCMA	27.8	0.0	228.0	52.5	308.3
NEMA	24.7	0.0	486.5	0.0	511.2
Total	**244.5**	**1.5**	**1,516.1**	**407.9**	**2,170.0**

*** Real Time Demand Response**

**** Real Time Emergency Generation**

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

NEW GENERATION

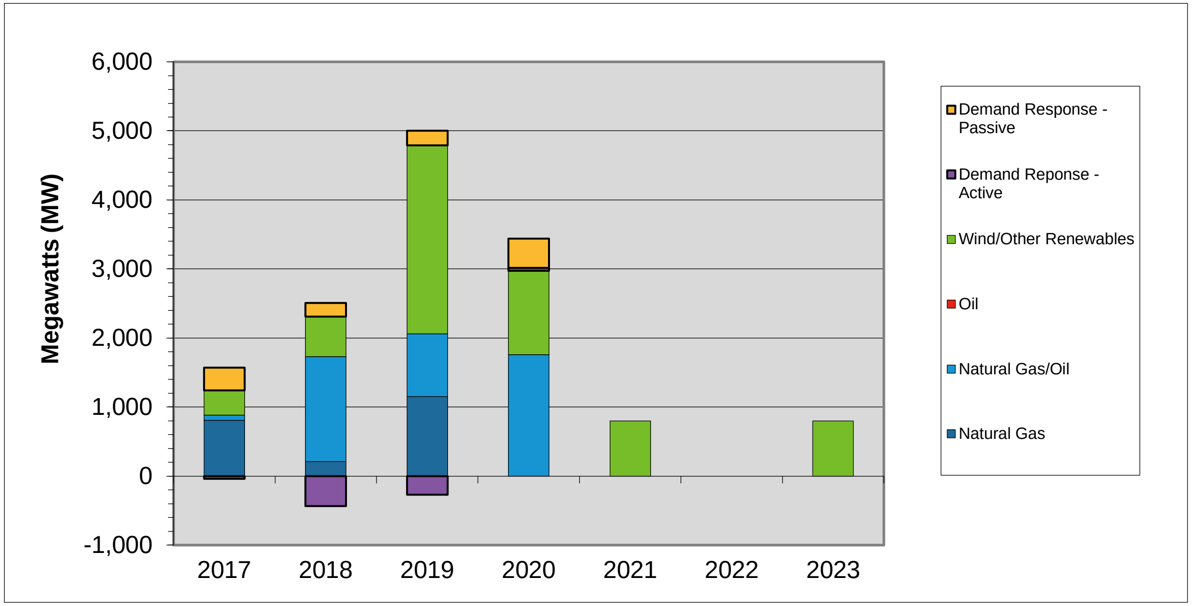
New Generation Update

Based on Queue as of 3/31/17

- Two new projects, with a total rating of 50 MW, have applied for interconnection study since the last update
  - The projects are photovoltaic facilities with expected in-service dates in 2019
- One project withdrew from the queue and no projects went commercial, resulting in a net decrease in new generation projects of 25 MW
- In total, 76 generation projects are currently being tracked by the ISO, totaling approximately 12,900 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



	2017	2018	2019	2020	2021	2022	2023	Total MW	% of Total[1]
Demand Response - Passive	330	196	212	422	0	0	0	1,160	8.7
Demand Response - Active	-37	-433	-270	42	0	0	0	-697	-5.2
Wind & Other Renewables	358	583	2,731	1,216	800	0	800	6,488	48.5
Oil	0	0	0	0	0	0	0	0	0.0
Natural Gas/Oil[2]	75	1,519	904	1,757	0	0	0	4,255	31.8
Natural Gas	808	210	1,154	0	0	0	0	2,172	16.2
Totals	**1,534**	**2,075**	**4,732**	**3,438**	**800**	**0**	**800**	**13,378**	**100.0**

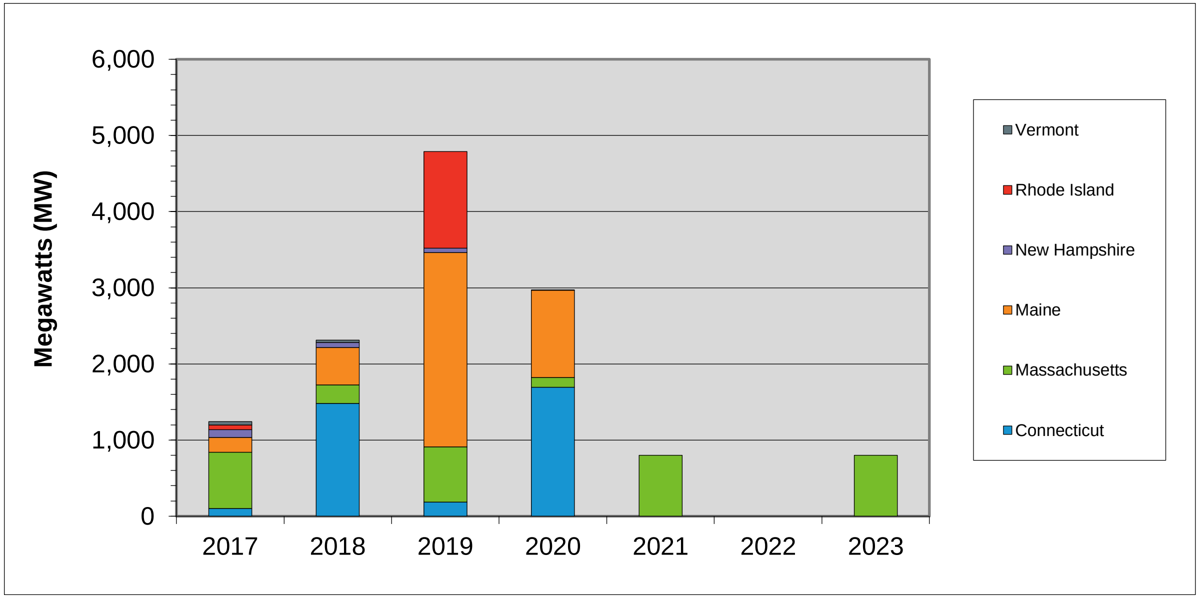
[1] **Sum may not equal 100% due to rounding**

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

- 2017 values include the 16 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	Total MW	% of Total[1]
Vermont	42	30	0	0	0	0	0	72	0.6
Rhode Island	61	0	1,268	0	0	0	0	1,329	10.3
New Hampshire	102	65	58	5	0	0	0	230	1.8
Maine	195	491	2,553	1,145	0	0	0	4,384	33.9
Massachusetts	741	245	725	128	800	0	800	3,439	26.6
Connecticut	100	1,481	185	1,695	0	0	0	3,461	26.8
Totals	**1,241**	**2,312**	**4,789**	**2,973**	**800**	**0**	**800**	**12,915**	**100.0**

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

- 2017 values reflect the 16 MW of generation that has gone commercial in 2017

New Generation Projection

By Fuel Type

	Total		Green		Yellow	
Fuel Type	**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	4	101	0	0	4	101
Landfill Gas	1	2	0	0	1	2
Natural Gas	13	2,235	1	100	12	2,135
Natural Gas/Oil	12	4,255	2	1,009	10	3,246
Oil	0	0	0	0	0	0
Solar	15	795	0	0	15	795
Wind	28	5,397	1	23	27	5,374
Battery Storage	2	77	0	0	2	77
Total	76	12,899	4	1,132	72	11,767

- 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

	Total		Green		Yellow	
Operating Type	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**
Baseload	4	107	0	0	4	107
Intermediate	18	5,421	1	801	17	4,620
Peaker	26	1,974	2	308	24	1,666
Wind Turbine	28	5,397	1	23	27	5,374
Total	76	12,899	4	1,132	72	11,767

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

New Generation Projection

By Operating Type and Fuel Type

	Total		Baseload		Intermediate		Peaker		Wind Turbine	
Fuel Type	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**
Biomass/Wood Waste	1	37	1	37	0	0	0	0	0	0
Hydro	4	101	1	5	2	30	1	66	0	0
Landfill Gas	1	2	1	2	0	0	0	0	0	0
Natural Gas	13	2,235	1	63	9	1,991	3	181	0	0
Natural Gas/Oil	12	4,255	0	0	7	3,400	5	855	0	0
Oil	0	0	0	0	0	0	0	0	0	0
Solar	15	795	0	0	0	0	15	795	0	0
Wind	28	5,397	0	0	0	0	0	0	28	5,397
Battery Storage	2	77	0	0	0	0	2	77	0	0
Total	76	12,899	4	107	18	5,421	26	1,974	28	5,397

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 6

Resource Type	Resource Type	FCA	Proration		Annual Bilateral for ARA 1		ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	**Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	2,001.510	1,918.662	-82.848	1,368.608	-550.054	1,271.984	-96.624	1,085.347	-186.64	842.791	-242.56	789.366	-53.425	638.393	-150.973
	Passive Demand	1,643.334	1,553.054	-90.280	1,521.535	-31.519	1,521.535	0.000	1,516.504	-5.03	1,700.586	184.08	1,694.766	-5.82	1,687.458	-7.308
Demand Total		**3,644.844**	**3,471.716**	**-173.128**	**2,890.143**	**-581.573**	**2,793.519**	-96.624	**2,601.851**	**-191.67**	**2,543.377**	**-58.47**	**2,484.132**	**-59.245**	**2,325.851**	-158.281
Generator	*Non-Intermittent*	29,866.098	27,957.613	-1,908.485	28,121.731	164.118	28,343.440	221.709	28,442.424	98.98	28,727.16	284.73	28,881.019	153.859	**28,971.511**	90.492
	Intermittent	891.069	840.563	-50.506	827.047	-13.516	828.252	1.205	829.219	0.97	820.743	-8.48	777.924	-42.819	**754.101**	-23.823
Generator Total		**30,757.167**	**28,798.176**	**-1,958.991**	**28,948.778**	**150.602**	**29,171.692**	222.914	**29,271.643**	**99.95**	**29,547.9**	**276.26**	**29,658.943**	**111.043**	**29,725.612**	66.669
Import Total		**1,924.000**	**1,768.111**	**-155.889**	**1,768.111**	**0.000**	**1,641.821**	-126.290	**1,616.821**	**-25.00**	**1,399.037**	**-217.78**	**1,337.037**	**-62**	**1,337.037**	0
*****Grand Total**		**36,326.011**	**34,038.003**	**-2,288.008**	**33,607.032**	**-430.971**	**33,607.032**	0.000	**33,490.315**	**-116.72**	**33,490.32**	**0.00**	**33,480.112**	**-10.208**	**33,388.5**	-91.612
Net ICR (NICR)		**33,456**	**33,456**	**0**	**33,456**	**0**	**33,456**	**0**	33,114	**-342**	**33,114**	**0.00**	**33,391**	**277**	**33,391**	**0**

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

** Change columns contain the changes in CSO amount resulting from the specific FCM Event as well as adjustments for Delisted MW released according to MR 1, Section 13.2.5.2, and changes that occurred (terminations, etc.) prior to the event reported in the column.

*** Grand Total reflects both CSO Grand Total and the net total of the Change Column.

Capacity Supply Obligation FCA 7

Resource Type	Resource Type	FCA	Proration		Annual Bilateral for ARA 1		ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	**Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	1,116.698	1,043.719	-72.979	944.27	-99.45	932.721	-11.549	781.206	-151.52	671.28	-109.926	575.63	-95.65	556.453	-19.177
	Passive Demand	1,631.335	1,519.740	-111.595	1,519.311	-0.43	1,543.793	24.482	1,544.276	0.48	1,544.119	-0.157	1,607.705	63.586	1,884.902	277.197
Demand Total		**2,748.033**	**2,563.459**	**-184.574**	**2,463.581**	**-99.88**	**2,476.514**	**12.933**	2,325.482	-151.03	2,215.399	-110.083	2,183.335	-32.064	2,441.355	258.02
Generator	*Non-Intermittent*	30,704.578	28,146.837	-2,557.741	28,127.044	-19.79	28,523.002	395.958	28,307.339	-215.66	28,791.131	483.792	28,948.677	157.546	29,152.793	204.116
	Intermittent	936.913	893.710	-43.203	903.244	9.53	913.083	9.839	838.626	-74.46	824.833	-13.793	800.286	-24.547	735.174	-65.112
Generator Total		**31,641.491**	**29,040.547**	**-2,600.944**	**29,030.288**	**-10.26**	**29,436.085**	**405.797**	29,145.965	-290.12	29,615.964	469.999	29,748.963	132.999	29,887.967	139.004
Import Total		**1,830.000**	**1,606.862**	**-223.138**	**1,606.862**	**0.00**	**1,616.401**	**9.539**	1,576.401	-40.00	1,576.401	0	1,440.401	-136	1,162.202	-278.199
*****Grand Total**		**36,219.524**	**33,210.868**	**-3,008.656**	**33,100.731**	**-110.14**	**33,529.000**	**428.269**	33,047.848	-481.15	33,407.764	359.916	33,372.699	-35.065	33,491.524	118.825
Net ICR (NICR)		**32,968**	**32,968**	**0**	33,529	561	33,529	0	33,529	0.00	33,529	0	33,152	-377	33,152	0

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

** Change columns contain the changes in CSO amount resulting from the specific FCM Event as well as adjustments for Delisted MW released according to MR 1, Section 13.2.5.2, and changes that occurred (terminations, etc.) prior to the event reported in the column.

*** Grand Total reflects both CSO Grand Total and the net total of the Change Column.

Capacity Supply Obligation FCA 8

Resource Type	Resource Type	FCA	Annual Bilateral for ARA 1		ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	**CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	1,080.079	887.493	-192.59	891.604	4.111	772.352	-119.252	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

** Change columns contain the changes in CSO amount resulting from, but not limited to, the specific FCM Event as well as adjustments for Delisted MW released according to MR 1, Section 13.2.5.2, and changes that occurred (terminations, etc.) prior to the event reported in the column.

*** Grand Total reflects both CSO Grand Total and the net total of the Change Column. 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								
	Passive Demand	2,156.151	2153.94	-2.211	2150.196	-3.744								
Demand Total		**2,803.411**	**2,750.641**	**-52.77**	**2,704.053**	**-46.588**								
Generator	*Non-Intermittent*	29,550.564	29,558.181	7.617	29,783.831	225.65								
	Intermittent	891.616	864.924	-26.692	872.425	7.501								
Generator Total		**30,442.18**	**30,423.105**	**-19.075**	**30,656.256**	**233.151**								
Import Total		**1,449**	**1449**	**0**	**1449**	**0**								
*****Grand Total**		**34,694.591**	**34622.746**	**-71.845**	**34,809.309**	**186.563**								
Net ICR (NICR)		**34,189**	**33,883**	**-306**	**33,883**	**0**								

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

** Change columns contain the changes in CSO amount resulting from, but not limited to, the specific FCM Event as well as adjustments for Delisted MW released according to MR 1, Section 13.2.5.2, and changes that occurred (terminations, etc.) prior to the event reported in the column.

*** Grand Total reflects both CSO Grand Total and the net total of the Change Column.

Capacity Supply Obligation FCA 10

Resource Type	Resource Type	FCA	Annual Bilateral for ARA 1		ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	377.525												
	Passive Demand	2,368.631												
Demand Total		**2,746.156**												
Generator	*Non-Intermittent*	30,520.433												
	Intermittent	850.143												
Generator Total		**31,370.576**												
Import Total		**1,449.8**												
*****Grand Total**		**35,566.532**												
Net ICR (NICR)		**34,151**												

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

** Change columns contain the changes in CSO amount resulting from, but not limited to, the specific FCM Event as well as adjustments for Delisted MW released according to MR 1, Section 13.2.5.2, and changes that occurred (terminations, etc.) prior to the event reported in the column.

*** Grand Total reflects both CSO Grand Total and the net total of the Change Column.

Capacity Supply Obligation FCA 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

** Change columns contain the changes in CSO amount resulting from, but not limited to, the specific FCM Event as well as adjustments for Delisted MW released according to MR 1, Section 13.2.5.2, and changes that occurred (terminations, etc.) prior to the event reported in the column.

*** Grand Total reflects both CSO Grand Total and the net total of the Change Column.

Active/Passive Demand Response

CSO Totals by Commitment Period

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

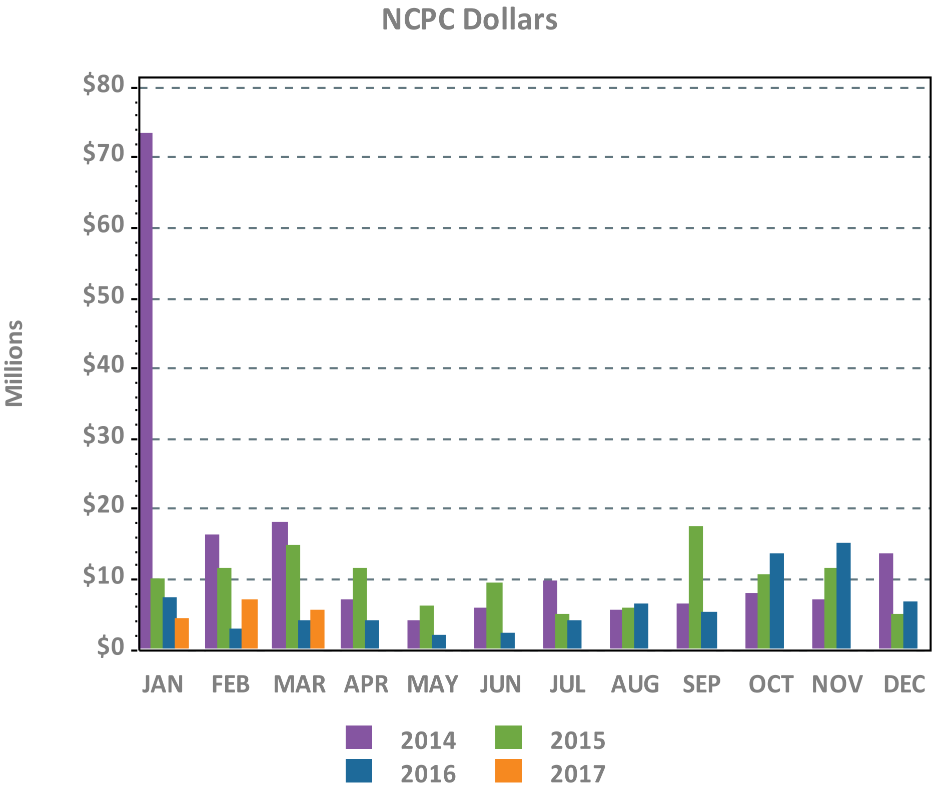
Definitions

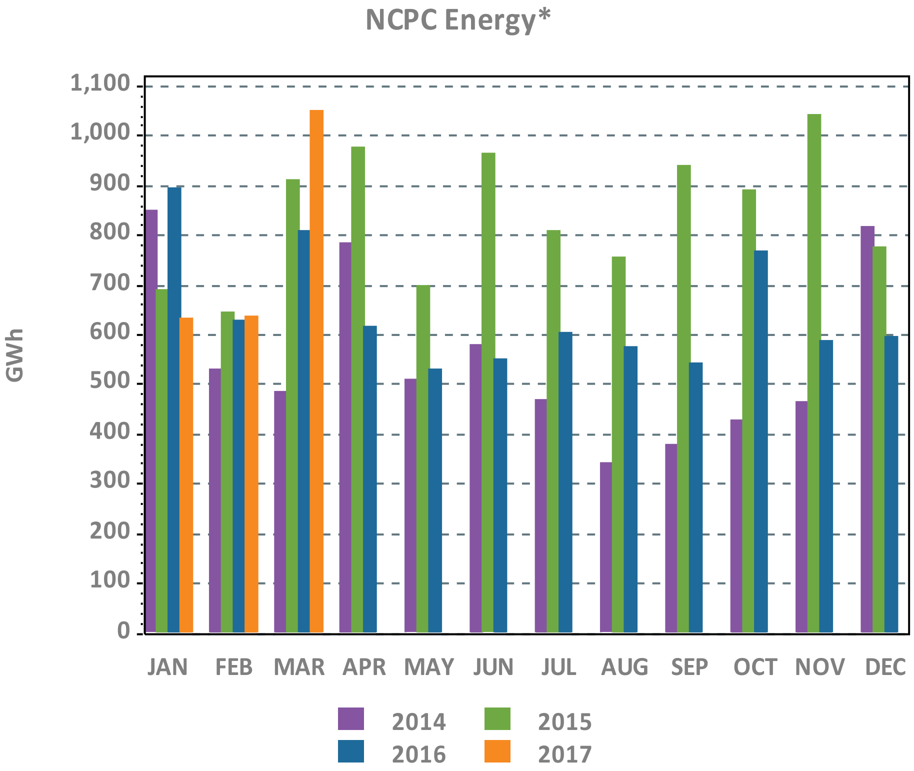
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing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

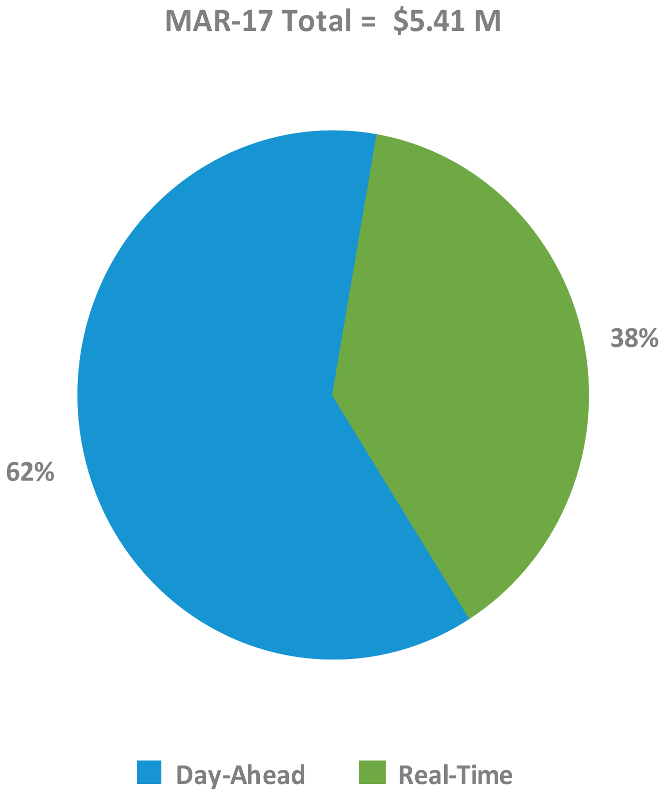
Year-Over-Year Total NCPC Dollars and Energy

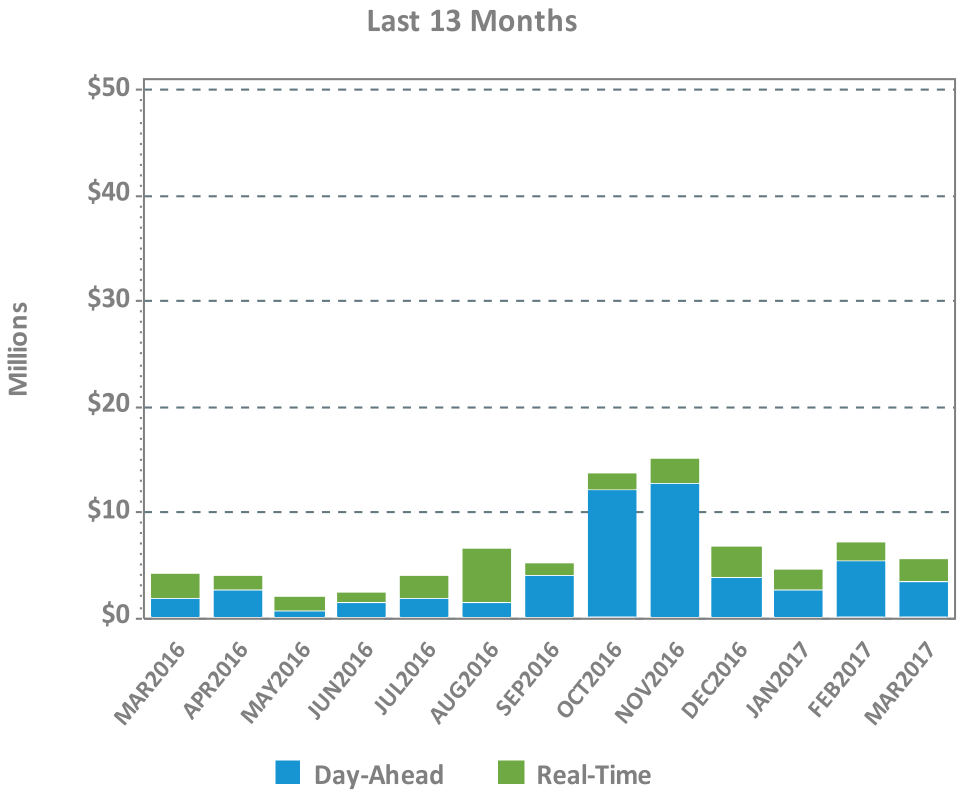




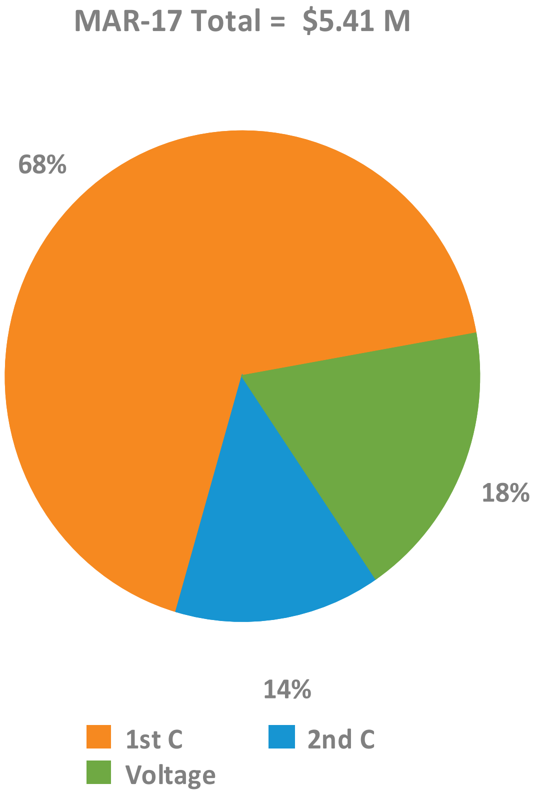
*** NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits, assessed during hours in which they are NCPC-eligible. All NCPC components (1st Contingency, 2nd Contingency, Voltage, and RT Distribution) are reflected.**

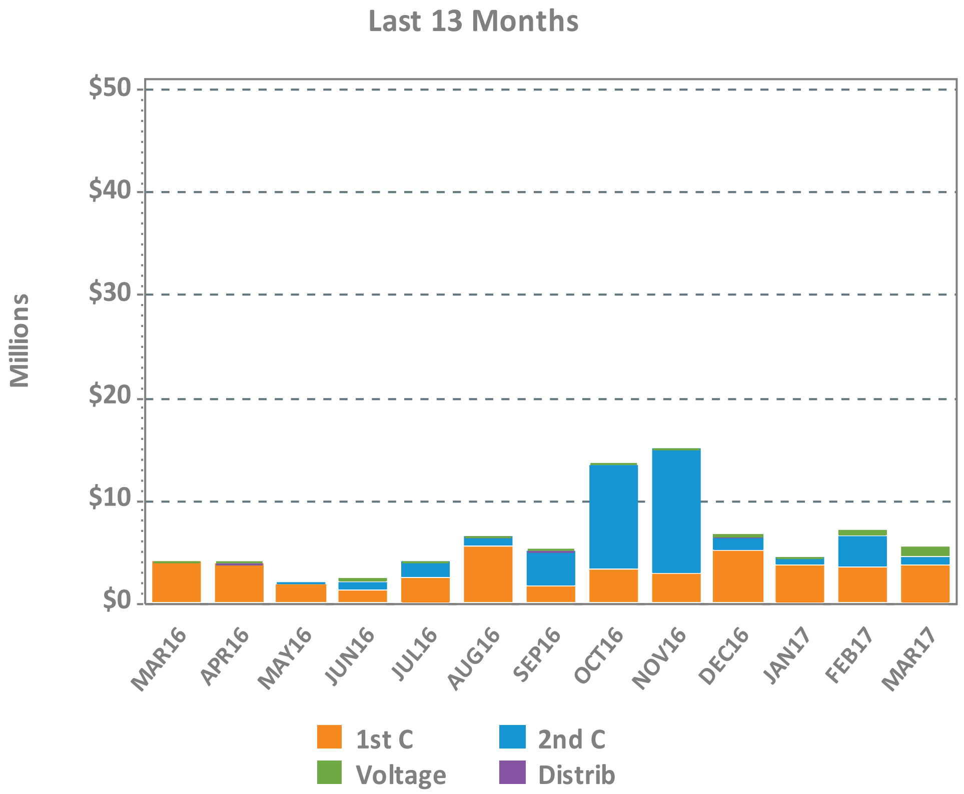
DA and RT NCPC Charges





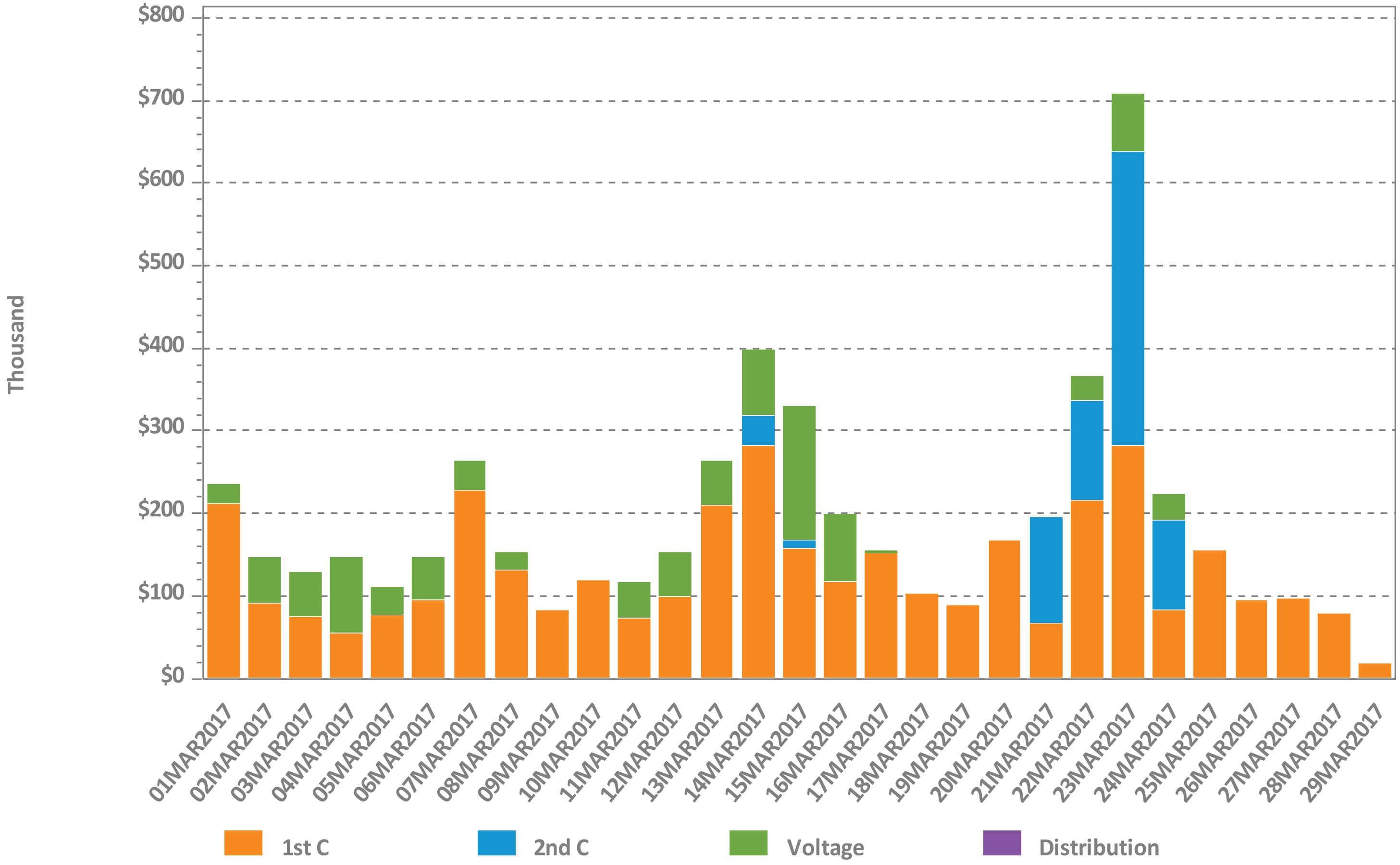
NCPC Charges by Type





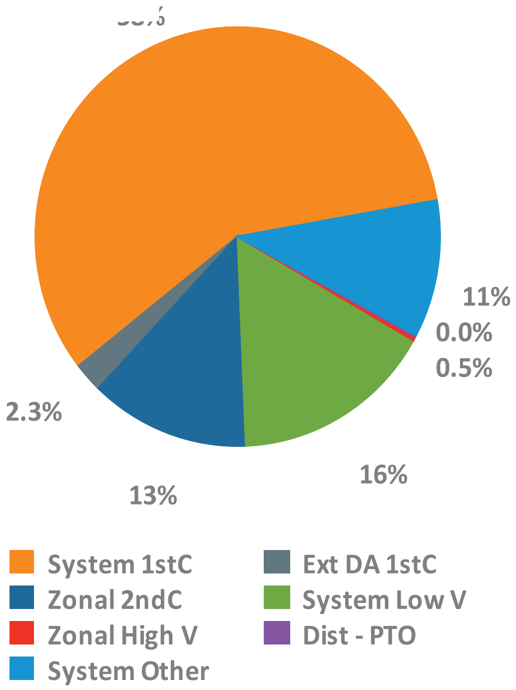
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type

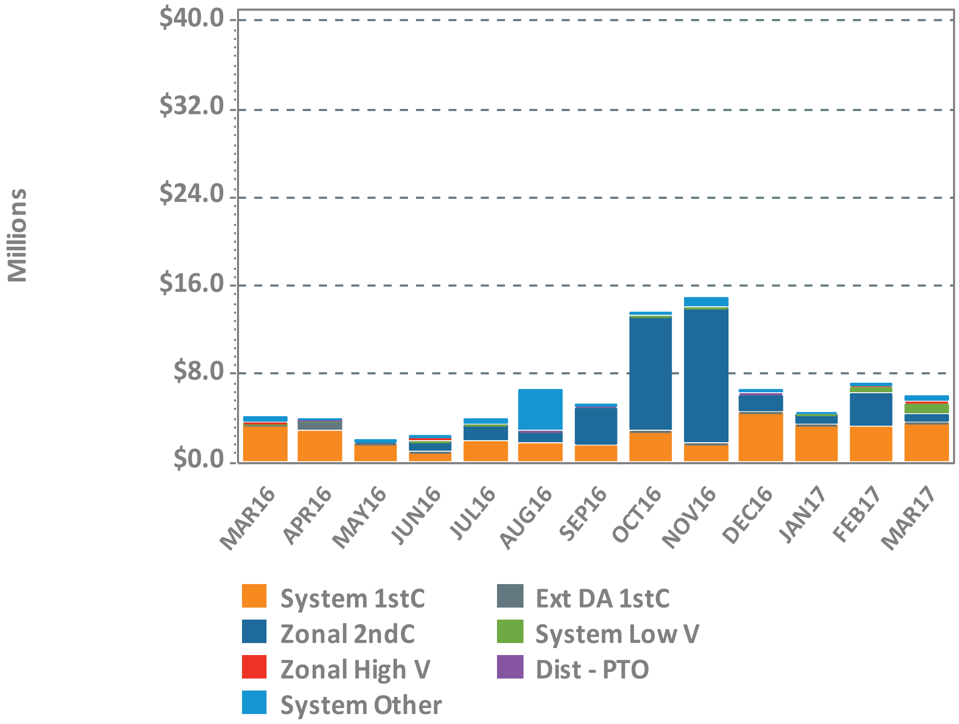


NCPC Charges by Allocation

MAR-17 Total = $5.97 M

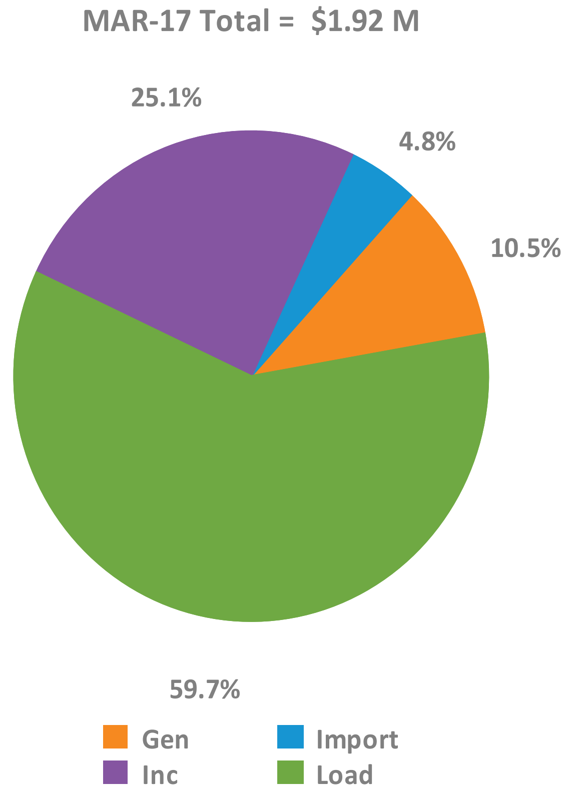


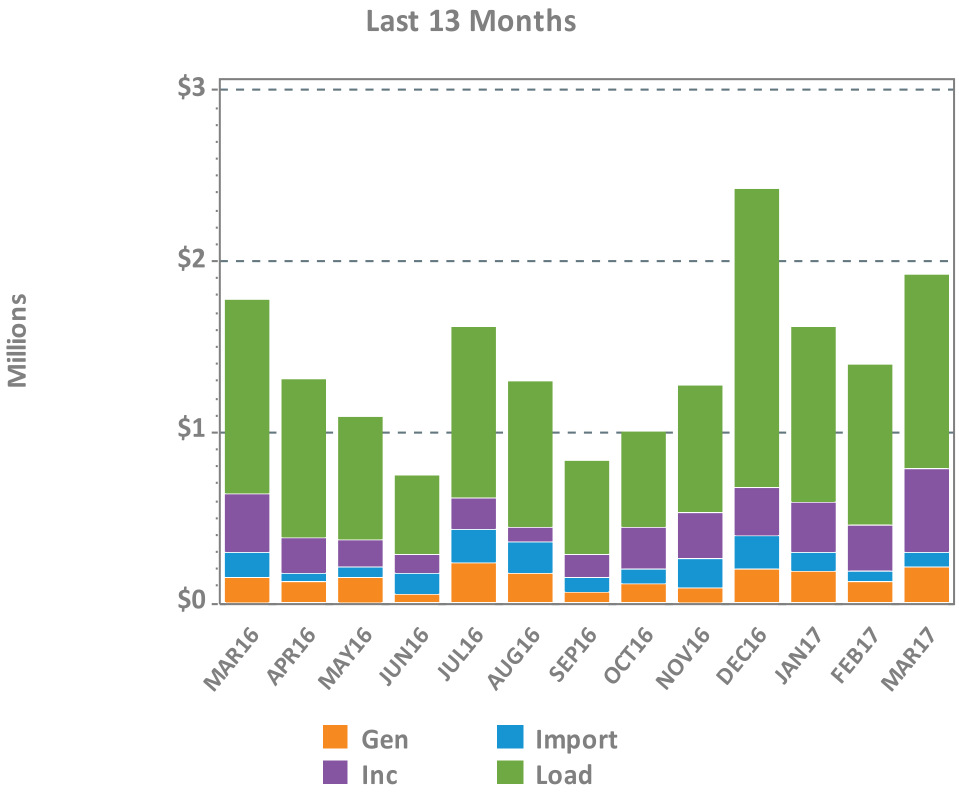
Last 13 Months



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.

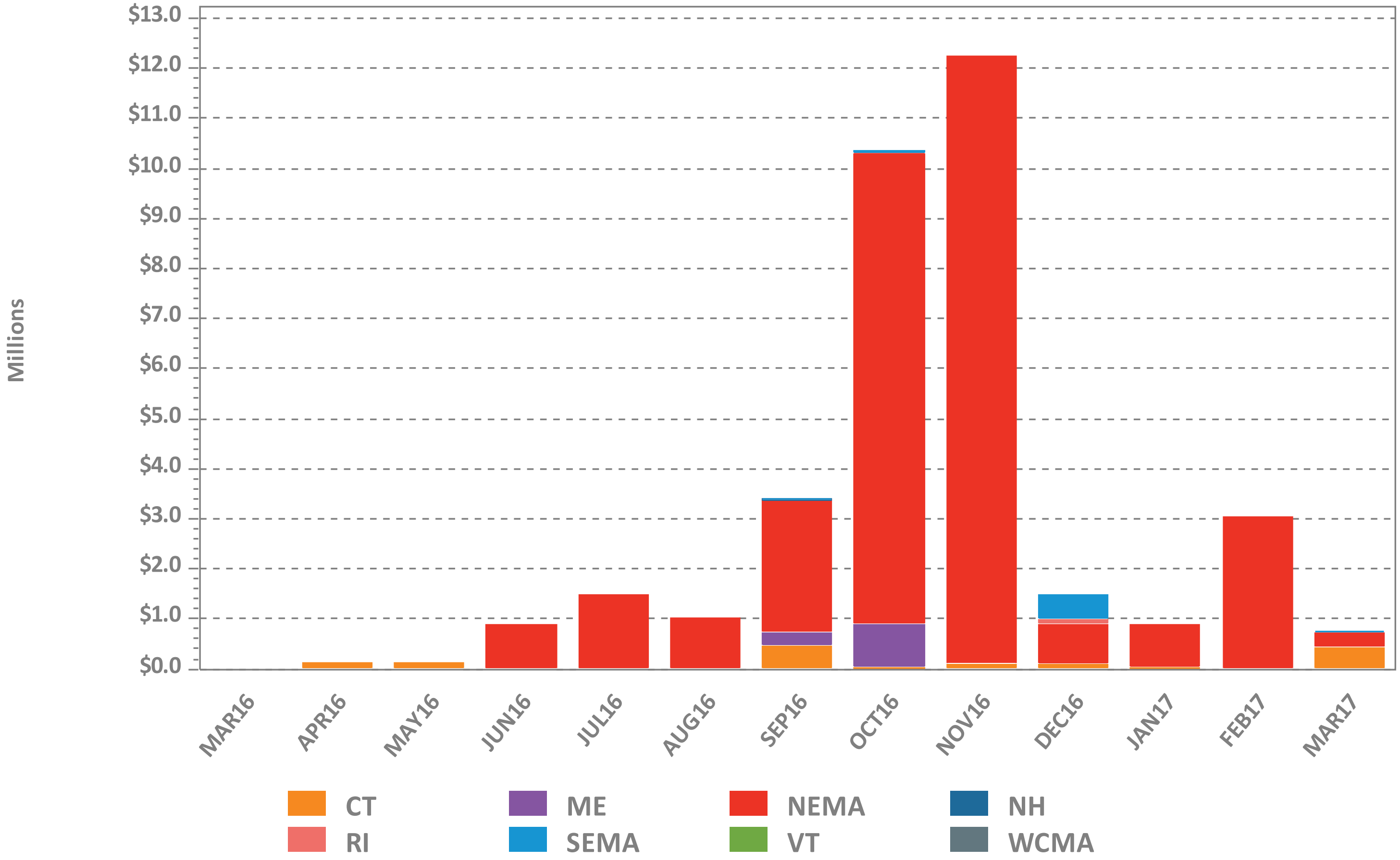
RT First Contingency Charges by Deviation Type





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

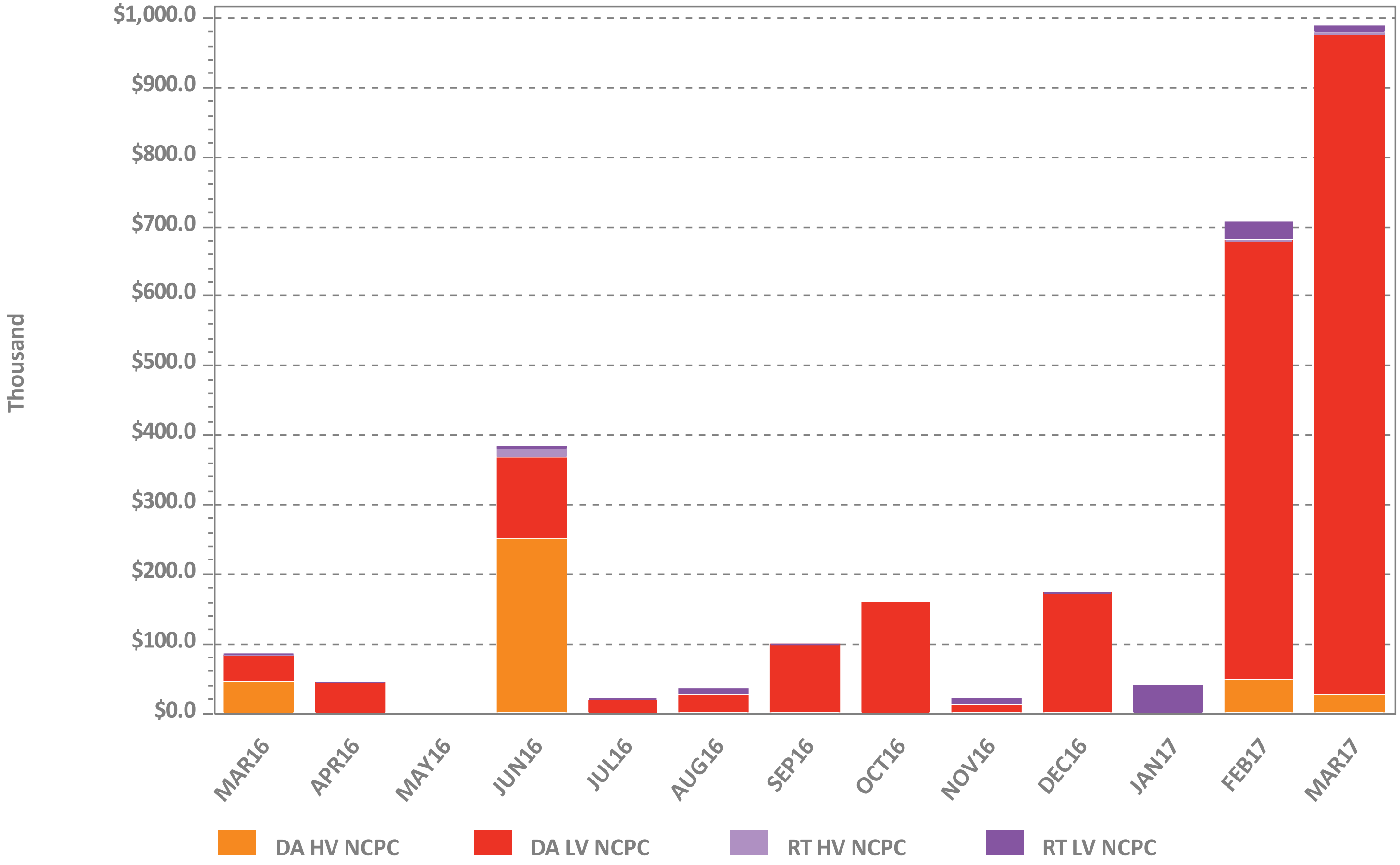
LSCPR Charges by Reliability Region



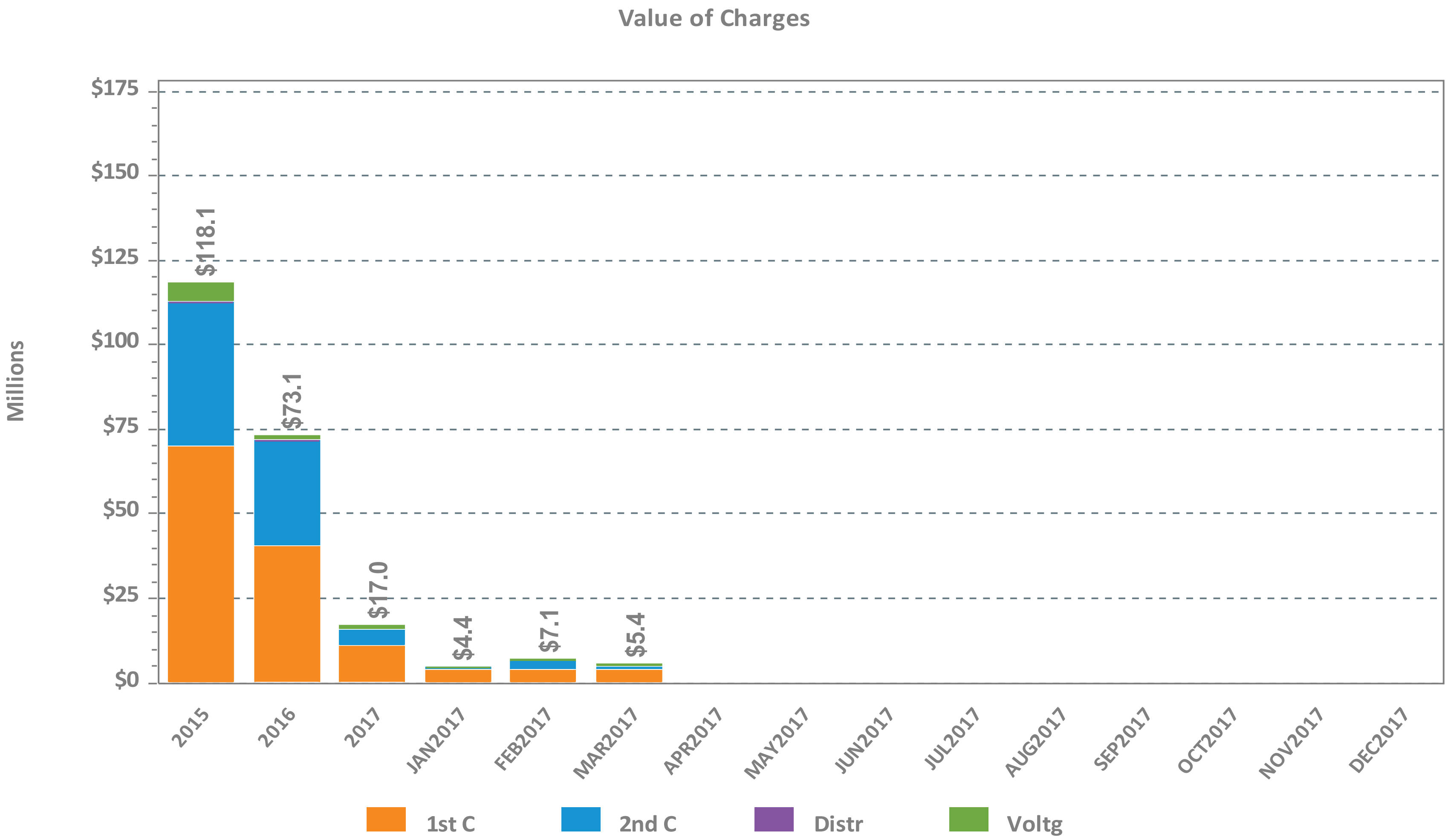
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

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

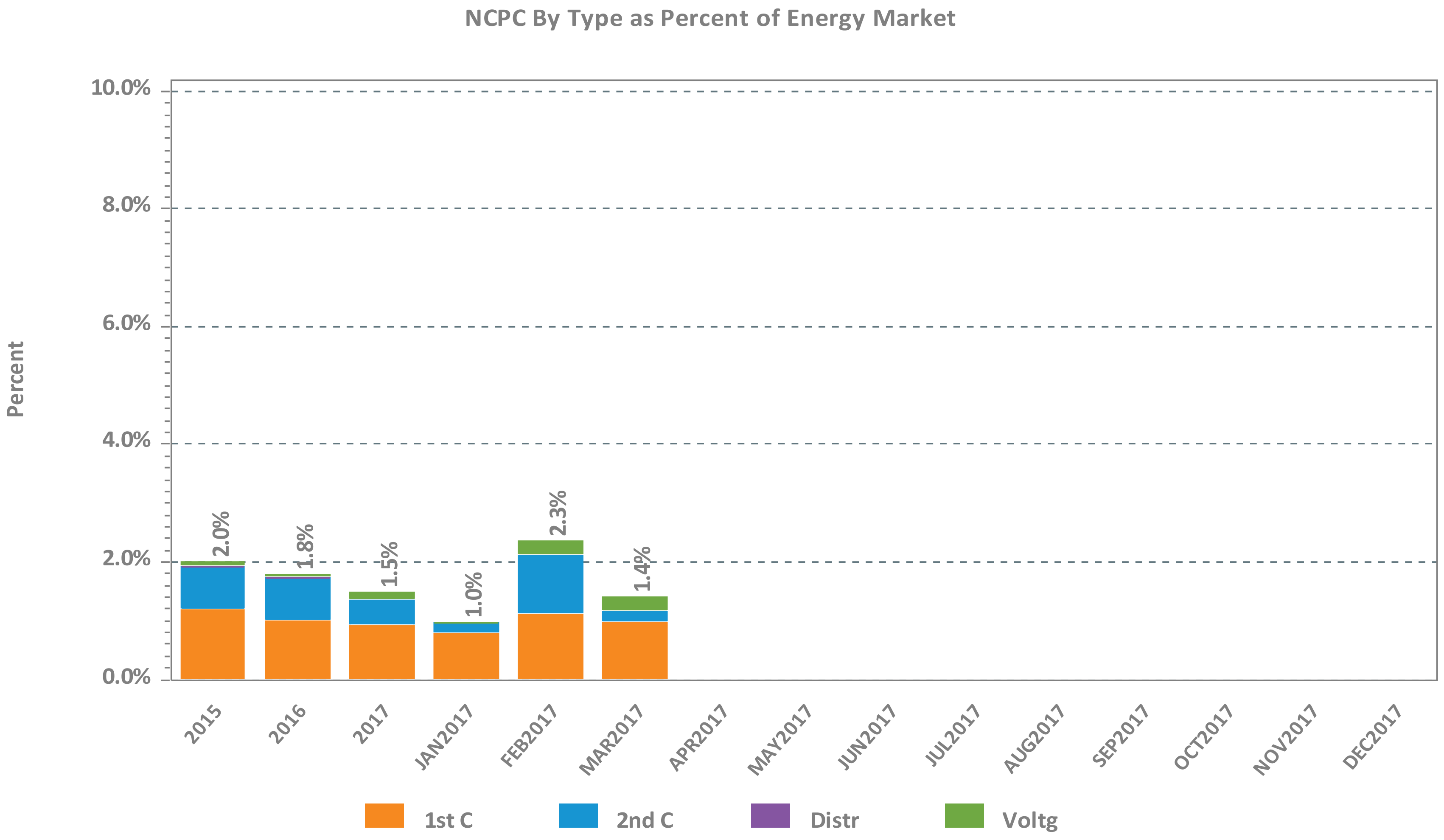
NCPC Charges for Voltage Support and High Voltage Control



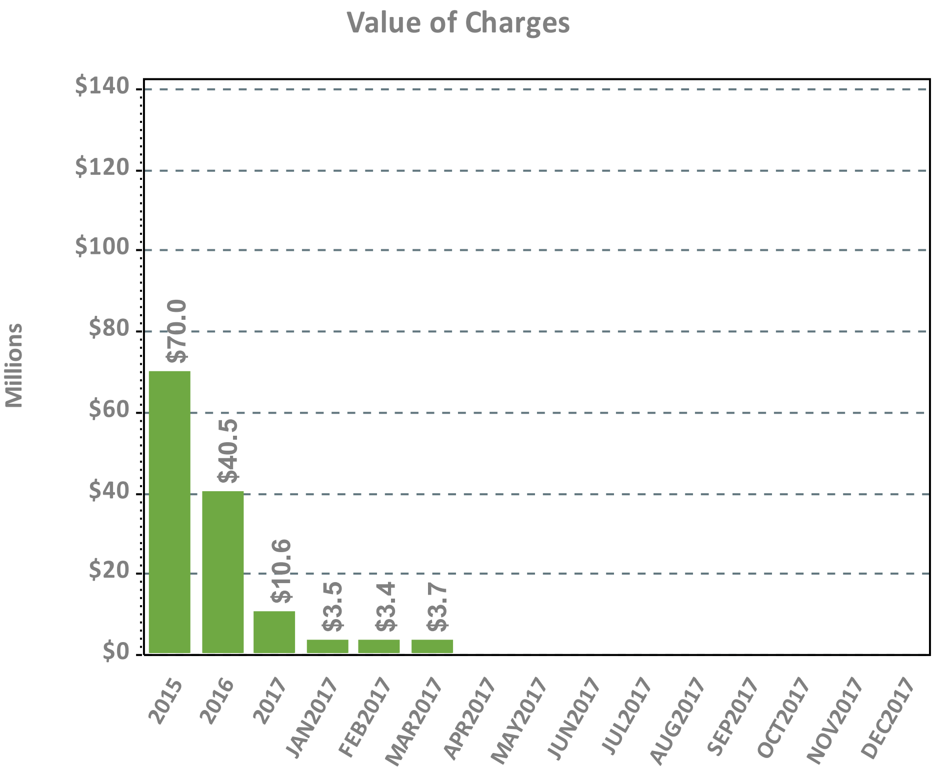
NCPC Charges by Type

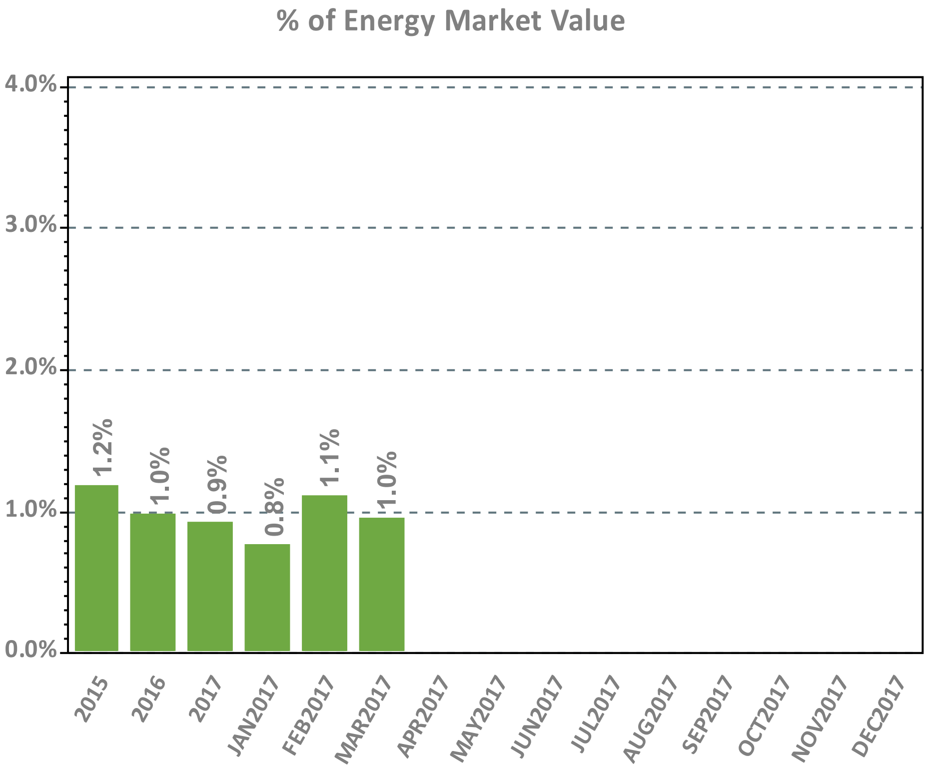


NCPC Charges as Percent of Energy Market



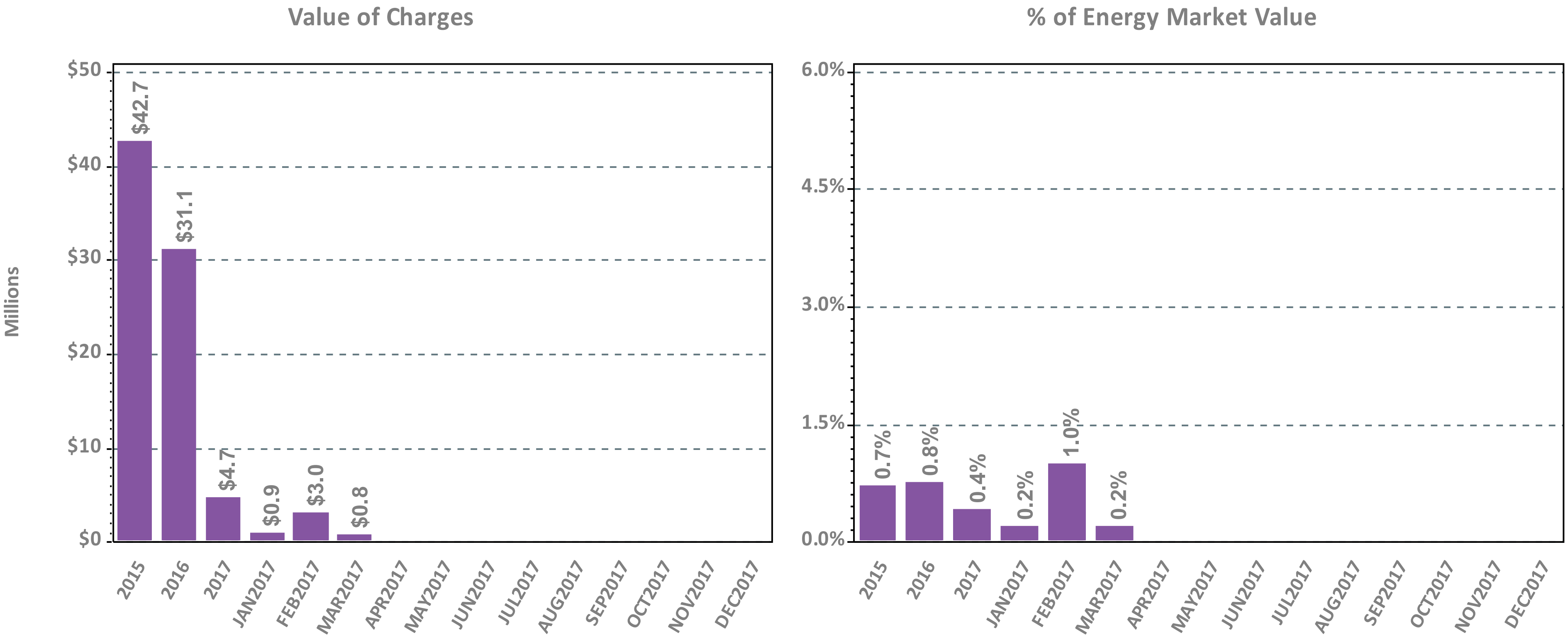
First Contingency NCPC Charges





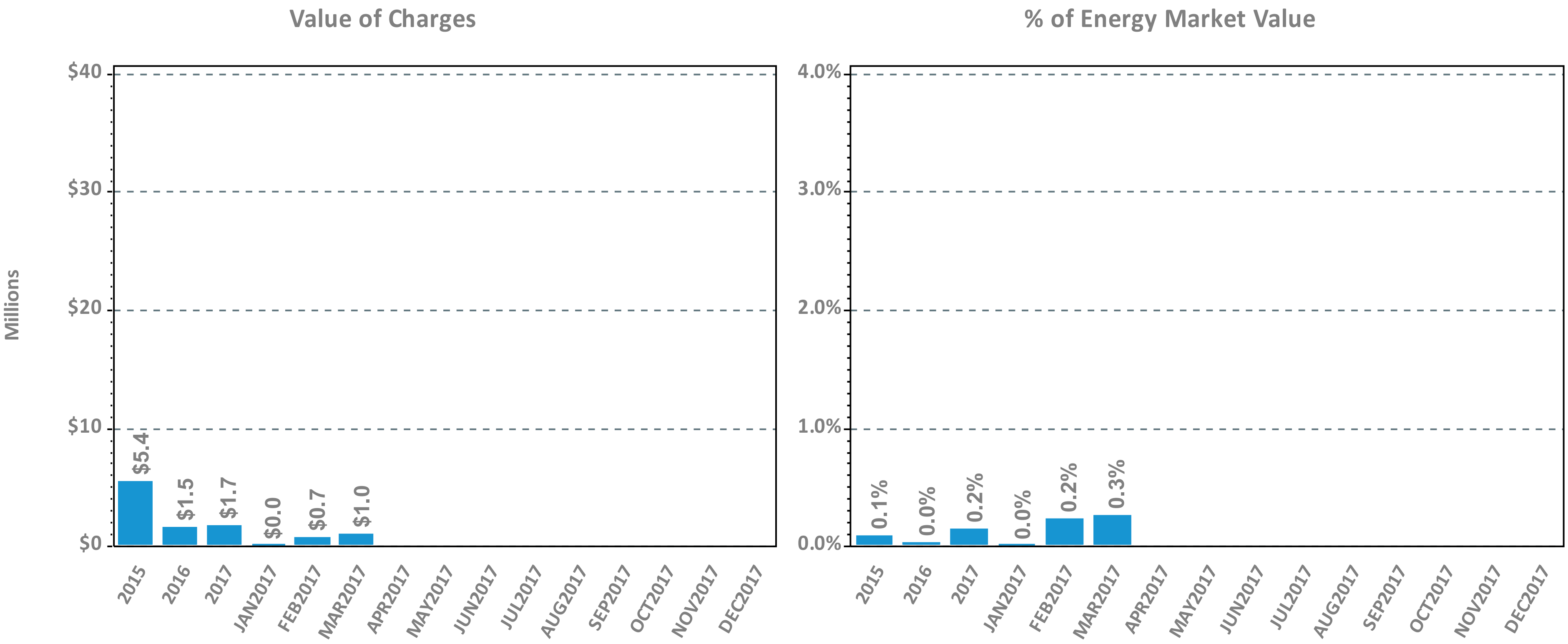
Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

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



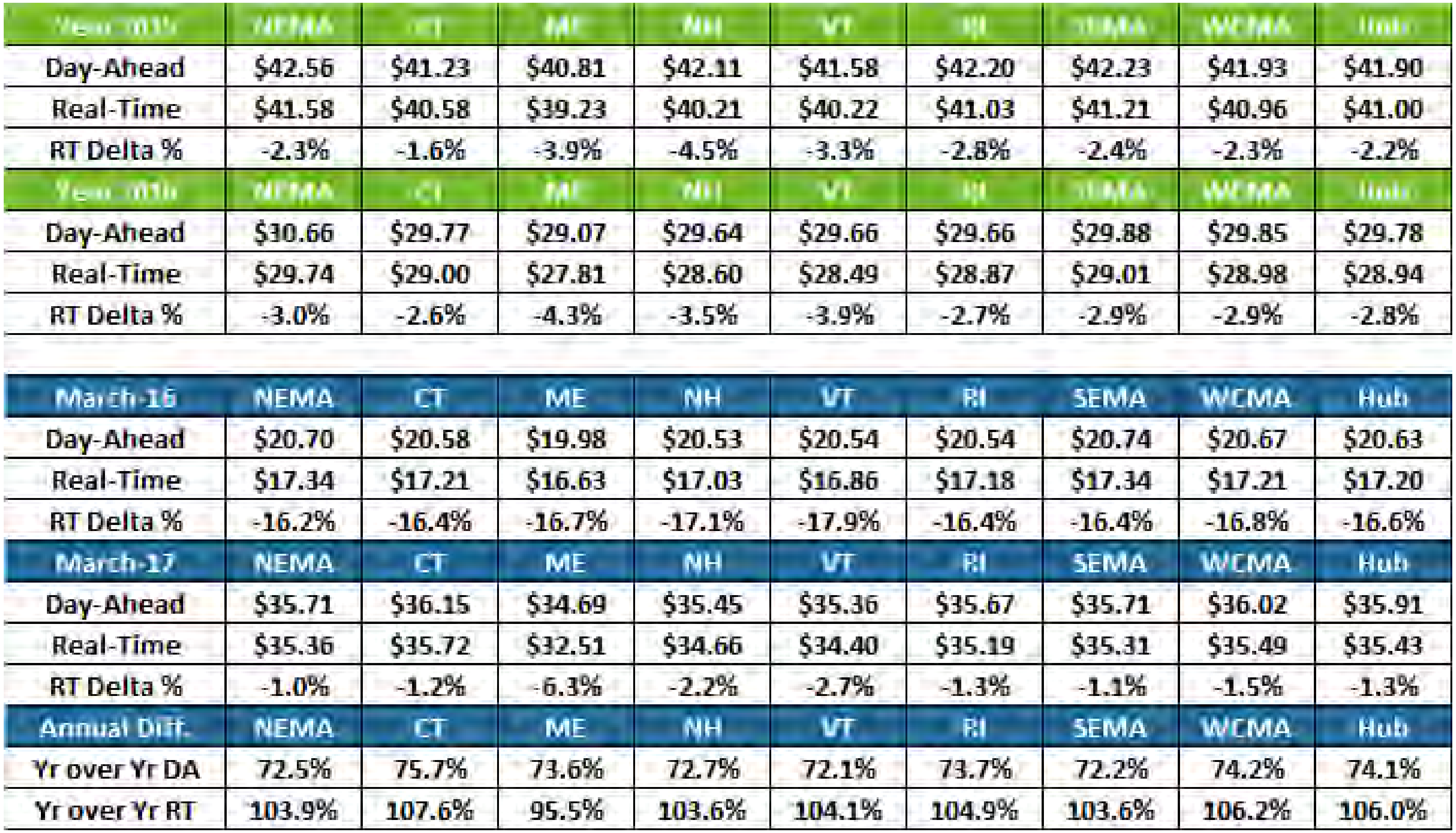
Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

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

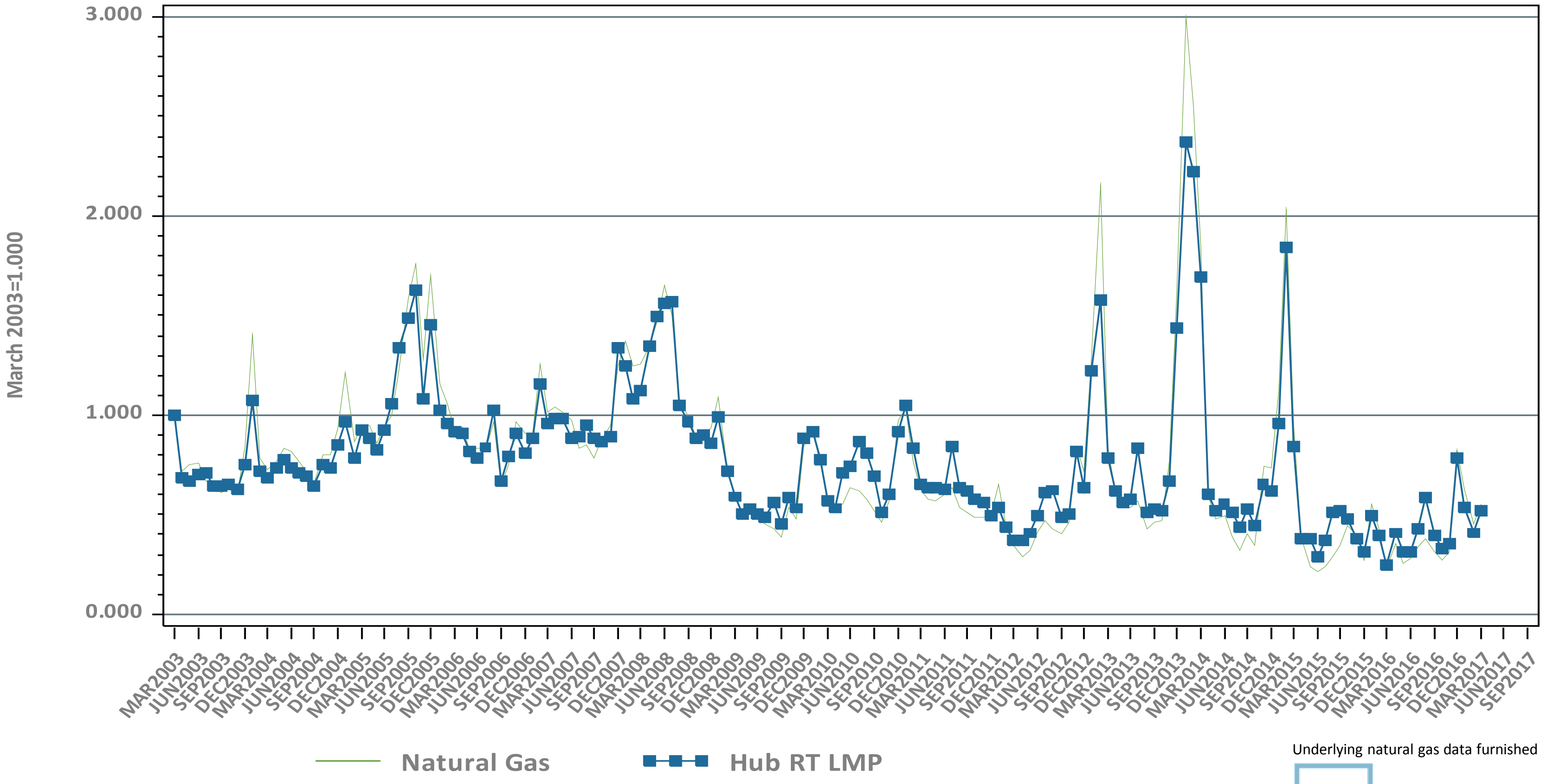
DA vs. RT LMPs ($/MWh)



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%

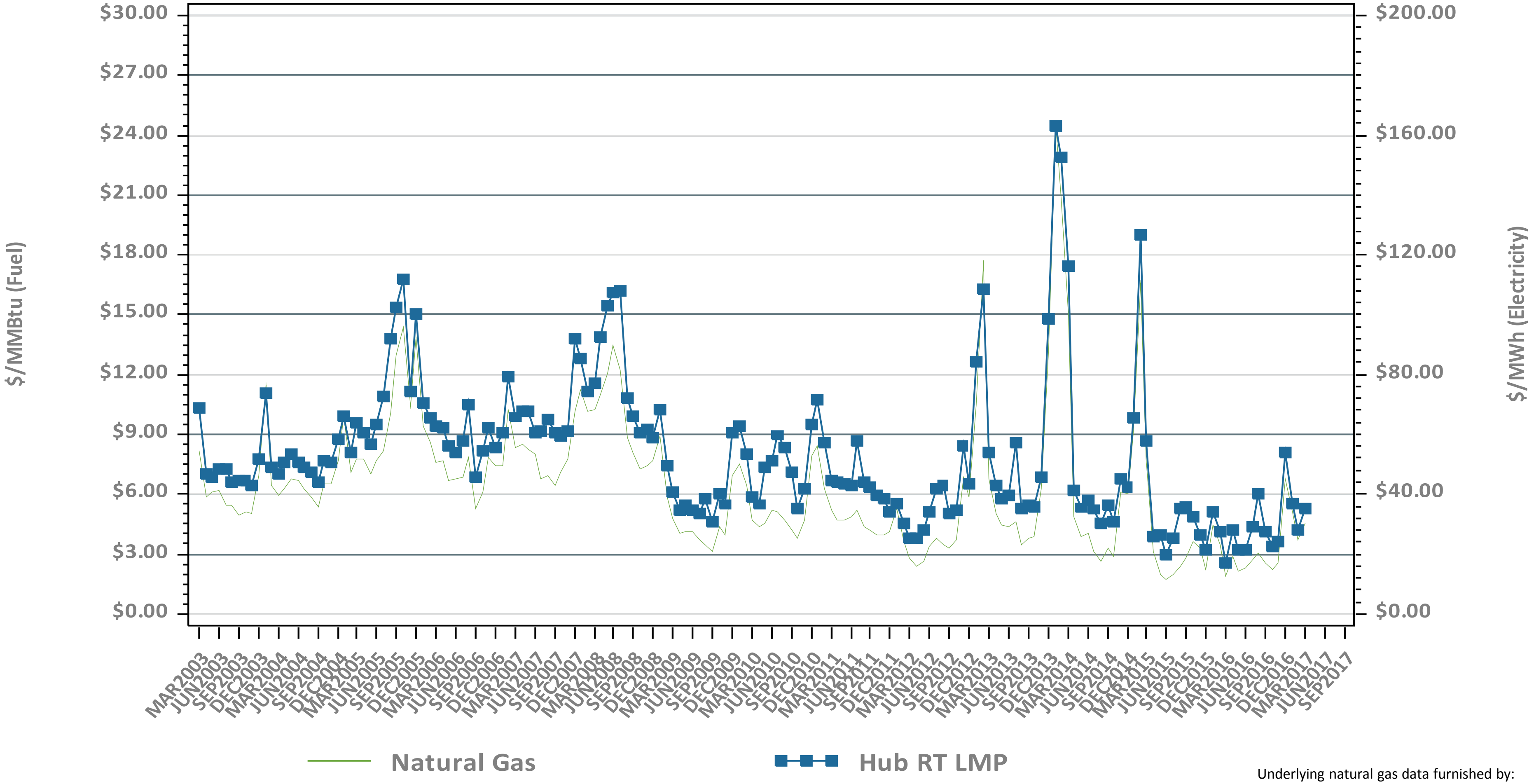
March-16	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$20.70	$20.58	$19.98	$20.53	$20.54	$20.54	$20.74	$20.67	$20.63
Real-Time	$17.34	$17.21	$16.63	$17.03	$16.86	$17.18	$17.34	$17.21	$17.20
RT Delta %	-16.2%	-16.4%	-16.7%	-17.1%	-17.9%	-16.4%	-16.4%	-16.8%	-16.6%
March-17	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$35.71	$36.15	$34.69	$35.45	$35.36	$35.67	$35.71	$36.02	$35.91
Real-Time	$35.36	$35.72	$32.51	$34.66	$34.40	$35.19	$35.31	$35.49	$35.43
RT Delta %	-1.0%	-1.2%	-6.3%	-2.2%	-2.7%	-1.3%	-1.1%	-1.5%	-1.3%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	72.5%	75.7%	73.6%	72.7%	72.1%	73.7%	72.2%	74.2%	74.1%
Yr over Yr RT	103.9%	107.6%	95.5%	103.6%	104.1%	104.9%	103.6%	106.2%	106.0%

Monthly Average Fuel Price and RT Hub LMP Indexes



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

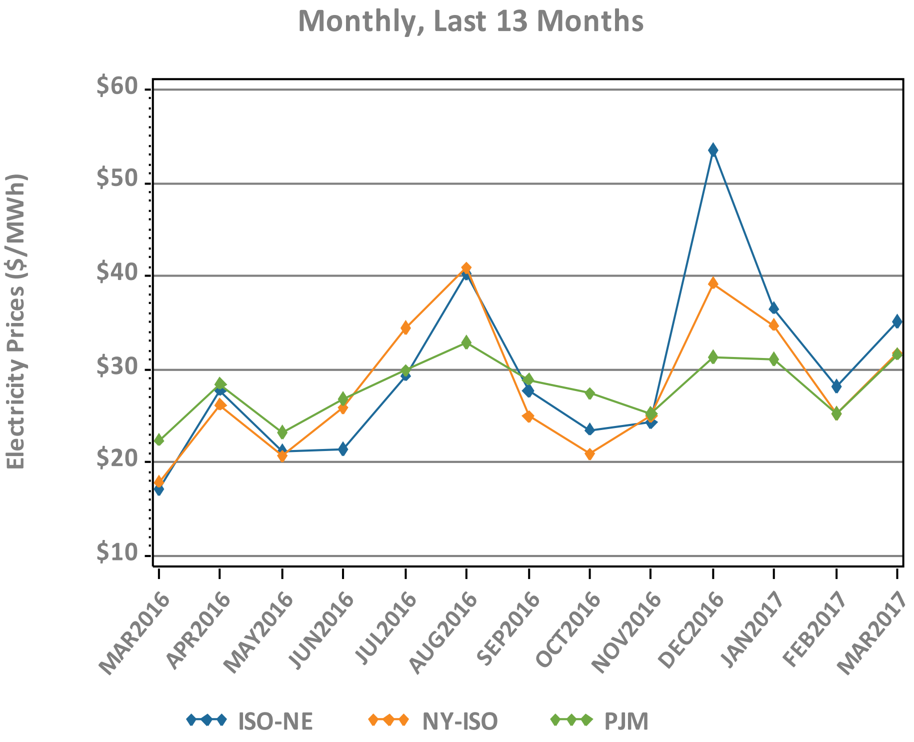
Monthly Average Fuel Price and RT Hub LMP



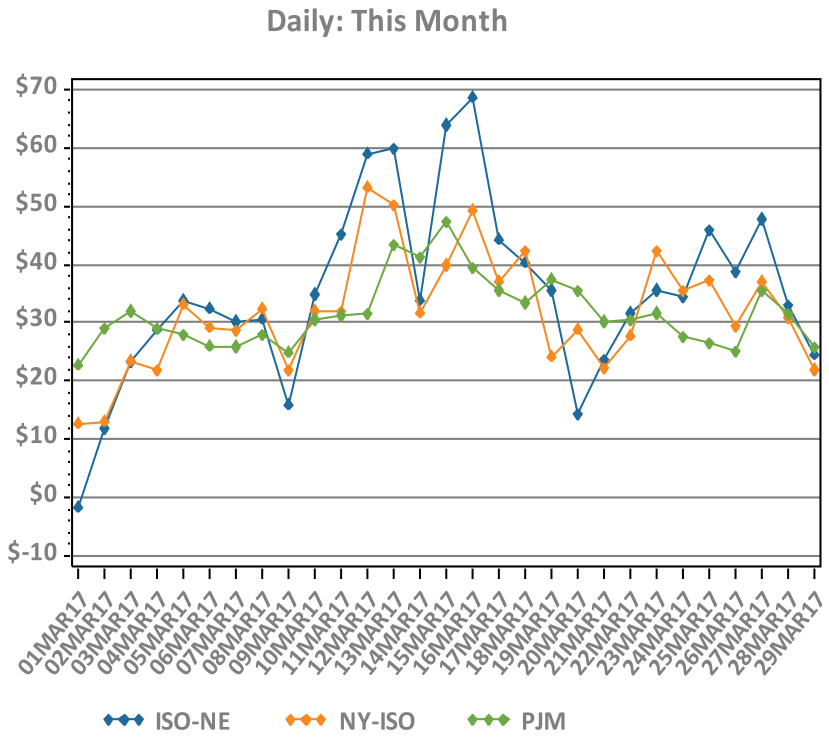
Underlying natural gas data furnished by:

ice Global markets in clear view

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

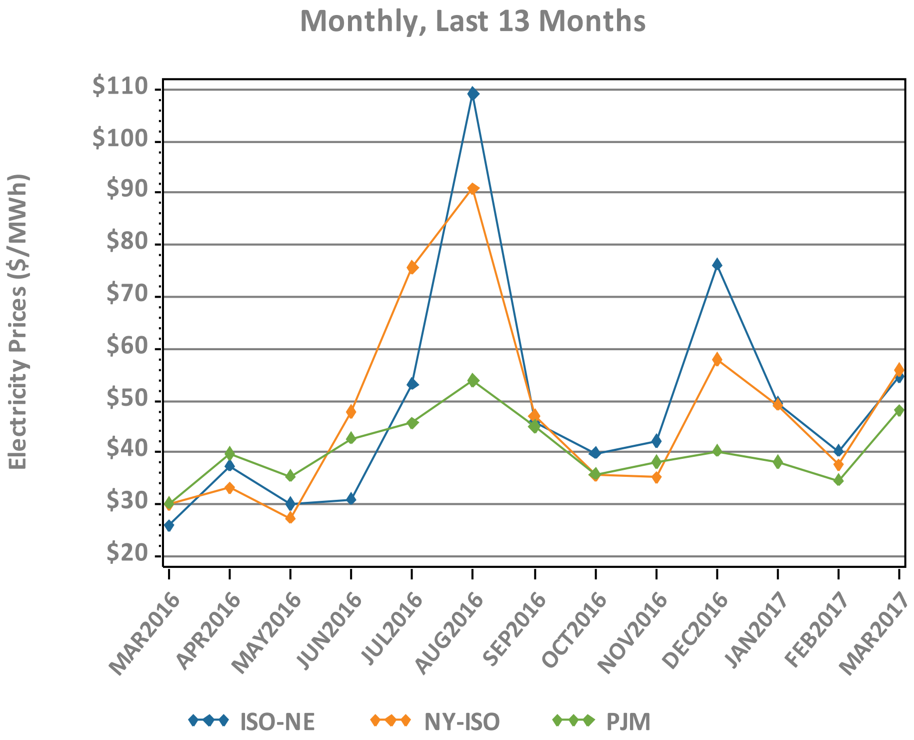


*Note: Hourly average prices are shown.

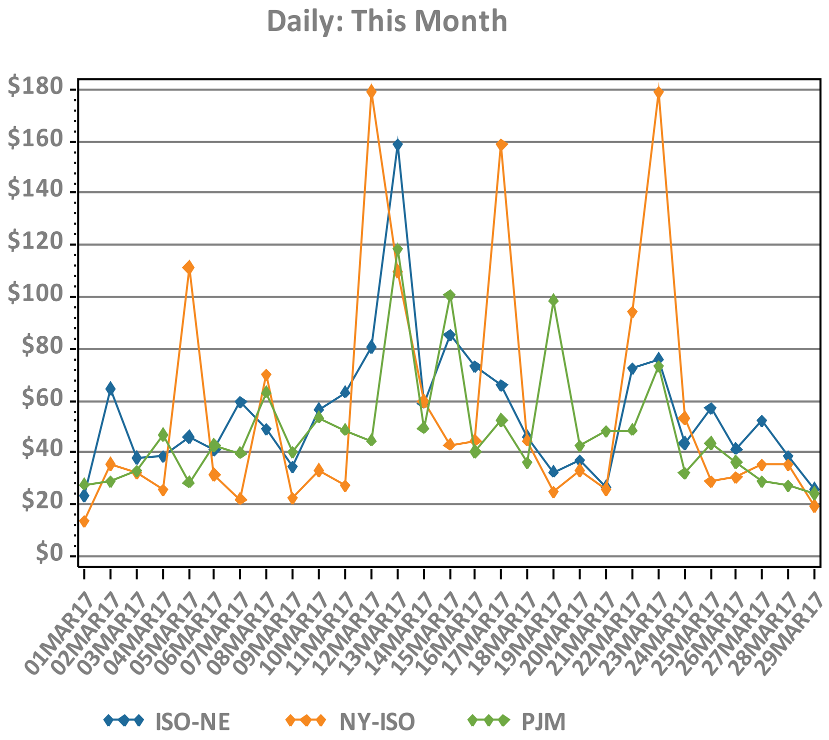


*Note: Hourly average prices are shown.

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



Monthly, Last 13 Months



Daily: This Month

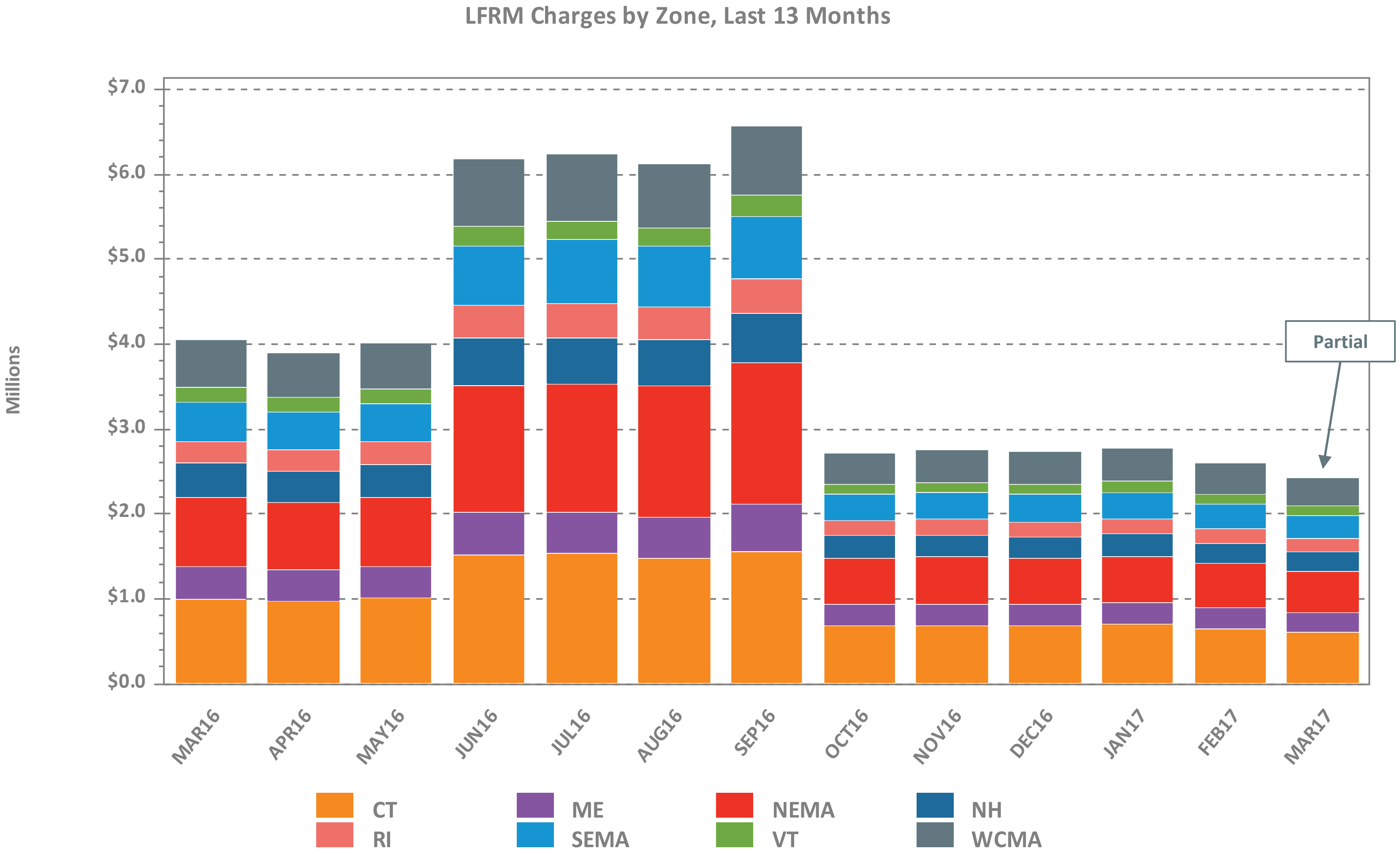
***Forecasted New England daily peak hours reflected**

Reserve Market Results – March 2017

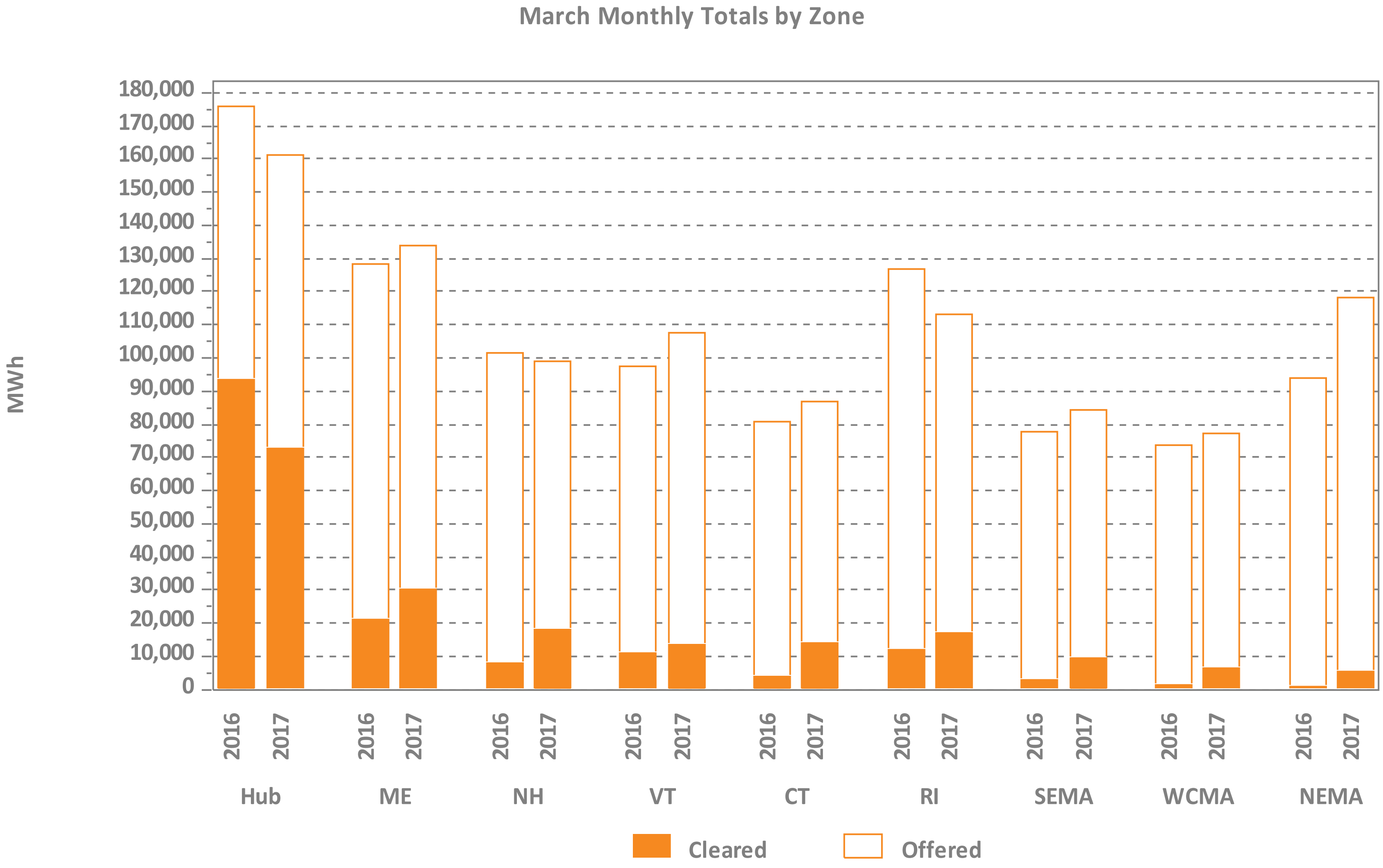
- Maximum potential Forward Reserve Market payments of \$2.6M were reduced by credit reductions of \$65K, failure-to-reserve penalties of \$98K and no failure-to-activate penalties, resulting in a net payout of \$2.4M or 94% of maximum
  - Rest of System: \$1.42M/1.5M (95)%
  - Southwest Connecticut: \$0.22M/0.25M (88)%
  - Connecticut: \$0.77M/0.83M (93)%
- \$1.1M total Real-Time credits were not reduced for any Forward Reserve Energy Obligation Charges for a net of \$1.1M in Real-Time Reserve payments
  - Rest of System: 243 hours, \$874K
  - Southwest Connecticut: 243 hours, \$50K
  - Connecticut: 243 hours, \$55K
  - NEMA: 244 hours, \$95K

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

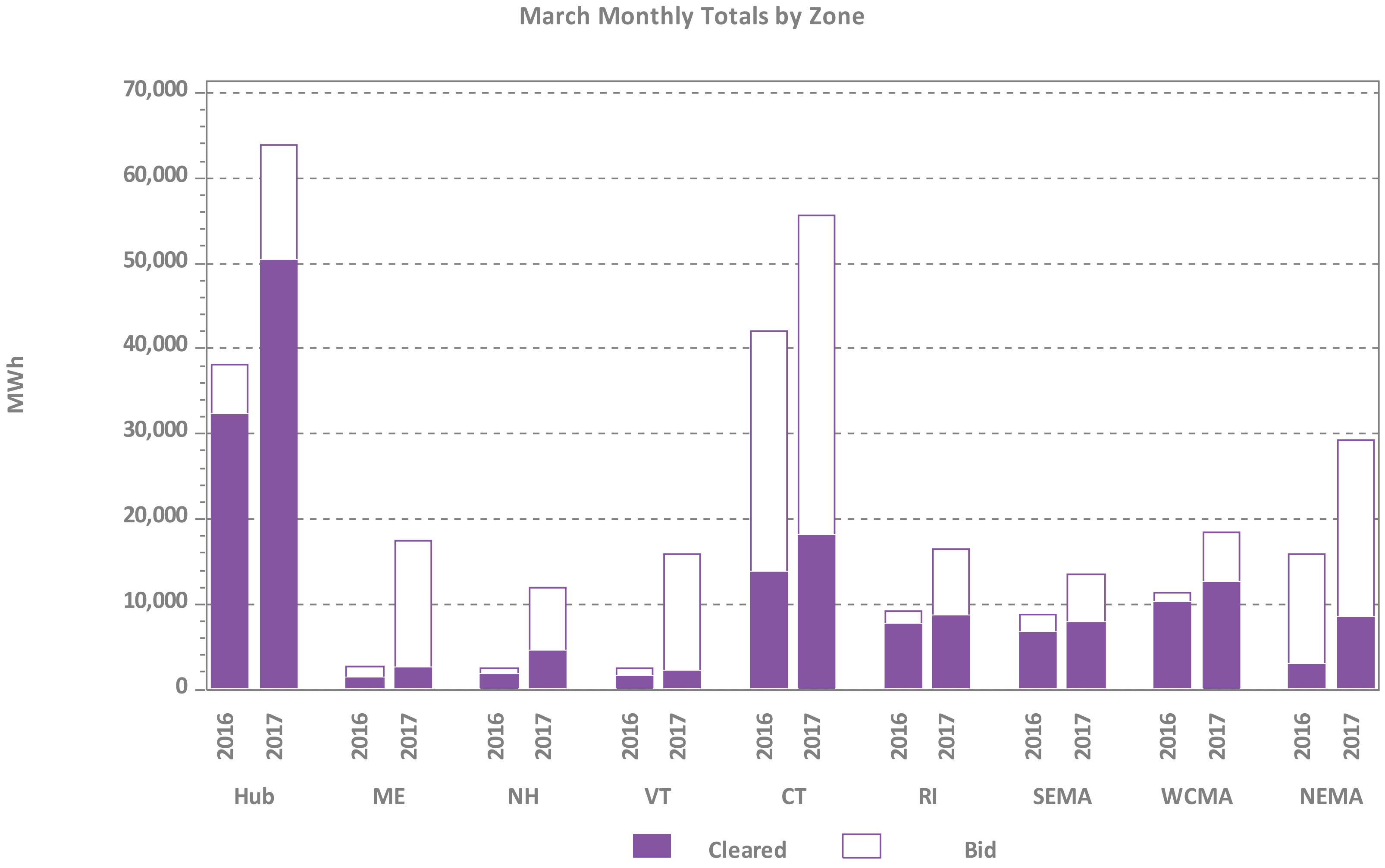
LFRM Charges to Load by Load Zone ($)



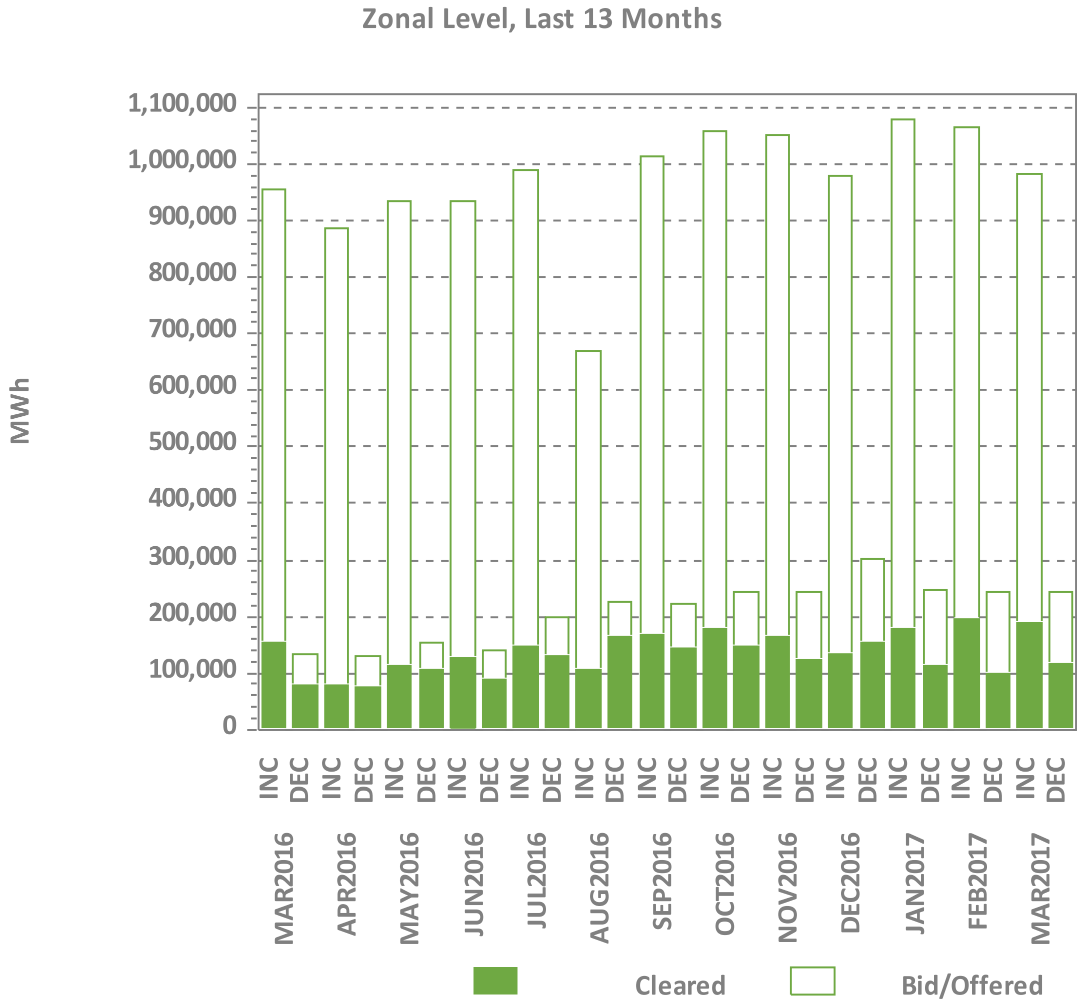
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

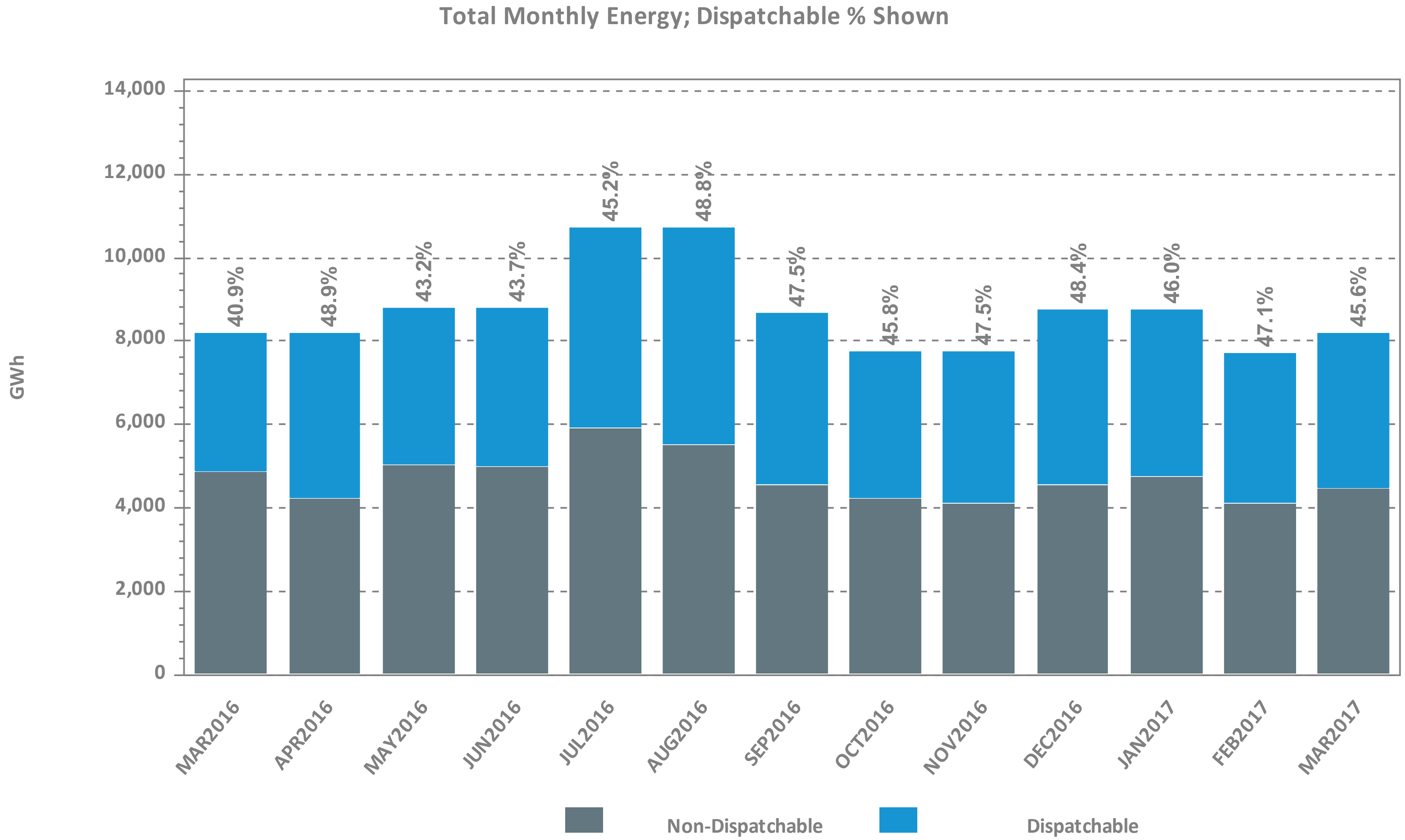


Total Increment Offers and Decrement Bids



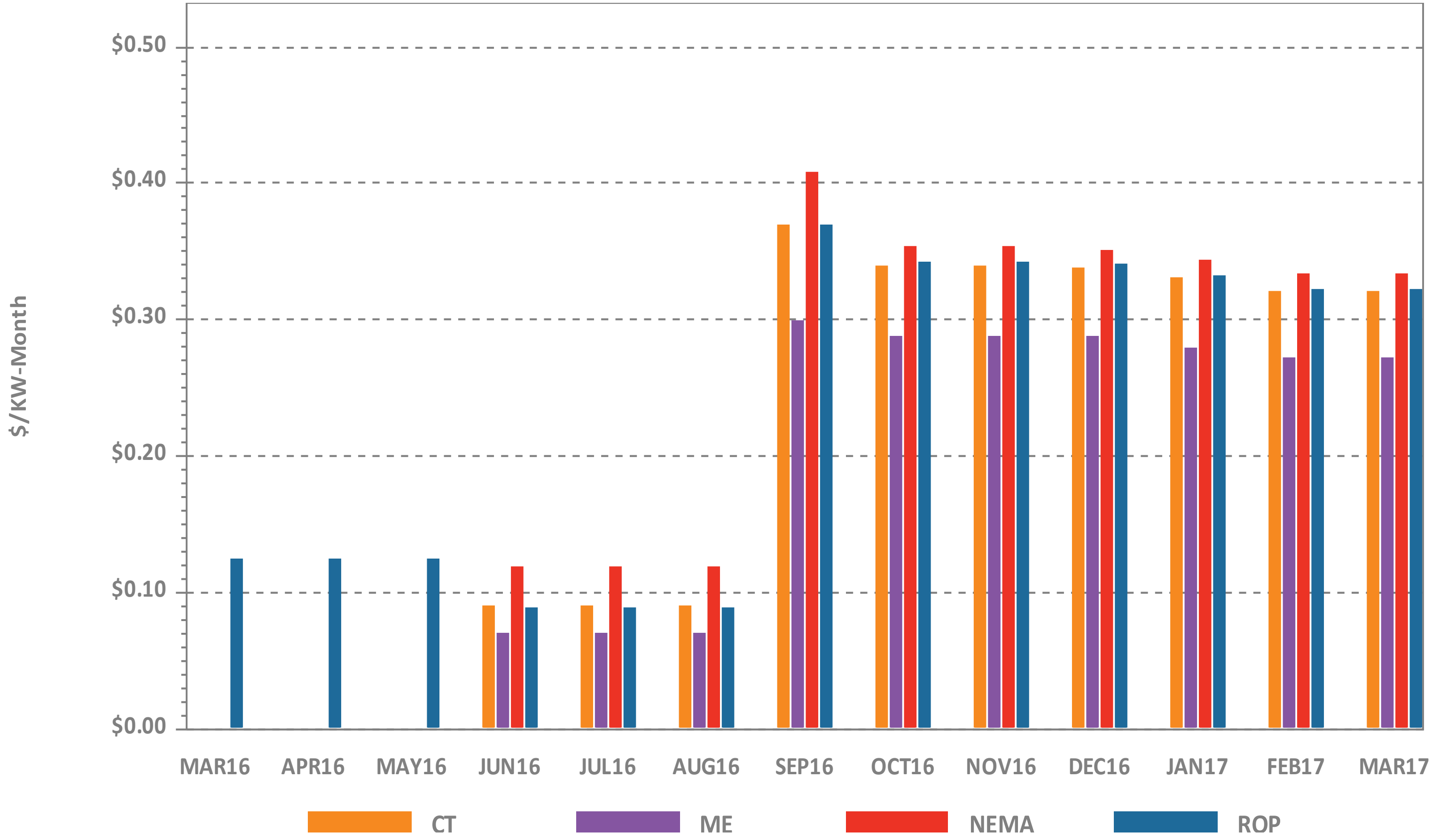
Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



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

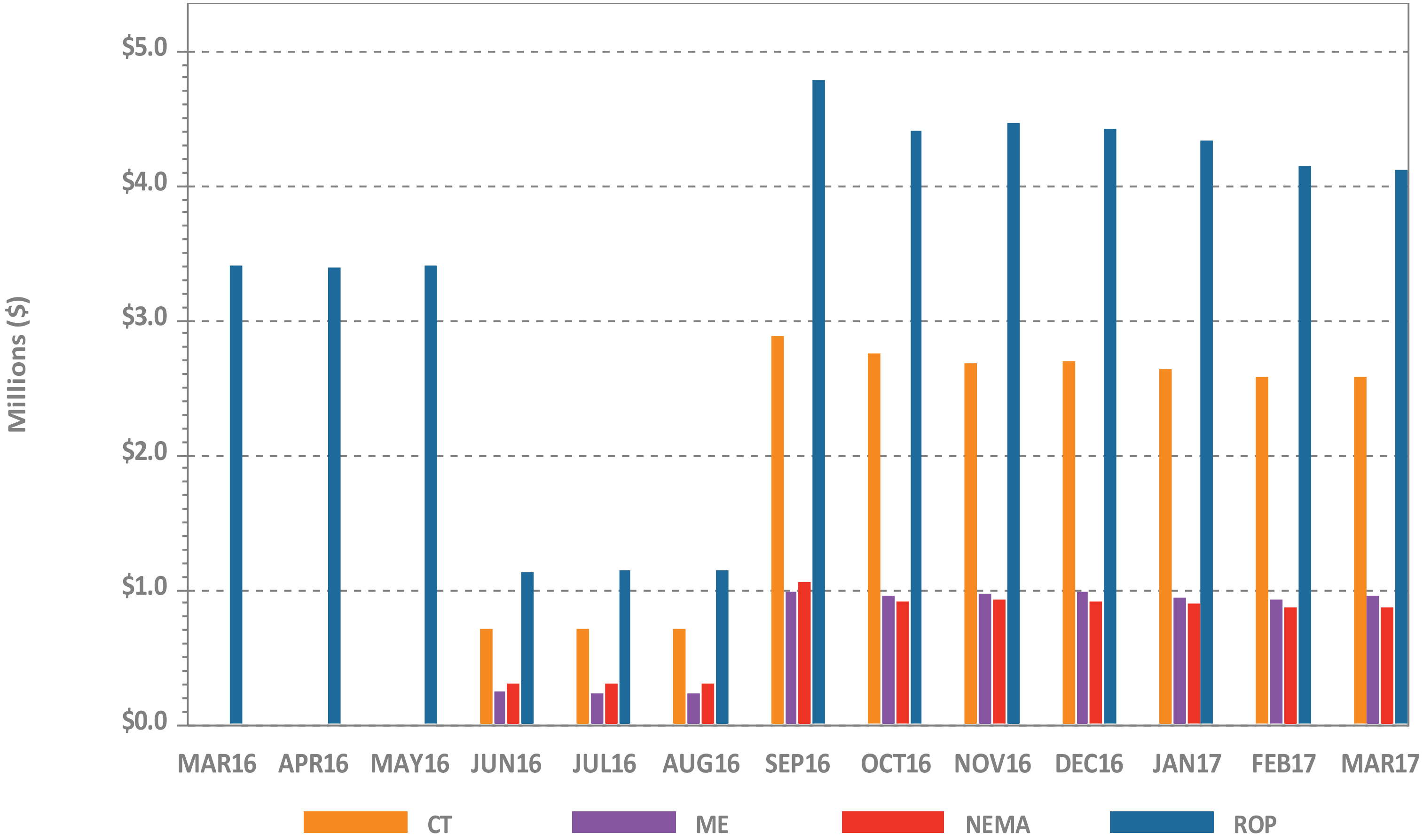
Rolling Average Peak Energy Rent (PER)



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

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

PER Adjustments



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

REGIONAL SYSTEM PLAN (RSP)

Planning Advisory Committee (PAC)

- RSP17 work is proceeding
- April 19 PAC Meeting Agenda*
  - Post Winter 2016/2017 Gas Review
  - Northeast Gas Association Gas Update
  - 2017 CELT ISO-NE Annual Energy and Summer Peak Forecast Update
  - 2017 Economic Study Stakeholder Presentations**
  - 2016 Interface Flow and Other System Performance Summaries
  - Mt. Tom Station Update
  - 2016 Economic Study Phase 2 - Scenario Analysis Natural Gas System Analysis Results
  - 2016 Economic Study Phase 2 - Emission Cost Sensitivity
  - Devon 7R Control House Modifications
- The second PAC meeting scheduled for April 20 has been canceled

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

** The presentation is dependent on economic study requests received from stakeholders.

Load, Energy Efficiency, and Photovoltaic Forecast

- Load Forecast
  - Development of the ten-year load forecast is nearly complete and compared to the 2016 CELT forecast:
    - Gross annual energy forecast is about 1.0% lower in 2025
    - Net annual energy forecast is about 3.9% lower in 2025
    - Net summer 90/10 forecast is about 2.7% lower in 2025
  - Next Load Forecast Committee is April 4 to discuss the final forecast which will be published as part of the 2017 CELT Report on or about May 1
- Energy-Efficiency (EE) Forecast
  - Comments received from the EE working group members have been addressed and/or considered
  - The 2017 forecast is nearly complete and compared to the 2016 CELT, the EE forecast is approximately 11% higher in 2025. Final forecast to be published on or about May 1.

Load, Energy Efficiency, and Photovoltaic Forecast, cont.

- Photovoltaic (PV) Forecast
  - Comments received from DGFWG members have been considered
    - Concerns that the forecast is too conservative and underestimating the amount of Behind-the-Meter (BTM) PV installed
  - Next DGFWG meeting will be held on April 14 where both the comments received and the finalized 2017 forecast will be discussed
  - As compared to the 2016 CELT forecast, the total 2017 nameplate PV forecast is approximately 33% higher in 2025, and the BTM PV portion of the forecast is approximately 15% higher in 2025
  - The PV forecast will be published as part of the 2017 CELT Report on or about May 1

Environmental Matters

- February 23 environmental update to PAC discussed the following matters:
  - Environmental performance of the generation system in 2016
    - Air emissions, water usage
  - Update on federal environmental regulatory actions
    - Regional MATS implementation, 2015 Ozone Standard developments
    - Other relevant federal regulatory activity
  - 2016-2017 Regional Greenhouse Gas Initiative Program Review Update
  - Massachusetts Global Warmings Solutions Act Generator Emissions Cap Update
- Environmental Advisory Group is scheduled to meet on April 14

Economic Studies and Keene Road Market Efficiency Transmission Upgrade Needs Assessment

- 2016 Economic Study - NEPOOL Scenario Analysis Phase I draft report remains on schedule for the second quarter
  - Phase I observations and key messages and results for requests for additional metrics and sensitivities were discussed with the PAC for the six base scenarios
  - Work is proceeding on the Phase II scopes of work discussed at the December 14 PAC meeting and are scheduled for completion during 2017
    - Natural gas pipeline results
    - Scope of work for FCA auction results
    - Scope of work for regulation, ramping, and reserves

Economic Studies and Keene Road Market Efficiency Transmission Upgrade Needs Assessment, cont.

- 2017 Economic Study requests are due to the ISO by close of business on April 3
  - The ISO will contact requestors by April 6 to discuss draft PAC presentations
  - Discussions of the requests are scheduled for the May PAC meeting
- Keene Road Market Efficiency Transmission Upgrade needs assessment final results were posted on the PAC website
  - At the March PAC meeting, the ISO concluded that a Market Efficiency Transmission Upgrade will not be pursued for the Keene Road Area

RSP Project Stage Descriptions

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

Connecticut River Valley

Status as of 4/3/17

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

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

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

New Hampshire/Vermont 10-Year Upgrades

Status as of 4/3/17

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected In-Service	Present Stage
Eagle Substation Add: 345/115 kV autotransformer	Dec-16	4*
Littleton Substation Add: Second 230/115 kV autotransformer	Oct-14	4
New C-203 230 kV line tap to Littleton NH Substation	Nov-14	4
New 115 kV overhead line, Fitzwilliam-Monadnock	Feb-17	4
New 115 kV overhead line, Scobie Pond-Huse Road	Nov-15	4*
New 115 kV overhead/submarine line, Madbury-Portsmouth	Dec-18	2
New 115 kV overhead line, Scobie Pond-Chester	Dec-15	4

* Placed in-service ahead of schedule

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

New Hampshire/Vermont 10-Year Upgrades, cont.

Status as of 4/3/17

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected In-Service	Present Stage
Saco Valley Substation - Add two 25 MVAR dynamic reactive devices	Aug-16	4
Rebuild 115 kV line K165, W157 tap Eagle-Power Street	May-15	4
Rebuild 115 kV line H137, Merrimack-Garvins	Jun-13	4
Rebuild 115 kV line D118, Deerfield-Pine Hill	Nov-14	4
Oak Hill Substation - Loop in 115 kV line V182, Garvins-Webster	Apr-15	4*
Uprate 115 kV line G146, Garvins-Deerfield	Mar-15	4
Uprate 115 kV line P145, Oak Hill-Merrimack	May-14	4

* Placed in-service ahead of schedule

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

New Hampshire/Vermont 10-Year Upgrades, cont.

Status as of 4/3/17

Project Benefit: Addresses Needs in New Hampshire and Vermont

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

* Placed in-service ahead of schedule

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

Greater Hartford and Central Connecticut (GHCC) Projects*

Status as of 4/3/17

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 In-Service	Present Stage
Add a 2nd 345/115 kV autotransformer at Haddam substation and reconfigure the 3-terminal 345 kV 348 line into two 2-terminal lines	Jun-17	3
Terminal equipment upgrades on the 345 kV line between Haddam Neck and Beseck (362)	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	Dec-17	2
Add a 37.8 MVAR capacitor bank at the Hopewell 115 kV substation	Dec-16	4**
Separation of 115 kV double circuit towers corresponding to the Branford – Branford RR line (1537) and the Branford to North Haven (1655) line and adding a 115 kV breaker at Branford 115 kV substation	Dec-17	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

** Placed in-service ahead of schedule

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 4/3/17

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 In-Service	Present Stage
Terminal equipment upgrades on the 115 kV line from Middletown to Dooley (1050)	Jun-15	4
Terminal equipment upgrades on the 115 kV line from Middletown to Portland (1443)	Jun-15	4
Add a new 115 kV underground cable from Newington to Southwest Hartford and associated terminal equipment including a 2% series reactor	Dec-18	2
Add a 115 kV 25.2 MVAR capacitor at Westside 115 kV substation	Dec-18	2
Loop the 1779 line between South Meadow and Bloomfield into the Rood Avenue substation and reconfigure the Rood Avenue substation	Dec-17	3
Reconfigure the Berlin 115 kV substation including two new 115 kV breakers and the relocation of a capacitor bank	Dec-17	3
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 4/3/17

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 In-Service	Present Stage
Separation of 115 kV DCT corresponding to the Bloomfield to South Meadow (1779) line and the Bloomfield to North Bloomfield (1777) line and add a breaker at Bloomfield 115 kV substation	Dec-17	3
Separation of 115 kV DCT corresponding to the Bloomfield to North Bloomfield (1777) line and the North Bloomfield – Rood Avenue – Northwest Hartford (1751) line and add a breaker at North Bloomfield 115 kV substation	Dec-17	3
Install a 115 kV 3% reactor on the 115 kV line between South Meadow and Southwest Hartford (1704)	Dec-18	2
Replace the existing 3% series reactors on the 115 kV lines between Southington and Todd (1910) and between Southington and Canal (1950) with a 5% series reactors	Dec-17	2
Replace the normally open 19T breaker at Southington 115 kV with a normally closed 3% series reactor	Dec-17	2
Add a 345 kV breaker in series with breaker 5T at Southington	Dec-17	3

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 4/3/17

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 In-Service	Present Stage
Add a new control house at Southington 115 kV substation	Dec-17	2
Add a new 115 kV line from Frost Bridge to Campville	Jun-18	3
Separation of 115 kV DCT corresponding to the Frost Bridge to Campville (1191) line and the Thomaston to Campville (1921) line and add a breaker at Campville 115 kV substation	Dec-18	3
Upgrade the 115 kV line between Southington and Lake Avenue Junction (1810-1)	Dec-16	4
Add a new 345/115 kV autotransformer at Barbour Hill substation	Dec-16	4**
Add a 345 kV breaker in series with breaker 24T at the Manchester 345 kV substation	Dec-16	4**
Reconductor the 115 kV line between Manchester and Barbour Hill (1763)	Dec-16	4**

* Replaces the NEEWS Central Connecticut Reliability Project

** Placed in-service ahead of schedule

Southwest Connecticut (SWCT) Projects

Status as of 4/3/17

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 In-Service	Present Stage
Add a 25.2 MVAR capacitor bank at the Oxford substation	Dec-16	4*
Add 2 x 25 MVAR capacitor banks at the Ansonia substation	Dec-18	2
Close the normally open 115 kV 2T circuit breaker at Baldwin substation	Dec-17	3
Rebuild Bunker Hill to a 9-breaker substation in breaker-and-a-half configuration**	Dec-18	1
Reconductor the 115 kV line between Bunker Hill and Baldwin Junction (1575)	Dec-16	4
Loop the 1990 line in and out the Bunker Hill substation**	Dec-18	1
Expand Pootatuck (formerly known as Shelton) substation to 4-breaker ring bus configuration and add a 30 MVAR capacitor bank at Pootatuck	Jun-18	2
Loop the 1570 line in and out the Pootatuck substation	Jun-18	2
Replace two 115 kV circuit breakers at the Freight substation	Dec-15	4

* Placed in-service ahead of schedule

** Project to be cancelled

Southwest Connecticut Projects, cont.

Status as of 4/3/17

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 In-Service	Present Stage
Add two 14.4 MVAR capacitor banks at the West Brookfield substation	Dec-17	2
Add a new 115 kV line from Plumtree to Brookfield Junction	Dec-18	1
Reconductor the 115 kV line between West Brookfield and Brookfield Junction (1887)	Dec-18	2
Reduce the existing 25.2 MVAR capacitor bank at the Rocky River substation to 14.4 MVAR	Dec-17	2
Reconfigure the 1887 line into a three-terminal line (Plumtree - W. Brookfield - Shepaug)	Dec-18	2
Reconfigure the 1770 line into 2 two-terminal lines (Plumtree - Stony Hill and Stony Hill - Bates Rock)	Dec-18	2
Install a synchronous condenser (+25/-12.5 MVAR) at Stony Hill	Dec-18	2
Relocate an existing 37.8 MVAR capacitor bank at Stony Hill to the 25.2 MVAR capacitor bank side	Dec-18	2

Southwest Connecticut Projects, cont.

Status as of 4/3/17

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 In-Service	Present Stage
Relocate the existing 37.8 MVAR capacitor bank from 115 kV B bus to 115 kV A bus at the Plumtree substation	Dec-17	3
Add a 115 kV circuit breaker in series with the existing 29T breaker at the Plumtree substation	Dec-16	4*
Terminal equipment upgrade at the Newtown substation (1876)	Dec-15	4*
Rebuild the 115 kV line from Wilton to Norwalk (1682) and upgrade Wilton substation terminal equipment	May-17	3
Reconductor the 115 kV line from Wilton to Ridgefield Junction (1470-1)	Dec-17	2
Reconductor the 115 kV line from Ridgefield Junction to Peaceable (1470-3)	Dec-17	2

* Placed in-service ahead of schedule

Southwest Connecticut Projects, cont.

Status as of 4/3/17

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 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

* Placed in-service ahead of schedule

Southwest Connecticut Projects, cont.

Status as of 4/3/17

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 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
Separate the 3827 (Beseck to East Devon) and 1610 (Southington to June to Mix Avenue) double circuit towers*	Dec-18	1
Upgrade the 1630 line relay at North Haven and Wallingford 1630 terminal equipment	Jan-17	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

* Project to be cancelled

Greater Boston Projects

Status as of 4/3/17

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

Upgrade	Expected In-Service	Present Stage
Install new 345 kV line from Scobie to Tewksbury	Dec-17	3
Reconductor the Y-151 115 kV line from Dracut Junction to Power Street	Sep-17	3*
Reconductor the M-139 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	Jun-17	3
Reconductor the N-140 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	Jun-17	3
Reconductor the F-158N 115 kV line from Wakefield Junction to Maplewood and associated work at Maplewood	Dec-15	4
Reconductor the F-158S 115 kV line from Maplewood to Everett	Jun-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	Jul-18	2

* Eversource portion of the project is complete

Greater Boston Projects, cont.

Status as of 4/3/17

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

Upgrade	Expected In-Service	Present Stage
Separate X-24 and E-157W DCT	Dec-17	2
Separate Q-169 and F-158N DCT	Dec-15	4
Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap	May-17	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

* Eversource portion of the project is complete

Greater Boston Projects, cont.

Status as of 4/3/17

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

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

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

Upgrade	Expected In-Service	Present Stage
Install a second 115 kV cable from Mystic to Woburn to create a bifurcated 211-514 line	Dec-18	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 4/3/17

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

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

Pittsfield/Greenfield Projects

Status as of 4/3/17

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

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

Pittsfield/Greenfield Projects, cont.

Status as of 4/3/17

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

Upgrade	Expected In-Service	Present Stage
Rebuild the Cumberland to Montague 1361 115 kV line and terminal work at Cumberland and Montague. At Montague Substation, reconnect Y177 115 kV line into 3T/4T position and perform other associated substation work	Dec-16	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

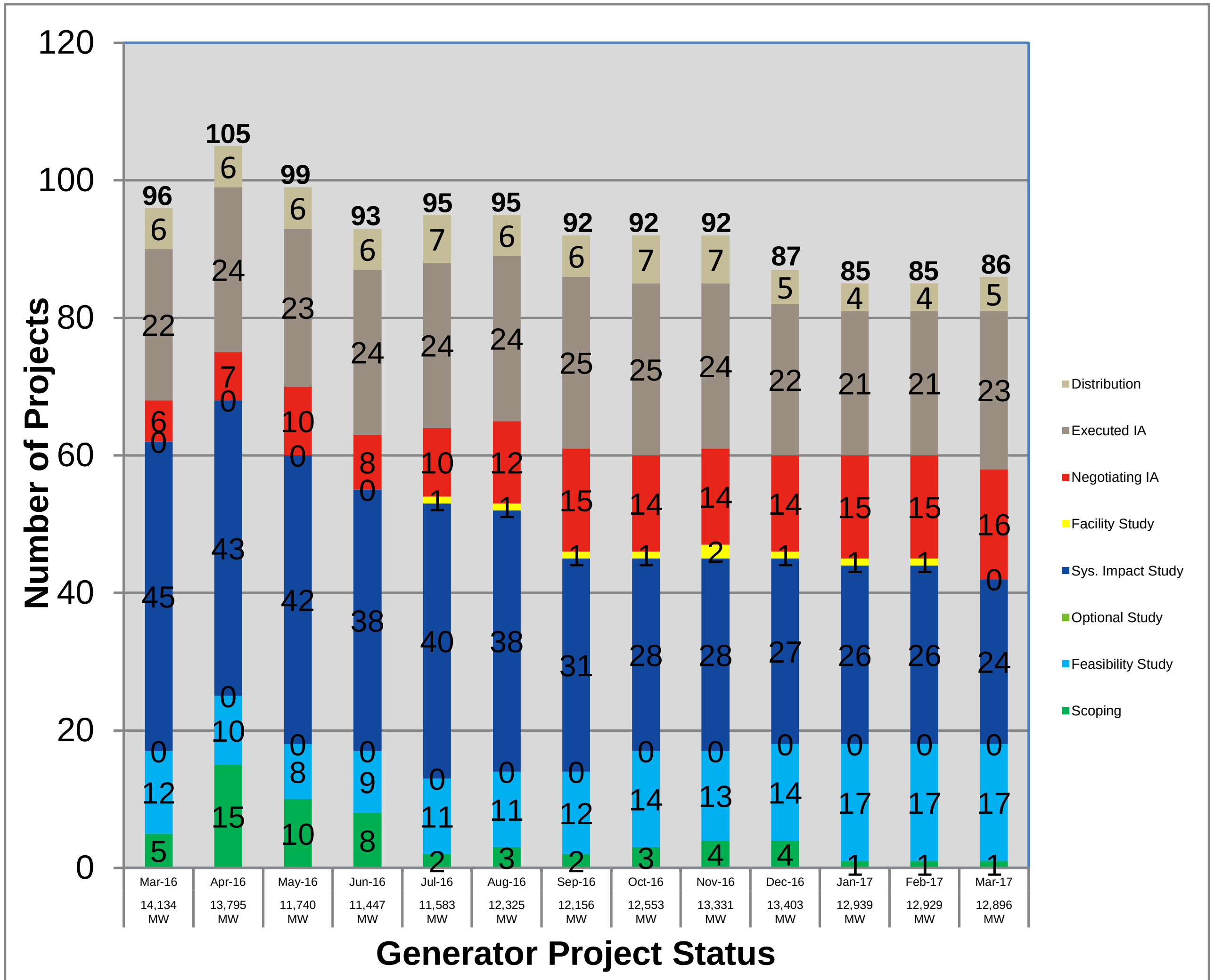
Pittsfield/Greenfield Projects, cont.

Status as of 4/3/17

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

Upgrade	Expected In-Service	Present Stage
Install a 115 kV 20.6 MVAR capacitor at the Doreen substation and operate the 115 kV 13T breaker N.O.	Dec-17	2
Install a 75-150 MVAR variable reactor at Northfield substation	Dec-17	2
Install a 75-150 MVAR variable reactor at Ludlow substation	Dec-17	2
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 March 2017, there are 8 ETU's in SIS, 1 in OSIS, 3 in FS, and 3 in Neg. IA

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

OPERABLE CAPACITY ANALYSIS

Spring 2017

Spring 2017 Operable Capacity Analysis

50/50 Load Forecast (Reference)	May - 2017 CSO	May - 2017 SCC
Operable Capacity MW [1]	30,241	32,828
OP CAP From OP-4 RTDR (+)	253	253
OP CAP From OP-4 RTEG (+)	13	13
Operable Capacity with OP-4 DR and RTEG	30,507	33,094
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	994	994
Non Commercial Capacity (+)	0	0
Non Gas-fired Planned Outages/Reductions MW (-)	1,463	3,896
Gas Generator Outages/Reductions MW (-)	3,255	1,960
Allowance for Unplanned Outages (-) [5]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [4]	0	0
Net Capacity (NET OPCAP SUPPLY MW) [3]	23,383	24,832
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,632	20,632
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,937	22,937
Operable Capacity Margin [3]	446	1,895

[1] Operable Capacity is based on the Capacity Supply Obligation (CSO) and Seasonal Claimed Capability (SCC) data as of **March 30, 2017**. This does not include Capacity associated with Settlement Only Generators (SOG).

[2] Load forecast that is based on the current CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 13, 2017**.

[3] Includes OP4 actions associated with RTEG and RTDR

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

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

Spring 2017 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	**May - 2017 CSO**	**May - 2017 SCC**
Operable Capacity MW [1]	30,241	32,828
OP CAP From OP-4 RTDR (+)	253	253
OP CAP From OP-4 RTEG (+)	13	13
Operable Capacity with OP-4 DR and RTEG	30,507	33,094
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	994	994
Non Commercial Capacity (+)	0	0
Non Gas-fired Planned Outages/Reductions MW (-)	1,463	3,896
Gas Generator Outages/Reductions MW (-)	3,255	1,960
Allowance for Unplanned Outages (-) [5]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [4]	0	0
Net Capacity (NET OPCAP SUPPLY MW) [3]	23,383	24,832
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	22,516	22,516
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	24,821	24,821
Operable Capacity Margin [3]	-1,438	11

[1] Operable Capacity is based on the Capacity Supply Obligation (CSO) and Seasonal Claimed Capability (SCC) data as of **March 30, 2017**. This does not include Capacity associated with Settlement Only Generators (SOG).

[2] Load forecast that is based on the current CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 13, 2017**.

[3] Includes OP4 actions associated with RTEG and RTDR

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

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

Spring 2017 Operable Capacity Analysis (MW)

50/50 Forecast (Reference)

ISO-NE 2017 OPERABLE CAPACITY ANALYSIS

April 7, 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]
4/8/2017	30,267	994	0	4,571	1,483	2,700	0	22,507	17,031	2,305	19,336	3,171	244	3,415	2	3,417
4/15/2017	30,267	994	0	4,840	1,750	2,700	0	21,971	16,431	2,305	18,736	3,235	244	3,479	2	3,481
4/22/2017	30,267	1,094	0	5,359	866	2,700	0	22,436	16,158	2,305	18,463	3,973	244	4,217	2	4,219
4/29/2017	30,241	994	0	4,806	438	3,400	0	22,591	15,559	2,305	17,864	4,727	253	4,980	13	4,993
5/6/2017	30,241	994	0	2,785	1,870	3,400	0	23,180	19,609	2,305	21,914	1,266	253	1,519	13	1,532
5/13/2017	**30,241**	**994**	**0**	**3,255**	**1,463**	**3,400**	**0**	**23,117**	**20,632**	**2,305**	**22,937**	**180**	**253**	**433**	**13**	**446**
5/20/2017	30,241	994	0	2,320	1,247	3,400	0	24,268	21,583	2,305	23,888	380	253	633	13	646
5/27/2017	30,241	994	0	1,263	666	3,400	0	25,906	22,626	2,305	24,931	975	253	1,228	13	1,241

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 and derates.
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. Preliminary net load forecast assumes Peak Load Exposure (PLE) of 26,265 MW and does include credit of Passive Demand Response (PDR) http://www.iso-ne.com/system-planning/system-plans-studies/celt
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).

Spring 2017 Operable Capacity Analysis (MW)

90/10 Forecast (Extreme)

ISO-NE 2017 OPERABLE CAPACITY ANALYSIS

April 7, 2017 - 90/10 FORECAST using CSO values with RTDR and RTEG

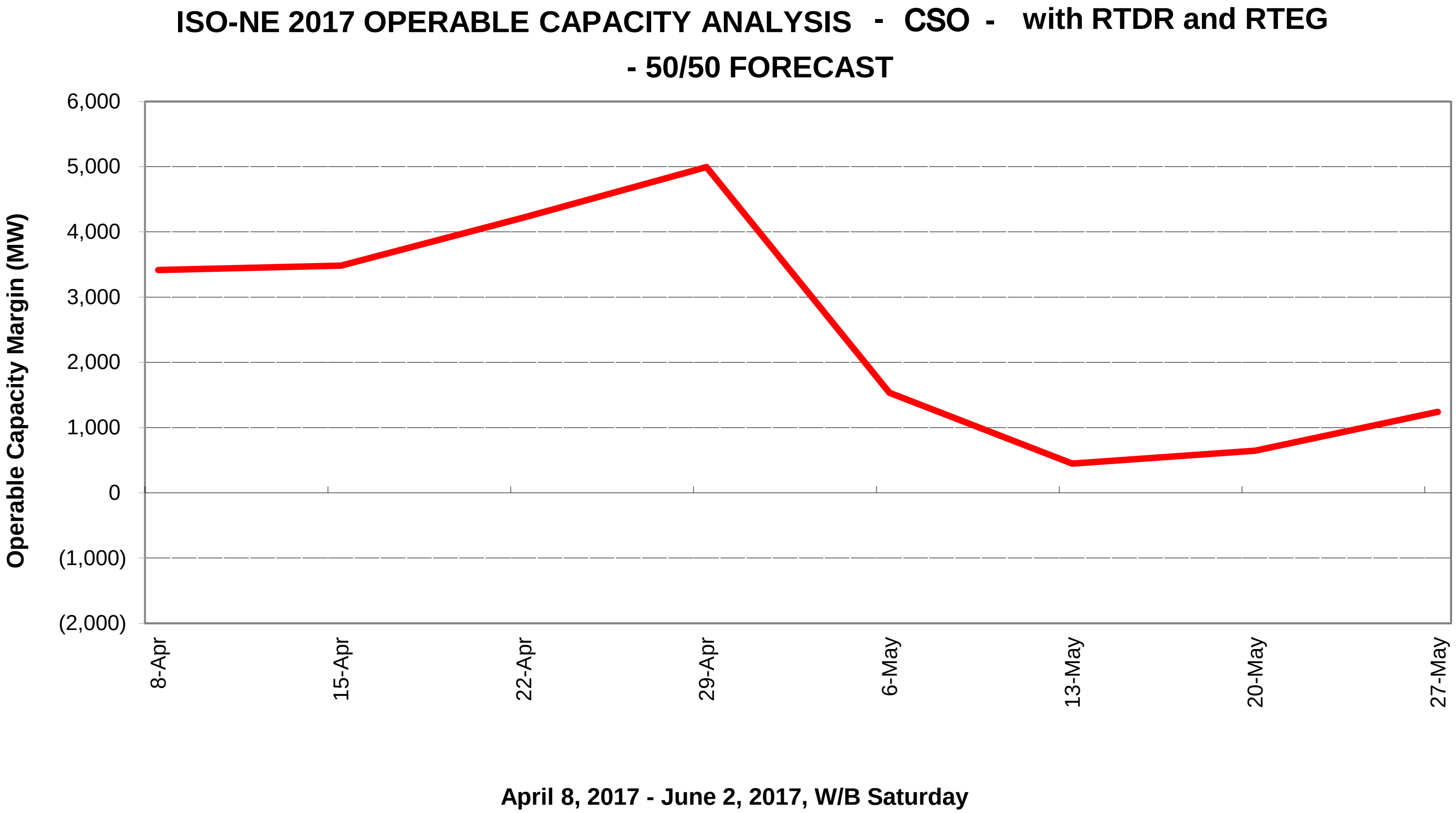
This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, and August and Mid September.

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW [1]	EXTERNAL NODE AVAIL CAPACITY MW [2]	NON COMMERCIAL CAPACITY MW [3]	NON-GAS PLANNED OUTAGES CSO MW [4]	GAS GENERATOR OUTAGES CSO MW [5]	ALLOWANCE FOR UNPLANNED OUTAGES MW [6]	GAS AT RISK MW [7]	NET OPCAP SUPPLY MW [8]	PEAK LOAD FORECAST MW [9]	OPER RESERVE REQUIREMENT MW [10]	NET LOAD OBLIGATION MW [11]	OPCAP MARGIN MW [12]	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW [13]	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW [14]	OPCAP FROM OP4 REAL-TIME EMER. GEN MW [15]	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW [16]
4/8/2017	30,267	994	0	4,571	1,483	2,700	0	22,507	17,595	2,305	19,900	2,607	244	2,851	2	2,853
4/15/2017	30,267	994	0	4,840	1,750	2,700	0	21,971	16,988	2,305	19,293	2,678	244	2,922	2	2,924
4/22/2017	30,267	1,094	0	5,359	866	2,700	0	22,436	16,707	2,305	19,012	3,424	244	3,668	2	3,670
4/29/2017	30,241	994	0	4,806	438	3,400	0	22,591	16,107	2,305	18,412	4,179	253	4,432	13	4,445
5/6/2017	30,241	994	0	2,785	1,870	3,400	0	23,180	21,410	2,305	23,715	(535)	253	(282)	13	(269)
5/13/2017	**30,241**	**994**	**0**	**3,255**	**1,463**	**3,400**	**0**	**23,117**	**22,516**	**2,305**	**24,821**	**(1,704)**	**253**	**(1,451)**	**13**	**(1,438)**
5/20/2017	30,241	994	0	2,320	1,247	3,400	0	24,268	23,544	2,305	25,849	(1,581)	253	(1,328)	13	(1,315)
5/27/2017	30,241	994	0	1,263	666	3,400	0	25,906	24,673	2,305	26,978	(1,072)	253	(819)	13	(806)
6/3/2017	29,491	1,246	0	866	0	2,800	0	27,071	28,648	2,305	30,953	(3,882)	380	(3,502)	2	(3,500)

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 and derates.
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. Preliminary net load forecast assumes Peak Load Exposure (PLE) of 26,265 MW and does include credit of Passive Demand Response (PDR) http://www.iso-ne.com/system-planning/system-plans-studies/celt 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).

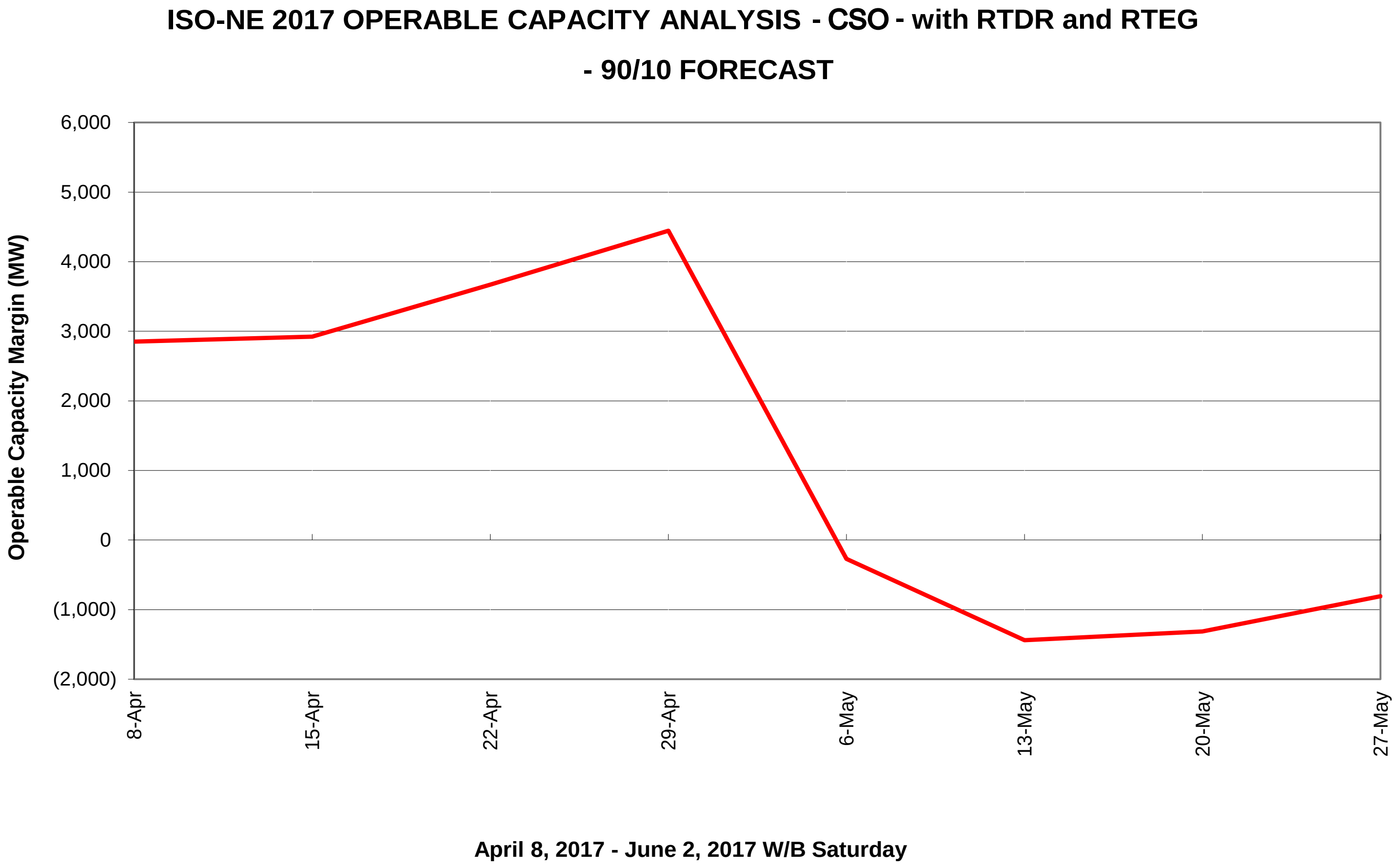
Spring 2017 Operable Capacity Analysis (MW)

50/50 Forecast (Reference)



Spring 2017 Operable Capacity Analysis (MW)

90/10 Forecast (Extreme)



OPERABLE CAPACITY ANALYSIS

Summer 2017

Summer 2017 Operable Capacity Analysis

50/50 Load Forecast (Reference)	**July - 2017 CSO**	**July - 2017 SCC**
Operable Capacity MW [1]	29,491	29,412
OP CAP From OP-4 RTDR (+)	380	380
OP CAP From OP-4 RTEG (+)	2	2
Operable Capacity with OP-4 DR and RTEG	29,873	29,794
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,246	1,246
Non Commercial Capacity (+)	0	0
Non Gas-fired Planned Outages/Reductions MW (-)	674	674
Gas Generator Outages/Reductions MW (-)	0	0
Allowance for Unplanned Outages (-) [5]	2,100	2,100
Generation at Risk Due to Gas Supply (-) [4]	0	0
Net Capacity (NET OPCAP SUPPLY MW) [3]	28,345	28,266
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	26,265	26,265
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	28,570	28,570
Operable Capacity Margin [3]	-225	-304

[1] Operable Capacity is based on the Capacity Supply Obligation (CSO) and Seasonal Claimed Capability (SCC) data as of **March 30, 2017**. This does not include Capacity associated with Settlement Only Generators (SOG).

[2] Preliminary net load forecast assumes Peak Load Exposure (PLE) of 26,265 MW and represents the peak demand of week beginning **July 15, 2017**.

[3] Includes OP4 actions associated with RTEG and RTDR

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

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

Summer 2017 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	July - 2017 CSO	July - 2017 SCC
Operable Capacity MW [1]	29,491	29,412
OP CAP From OP-4 RTDR (+)	380	380
OP CAP From OP-4 RTEG (+)	2	2
Operable Capacity with OP-4 DR and RTEG	29,873	29,794
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,246	1,246
Non Commercial Capacity (+)	0	0
Non Gas-fired Planned Outages/Reductions MW (-)	674	674
Gas Generator Outages/Reductions MW (-)	0	0
Allowance for Unplanned Outages (-) [5]	2,100	2,100
Generation at Risk Due to Gas Supply (-) [4]	0	0
Net Capacity (NET OPCAP SUPPLY MW) [3]	28,345	28,266
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	28,648	28,648
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	30,953	30,953
Operable Capacity Margin [3]	-2,608	-2,687

[1] Operable Capacity is based on the Capacity Supply Obligation (CSO) and Seasonal Claimed Capability (SCC) data as of **March 30, 2017**. This does not include Capacity associated with Settlement Only Generators (SOG).

[2] Preliminary net load forecast assumes Peak Load Exposure (PLE) of 26,265 MW and represents the peak demand of week beginning **July 15, 2017**.

[3] Includes OP4 actions associated with RTEG and RTDR

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

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

Summer 2017 Operable Capacity Analysis (MW)
50/50 Forecast (Reference)

ISO-NE 2017 OPERABLE CAPACITY ANALYSIS

April 7, 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 [1]	EXTERNAL NODE AVAIL CAPACITY MW [2]	NON COMMERCIAL CAPACITY MW [3]	NON-GAS PLANNED OUTAGES CSO MW [4]	GAS GENERATOR OUTAGES CSO MW [5]	ALLOWANCE FOR UNPLANNED OUTAGES MW [6]	GAS AT RISK MW [7]	NET OPCAP SUPPLY MW [8]	PEAK LOAD FORECAST MW [9]	OPER RESERVE REQUIREMENT MW [10]	NET LOAD OBLIGATION MW [11]	OPCAP MARGIN MW [12]	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW [13]	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW [14]	OPCAP FROM OP4 REAL-TIME EMER. GEN MW [15]	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW [16]
6/3/2017	29,491	1,246	0	866	0	2,800	0	27,071	26,265	2,305	28,570	(1,499)	380	(1,119)	2	(1,117)
6/10/2017	29,491	1,246	0	866	0	2,800	0	27,071	26,265	2,305	28,570	(1,499)	380	(1,119)	2	(1,117)
6/17/2017	29,491	1,246	0	866	0	2,800	0	27,071	26,265	2,305	28,570	(1,499)	380	(1,119)	2	(1,117)
6/24/2017	29,491	1,246	0	674	0	2,800	0	27,263	26,265	2,305	28,570	(1,307)	380	(927)	2	(925)
7/1/2017	29,491	1,246	0	688	0	2,100	0	27,949	26,265	2,305	28,570	(621)	380	(241)	2	(239)
7/8/2017	29,491	1,246	0	688	0	2,100	0	27,949	26,265	2,305	28,570	(621)	380	(241)	2	(239)
7/15/2017	**29,491**	**1,246**	**0**	**674**	**0**	**2,100**	**0**	**27,963**	**26,265**	**2,305**	**28,570**	**(607)**	**380**	**(227)**	**2**	**(225)**
7/22/2017	29,491	1,246	0	674	0	2,100	0	27,963	26,265	2,305	28,570	(607)	380	(227)	2	(225)
7/29/2017	29,491	1,246	0	688	0	2,100	0	27,949	26,265	2,305	28,570	(621)	380	(241)	2	(239)
8/5/2017	29,491	1,246	0	674	0	2,100	0	27,963	26,265	2,305	28,570	(607)	380	(227)	2	(225)
8/12/2017	29,491	1,246	0	764	0	2,100	0	27,873	26,265	2,305	28,570	(697)	380	(317)	2	(315)
8/19/2017	29,491	1,246	0	688	0	2,100	0	27,949	26,265	2,305	28,570	(621)	380	(241)	2	(239)
8/26/2017	29,491	1,246	0	674	0	2,100	0	27,963	26,265	2,305	28,570	(607)	380	(227)	2	(225)
9/2/2017	29,491	1,246	0	678	0	2,100	0	27,959	26,265	2,305	28,570	(611)	380	(231)	2	(229)
9/9/2017	29,491	1,246	0	678	0	2,100	0	27,959	26,265	2,305	28,570	(611)	380	(231)	2	(229)

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 and derates.
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. Preliminary net load forecast assumes Peak Load Exposure (PLE) of 26,265 MW and does include credit of Passive Demand Response (PDR) http://www.iso-ne.com/system-planning/system-plans-studies/celt 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).

Summer 2017 Operable Capacity Analysis (MW)

90/10 Forecast (Extreme)

ISO-NE 2017 OPERABLE CAPACITY ANALYSIS

April 7, 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 [1]	EXTERNAL NODE AVAIL CAPACITY MW [2]	NON COMMERCIAL CAPACITY MW [3]	NON-GAS PLANNED OUTAGES CSO MW [4]	GAS GENERATOR OUTAGES CSO MW [5]	ALLOWANCE FOR UNPLANNED OUTAGES MW [6]	GAS AT RISK MW [7]	NET OPCAP SUPPLY MW [8]	PEAK LOAD FORECAST MW [9]	OPER RESERVE REQUIREMENT MW [10]	NET LOAD OBLIGATION MW [11]	OPCAP MARGIN MW [12]	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW [13]	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW [14]	OPCAP FROM OP4 REAL-TIME EMER. GEN MW [15]	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW [16]
6/3/2017	29,491	1,246	0	866	0	2,800	0	27,071	28,648	2,305	30,953	(3,882)	380	(3,502)	2	(3,500)
6/10/2017	29,491	1,246	0	866	0	2,800	0	27,071	28,648	2,305	30,953	(3,882)	380	(3,502)	2	(3,500)
6/17/2017	29,491	1,246	0	866	0	2,800	0	27,071	28,648	2,305	30,953	(3,882)	380	(3,502)	2	(3,500)
6/24/2017	29,491	1,246	0	674	0	2,800	0	27,263	28,648	2,305	30,953	(3,690)	380	(3,310)	2	(3,308)
7/1/2017	29,491	1,246	0	688	0	2,100	0	27,949	28,648	2,305	30,953	(3,004)	380	(2,624)	2	(2,622)
7/8/2017	29,491	1,246	0	688	0	2,100	0	27,949	28,648	2,305	30,953	(3,004)	380	(2,624)	2	(2,622)
7/15/2017	**29,491**	**1,246**	**0**	**674**	**0**	**2,100**	**0**	**27,963**	**28,648**	**2,305**	**30,953**	**(2,990)**	**380**	**(2,610)**	**2**	**(2,608)**
7/22/2017	29,491	1,246	0	674	0	2,100	0	27,963	28,648	2,305	30,953	(2,990)	380	(2,610)	2	(2,608)
7/29/2017	29,491	1,246	0	688	0	2,100	0	27,949	28,648	2,305	30,953	(3,004)	380	(2,624)	2	(2,622)
8/5/2017	29,491	1,246	0	674	0	2,100	0	27,963	28,648	2,305	30,953	(2,990)	380	(2,610)	2	(2,608)
8/12/2017	29,491	1,246	0	764	0	2,100	0	27,873	28,648	2,305	30,953	(3,080)	380	(2,700)	2	(2,698)
8/19/2017	29,491	1,246	0	688	0	2,100	0	27,949	28,648	2,305	30,953	(3,004)	380	(2,624)	2	(2,622)
8/26/2017	29,491	1,246	0	674	0	2,100	0	27,963	28,648	2,305	30,953	(2,990)	380	(2,610)	2	(2,608)
9/2/2017	29,491	1,246	0	678	0	2,100	0	27,959	28,648	2,305	30,953	(2,994)	380	(2,614)	2	(2,612)
9/9/2017	29,491	1,246	0	678	0	2,100	0	27,959	28,648	2,305	30,953	(2,994)	380	(2,614)	2	(2,612)

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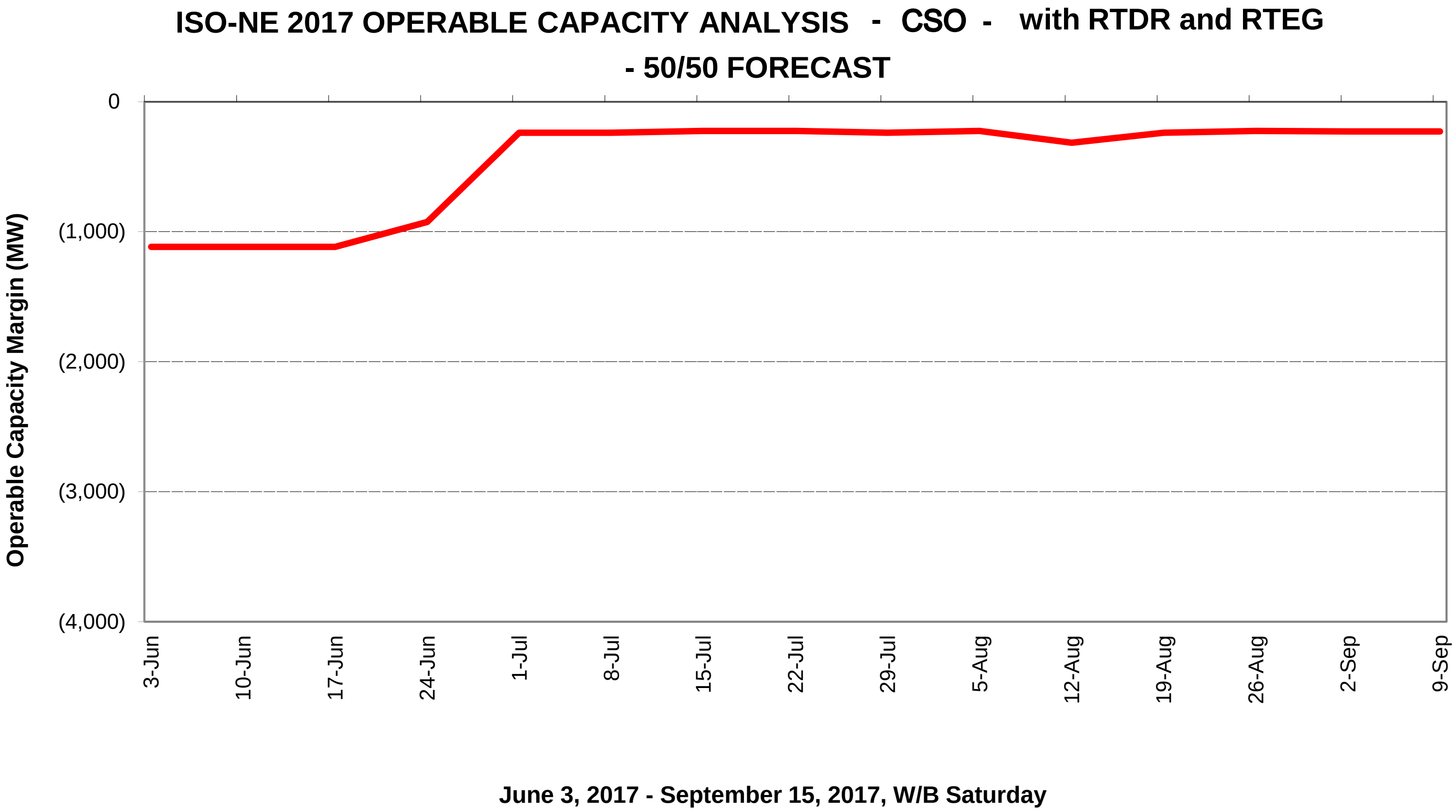
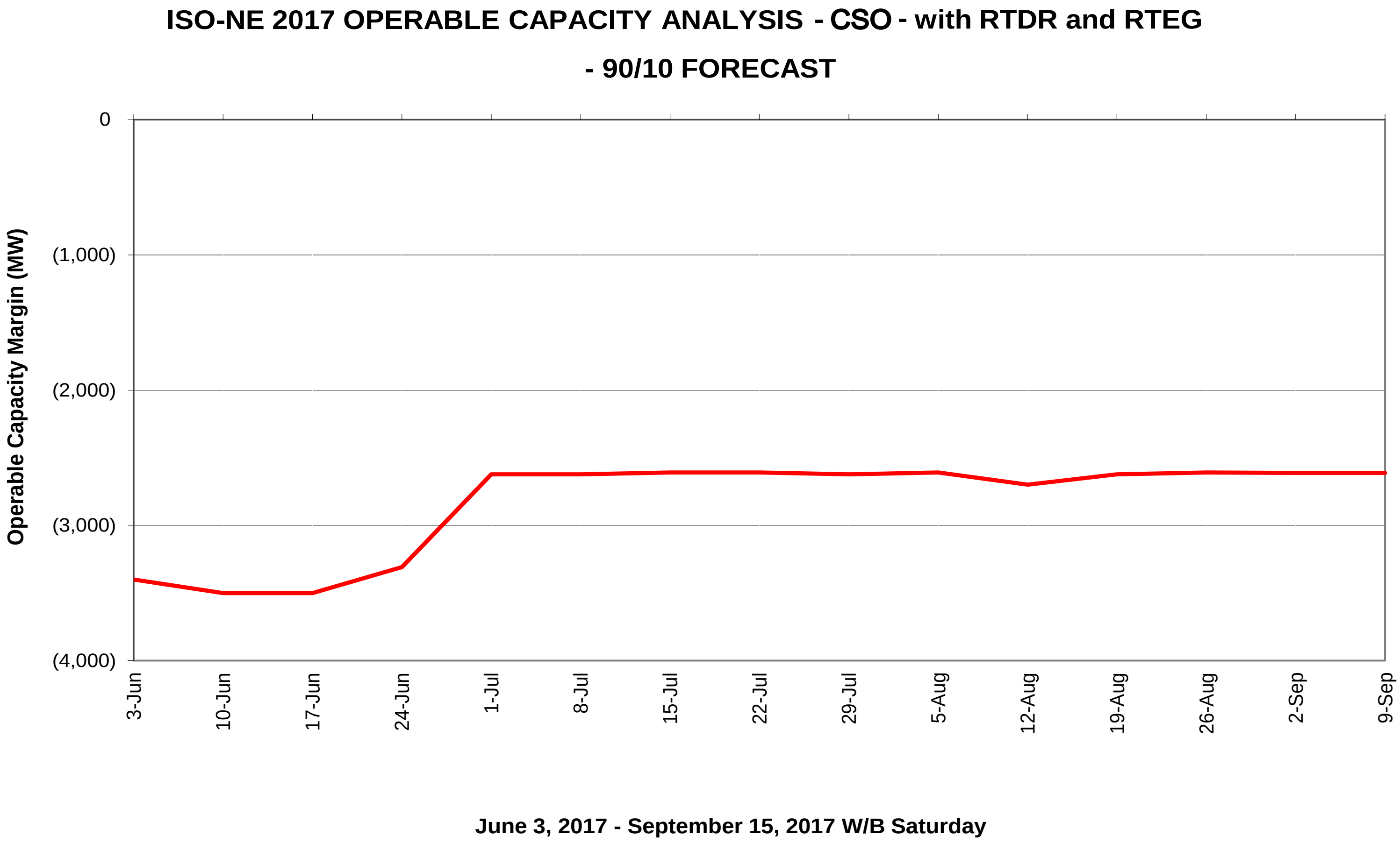
16. OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (14 + 15 = 16)
This does not include Emergency Energy Transactions (EETs).

Summer 2017 Operable Capacity Analysis (MW)
50/50 Forecast (Reference)



Summer 2017 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.	**April 244** [3] **May 253** [3] **June – September 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	134 [4] **April 2** [3] **May 13** [3] **June – September 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 March 30, 2017.
4. The MW values are based on a 26,704 MW system load and the most recent voltage reduction test % achieved.

Possible Relief Under OP4: Appendix A, cont.

OP 4 Action Number	Page 2 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
7	Request generating resources not subject to a Capacity Supply Obligation to voluntary provide energy for reliability purposes	0
8	Voltage Reduction requiring 10 minutes or less	267 [4]
9	Transmission Customer Generation Not Contractually Available to Market Participants during a Capacity Deficiency. Voluntary Load Curtailment by Large Industrial and Commercial Customers.	5 200 [2]
10	Radio and TV Appeals for Voluntary Load Curtailment Implement Power Warning	200 [2]
11	Request State Governors to Reinforce Power Warning Appeals.	100 [2]
Total		**April 2,792 [3]** **May 2,812[3]** **June – September 2,928 [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 March 30, 2017.
4. The MW values are based on a 26,704 MW system load and the most recent voltage reduction test % achieved.

APRIL 7, 2017 | BOSTON, MA

Operational Load Forecast Improvement Effort

Vamsi Chadalavada

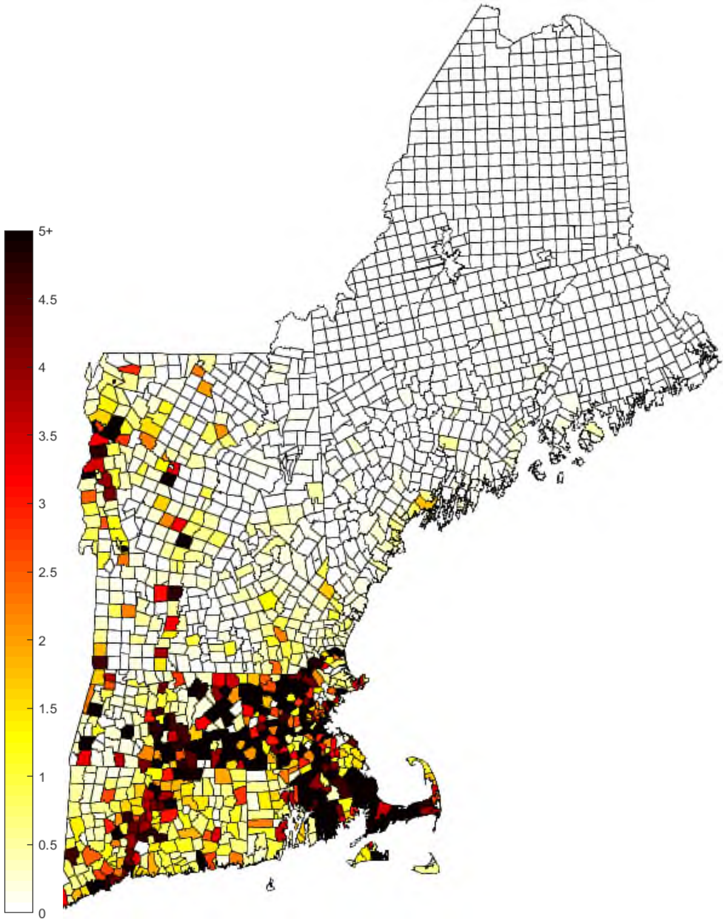
EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Operational Load Forecast – Introduction

- Historically, New England's power demand has been forecasted based on a weather forecast encompassing the major population centers of the region
  - Temperature, Dew Point, Wind Speed, Cloud Cover
  - Population weighted average for each parameter
- The introduction of behind-the-meter photovoltaic (BTM PV) power generation has added unpredictability to the current load forecast process

BTM PV Installations

- Behind-the-meter (BTM) power generation offsets the system load
- There are approximately 2,000 MW of PV installations in New England, with more than 95% of it BTM
- Current BTM PV installations are geographically dispersed as shown

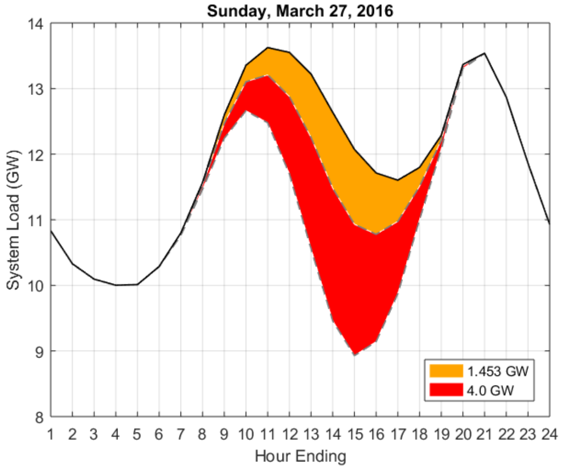


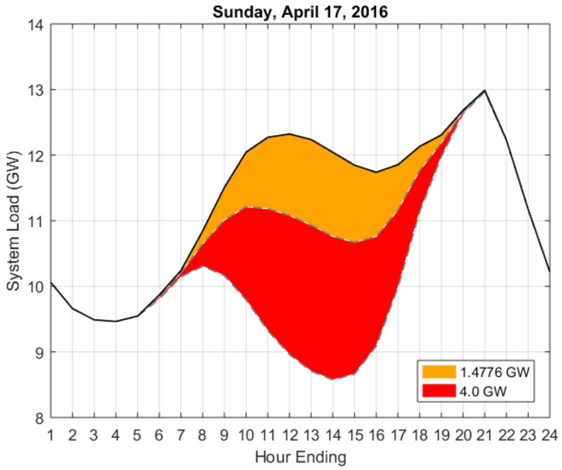
Operational Load Forecast Deviations

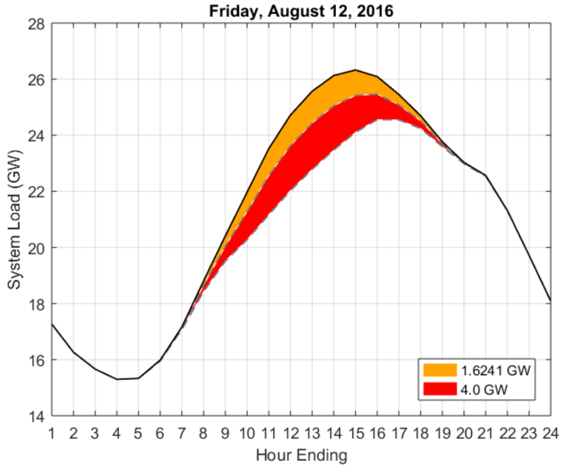
- Load profiles are showing dramatic changes due to the effects of BTM PV generation
- Expected BTM PV installation growth in the coming years will result in deeper troughs of mid-day loads, especially during light load periods (*See* Gross vs. Net Load profiles on slide 5)
  - In areas with deep BTM PV penetration, such as California, mid-day loads are lower than overnight loads

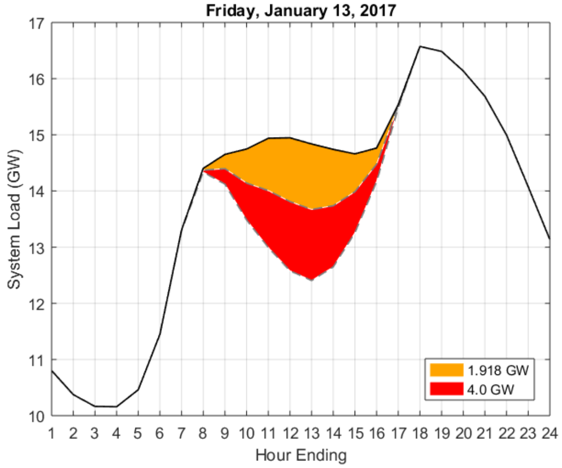
Operational Load Forecasts – Gross and Net

- Gross vs. Net Load Profiles
  - Actual, Recent BTM PV and 4,000 MW of BTM PV penetration





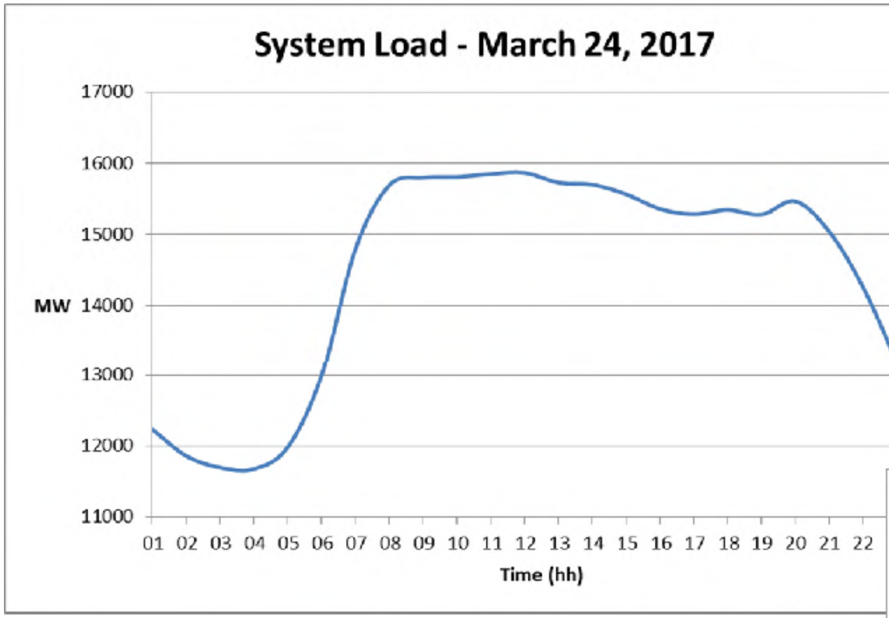




Operational Load Forecast Challenges

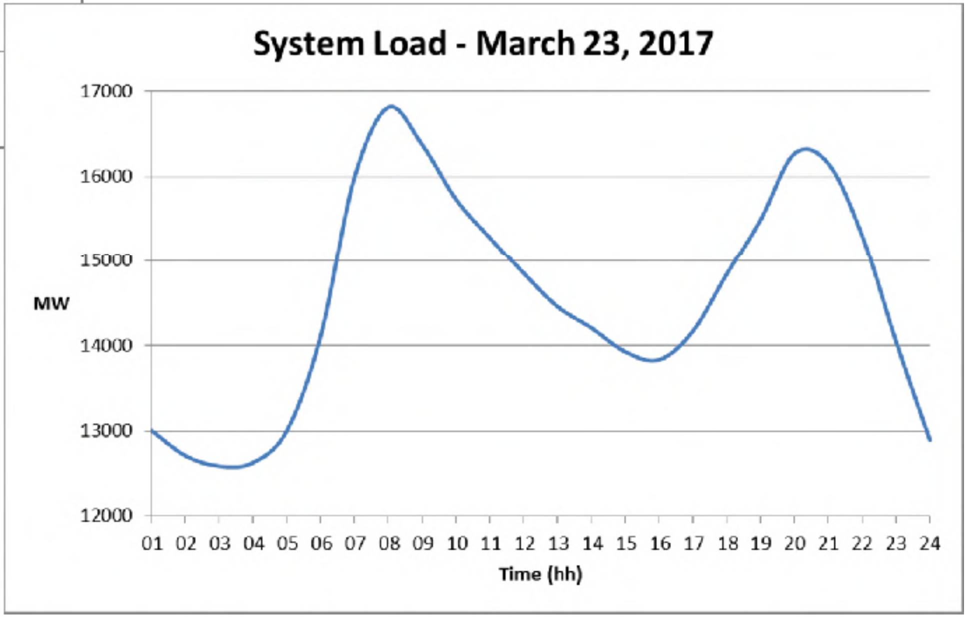
- BTM PV output is strongly influenced by very granular weather conditions
- Regional trends in BTM PV system installations are not directly incorporated in existing Load Forecasting processes
- Additional weather variables and data are needed to accurately account for BTM PV in the Load Forecast process
  - Highly granular irradiance observations from the past
  - Highly granular irradiance forecasts for the future
  - BTM PV panel installation data, used to convert irradiance into power
    - Nameplate capability and installation date
- The ISO is working to provide improved forecasts using new methods incorporating the effects of BTM PV generation

Cloudy Day vs. Sunny Day



- Cloudy Day
  - BTM PV reduced by clouds
  - Higher mid-day load profile

- Sunny Day
  - BTM PV at higher output
  - Lower mid-day load profile

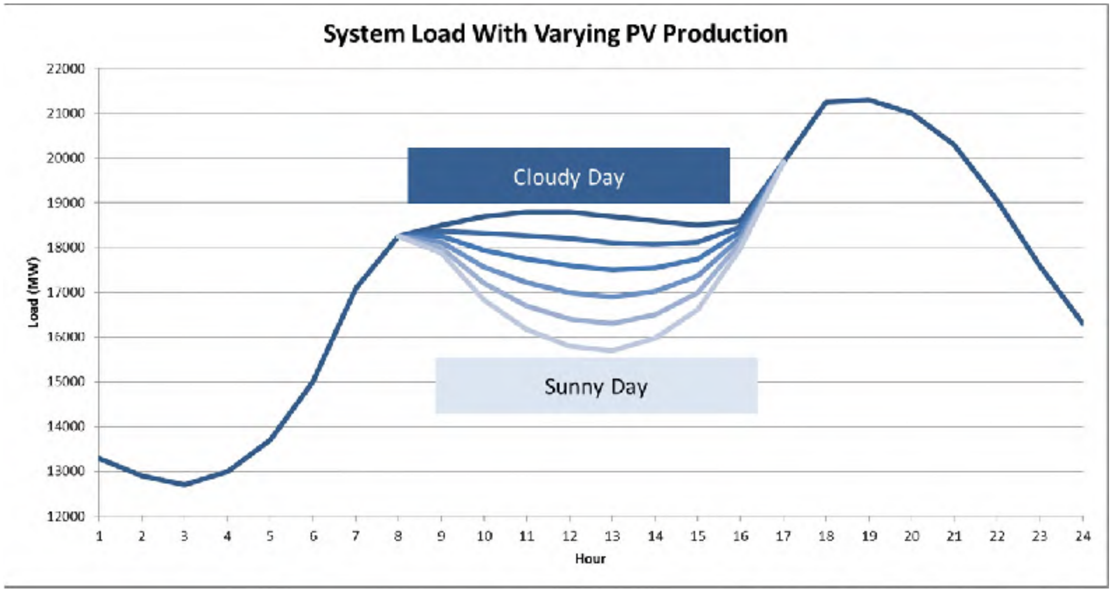


Current Operational Load Forecast Process

- To forecast system demand today, models use historical weather observations and actual demand data
- However, current models do not fully capture the impact of BTM PV installations
  - For example, assume the past 50 'Wednesdays' were a mix of cloud conditions, different BTM PV installations/output, and various other factors
  - Current models do not have the capability to understand and quantify the 'BTM PV Impact' as BTM PV installations are rapidly increasing and there is less correlation to similar days in history
  - So, for the next sunny Wednesday, the current models capture 'some, but not all' of the BTM PV Impact

Current Load Forecast Process, cont.

- To compensate for this ‘some, but not all’ BTM PV impact, the ISO uses other tools/processes to adjust the load forecast
  - For example, in the load forecast curve below, the current model might produce a mid-day profile of ~17,000 MWs on a sunny day
  - ISO might further adjust the forecast, based on offline processes to adjust the mid-day profile to ~16,300 MWs



Improving Model Performance

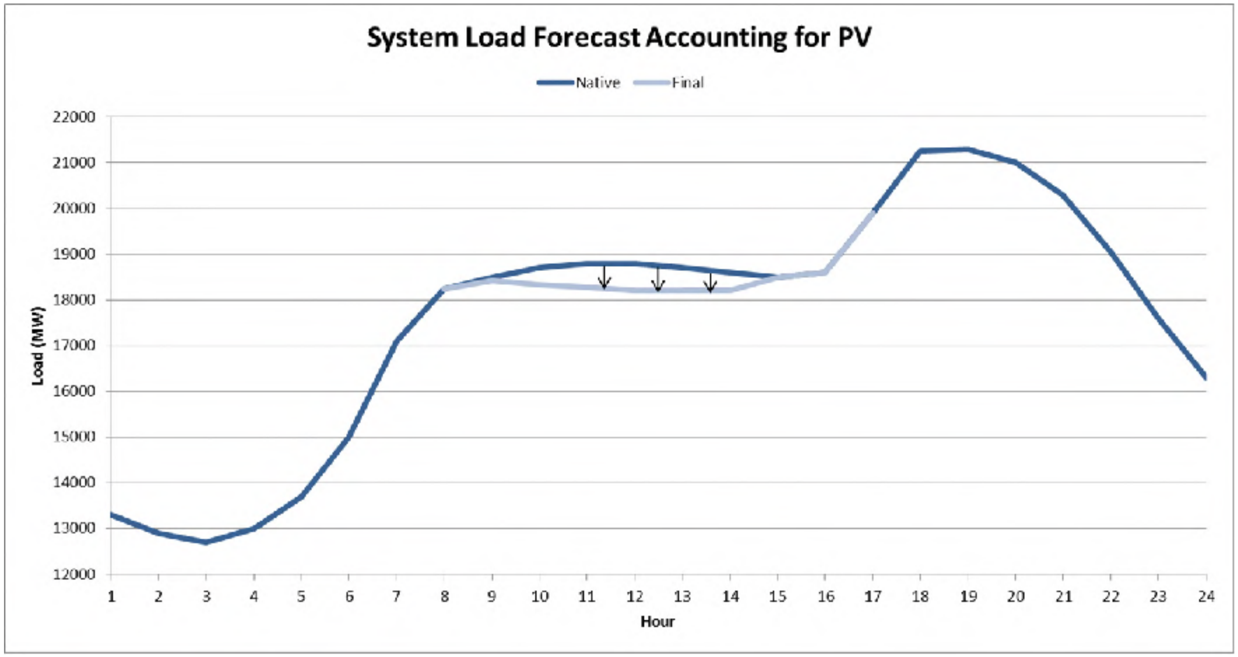
- To improve the performance of the load forecast models with regards to BTM PV, the ISO needs to generate gross load forecasts that do not include ‘any BTM PV’ impact
- This requires the ISO to fully separate the impact of BTM PV, both from its load forecast models and load forecast outputs
- In order to achieve this separation, we need to know the hourly BTM PV output for that day

Improving Model Performance

- The ISO will use statistical samplings of BTM PV output to estimate the production from all panels in a given area to calculate the hourly BTM PV output
- Statistical sampling method verification
  - As part of an ongoing pilot project with VELCO, the ISO compared the statistically sampled production data for Vermont to VELCO’s data, which includes more than 90% of total BTM PV production in the state
  - Results demonstrated ISO’s BTM PV production estimation method closely matches VELCO’s data

Improving Model Performance, cont.

- Once the data collection and modeling changes are complete, the new load forecast model will only provide gross load forecasts that exclude any BTM PV impact
- Hourly BTM PV output will then be subtracted from the gross load forecast to provide the net load forecast that needs to be served in real-time



Current Projects (2017)

- The ISO's current efforts are focused on providing the infrastructure and software to collect BTM PV related data
- These efforts include the following:
  - Use of third-party vendors to collect BTM PV production data
  - Validation of collected BTM PV production data
  - Collection of hourly irradiance data
  - Collection and tracking of BTM PV system installations in cooperation with local utilities

Upcoming Projects (2018)

- Automation and modeling changes to net out BTM PV effects and generate daily gross load forecasts
  - Output of load forecast models going forward will exclude BTM PV impacts
- Automation to calculate the BTM PV offsets using the latest BTM PV installation data and irradiance data
- Continue to monitor industry developments to enhance this approach
  - As new methods are analyzed and studied, an ideal end state would be implementation of dynamic load forecast models that are equipped to directly include BTM PV variables and publish 'net load'

MARCH, 2017

Updated 2017 Work Plan

April Participants Committee Discussion

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Objectives and Highlights

- The objective of this report is to reflect changes to the Annual Work Plan since its initial release in September, 2016
  - In Q3 2017, the ISO will begin the full cycle again and release a new Work Plan for discussion covering Q4 2017-Q2 2019
- Emerging work from IMAPP and NOPRs continue to affect the timing of the various activities in the ISO's 2017 Annual Work Plan
- The ISO is assessing fuel security issues on the bulk power grid and plans to discuss its findings with stakeholders during the second half of 2017
- Highlights of this Update include:
  - An ISO IMAPP Concept Timeline
  - Notices of Proposed Rulemaking (NOPR)
  - Continued Emphasis on Previously Committed Work
  - Market Initiative Reprioritization

Highlights: An ISO IMAPP Concept Timeline

- The ISO has provided insight on several conceptual proposals offered by stakeholders through NEPOOL's IMAPP process
  - See IMAPP materials from September 2016 and January 2017
- The ISO plans to release a summary of its concept, for accommodating additional state subsidized resources and their associated pricing impacts on the capacity market, ahead of the FERC Technical Conference on May 1-2, 2017
- The ISO will prepare a discussion paper of its initial concept prior to the May IMAPP meeting, and would plan to then turn to the NEPOOL committee process for this near term IMAPP approach
  - The NECPUC symposium and the NEPOOL Participants Committee summer meetings may allow for additional feedback and dialogue on the concept
- The ISO anticipates any potential proposals to be filed with FERC by the end of 2017 to allow for implementation by the relevant FCA 13 submission windows

Highlights: Notices Of Proposed Rulemaking (NOPR)

- The FERC has published numerous NOPRs and Final Rules since Q4 2016, such as:
  - Electric Storage Participation in Regions with Organized Wholesale Electric Markets, RM16-23-000; AD16-20-000
  - Uplift Cost Allocation and Transparency in Markets Operating by Regional Transmission Organizations and Independent System Operators, RM17-2-000
  - Fast-Start Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators, RM17-3-000
  - Reform of Generator Interconnection Procedures and Agreements, RM17-8-000
  - Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators, RM16-5-000, Order 831
- These items will require significant time and effort from ISO staff to respond review and respond to these proposed rules

Highlights: Continued Emphasis on Previously Committed Work

- Order 1000 Planning for Public Policy
  - Order 1000 related implementation efforts are underway and will continue in 2017 as we gain experience, identify, and implement necessary process improvements
- Cyber security will continue to be a big area of emphasis
  - Over the past year, our experience with CIP Version 5 indicates that compliance with current and emerging cyber security standards will continue to require significant investment in resources and budget
  - In addition to the FERC Order 829 on supply chain management, the ISO is working on various projects in 2017 (and 2018) to strengthen its overall cyber security defense posture
    - This includes projects related to asset management, enhanced network security and access management
- Four implementation milestones have recently occurred:
  - February 6, 2017
    - Zonal Demand Curves (FCA 11)
  - March 1, 2017
    - Real-Time Fast-Start Pricing
    - Sub-Hourly Real-Time Settlement
    - Market Enhancements for Dispatchable Asset Related Demand (DARD) Pumps

Highlights: Continued Emphasis on Previously Committed Work, cont.

- The ISO's market initiative work is returning to a balanced state
- The ISO has been in midst of implementing significant market changes, however, the volume of proposed market changes is normalizing
  - In 2015, the Markets Committee heard discussion on over 40 market projects, 17 of which were new market approaches that have been implemented or are in the process of being implemented
    - *e.g.* Fast Start and DARD Pumps
  - In 2016, the Markets Committee heard discussion on over 25 market projects, 9 of which resulted in new market approaches currently in implementation
- The pending NOPRs and market changes of significant scope, coupled with our focus on implementing key changes, have the ISO prioritizing changes in a more measured way

Highlights: Market Initiative Reprioritization

- In light of the efforts and timing on IMAPP-related work, the ISO is considering moving up its plans to discuss a potential pricing approach for resource ramping
  - Previously, the resource ramping assessment was delayed to follow both IMAPP and the Day-Ahead Reserve Market Enhancement Assessment
  - As public policy approaches have evolved and bring the potential for additional variable resources in the wholesale markets, the ISO plans to assess ramp pricing issues under these circumstances
  - By Q4 2017, the ISO aims to hold technical sessions to discuss how ramping currently works and to survey options in other regions
  - This sequencing change prioritizes the resource ramping assessment and, in light of other commitments, pushes out the timeframe for the Day Ahead Reserve Market Enhancements Assessment

Planning/ Operations Related Activities

<table>
<tr><th colspan="3">2017</th><th colspan="2">2018</th></tr>
<tr><th>Q2</th><th>Q3</th><th>Q4</th><th>Q1</th><th>Q2</th></tr>
<tr><td colspan="5">Order 1000 Implementation (slide 11)</td></tr>
<tr><td colspan="5">Transmission Planning Studies (slide 12)</td></tr>
<tr><td colspan="5">Transmission Cost Allocation</td></tr>
<tr><td colspan="5">Annual Economic Studies (slide 13)</td></tr>
<tr><td colspan="5">Interregional Planning</td></tr>
<tr><td>Data Collection and Finalization of 2017 EE Forecasts</td><td></td><td></td><td colspan="2">Data Collection and Finalization of 2018 EE Forecasts</td></tr>
<tr><td>2017 PV Forecast</td><td></td><td></td><td colspan="2">2018 PV Forecast</td></tr>
<tr><td colspan="5">Stakeholder and Regulatory Review of ICR/LSR</td></tr>
<tr><td>FCA 12: ID Potential Zones</td><td>FCA 12: Zonal Requirements</td><td>FCA 13 Zones: Expected Topology</td><td colspan="2">FCA 13: Regional Transfer Limits/ ID Potential Zones</td></tr>
<tr><td></td><td></td><td></td><td></td><td>Black Start Review (slide 14)</td></tr>
<tr><td></td><td></td><td colspan="3">FCA 13 CONE Adjustment</td></tr>
<tr><td colspan="5">Generator Interconnection Studies (slide 15)</td></tr>
<tr><td colspan="2">RSP 17</td><td></td><td></td><td></td></tr>
<tr><td colspan="2"></td><td colspan="2">2017/18 Winter Reliability Program</td><td></td></tr>
<tr><td colspan="5">NERC/FERC Compliance/Cyber Security</td></tr>
</table>

UPDATE: PLANNING/OPERATIONS ACTIVITIES

Update: Planning and Operations Activities Completed between Q4 2016 and Q1 2017

- FCA 12 Zones: Expected Topology
  - The ISO presented an overview of the expected power system topology for the 2021/2022 Capacity Commitment Period (FCA #12)
- 2016/2017 Winter Reliability Program
  - Program ends March 15, 2017
    - Settlement will continue into Q2 2017
- FCA 11/ ARA3 CCP8
- Regional Transfer Limits

Update: Order 1000 Implementation

Planning for Public Policy

- The FERC accepted the ISO's proposed changes to the Transmission Study Process Timeline on March 10, 2017 (Docket No. ER17-857-000)
- The ISO has commenced its first Order 1000 related Public Policy Process, requesting submissions for particular transmission needs driven by Public Policy requirements
  - Five submittals were provided to the ISO
  - NESCOE Communication and Stakeholder feedback will follow in Q2 2017
  - If necessary, the ISO will provide a draft scope for the Public Policy Study by September 1, 2017

Update: Transmission Planning Studies

- Updated Needs Assessments will be conducted in 2017, in accordance with the Planning Process to reflect the following:
  - Recent changes to Planning Procedure 3 which establishes the reliability criteria for the PTF in New England
    - Including changes in system events that must be considered
  - Updated regional load forecast, Energy-Efficiency (EE) forecast, and Solar PV forecast
  - The resource mix will be adjusted for the results of the first 11 Forward Capacity Market Auctions and newly obtained information related to upcoming FCA 12
    - New Resources
    - De-list bids, including retirements
    - Other resource changes
  - Probabilistically based local generation dispatches
    - This is expected to be incorporated into Needs Assessments beginning in Q2-Q3 2017
  - The results of updated NPCC Bulk Power System classification testing

Update: Annual Economic Studies

- As part of the NEPOOL 2016 economic study request, the ISO has reviewed potential impacts of emerging public policy on performance of the power system and markets in New England
  - Phase I of the study is complete
  - Results were discussed at the PAC, an IMAPP meeting, and the New England Electricity Restructuring Roundtable
  - The final report will be released in June 2017
- The second phase of the study will look at the operability of each scenario and assess additional market outcomes. Phase II has three parts:
  - Natural Gas Pipeline Constraints: Is expected to be discussed with PAC in Q2 2017
  - FCA prices: The ISO consultant is expected to provide results, to be discussed with the PAC in Q2 2017
  - Frequency Regulation, Ramping and Reserves: The ISO consultant is expected to provide results, to be discussed with the PAC in Q4 2017

Update: Black Start Review

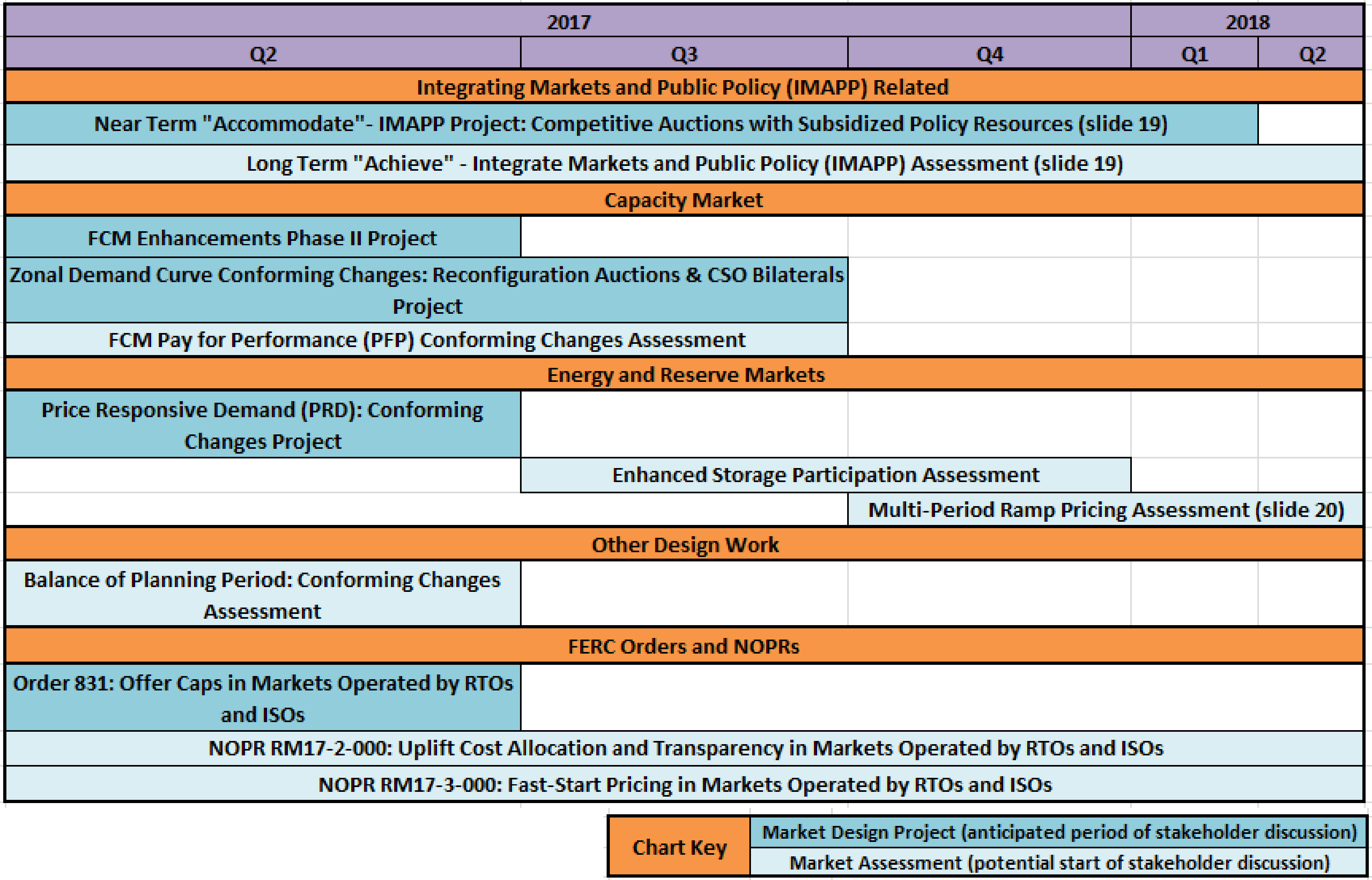
- The ISO compensates certain resources that are capable of providing black start services
- The ISO continues to review possible compensation mechanisms
- The start of the stakeholder process has been moved from Q2 2017 to Q2 2018

Update: Wind Interconnection Group Studies

- In response to the backlog of Interconnection Requests in Maine, and following stakeholder discussions in 2016, the ISO presented a proposal on interconnection clustering in Q4 2016
  - This proposal was favorably voted at the TC January 24, 2017 and PC February 3, 2017
  - The associated filing has moved from Q1 2017 to Q2 2017
- The ISO has conducted a strategic transmission assessment to identify the transmission expansion that could enable the interconnection of requested generation in Maine
  - Presented study results in Q4 2016 and Q1 2017
  - Planning to issue the final report in Q2 2017

UPDATE: MARKET RELATED ACTIVITIES

Markets Related Activities



2017			2018	
Q2	Q3	Q4	Q1	Q2
Integrating Markets and Public Policy (IMAPP) Related				
Near Term "Accommodate"- IMAPP Project: Competitive Auctions with Subsidized Policy Resources (slide 19)				
Long Term "Achieve" - Integrate Markets and Public Policy (IMAPP) Assessment (slide 19)				
Capacity Market				
FCM Enhancements Phase II Project				
Zonal Demand Curve Conforming Changes: Reconfiguration Auctions & CSO Bilaterals Project				
FCM Pay for Performance (PFP) Conforming Changes Assessment				
Energy and Reserve Markets				
Price Responsive Demand (PRD): Conforming Changes Project				
	Enhanced Storage Participation Assessment			
		Multi-Period Ramp Pricing Assessment (slide 20)		
Other Design Work				
Balance of Planning Period: Conforming Changes Assessment				
FERC Orders and NOPRs				
Order 831: Offer Caps in Markets Operated by RTOs and ISOs				
NOPR RM17-2-000: Uplift Cost Allocation and Transparency in Markets Operated by RTOs and ISOs				
NOPR RM17-3-000: Fast-Start Pricing in Markets Operated by RTOs and ISOs				

Chart Key	
	Market Design Project (anticipated period of stakeholder discussion)
	Market Assessment (potential start of stakeholder discussion)

Update: Markets Related Activities Completed between Q4 2016 and Q1 2017

- Natural Gas Index Changes
  - Filed Q4 2016
  - Implemented Q1 2017
- NCPC Modifications for Real-Time Sub-Hourly Settlement
  - Filed Q1 2017
  - Implemented Q1 2017
- Order 825 Compliance (Settlement Intervals and Shortage Pricing in Markets Operated by RTOs and ISOs)
  - Filed Q1 2017
- CONE Recalculation and ORTP Updates Project
  - Filed Q1 2017
  - Implemented Q1 2017

Update: IMAPP Project and Assessment

- As a result of the Integrating Markets and Public Policy (IMAPP) discussions, the ISO is developing a conceptual approach to maintain transparent and competitive markets that can incorporate the state subsidized policy resources in the near term
- The ISO will begin to work with NEPOOL and the states on its near term approach
  - This effort is expected to continue from the present through Q2 2018
  - Any potential implementation efforts will depend on the scope of a final proposal
- Additionally, the ISO will continue to work with stakeholders on achieving state policies through markets as long term solution in line with NEPOOL's bifurcated IMAPP (accommodate/ achieve) process

Update: Multi-Period Ramp Pricing

- The ISO is planning to assess the potential development of a new system ramping product to convey, through transparent prices, the costs incurred when the system must be re-dispatched in advance of a sustained load ramp
- By Q4 2017, the ISO aims to hold technical sessions to discuss how ramping currently works and to survey options in other regions

UPDATE: CAPITAL PROJECTS

Capital Projects

<table>
<tr><th colspan="3">2017</th><th colspan="2">2018</th></tr>
<tr><th>Q2</th><th>Q3</th><th>Q4</th><th>Q1</th><th>Q2</th></tr>
<tr><td></td><td></td><td colspan="2">Forward Capacity Auction (FCA) 12</td><td></td></tr>
<tr><td colspan="2">Balance of Planning Period: Financial Assurance</td><td></td><td></td><td></td></tr>
<tr><td colspan="5">EMP 3.1 Upgrade and Customs Reduction</td></tr>
<tr><td colspan="3">Desktop Segregation Project - Cyber Security</td><td></td><td></td></tr>
<tr><td colspan="3">Infrastructure Enhancements</td><td></td><td></td></tr>
<tr><td></td><td colspan="2">IMM Data Needs</td><td></td><td></td></tr>
<tr><td colspan="5">Price Responsive Demand</td></tr>
<tr><td colspan="5">FCM Pay for Performance</td></tr>
<tr><td>2017 Issue Resolution Phase I</td><td colspan="2">2017 Issue Resolution Phase II</td><td></td><td></td></tr>
</table>

Capital Projects Completed from Q4 2016-Q1 2017

- The FCA-11 held on February 6, 2017, included the implementation of two recent projects:
    1) Zonal Demand Curves and
    2) Resource Retirement Reforms
- Real-Time Fast-Start Pricing
    - Implemented March 1, 2017
- Sub-Hourly Settlement
    - Implemented March 1, 2017
- Market Enhancements for Dispatchable Asset Related Demand (DARD) Pumps
    - Implemented March 1, 2017

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Eric Runge, NEPOOL Counsel

DATE: March 31, 2017

RE: Vote on NEPOOL Comments on Interconnection Reform Notice of Proposed Rulemaking in FERC Docket No. RM17-8-000

At the April 7, 2017 Participants Committee meeting you will be asked to vote to support the filing of NEPOOL Comments on the Notice of Proposed Rulemaking in Docket No. RM17-8-000, regarding Reform of Generator Interconnection Procedures and Agreements (the "Interconnection Reform NOPR").[1] Participants Committee approval of the NEPOOL Comments was recommended by the Transmission Committee, by a unanimous vote at the March 28 Transmission Committee meeting, with no abstentions. This item would have been on the Consent Agenda but for the timing of the votes.

By way of brief background, in the Interconnection Reform NOPR the Commission proposes reforms designed to improve certainty, promote more informed interconnection, and enhance interconnection processes. The reforms proposed are to the *pro forma* Large Generator Interconnection Procedures ("LGIP") and Large Generator Interconnection Agreement ("LGIA") only. The Interconnection Reform NOPR is the first major overhaul of the LGIP and LGIA since their establishment in 2003, and comes in response to developments since then affecting interconnections, including the changing resource mix, the emergence of new technologies, and state and federal policies that have impacted the resource mix. The proposed reforms fall into three main categories: (1) reforms to improve certainty by affording interconnection customers more predictability in the interconnection process; (2 reforms to improve transparency by providing improved information for the benefit of all participants in the interconnection process; and (3) reforms to enhance interconnection processes by making use of underutilized existing interconnections, providing interconnection service earlier, or accommodating changes in the development process. Comments on the proposed reforms are due by April 13.

The NEPOOL Comments have been developed to be consistent with NEPOOL's business priorities and with NEPOOL positions on existing features of our interconnection rules, including their interrelationship with the Forward Capacity Market. The Interconnection Reform

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[1] The Interconnection Reform NOPR can be accessed through the following link and will be posted for the Transmission Committee: https://www.ferc.gov/whats-new/comm-meet/2016/121516/E-1.pdf.

NOPR proposals were reviewed with the Transmission Committee and the NEPOOL Comments were developed over the course of three meeting with input from the Committee.

The following resolution could be used for Participants Committee consideration of this item:

> RESOLVED, that the Participants Committee approves the filing of the NEPOOL Comments in the Interconnection Reform NOPR proceeding, as recommended by the Transmission Committee at its March 28, 2017 meeting and as reflected in the materials distributed to the Participants Committee for its April 7, 2017 meeting, together with [any changes agreed to at the meeting and] such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Transmission Committee.

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Reform of Generator Interconnection Procedures and Agreements	**))**	**Docket No. RM17-8-000**

[DRAFT 3/28/17 as recommended by Transmission Committee]

COMMENTS OF THE
NEW ENGLAND POWER POOL PARTICIPANTS COMMITTEE

(April 10, 2017)

The New England Power Pool ("NEPOOL")[1] Participants Committee[2] submits these Comments in response to the Federal Energy Regulatory Commission's (the "Commission") Notice of Proposed Rulemaking in Docket No. RM17-8-000, regarding Reform of Generator Interconnection Procedures and Agreements (the "NOPR"). The NOPR proposes several reforms to the Large Generator Interconnection Procedures ("LGIP") and the Large Generator Interconnection Agreement ("LGIA"). Since implementing Order 2003[3] in New England, NEPOOL has worked repeatedly with ISO New England Inc. ("ISO-NE" or "the ISO") to improve the interconnection rules in the ISO-NE Open Access Transmission Tariff ("ISO-NE

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[1] Capitalized terms not defined herein have the meanings ascribed thereto in the Second Restated NEPOOL Agreement, Participants Agreement, or the ISO New England Inc. ("ISO-NE") Transmission, Markets and Services Tariff ("ISO-NE Tariff" or the "Tariff").

[2] NEPOOL is a voluntary association organized in 1971 pursuant to the New England Power Pool Agreement, and it has grown to include over 460 members. The Participants include all of the electric utilities rendering or receiving services under the ISO-NE Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, demand response providers, developers, end users and a merchant transmission provider. Pursuant to revised governance provisions accepted by the Commission in *ISO New England Inc. et al.*, 109 FERC ¶ 61,147 (2004), the Participants act through the NEPOOL Participants Committee. The NEPOOL Participants Committee is authorized by Section 6.1 of the Second Restated NEPOOL Agreement and Section 8.1.3(c) of the Participants Agreement to represent NEPOOL in proceedings before the Commission. NEPOOL is the principal stakeholder organization for the New England RTO.

[3] *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003) (Order No. 2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160 (Order No. 2003-A), *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004) (Order No. 2003-B), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005) (Order No. 2003-C), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 552 U.S. 1230 (2008).

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OATT"), so that those rules support competitive ISO-NE markets and facilitate entry of new resources into those markets, including the Forward Capacity Market ("FCM"). NEPOOL's comments on the NOPR proposals are consistent with those objectives.

I. CORRESPONDENCE AND COMMUNICATIONS

All correspondence and communications in this proceeding should be addressed to the following persons for NEPOOL:

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II. BACKGROUND OF INTERCONNECTION REFORMS IN NEW ENGLAND

Since incorporating the LGIP and LGIA in Schedule 22, and the Small Generator Interconnection Procedures ("SGIP") and Small Generator Interconnection Agreement ("SGIA") GIP/SGIA in Schedule 23 of the ISO-NE OATT, the ISO and NEPOOL have made several further voluntary enhancements to the interconnection rules in New England. In a 2008 joint filing, ISO-NE, NEPOOL, and the New England transmission owners revised Schedules 22 and 23 to better integrate the interconnection rules with the FCM.[4] Those FCM-related revisions included: (i) an additional new type of interconnection service, called Capacity Network Resource Interconnection Service ("CNRIS"), which assures intra-zonal deliverability of resources receiving that service; (ii) reforms to achieve greater certainty of commitment of

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[4] *See* Joint Filing of ISO-NE, NEPOOL and the Participating Transmission Owners in Docket No. ER04-432-006 (October 31, 2008). The Commission accepted the FCM revisions in *ISO New England Inc. and New England Power Poo*l, 126 FERC ¶ 61,080 (2009).

projects in the interconnection queue by increasing certain milestone and deposit requirements; and (iii) better alignment of the timing of the interconnection process with the FCM process.

In 2012, ISO-NE and the New England transmission owners, supported by NEPOOL, revised the interconnection rules to address certain concerns raised by Interconnection Customers and certain deficiencies, and to provide additional clarification.[5] These revisions included: (i) changes to the site control and study deposit requirements for certain existing generating facilities; (ii) clarifications regarding the factors that trigger the need for an interconnection re-study; and (iii) additions to the Interconnection Request technical requirements.

In 2015, the ISO-NE and the New England transmission owners, supported by NEPOOL, revised the interconnection rules to add a new Schedule 25 to the ISO-NE OATT, designed to provide clear interconnection rules and processes for Elective Transmission Upgrades ("ETUs").[6] These ETU revisions treated ETUs like large generators with interconnection standards and service applicable to ETUs. The ETU revisions also contained provisions to better integrate ETU interconnections with the FCM under specific circumstances of ETUs combined with generators or capacity contracts.

In 2016, ISO-NE and the New England transmission owners filed interconnection process improvements supported by NEPOOL that were designed primarily to make inverter-based generation more study-ready and to improve the overall efficiency and flexibility of the

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[5] *See* Revision Clean-Up to the Interconnection Procedures Under Schedules 22 and 23 of the ISO Open Access Transmission Tariff, Docket No. ER12-1847-000 (filed May 25, 2012). The filing was accepted by Letter Order issued June 21, 2012.

[6] *See ISO New England Inc.*, 151 FERC ¶ 61,024 (2015). ETUs are transmission facilities that are interconnected to the regional transmission system but are funded solely by participants in the ETU and not by all regional transmission customers.

interconnection process.[7] Those improvements were more about process, but the ISO, NEPOOL and other New England stakeholders anticipated a second phase of work that would potentially help with needed infrastructure and ISO-NE interconnection queue ("Queue") backlog.

In April, ISO-NE, NEPOOL and the New England transmission owners expect to file a proposal for the potential clustering of interconnection requests and cost allocation for clustered projects.[8] The proposal was developed through extensive discussions among the ISO and stakeholders and is supported by NEPOOL.[9] The clustering proposal is an attempt to respond to the Queue backlog in Northern and Western Maine. The tariff revisions provide for a clustering study and cost allocation of interconnection upgrades, and a process for identifying "Cluster-Enabling Transmission Upgrades" ("CETUs"), with the clustering process triggered by a Queue backlog under certain conditions. While the revisions are designed to be used whenever the trigger occurs, they also recognize the current Queue backlog in Maine and will address that as

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[7] *See* "Interconnection Process Improvements" Filing in Docket No. ER16-946-000. The Commission conditionally accepted the filing be letter order on April 15, 2016. *See ISO New England Inc.*, 155 FERC ¶ 61,031 (2016). Among the revisions contained in the Interconnection Process Improvements were the following: (1) reactive performance requirements for wind generators, intended to reduce dependency on interconnection studies to identify required reactive upgrades and improve their operation over a wider range of operating conditions; (2) new technical data requirements for wind and inverter-based generators, including detailed project design descriptions and standardizing model requirements, to increase these projects' readiness to initiate study analysis and reduce time to complete studies; (3) adding clarifications throughout the interconnection procedures, such as in relation to access to base case databases and the application of Material Modification; (4) incorporating an optional alternative scope of a Feasibility Study, focusing on the expected areas of concern for the proposed interconnection (e.g., performing targeted analysis of stability issues for a wind generator interconnecting in Maine); and, (5) adopting certain modeling and performance requirements consistent with recent NERC initiatives.

[8] The ISO-NE interconnection clustering proposal provides rules for clustering interconnection studies and cost allocation and the development of cluster-enabling transmission upgrades when two or more interconnection requests in the same electrical part of the system cannot proceed without major transmission upgrades.

[9] At its February 3, 2017 meeting, the Participants Committee voted 95% in favor to support the interconnection clustering revisions proposed by ISO-NE.

the first cluster for all eligible interconnection customers, based on eligibility criteria set forth in the tariff.

III. COMMENTS

General Comments

1. ISO-NE's interconnection process has been used successfully to interconnect several thousand megawatts of new generation in New England since Order 2003 was implemented, and especially since the interconnection process was integrated with the FCM. ISO-NE and NEPOOL have worked together repeatedly to improve the process, as described above. There is, however, a significant Queue backlog in Northern and Western Maine, with multi-year delays for Interconnection Customers to obtain needed interconnection studies. While there are some issues with the process, the delays are largely caused by the lack of transmission infrastructure in this relatively remote region, far from New England's load centers, and the serial Queue process that would assign the large costs of significant interconnection upgrades to the first in line.

2. Several of the Commission's proposals in the NOPR are consistent with NEPOOL priorities, which include supporting vibrant ISO-NE markets and facilitating new entry into those markets through interconnection and qualification for the FCM. A key NEPOOL priority since 2016 has been to address the time it takes for ISO-NE to evaluate, study and approve new interconnections. Another NEPOOL priority is to facilitate market entry by having the ISO provide more transparent and useful information regarding capacity and energy deliverability of potential new resources on the ISO-NE system. NEPOOL supports several of the NOPR proposals because they are consistent with these priorities, as discussed with reference to particular proposals below. Consistent with these priorities, NEPOOL supported the

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Interconnection Process Improvements of 2016 and the interconnection clustering proposal that is expected to be filed in the near future.

3. FERC's final rule should allow for significant regional flexibility, especially for regions such as New England that have demonstrated ongoing improvement of the interconnection process and rules, and that have integrated the rules with region-specific features, such as the FCM and ETU provisions. Especially where interconnections provisions intersect with the FCM qualification process, the Commission should allow maximum flexibility to deviate from *pro forma* rules to avoid unintended disruptions to market participants in the FCM. To the extent that the proposals would cause problems for the integrated interconnection and FCM process in New England, NEPOOL would not support their adoption inNew England.

4. In reviewing the NOPR, NEPOOL finds that several of the features of the proposals have already been implemented in some ways in New England, others could be improvements, and others are not needed or would not fit well for New England and could disrupt existing cost allocation or market participation provisions for interconnections in New England, as discussed below.

Comments on Specific Proposals in the NOPR to Improve Certainty

1. Periodic Restudy Process for Cluster Studies: This proposal would require Transmission Providers that conduct cluster studies to move toward a scheduled, periodic restudy process.[10] The Interconnection Clustering Revisions discussed above do not contain a mandatory periodic restudy provision, but instead a restudy of the cluster is triggered only by withdrawal of a cluster participant from the cluster. The Commission should allow for maximum flexibility for each region to decide whether they need or want a set restudy process

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[10] NOPR at P 46 *et seq.*

and, if such a process is desired, to determine the timing for it. The ISO-NE clustering proposal does not include such a process, partly based on the view that restudies are triggered largely off of interconnection customer withdrawals from the Queue, which are not done on any predetermined, periodic basis. The Transmission Provider should have flexibility to determine specifically when a restudy should be done, with the general direction that restudies should be done only when needed and when least disruptive to others in the interconnection queue and to the integrated markets. NEPOOL does not support a fixed restudy schedule that could cause problems in the ISO-NE integrated interconnection/FCM processes.

2. **Interconnection Customer Option to Build**: This proposal would provide a unilateral right for the Interconnection Customer to build Interconnecting Transmission Owner's interconnection facilities and stand-alone network upgrades if the parties are in agreement as to what facilities need to be built, including the design and construction details.[11] NEPOOL supports this proposal because it would provide a tariff mechanism that gives more flexibility to market participants to achieve interconnection of new resources, potentially in a more efficient way. However, NEPOOL believes that careful thought would need to be put into how this option would work in the case of a clustered interconnection study in which the cost of Interconnecting Transmission Owner interconnection facilities are being shared by multiple Interconnection Customers.

3. **Interconnecting Transmission Owner Self-Funding of Network Upgrades**: This proposal would require mutual agreement between the Interconnecting Transmission Owner and Interconnection Customer for the Interconnecting Transmission Owner to opt initially to self-

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[11] *Id*. at P 59 *et seq.* NEPOOL recognizes that different transmission owners will have different standards and requirements regarding deign and construction and that agreement on the details might be difficult in some instances.

fund the costs of the construction of network upgrades.[12] This proposal could provide greater flexibility for market participants to allow for self-funding of network upgrades by the Interconnecting Transmission Owner, while providing protection for the Interconnection Customer by requiring mutual agreement. For this reason NEPOOL supports this proposal.

4. Dispute Resolution by ISO/RTO: This proposal would have the RTO/ISO serve as decision-maker in interconnection disputes in RTO/ISO regions, and would eliminate the need for mutual agreement of parties to use the dispute resolution processes in the tariff.[13] NEPOOL views this proposal as problematic for regions with three-party interconnection agreements, such as New England. Since implementation of Order 2003, Interconnection Agreements in New England have been among the Interconnection Customer, the Interconnecting Transmission Owner, and the ISO, and disputes can occur between the ISO and either of the two other parties. In the New England RTO, the ISO serves in the role of Transmission Provider for many functions under the Tariff, while in some cases the transmission owners serve in that role. For purposes of administering the Queue, ISO-NE is the Transmission Provider, and therefore could be the subject of an interconnection-related dispute. Thus, having ISO staff members be decision-makers in a dispute resolution involving the ISO would not be appropriate. The final rule in this proceeding should take such situations into account. Additionally, from NEPOOL's perspective, use of ISO-NE staff for dispute resolutions could adversely affect the ISO's performance of its core duties and NEPOOL priorities in the ISO work plan, which would be undesirable. As to the elimination of the requirement for mutual agreement to trigger dispute resolution mechanisms, this proposal would likely help Interconnection Customers get disputes resolved and achieve interconnection and, therefore, NEPOOL supports it.

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[12] *Id*. at P 71 *et seq.*

[13] *Id*. at P 84 *et seq.*

5. Cap on Network Upgrade Costs: The Commission seeks comments on whether there should be a cap on network upgrade costs for which the Interconnection Customer is otherwise responsible.[14] New England resolved its disputes over cost allocation for interconnections and regional transmission upgrades well over a decade ago. The interconnection cost allocation method provided for under Schedule 11 of the ISO-NE OATT allocates all costs of interconnection that would not have been incurred *but for* the interconnection to the Interconnection Customer. Individual NEPOOL Participants have various and sometimes divergent views on how to address the network upgrade cost issue identified in the NOPR, but NEPOOL as an organization does not support a proposal that would require the re-opening of interconnection cost allocation disputes, or the imposition of a mandatory, generic rule governing cost-containment and cost allocation of interconnection-related network upgrade costs. NEPOOL suggests leaving this issue out of any final rule requirements, and letting regions adopt solutions regarding interconnection-related network upgrade costs that work best for them.

Comments on Specific Proposals in the NOPR to Improve Transparency/Information

1. Identification of Contingent Facilities: The proposal would 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.[15] The proposal would also require Transmission Providers to provide, "upon request of the interconnection customer, the estimated network upgrade costs and estimated in-service completion time associated with each identified contingent facility when this information is not commercially sensitive."[16] NEPOOL agrees that having a transparent method for identifying contingent facilities spelled out

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[14] *Id*. at P 95 *et seq.*

[15] *Id*. at P 103 *et seq.*

[16] *Id*. at P 104

in the tariff would provide helpful information to Interconnection Customers and facilitate market entry and, therefore, supports the NOPR proposal. For the same reason, NEPOOL also supports the proposed requirement to provide requested cost estimates related to contingent facilities.

2. Assumptions for Network Models: The proposal would 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.[17] As described above, in 2016 ISO-NE and NEPOOL undertook interconnection process improvements that included provisions regarding network models used for interconnection studies.[18] Additionally, ISO-NE and New England stakeholders have developed a "Transmission Planning Technical Guide" that describes in one document the current standards, criteria and assumptions used in various transmission planning studies in New England, including for System Impact Studies under the ISO-NE LGIP.[19] NEPOOL agrees that collecting and posting network model assumption information in one place, subject to appropriate security and confidentiality protections, would be helpful to market participants. NEPOOL, however, suggests that it would be better to include such assumptions in accessible documents on the Transmission Provider's website rather than putting them in the tariff, where changes to the assumptions could require amendments to the tariff and filings with the Commission.

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[17] *Id.* at P 118 *et seq.*

[18] Specifically, the Interconnection Process Improvements revised the Base Case provisions in the interconnection procedures to provide Interconnection Customer direct access to Base Case power flow, short circuit and stability databases that reflect all approved generation and transmission projects.

[19] The ISO-NE Transmission Planning Technical Guide can be accessed here: https://www.iso-ne.com/static-assets/documents/2017/01/planning_technical_guide_1_23_2017.pdf.

3. Congestion and Curtailment Information: This proposal would require that congestion and curtailment information be posted in one location on each Transmission Provider's OASIS site, and that such information be provided in a more granular way to help Interconnection Customers make appropriate interconnection decisions.[20] In New England, ISO-NE already provides certain congestion information to market participants on a regular basis through market performance reports posted on its website, and through monthly reports of the Chief Operating Officer, annual reports of the ISO-NE Market Monitor and through the Regional System Plan. NEPOOL agrees that centralizing the location of such information on the ISO's website (not on OASIS) in ISO regions would benefit market participants and facilitate market entry of new resources.

For the same reason, NEPOOL supports the proposal to require the posting of more granular information about both congestion and curtailments on the system. NEPOOL notes that a significant concern with the ISO-NE interconnection process today is that some projects in the Queue, especially in Northern New England cannot get an accurate projection of how often they would be curtailed in their energy dispatch.

Providing the opportunity for market participants to obtain more meaningful information concerning the energy deliverability of prospective new resources given the system topology is a NEPOOL priority. NEPOOL would support a final rule that would require the Transmission Provider (ISO-NE in New England for this responsibility) to make energy curtailment information and projections readily available for market participants, especially for those with projects in the interconnection queue.

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[20] NOPR at P 128 *et seq.*

4. Energy Storage Inclusion: This proposal would revise the definition of "Generating Facility" in the *pro forma* LGIP and LGIA to explicitly include electric storage resources.[21] Energy storage, in the form of pumped storage, is already an important part of the ISO-NE system, and other forms of energy storage are likely to become a significant part of the ISO-NE system as the technology develops.[22]

As NEPOOL stated in its comments in the energy storage rulemaking proceeding in Docket No. RM16-23-000, energy storage resources are able to participate in the New England wholesale markets in a variety of ways.[23] New England market rules currently offer a flexible framework under which energy storage assets can participate in the wholesale markets as a generator, load, or both, depending on the facility's physical and operational characteristics.[24] Participation models for energy storage resources supplying electricity to the wholesale markets include participation as a generator, a Settlement-Only Generator, a Demand Resource ("DR"), or an Alternative Technology Regulation Resource ("ATRR").[25] In each of the New England

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[21] *Id*. at P 136 *et seq.*

[22] In 2016 ISO-NE published a white paper designed to facilitate energy storage resources in the ISO-NE markets entitled "How Energy Storage Can Participate in New England's Wholesale Electricity Markets", which can be accessed here: https://www.iso-ne.com/static-assets/documents/2016/01/final_storage_letter_cover_paper.pdf.

[23] The ways in which energy storage resources currently are able to participate in the New England wholesale markets are described in detail in ISO-NE's response to the Commission's data request in Docket No. AD16-20. *See* Electric Storage Participation in Regions with Organized Wholesale Electric Markets, Docket No. AD16-20, Response to Electric Storage Data Request of ISO-NE (May 16, 2016).

[24] *See id*.

[25] The ATRR is a construct that was developed in 2008 in the New England wholesale markets to enable energy storage devices to participate in the Regulation Market in a manner that specifically acknowledges the physical and operational characteristics and capabilities of energy storage devices.

wholesale electric markets, an energy storage resource is able to be the resource that sets the clearing price, depending on how that resource participates in the markets.[26]

The NOPR proposal in this proceeding to include energy storage resources in the definition of generator would tend to facilitate new entry of energy storage resources into the ISO-NE markets and, therefore, NEPOOL supports this proposal.

5. Reporting Requirements for Interconnection Study Deadlines: This proposal would create a system of reporting requirements for aggregate interconnection study performance, and would require that Transmission Providers post summary statistics related to processing interconnection studies and meeting deadlines.[27] Such reporting requirements will provide greater Transmission Provider accountability, thereby tending to improve Transmission Provider performance and facilitating market entry by Interconnection Customers. For this reason, NEPOOL supports this proposal.

6. Affected Systems: The FERC also seeks comment on proposals or additional steps that FERC could take to improve resolution of issues that arise when affected systems are impacted by a proposed interconnection.[28] NEPOOL does not have a comment to improve affected system coordination, but will note that in the Northeast there is close coordination among the neighboring control areas of ISO-NE, NYISO and PJM, as well as between ISO-NE and its

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[26] In each market, the clearing price may be set by any of the following: in the Real-Time Energy Market, by a storage resource registered as dispatchable Generator Assets; in the Day-Ahead Energy Market, by storage resources of one MW and above offered into the market as a Generator Resource, Asset Related Demand or Dispatchable Asset Related Demand; in the FCM, by storage resources qualifying as a new Generator Resource or as a Demand Resource; in the Forward Reserve Market, by storage resources assigned to meet performance requirements; and in the Regulation Market, by storage resources or an aggregation of storage resources (one MW or greater) offering ATRR. As of March 1, 2017, DARDs will also be able to set the Real-Time Energy Market price, and as of June 1, 2018, DR will be able to set the energy price in the Day-Ahead and Real-Time Energy Markets.

[27] NOPR at P 148 *et seq.*

[28] *Id*. at P 158 *et seq.*

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neighboring control areas in Quebec and New Brunswick. The interregional planning process that has been in place for several years among those RTOs/ISOs takes into account interconnection of generation or ETUs with interregional impacts.

Comments on Reforms to Enhance Processes:

1. **Limit Interconnection Service Below Capacity Rating**: This proposal would allow Interconnection Customers to limit their requested level of interconnection service below their generating facility capacity.[29] Specifically, the proposal would add the following language to the LGIP in addition to a number of other supporting language additions:

> The Transmission Provider shall have a process in place to consider requests for Interconnection Service below the Generating Facility Capacity. These requests for Interconnection Service shall be studied at the level of Interconnection Service requested for purposes of Interconnection Facilities, Network Upgrades, and associated costs, but may be subject to other studies at the full Generating Facility Capacity to ensure safety and reliability of the system, with the study costs borne by the Interconnection Customer. Any Interconnection Facility and/or Network Upgrade costs required for safety and reliability also would be borne by the Interconnection Customer. Interconnection Customers may be subject to additional control technologies as well as testing and validation of those technologies consistent with Article 6 of the LGIA. The necessary control technologies and protection systems as well as any potential penalties for exceeding the level of Interconnection Service established in the executed, or requested to be filed unexecuted, LGIA shall be established in Appendix C of that executed, or requested to be filed unexecuted, LGIA.

The proposal is intended to allow generating facilities that do not intend to use the full generating facility capacity to avoid constructing network upgrades and interconnection facilities to meet a level of interconnection service that is not necessary, subject to proper control technology being in place and penalty provisions for exceeding limits.[30] NEPOOL supports this proposal because it provides options and flexibility for market participants and would tend to facilitate market entry of new resources.

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[29] *Id*. at P 167 *et seq.*

[30] *Id*.

NEPOOL notes that currently in the ISO-NE interconnection process, interconnection Customers can request an amount of interconnection service less than the nameplate capacity rating of the intended interconnected project. Interconnection Customers must do so *at the time of* the Interconnection Request or prior to the start of the System Impact Study. In the case of a generator made up of multiple generating units, such as a wind farm, ISO-NE would need to study a number of possible generating unit output combinations,[31] which could lead to increased study costs and timelines but would potentially allow for reduced upgrade requirements as intended by the Commission's proposal. ISO-NE will study such requests at the lower amount and the Interconnection Customer must explain how it will limit output of its facility. Again, this flexibility occurs at the commencement of the interconnection process with the Interconnection Request, as the NOPR seems to propose, or prior to the start of the System Impact Study.

While not a NEPOOL position on the NOPR, what some NEPOOL Participants see as desirable is the flexibility for the Interconnection Customer, *once studies have started or after studies are completed and upgrade costs are estimated*, to base necessary upgrades on either a smaller unit size that has been approved as non-material, or a unit size based on agreement to limit output below the originally requested service, all without losing its queue position. The concern some developers have is that studies can show unacceptable upgrade costs, which can be a barrier to entry if the interconnection customer does not have flexibility to reduce the requested capacity used for determining upgrades without losing its Queue position. In some cases, even a small reduction in the capacity amount of interconnection service can significantly reduce

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[31] ISO-NE has explained that in the case of a generator made up of multiple generating units, if it were limited to an interconnection service level below its generating facility capacity then it would be unknown which combination of generators would be at full output and which would be at partial or zero output at any given time. Given this uncertainty, ISO-NE would have to study multiple combinations of generating unit output levels.

interconnection upgrade costs and make projects viable. The final rule should be clear about when Interconnection Customers have flexibility to reduce their requested level of interconnection service, as well as provide guidance on the appropriateness of affording any flexibility to reduce capacity for purposes of determining upgrades *after* interconnection studies have started or are complete.

2. Provisional Agreements: This proposal would 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 study process.[32] Section 5.9 of the *pro forma* LGIA and of the LGIA in Schedule 22 of the ISO-NE OATT already allow for limited operation prior to completion of interconnection facilities and upgrades. ISO-NE's LGIA Section 5.9 states:

> Limited Operation. If any of the Interconnecting Transmission Owner's Interconnection Facilities or Network Upgrades are not reasonably expected to be completed prior to the Commercial Operation Date of the Large Generating Facility, System Operator and the Interconnecting Transmission Owner shall, upon the request and at the expense of Interconnection Customer, perform operating studies on a timely basis to determine the extent to which the Large Generating Facility and the Interconnection Customer's Interconnection Facilities may operate prior to the completion of the Interconnecting Transmission Owner's Interconnection Facilities or Network Upgrades consistent with Applicable Laws and Regulations, Applicable Reliability Standards, Good Utility Practice, and this LGIA. System Operator and Interconnecting Transmission Owner shall permit Interconnection Customer to operate the Large Generating Facility and the Interconnection Customer's Interconnection Facilities in accordance with the results of such studies.

Interconnection customers in ISO-NE already take advantage of this provision, and NEPOOL is not aware of any issues in New England regarding its implementation. The Commission proposes to extend this further, to allow limited operation prior to completion of all interconnection studies. NEPOOL does not have a position on this proposal, but would not support such a change if it raised concerns related to system reliability, introduced delays in the

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[32] *Id*. at P 185 *et seq.*

interconnection study process for other Interconnection Customers, or interacted detrimentally with the ISO-NE integrated interconnection/FCM processes.

3. Surplus Interconnection Service: This proposal would require Transmission Providers to create a process for Interconnection Customers to utilize surplus interconnection service at existing interconnection points.[33] NEPOOL does not have a position on this proposal for New England, but would caution that it might not be compatible with ISO-NE's FCM. There are many complicated market rules associated with the FCM, including rules regarding how the FCM relates to interconnection service, and the NOPR proposal might disrupt those rules and their purpose. The NOPR proposal would allow for unused interconnection service to be used for a different resource. The ISO-NE market rules, however, require retirement and delist of existing capacity resources if one wants to reduce or no longer use Capacity Network Resource Interconnection Service. Those retirements and delists of existing capacity resources with Capacity Supply Obligations in the FCM are made known to market participants and then factor into the Forward Capacity Auctions. The NOPR proposal could disrupt this interaction between the FCM and interconnection service and market participation in the FCM. To the extent that this proposal is adopted in a final rule, the Commission should allow for maximum flexibility for regions, such as New England, to deviate from it to accommodate their market constructs.

4. Technology Changes: This proposal would 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.[34] The proposal would require the Transmission Provider to establish a technological change procedure in the tariff to assess and, if necessary, study whether it can accommodate a technological change request without the change considered

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[33] *Id*. at P 199 *et seq.*

[34] *Id*. at P 216 *et seq.*

to be a material modification.[35] NEPOOL supports this proposal, because it would facilitate market entry and provide flexibility for market participants. ISO-NE's Interconnection Process Improvements in 2016 included improvements that addressed technology changes and material modifications, including revisions to the Material Modification and the System Impact Study provisions to allow for Interconnection Customers to true up the project's technical data prior to the commencement of the System Impact Study.

5. Modeling Electric Storage: This proposal would 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.[36] NEPOOL supports this proposal because it would tend to improve modeling of electric storage and thereby facilitate entry of electric storage resources into the ISO-NE markets.

IV. CONCLUSION

NEPOOL requests that the Commission take these Comments into consideration in its development of a final rule in this proceeding.

Respectfully submitted,

NEPOOL Participants Committee

By: /s/ ________________________
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Dated: April 10, 2017

Its Attorneys

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[35] *Id.*

[36] *Id.* at P 229 *et seq.*

memo

To: NEPOOL Participants Committee

From: Jay Dwyer, Secretary, NEPOOL Transmission Committee

Date: March 28, 2017

Subject: Actions of the Transmission Committee

This memo is notification to the Participants Committee of the following actions taken by the Transmission Committee at its March 28, 2017 meeting held as a teleconference.

Agenda Item No. 1(A):

February 21, 2017 Meeting Minutes

ACTION: APPROVED

Based on a voice vote indicating no oppositions and no abstentions, the Transmission Committee unanimously approved the minutes of the February 21, 2017 Transmission Committee meeting.

Agenda Item No. 2:

REVISION TO SECTION II.44 OF THE TARIFF

ACTION: APPROVED

The following motion was moved and seconded by the Transmission Committee:

Resolved, that the Transmission Committee recommends Participants Committee support for ISO New England Inc. proposed revisions to Section II.44 of the ISO New England Transmission, Markets and Services Tariff , as reflected in the materials distributed to the Transmission Committee for its March 28, 2017 meeting with any changes adopted by ISO New England Inc. at the meeting, and any non-substantive changes approved by the Chair and Vice-Chair of the Transmission Committee after the meeting.

The motion was then voted. Based on a voice vote indicating no oppositions and no abstentions, the motion passed unanimously.

Agenda Item No. 3:

NEPOOL COMMENTS ON FERC NOPR ON REFORM OF INTERCONNECTION PROCEDURES AND AGREEMENTS IN DOCKET NO. RM17-8-000

ACTION: APPROVED

The following motion was moved and seconded by the Transmission Committee

Resolved, that the Transmission Committee recommends Participants Committee approval for filing with the FERC of the proposed NEPOOL Comments, as reflected in the materials distributed to the Transmission Committee for its March 28, 2017 meeting with any changes adopted at the meeting and any non-substantive changes approved by the Chair and Vice Chair of the Transmission Committee after the meeting

The motion was then voted. Based on a voice vote indicating no oppositions and no abstentions, the motion passed unanimously.

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Eric Runge, NEPOOL Counsel

DATE: March 31, 2017

RE: Vote on Conforming Revision to Section 44 of ISO-NE Open Access Transmission Tariff

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At the April 7, 2017 Participants Committee meeting you will be asked to vote to support a minor revision to the Section II.44 of the ISO New England Transmission, Markets and Services Tariff (ISO-NE Tariff). The ISO has proposed this revision to conform this section on External Transactions to changes that have been made to the Market Rules regarding the Day-Ahead Energy Market Scheduling deadline. The Transmission Committee voted unanimously at its March 28, 2017 meeting to recommend Participants Committee support for this revision. This item would have been on the Consent Agenda but for the timing of the votes.

The following resolution could be used for Participants Committee consideration of this item:

> RESOLVED, that the Participants Committee supports the revision to Section II.44 of the ISO-NE Tariff, as recommended by the Transmission Committee at its March 28, 2017 meeting and as reflected in the materials distributed to the Participants Committee for its April 7, 2017 meeting, together with [any changes agreed to at the meeting and] such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Transmission Committee.

II.44 Scheduling and Curtailment Rules

For purposes of scheduling and Curtailment of Real-Time External Transactions over interconnections between the New England Control Area and neighboring Control Areas, the following rules shall apply:
(1) For External Interfaces that are not subject to Coordinated Transaction Scheduling

(a) Real-Time External Transaction sales and purchases that (i) are supported by those service agreements referenced in Attachment G-3 to this OATT that have not opted for Auction Revenue Rights consideration under applicable ISO System Rules or (ii) are supported by those service agreements referenced in Attachment H to this OATT, and (iii) have been submitted into the Real-Time Energy Market prior to the Day-Ahead Energy Market Scheduling deadline established in Section III.1.10.1A of the Tariff ~~noon the day before the Operating Day~~ as a Self-Scheduled Real-Time External Transaction ("real-time without price") at an External Node referenced in Attachment G-3 or Attachment H to this OATT shall be assigned the highest transmission priority when compared to other Real-Time External Transaction purchases or sales at that node having the same offer price or bid price. In the event that the transfer limit for a given external interface does not allow all Excepted Transactions or MEPCO Grandfathered Transactions submitted over that interface to flow, they shall be scheduled or curtailed on a pro-rata basis. For Real-Time External Transactions referenced in Attachment G-3 or Attachment H to this OATT that also require an advance physical reservation associated with a MTF or OTF external interface, the MTF or OTF transmission priority shall take precedence over the above language for the purposes of scheduling and curtailment under Sections II.44(1)(c) and II.44(1)(d) of this OATT, respectively. For Excepted Transactions or MEPCO Grandfathered Transactions that are tied within economic merit, and tied within transmission priority, such transactions cleared in the Day-Ahead Energy Market that have a corresponding Real-Time Energy Market External Transaction will have scheduling and curtailment priority in the Real-Time Energy Market before Excepted Transactions or MEPCO Grandfathered Transactions not cleared in the Day-Ahead Energy Market;

(b) For external interfaces where advance physical reservations are not required, in the event …

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Dave Doot and Pat Gerity, NEPOOL Counsel

DATE: March 31, 2017

RE: Clean-up Amendments to the NEPOOL and Participants Agreements; Amendments to Implement a Small Standard Offer Provider Proposal

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At the April 7, 2017 meeting, you will be asked to consider approving for balloting two sets of amendments. The first set of amendments are clean-up changes to both the Second Restated NEPOOL Agreement ("2d RNA") and the Participants Agreement ("PA"), primarily to conform the PA to the 2d RNA's *currently effective* Provisional Member arrangements (the "Clean-Up Changes"). The second set of amendments, to the 2d RNA only, would allow any entity that qualifies as "Small Standard Offer Service Provider" the option of participating in the Pool if it wishes as either a member of the Supplier Sector, as some do now, or alternatively as a member in the Provisional Member Group Seat until its business grows to the point it no longer qualifies as "Small" (the "Small Standard Offer Provider Proposal"). This memorandum provides additional information describing the Clean-Up Changes and the Small Standard Offer Provider Proposal, and includes the two sets of amendments to implement those Changes.

A. Clean-Up Changes

Separate from the Small Standard Offer Provider Proposal, there are certain changes, now reflected in the Clean-Up Changes, which were brought to light during discussions on the Small Standard Offer Provider Proposal, that are needed to conform the PA to the current Provisional Member arrangements. Absent the Clean-Up Changes to the PA, the calculation of votes taken at the Principal Committees under the two Agreements is not exactly the same (with the vote of members of the Provisional Member Group Seat not recognized in the PA). The only revisions to the PA in the Clean-up Changes are to ensure that the votes under the PA will account for the vote of members in the Provisional Member Group Seat and, thus, will always be identical to votes under the 2d RNA.[1] In addition, the Clean-up Changes include a change to the 2d RNA to make the application fee applicable to Data-Only Participants identical to their current annual fee amount.

The following form of resolution could be used to direct the balloting of the Clean-Up Changes:

> RESOLVED that the Participants Committee authorizes and directs the Balloting Agent (as defined in the Second Restated NEPOOL Agreement) to circulate ballots for the approval of agreements amending the Second Restated New England Power Pool Agreement and Participants Agreement, to reflect the ***Clean-Up Changes*** presented at this meeting, together with [such changes as were discussed and agreed to by the Committee and] such non-substantive changes as may be agreed to after the meeting by the Chairs of the Participants Committee and Membership Subcommittee, to each Participant for execution by

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[1] Please note that the votes of members in the Provisional Members Group Seat are only counted when cast affirmatively or negatively and can never exceed a 0.2% vote individually or 1.0% in aggregate.

its voting member or alternate on this Committee or such Participant's duly authorized officer.

The motion to ballot the Clean-Up Changes must be approved by a 66 2/3% Vote. If approved, the ballots would be circulated for signature. To be approved in balloting, changes to the 2d RNA must be approved by a 66 2/3% Vote from enough members to satisfy the Minimum Response Requirement; PA Changes, by 70%.

B. Small Standard Offer Provider Proposal

The Small Standard Offer Provider Proposal is offered as a compromise to a prior proposal. Rather than create a Supplier Sector group seat arrangement for Small Standard Offer Service Providers, the Proposal would allow such Providers to be members of the Provisional Member Group Seat for voting purposes. There has been no consensus on either the earlier proposal or the current Small Standard Offer Provider Proposal (although the latter proposal appears to have more support than the earlier proposal). Having discussed this now in NEPOOL meetings for four months, the proponent (Jeff Jones of Maine Power LLC[2]) has asked for action by the Participants Committee.

The Small Standard Offer Provider Proposal can be summarized as follows: Those Entities that meet the definition of Small Standard Offer Service Provider[3] (and who are not a Related Person to one or more Participants) would be able to participate for governance purposes as voting members of the Provisional Member Group Seat and would be subject to a $5,000 annual fee, which would satisfy their financial responsibilities for Participant Expenses. The relevant application fee for new applicants would similarly be set at $5,000. Small Standard Offer Service Providers would vote in a group seat with the Provisional Members. By way of comparison, under current arrangement, most members of the Supplier Sector pay roughly $15,000 in annual fees and Participant Expenses (versus the proposed $5,000 for Small Standard Offer Service Providers).

The Small Standard Offer Provider Proposal was discussed and refined by those participating in a special Membership Subcommittee meeting on February 22. The Subcommittee, however, did not reach a consensus on the Proposal. Those supporting the Proposal view it as consistent with NEPOOL's history of implementing appropriate arrangements to facilitate and make as inclusive as practical participation in the New England Markets and stakeholder processes. They believe that the Small Standard Offer Provider Proposal minimizes the impact on all existing members of allowing new, small members to join NEPOOL. Most significantly, they view the Provisional Member treatment as addressing in compromise objections raised over the impact of prior proposals on existing members.

Those who indicated at the Subcommittee meeting that they did not support the Proposal identified a number of continuing objections, including the following: (i) concerns that application of the

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[2] Maine Power LLC became a NEPOOL member on December 1, 2016. Maine Power was selected by the Maine Public Utilities Commission to serve large non-residential class standard offer load in Maine's Emera Maine - Bangor Hydro District. During consideration of this and he prior proposal, Maine Power has been a member of the Supplier Sector.

[3] "Small Standard Offer Service Provider" is defined as follows: a Participant that (a) has been selected by a New England state's public utilities commission to provide "standard offer" electric generation service to all or a specified portion of consumers in that state receiving standard offer service; (b) serves no load except such standard offer load; (c) has, together with each of its Related Persons, an average hourly aggregate RTLO (averaged over all hours in which that Participant had an RTLO during the prior twelve (12) calendar months) that is ten (10) MWh or less; and (d) has submitted a request to be treated as a Small Standard Offer Service Provider.

proposed treatment would not necessarily be limited to Entities defined in the Proposal and could be requested by others in similar but not exactly the same circumstances ("slippery slope" concerns); (ii) a preference to maintain consistent requirements/obligations for all competitive suppliers and competitive concerns if such consistency is lost ("level playing field"); (iii) concerns with potential impacts on Participant Expenses allocation if the resulting participation is not limited; (iv) a discomfort with establishing arrangements applicable to too-narrow a class of Entity; and (v) reacting specifically to the proposed Provisional Member treatment, the fact that some current members of NEPOOL that would meet the definition of Small Standard Offer Service Providers can and do participate currently in the Supplier Sector.

The following form of resolution could be used to direct the balloting of the Small Standard Offer Provider Proposal:

> RESOLVED that the Participants Committee authorizes and directs the Balloting Agent (as defined in the Second Restated NEPOOL Agreement) to circulate ballots for the approval of agreements amending the New England Power Pool Agreement, to effect the ***Small Standard Offer Provider Proposal***, as presented at this meeting, together with [such changes as were discussed and agreed to by the Committee and] such non-substantive changes as may be agreed to after the meeting by the Chairs of the Participants Committee and Membership Subcommittee, to each Participant for execution by its voting member or alternate on this Committee or such Participant's duly authorized officer.

The motion to ballot the Small Standard Offer Provider Proposal must be approved by a 66 2/3% Vote. If approved, the ballots would be circulated for execution. To be approved in balloting, we must receive enough executed ballots to satisfy the Minimum Response Requirement and enough members must vote in favor to achieve a 66 2/3% Vote. Any changes to the PA or 2d RNA that are approved in balloting must be filed with the FERC. We will request that the approved Amendments become effective as of May 1, 2017. If the Small Standard Offer Provider Proposal is accepted, we expect that Maine Power LLC would thereafter join the Provisional Member Group Seat.

If there are any questions in advance of the meeting concerning the Amendments, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

ONE HUNDRED THIRTIETH AGREEMENT AMENDING NEW ENGLAND POWER POOL AGREEMENT
(Provisional Member / Data-Only Participant Clean-Up Changes)

THIS ONE HUNDRED THIRTIETH AGREEMENT AMENDING NEW ENGLAND POWER POOL AGREEMENT, dated as of April 7, 2017 (“130th Agreement”), amends the New England Power Pool Agreement (the “NEPOOL Agreement”).

WHEREAS, effective February 1, 2005 the NEPOOL Agreement was amended by the One Hundred Seventh Agreement Amending New England Power Pool Agreement and restated as the Second Restated NEPOOL Agreement, and has subsequently been amended numerous times; and

WHEREAS, the Participants desire to amend further the Second Restated NEPOOL Agreement to reflect the revision detailed herein.

NOW, THEREFORE, upon approval of this 130th Agreement by the NEPOOL Participants Committee in accordance with the procedures set forth in the Second Restated NEPOOL Agreement, the Participants agree as follows:

SECTION 1
AMENDMENTS

1.1 Addition of Definition. The following definition is added to Section 1 of the Second Restated NEPOOL Agreement and inserted in the appropriate alphabetical order:

> Provisional Member Fixed Voting Share for each member of the Provisional Member Group Seat is the quotient obtained by dividing (i) the Provisional Member Group Seat Voting Share by (ii) the total number of voting members in the Provisional Member Group Seat, whether or not the member is in attendance.

1.2 Amendment to Section 1.50. Section 1.50 (Member Adjusted Voting Share) is amended so that it reads as follows:

> (a) for a voting member of each active Sector (other than the AR Sector) which casts an affirmative or negative vote on a proposed action or amendment and which has been appointed by a Participant or group of Participants which are members of a Sector satisfying its Sector Quorum requirement for the proposed action or amendment, is the quotient obtained by dividing (i) the Sector Voting Share of that Sector for the Participants Committee or the Adjusted Sector Voting Share of that Sector for the Technical Committees, in each case minus the aggregate ~~Provisional~~ Member Adjusted ~~Group Seat~~ Voting Shares of the members of the Provisional Member Group Seat which cast affirmative or negative votes on the matter, by (ii) the number of voting members appointed by members of that Sector which cast affirmative or negative votes on the matter, adjusted, if necessary, for End User Participants and group voting members as provided in the definition of “Member Fixed Voting Share”; and

(b) for a voting member of an AR Sub-Sector which casts an affirmative or negative vote on a proposed action or amendment and which has been appointed by a Participant or group of Participants which are members of an AR Sub-Sector satisfying its AR Sub-Sector Quorum Requirement for a proposed action or amendment, is the quotient obtained by dividing (i) the Adjusted AR Sub-Sector Voting Share of that Sub-Sector which cast affirmative or negative votes on the matter by (ii) the number of voting members appointed by members of that Sub-Sector which cast affirmative or negative votes on the matter; and

(c) for a member of the Provisional Member Group Seat which casts an affirmative or negative vote on a proposed action or amendment, is the member's Provisional Member Fixed Voting Share.

1.3 Deletion of 1.51(a). Section 1.51(a) (the substance of which was moved to the Definition Section pursuant to Section 1.1 of this Agreement) and is deleted and sub-sections (b) and (c) re-numbered to reflect that deletion.

~~(a) for a member of the Provisional Member Group Seat, whether or not the member is in attendance, is the quotient obtained by dividing (i) the Provisional Member Group Seat Voting Share by (ii) the total number of Provisional Members in the Provisional Member Group Seat; and~~

1.4 Amendment to Section 1.55. Sub-section (a) of Section 1.50 (NEPOOL Vote) is amended so that it reads as follows:

(a) with respect to an amendment or proposed action of the Participants Committee is the sum of (i) the Member Adjusted Voting Shares of the voting members of the Committee which cast an affirmative vote on the proposed action or amendment and which have been appointed by a Participant or group of Participants which are members of a Sector satisfying its Sector Quorum requirements, (ii) the Member Fixed Voting Shares of the voting members of the Committee which cast an affirmative vote on the proposed action or amendment and which have been appointed by a Participant or group of Participants which are members of a Sector which fails to satisfy its Sector Quorum requirements~~ or which are Provisional Members in~~, and (iii) the Member Adjusted Voting Shares of the members of the Provisional Member Group Seat which cast an affirmative vote on the proposed action or amendment; and

1.5 Data-Only Participant Applicant Clean-up Amendment to Section 3.1(c). Section 3.1(c) (Membership) is amended to read as follows:

(c) The application fee to be paid by each Entity seeking to become a Participant (i) shall be in addition to the annual fee provided by Section 14.1 and (ii) shall be (1) $500 for an applicant which qualifies for membership only as an End User Participant~~ or a Data-Only Participant~~, (2) $1,000 for an applicant which together with its Related Persons owns or controls less than 5 MW (or its equivalent) of Alternative

Resources and qualifies for membership as an AR Provider ~~or~~ ; (3) $1,500 for an applicant which qualifies for membership as a Data-Only Participant or as a Provisional Member, and (4) $5,000 for all other applicants, or such other amount as may be fixed by the Participants Committee.

SECTION 2
MISCELLANEOUS

2.1 This 130th Agreement shall become effective May 1, 2017, or on such other date as the Commission shall provide that the amendment reflected herein shall become effective.

2.2 Capitalized terms used in this 130th Agreement that are not defined herein shall have the meanings ascribed to them in the Second Restated NEPOOL Agreement.

AMENDMENT NO. 10 TO
PARTICIPANTS AGREEMENT
(Provisional Member Clean-Up Changes)

THIS AMENDMENT NO. 10 TO PARTICIPANTS AGREEMENT ("Amendment No. 10") is made and entered into as of the 7th day of April, 2017 by and between ISO New England Inc. (the "ISO") and the New England Power Pool, an unincorporated association created pursuant to the New England Power Agreement dated as of September 1, 1971, as amended and restated, acting herein by and through the NEPOOL Participants Committee ("NEPOOL").

WHEREAS, the Participants Agreement by and among the ISO and NEPOOL became effective as of February 1, 2005 and has subsequently been amended nine times.

WHEREAS, the ISO and NEPOOL desire to amend the Participants Agreement to reflect the revisions detailed herein.

NOW, THEREFORE, upon approval of this Amendment No. 10 by the ISO and by the NEPOOL Participants Committee in accordance with the procedures set forth in the Participants Agreement, the ISO and NEPOOL agree as follows:

1. Amendments to Section 1.1 (Defined Terms).

1.1 Addition of Definitions. The following definitions are added to Section 1.1 of the Participants Agreement:

"Provisional Member Fixed Voting Share" shall have the meaning given it in the RNA.

"Provisional Member Group Seat" shall have the meaning given it in the RNA.

1.2 Amendment to Definition of "Member Adjusted Voting Share". The definition of Member Adjusted Voting Share is amended so that it reads as follows:

(a) for a voting member of each active Sector (other than the AR Sector) which casts an affirmative or negative vote on a proposed action or amendment and which has been appointed by a Participant or group of Participants which are members of a Sector satisfying its Sector Quorum requirement for the proposed action or amendment, is the quotient obtained by dividing (i) the Sector Voting Share of that Sector for the Participants Committee or the Adjusted Sector Voting Share of that Sector for the Technical Committees, in each case minus the aggregate Member Adjusted Voting Shares of the members of the Provisional Member Group Seat which cast affirmative or negative votes on the matter, by (ii) the number of voting members appointed by members of that Sector which cast affirmative or negative votes on the matter, adjusted, if necessary, for End User Participants and group voting members as provided in the definition of "Member Fixed Voting Share"; ~~and~~

(b) for a voting member of an AR Sub-Sector which casts an affirmative or negative vote on a proposed action or amendment and which has been appointed by a

Participant or group of Participants which are members of an AR Sub-Sector satisfying its AR Sub-Sector Quorum Requirement for a proposed action or amendment, is the quotient obtained by dividing (i) the Adjusted AR Sub-Sector Voting Share of that Sub-Sector by (ii) the number of voting members appointed by members of that Sub-Sector which cast affirmative or negative votes on the matter; and

(c) for a member of the Provisional Member Group Seat which casts an affirmative or negative vote on a proposed action or amendment, is the member's Provisional Member Fixed Voting Share.

1.3 Amendment to Definition of "Participant Vote". Sub-section (a) of the definition of Participant Vote is amended so that it reads as follows:

(a) with respect to an amendment or proposed action of the Participants Committee, the sum of (i) the Member Adjusted Voting Shares of the voting members of the Committee which cast an affirmative vote on the proposed action or amendment and which have been appointed by a NEPOOL Participant or group of NEPOOL Participants which are members of a Sector satisfying its Sector Quorum requirements and, in the case of amendments, including-Member Adjusted Voting Shares of Individual Participants; and (ii) the Member Fixed Voting Shares of the voting members of the Committee which cast an affirmative vote on the proposed action or amendment and which have been appointed by a NEPOOL Participant or group of NEPOOL Participants which are members of a Sector which fails to satisfy its Sector Quorum requirements plus, in the case of amendments, the Member Fixed Voting Shares of Individual Participants, and (iii) the Member Adjusted Voting Shares of the members of the Provisional Member Group Seat which cast an affirmative vote on the proposed action or amendment; and

2. Effective Date. This Amendment No. 10 shall become effective on May 1, 2017 or on such other date as the Commission shall provide that the amendments reflected herein shall become effective.

3. Counterparts. Counterparts of this Amendment No. 10 may be signed by the parties, each of which shall be an original but both of which together shall constitute one and the same instrument.

4. Governing Law. This Amendment No. 10 shall be governed by and enforced in accordance with the laws of the State of Delaware.

5. Miscellaneous. Terms used in this Amendment No. 10 that are not defined herein shall have the meanings ascribed to them in the Participants Agreement, the Second Restated NEPOOL Agreement, or the ISO's Transmission, Markets and Services Tariff.

[The next page is the signature page.]

IN WITNESS WHEREOF, the ISO and NEPOOL have caused this Amendment No. 10 to be executed by their duly authorized representatives as of the date first written above.

ISO NEW ENGLAND INC.	NEW ENGLAND POWER POOL acting through the NEPOOL Participants Committee
By:_____________________________	By:_______________________________
Name: Gordon van Welie	Name: Thomas W. Kaslow
Title: President and Chief Executive Officer	Title: Chair, NEPOOL Participants Committee

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ONE HUNDRED THIRTY-FIRST AGREEMENT AMENDING NEW ENGLAND POWER POOL AGREEMENT
(Small Standard Offer Provider Proposal)

THIS ONE HUNDRED THIRTY-FIRST AGREEMENT AMENDING NEW ENGLAND POWER POOL AGREEMENT, dated as of April 7, 2017 (“130th Agreement”), amends the New England Power Pool Agreement (the “NEPOOL Agreement”).

WHEREAS, effective February 1, 2005 the NEPOOL Agreement was amended by the One Hundred Seventh Agreement Amending New England Power Pool Agreement and restated as the Second Restated NEPOOL Agreement, and has subsequently been amended numerous times; and

WHEREAS, the Participants desire to amend further the Second Restated NEPOOL Agreement to reflect the revision detailed herein.

NOW, THEREFORE, upon approval of this 131st Agreement by the NEPOOL Participants Committee in accordance with the procedures set forth in the Second Restated NEPOOL Agreement, the Participants agree as follows:

SECTION 1
AMENDMENTS

1.1 Addition of Definition. The following definition is added to Section 1 of the Second Restated NEPOOL Agreement and inserted in the appropriate alphabetical order:

> Small Standard Offer Service Provider is a Participant that (a) has been selected by a New England state’s public utilities commission to provide “standard offer” electric generation service to all or a specified portion of consumers in that state receiving standard offer service; (b) serves no load except such standard offer load; (c) has, together with each of its Related Persons, an average hourly aggregate RTLO (averaged over all hours in which that Participant had an RTLO during the prior twelve (12) calendar months) that is ten (10) MWh or less; and (d) has submitted a request to be treated as a Small Standard Offer Service Provider.

1.2 Amendment to Section 1.68B. Section 1.68B (Provisional Member Group Seat) is amended to read as follows:

> Provisional Member Group Seat is the group comprised of (i) all Provisional Members that are not Related Persons to Participants that are eligible to designate a voting member of a Sector (other than the End User Sector), (ii) all Small Standard Offer Service Providers that are not Related Persons to Participants that are eligible to designate a voting member of a Sector (other than the End User Sector), and (iii) solely for purposes of voting on matters related to the administration of the GIS, all GIS-Only Participants.

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1.3 Amendment to Section 6.2(g). Sub-section (g) of Section 6.2 (Sector Representation) is amended to read as follows:

(g) a Provisional Member that does not have a Related Person that is a member of a Sector and a Small Standard Offer Service Provider shall be in the Provisional Member Group Seat.

SECTION 2
MISCELLANEOUS

2.1 This 131st Agreement shall become effective May 1, 2017, or on such other date as the Commission shall provide that the amendment reflected herein shall become effective.

2.2 Capitalized terms used in this 131st Agreement that are not defined herein shall have the meanings ascribed to them in the Second Restated NEPOOL Agreement.

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates
FROM: Jeff Jones
DATE: April 3, 2017
RE: Maine Power Compromise Membership Proposal

We are asking for your support for this compromise proposal at the April NEPOOL Participants Committee meeting. In summary:

- A small supplier's share of NEPOOL's Expenses are unreasonably high, creating an "unlevel playing field".
- NEPOOL is out of step with costs of participation in wholesale electricity markets.
- Except for the Supplier Sector, there is reduced membership cost (generally along with reduced voting share arrangements) in the other NEPOOL sectors.
- The Membership Committee has had multiple meetings to formulate this compromise proposal.
- This proposal is not unreasonable and if accepted by NEPOOL, it should be accepted by the FERC without major fanfare.

In support of our position:

1. A small supplier's share of NEPOOL's Expenses are unreasonably high, creating an "unlevel playing field". Certain customers must pay over one-half of a cent per kilowatt-hour[1] just for these stakeholder expenses. This is in addition to the other costs of running the ISO-NE RTO. This puts small suppliers at a competitive disadvantage and unfairly creates an unlevel playing field and a significant barrier to entry. The simple math is that a fixed cost over small amount of kWh results in high prices.

2. NEPOOL is out of step with costs of participation in wholesale electricity markets. Although some other RTOs have similar annual voting membership fees, they have no additional expense assessments. Further, some other RTOs do not have any charges for this type of participation.

RTO Annual Fees for Market Participation:

- ISO-NE - $17,000 (approx.) = $5,000 + approximately $1,000/month x 12 months
- PJM - $5,000 (prorated for partial year)
- ERCOT - $2,000 ($500 for Associate Membership/Market Participant without votes)
- NYISO - $0 for being a customer ($5,000 annual fee for committee membership)
- CAISO - $0
- SWPP- $0 for Non-Member Market Participants (do not vote)
- MISO - $0 for Non-Member Market Participants (do not vote)

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[1] 0.6 cents/kWh = $5.7/MWh = $17k / 3,000 MWh

3. Except for the Supplier Sector, there is reduced membership cost (generally along with reduced voting share arrangements) in the other NEPOOL sectors. In the past, every other sector has grappled with this issue. Initially it has often been felt that any reduced level of membership is a "slippery slope", but in the end accommodations have been achieved. It is time for the Supplier Sector to follow suit.

NEPOOL Sectors:

Public Entity - The old NEPOOL Expense allocation is employed to allocate sector expenses. This formula reduces costs for small public entities but grants each Public Entity equal voting share.

Transmission - This sector has a group seat (reduced expense for smaller voting share) and, for prospective TOs, an ability to join and participate in NEPOOL through the Provisional Group Seat.

Generator - One group seat arrangement is available to generators that seek lower cost to participate in return for reduced voting share. For prospective generators, an ability to join and participate in NEPOOL through the Provisional Group Seat exists.

End User - A minimal, flat fee for governance-only participation exists with a volumetric increase in NEPOOL Expense for MPEUs, subject to a cap of the lowest Expenses paid by a member of the Supplier Sector.

Alternative Resources - Four group seats with reduced NEPOOL dues and expenses are available. For prospective A/R Participants, the ability exists to join and participate in NEPOOL through the Provisional Group Seat.

Provisional Group Seat – While not a "traditional" sector, the Provisional Sector has accommodated those Participants that do not fit easily into a sector. For example, SREC Trade was admitted to NEPOOL in return for a special arrangement for NEPOOL Dues and Expenses as well as a unique Voting Share.

For the Supplier Sector, there is only one form of membership. Its costs are identical whether the Supplier's business is small or large. There are neither volumetric adjustments [nor the ability to join the Provisional Group Sector if this proposal is not approved].

4. The Membership Committee has had multiple meetings to formulate this compromise proposal. We at Maine Power have been working at this for about six months. We started by asking for a broad change to the membership arrangement, but were asked to limit it to a narrow spectrum, but that created a tension as being too narrow. This was a compromise. This, like any compromise, is not ideal to everyone. However, Maine Power believes that it is a fair resolution to this particular load issue. We hope that our proposal will be supported at this time, rather than spending much more of everyone's resources to drag this slowly to resolution.

5. This proposal is not unreasonable and if accepted by NEPOOL, it should be accepted by the FERC without major fanfare. This should be a small issue and it seems to us unlikely that anyone would want this to be contested there.

We hope that you can vote to ballot the amendments and vote for these amendments.

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of April 5, 2017

The following activity, as more fully described in the attached litigation report, has occurred since the report dated March 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	NEPGA PER Complaint (EL16-120)	Mar 2	NESCOE, RESA answer NEPGA request for clarification of *PER Complaint Order*
			Mar 16	NEPGA answers NESCOE, RESA answers
			Mar 17	FERC issues tolling order affording it additional time to consider NEPGA request for clarification of *PER Complaint Order*
	3	Base ROE Complaint IV (2016) (EL16-64)	Mar 6	Settlement Judge Long issues status report recommending settlement judge procedures be continued concurrently with hearings
			Mar 21	Judge Long re-schedules 3rd settlement conf. to May 3
			Mar 24	TOs file testimony answering EMCOS' testimony
	4	206 Proceeding: RNS/LNS Rates and Rate Protocols (EL16-19)	Mar 21	Judge Dring schedules settlement conf. for Apr 5
			Apr 5	Settlement conf. held

II. Rate, ICR, FCA, Cost Recovery Filings

	6	FCA11 Results Filing (ER17-1073)	Mar 3-Apr 5	Eversource, Exelon, National Grid, NESCOE, NRG, Dominion intervene
	6	Exelon Request for Additional Cost Recovery (ER17-933)	Mar 13	Exelon, NEPGA respond to ISO-NE Feb 24 answer; NEPGA moves to intervene out-of-time
			Mar 29	ISO-NE IMM answers Exelon's and NEPGA's Mar 13 pleadings
			Mar 30	Exelon's request is preliminarily found not to be shown to be just and reasonable, but, pursuant to FERC's Feb 3 *Absence of a Quorum Delegation Order*, is accepted for filing, suspended for a nominal period, to become effective Mar 30, 2017, subject to refund and further Commission order
*	7	ISO Securities: Authorization for Future Drawdowns (ES17-15)	Mar 31	ISO-NE requests continued authorization for drawdowns under previously authorized Revolving Credit Line and Payment Default Shortfall Fund; comment date Apr 21

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

	7	Waiver Request: FCM Qualification for FCA8 MRAs (Emera ESS6) (ER17-1031)	Mar 15	NEPOOL intervenes
	8	Active Demand Resource Types Removal (ER17-925)	Mar 15	FERC accepts filing, eff. in two parts – Feb 24, 2017 and Jun 1, 2018, as requested
	8	CONE & ORTP Updates (ER17-795)	Mar 6	ISO-NE submits filing designed to extend indefinitely the date by which the FERC must take action in this contested proceeding; NEPGA answers ISO-NE's Feb 17 answer
			Mar 21	ISO-NE answers NEPGA's Mar 6 answer; NEPOOL files comments in response to Mar 6 ISO-NE filing
	9	NYISO Tariff Revisions in Response to FCM Enhancements (ER17-446)	Mar 27	NYISO submits, and corrects, compliance filing
				NRG requests reh'g of Jan 27 order

	10	2013/14 Winter Reliability Program Remand Proceeding (ER13-2266)	Mar 10 Mar 27	TransCanada answers ISO-NE Feb 28 answer Verso moves to intervene out-of-time

IV. OATT Amendments / TOAs / Coordination Agreements

	11	Attachment K Revisions (ER17-857)	Mar 10	FERC accepts revisions, eff. Mar 27, 2017

V. Financial Assurance/Billing Policy Amendments

*	11	FAP FCM Capacity Charge Calculation Changes (ER17-1103)	Mar 6 Mar 21-24	ISO-NE and NEPOOL jointly file changes Eversource, National Grid intervene

VI. Schedule 20/21/22/23 Changes

*	11	Schedule 21-ES: Eversource Recovery of NU/NSTAR Merger-Related Costs (ER16-1023)	Mar 1	ISO-NE and NEPOOL jointly file changes Eversource, National Grid intervene
	12	Schedule 21-EM: Recovery of Bangor Hydro/Maine Public Service Merger-Related Costs (ER15-1434 et al.)	Mar 16	Settlement judge issues 5th status report (i) reporting that the parties have reached a settlement in principle and are memorializing their agreement, which they intend to file in late April/early May; and (ii) recommending that settlement procedures be continued

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

	13	Capital Projects Report - 2016 Q4 (ER17-963)	Mar 28	FERC accepts 2016 Q4 Report
*	13	Reserve Market Compliance (22nd) Semi-Annual Report (ER06-613)	Apr 3	ISO-NE submits 22nd semi-annual report
*	14	ISO-NE FERC Form 715	Mar 31	ISO-NE submits annual report of total MWh of transmission service

IX. Membership Filings

*	14	April 2017 Membership Filing (ER17-1364)	Mar 31 Apr 4	NEPOOL requests FERC accept (i) the membership of GridAmerica Holdings; and (ii) the name changes of ENGIE Energy Marketing NA, Inc. and Verso Energy Services LLC; comment date Apr 21 NEPOOL files errata correcting effective date on Sheet No. 65
	14	March 2017 Membership Filing (ER17-1048)	Mar 28	FERC accepts (i) the memberships of Rubicon NYP Corp. and TransCanada Hydro Northeast; (ii) the termination of the Participant status of Duke Energy Comm. Enterprises, CinCap V and South Jersey Energy ISO2; and (iii) the name changes of McGill St-Laurent Inc. and St. Anselm College

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

*	14	Revised Reliability Standards: IRO-002-5; TOP-001-4 (RD17-4)	Mar 6	NERC files changes to IRO-002 and TOP-001; comment date Apr 10
*	14	Revised Reliability Standard: CIP-003-7 (RM17-11)	Mar 3	NERC files changes to CIP-003-7; has not been noticed for public comment

	15	*Frequency Control Changes NOPR*: Revised BAL-005-1 & FAC-001-3 (RM16-13)	Mar 10	FERC issues data request; response date Apr 10
*	16	Annual NERC CMEP Filing (RR15-2)	Mar 10-22	APPA/ELCON/NRECA/TAPS, PPL, AEP, EEI, IRC submit comments

XI. Misc. - of Regional Interest

*	17	203 Application: GMP/VT Transco (Highgate) (EC17-86)	Mar 1	GMP and VT Transco request FERC authorization for GMP to sell its undivided ownership share in Highgate to VT Transco and for VTransco to acquire the ownership shares of GMP and certain other joint owners
*	17	203 Application: Helix Generation/ TransCanada (EC17-38)	Mar 31	FERC authorizes proposed transaction, which includes Helix acquisition of TransCanada's New England, non-hydro assets
	17	203 Application: NSTAR/WMECO merger (EC17-62)	Mar 2	FERC authorizes merger
*	17	IAs: WMECO/Nautilus Hydros (ER17-1340 et al.)	Mar 29	Eversource files five two-party interconnection agreements to cover hydro facilities transferred from Essential Power to Nautilus; comment date Apr 17
			Apr 4	Nautilus Hydro intervenes
*	18	IA: WMECO/Essential Power (ER17-1322)	Mar 29	Eversource files five amended IA to remove hydro facilities transferred to Nautilus and amend remaining provisions applicable to Essential Power fossil-fueled units; comment date Apr 17
			Apr 4	Essential Power intervenes
*	18	SGIA: ISO-NE/GMP (ER17-1296)	Mar 24	ISO-NE/GMP file non-conforming SGIA; comment date Apr 14
	18	LGIA: CMP/Wight Brook (ER17-938)	Mar 30	FERC accepts Wight Brook Hydro LGIA, eff. Feb 1
	19	LGIA: CMP/Stony Brook (ER17-937)	Mar 30	FERC accepts Stony Brook Hydro LGIA, eff. Feb 1
	19	LGIA: CMP/ReEnergy Livermore Falls (ER17-909)	Mar 15	FERC accepts ReEnergy LGIA, eff. Jan 1, 2017
	19	Emera MPD OATT Changes (ER15-1429; EL16-13, ER12-1650)	Mar 15	FERC accepts Emera refund report identifying the amounts to be refunded to customers under the MPD OATT
			Mar 24	Settlement Judge issues status report recommending settlement judge procedures be continued

XII. Misc. - Administrative & Rulemaking Proceedings

*	21	State Policies & Wholesale Markets Operated by ISO-NE, NYISO, PJM (AD17-11)	Mar 3	FERC staff issues notice of IMAPP tech. conf. covering the Northeast's organized markets
	22	Agency Operations in the Absence of a FERC Quorum (AD17-10)	Mar 8	WPA requests rehearing of *Absence of a Quorum Delegation Order*
			Mar 21	WPA withdraws request for rehearing
	23	NOI: FERC's Policy for Recovery of Income Tax Costs & ROE Policies (PL17-1)	Mar 8-9	Parties submit comments
	24	NOPR: LGIA/LGIP Reforms (RM17-8)	Mar 14	Industrial Energy Consumers of America submits comments; comment deadline Apr 13, 2017

	24	NOPR: Fast-Start Pricing in RTO/ISO Markets (RM17-3)	Mar 17	MISO, PJM IMM file reply comments
	26	NOPR: Primary Frequency Response - Essential Rel. Services & the Evolving BPS (RM16-6)	Mar 13	ELCON submits supplemental comments

XIII. Natural Gas Proceedings

	30	New England Pipeline Proceedings Atlantic Bridge Project (CP16-9)	Mar 14	Algonquin/Maritimes Northeast request authorization to proceed with construction of certain Projects segments
			Mar 27	FERC grants authorization to proceed as requested on Mar 14; issues tolling order affording additional time to consider requests for rehearing of Jan 25 order granting certificate of public convenience and necessity

XIV. State Proceedings & Federal Legislative Proceedings

No Activity Reported

XV. Federal Courts

*	32	Demand Curve Changes (17-1110)	Apr 3	NextEra, NRG and PSEG again challenge *Demand Curve Orders*
	32	FCA10 Results and FCA9 Results (16-1408 and 16-1068 consol.)	Mar 14	Petitions file Petitioners' Brief

MEMORANDUM

TO: NEPOOL Participants Committee Member and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: April 5 1, 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"), state regulatory commissions, and the Federal Courts and legislatures through April 5, 2017. If you have questions, please contact us.[1]

I. Complaints/Section 206 Proceedings

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

As previously reported, the FERC, on January 19, (i) granted in part NEPGA's complaint[2] 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.[3] In granting NEPGA's complaint in part, 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."[4] 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.[5] The FERC established a refund effective date of September 30, 2016 (the date of the complaint). In establishing a September 30, 2016 effective date, the FERC clarified that "any changes to the calculation of the PER Strike Price under ISO-NE Tariff section III.13.7.2.7.1.1.1 would be prospective only from September 30, 2016, as required by FPA section 206, and would not impact the application of any PER Adjustment occurring before September 30, 2016."[6] On February 15, NEPGA requested clarification of the *PER 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

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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] NEPGA's complaint asked the FERC (i) to find the ISO Tariff's Peak Energy Rent ("PER") Adjustment provisions unjust & unreasonable; (ii) to direct the ISO to file revisions to the PER Adjustment sections of the Tariff that return the PER Adjustment to a just & reasonable level; (iii) to establish a refund effective date of September 30, 2016; and (iv) to issue an order granting the complaint by November 29, 2016.

[3] *New England Power Generators Assoc., Inc. v. ISO New England Inc.*, 158 FERC ¶ 61,034 (Jan. 19, 2017).

[4] *Id.* at P 48.

[5] *Id.* at P 57.

[6] *Id.* at P 61.

that would have been charged to capacity suppliers if the PER Adjustment were calculated using a just and reasonable PER Strike Price." On March 3, NESCOE and RESA answered NEPGA's rehearing request. NEPGA answered those answers on March 17. The FERC issued a tolling order on March 16, 2017, affording it additional time to consider NEPGA's request for rehearing, which remains pending.

Settlement Judge Procedures. On January 25, Chief Cintron designated Judge H. Peter Young as the Settlement Judge in these proceedings. A first settlement conference was held on February 16. On February 17, Judge Young issued a status report indicating that, at the February 16 conference, the ISO had committed to conduct and circulate a revised Strike Price analysis based on updated data by March 3, 2017 and to provide and Real-Time pricing data by March 23. Participants in the settlement proceedings are to respond to that information by April 7, 2017. A second settlement conference is scheduled for May 3. Accordingly, Judge Young recommended that settlement judge procedures be continued. On February 23, the Acting Chief Judge issued an order continuing the settlement judge procedures. Requests to intervene out-of-time by NHEC (contested by NEPGA) and Cogentrix (uncontested) were both granted.

If you have any questions concerning this matter, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com), Jamie Blackburn (202-218-3905; jblackburn@daypitney.com), or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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

On September 20, 2016, the FERC established hearing and settlement judge procedures (and set a refund effective date of April 29, 2016) for the 4th ROE Complaint.[7] As previously reported, EMCOS[8] filed the 4th ROE complaint on April 29, 2016. The 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 Complaint: (1) the continuing decline of the market cost of equity capital, which makes NETOS' currently authorized ROE "excessive, unjust and unreasonable, and therefore ripe for adjustment under FPA Section 206"; (2) "divergent rulings concerning the persistence of the "anomalous" capital market conditions"; and (3) "the extent to which the Commission's anomalous conditions rationale in Opinion No. 531 is intended to reflect changes in its long-standing reliance on the DCF methodology, and particularly the DCF midpoint, for determining ROE remains unclear."

In setting the complaint for hearing and settlement judge procedures, the FERC found that the Complaint "raises issues of material fact that cannot be resolved based upon the record before us and that are more appropriately addressed in the hearing and settlement judge procedures we order."[9] The FERC also found "unpersuasive the assertions of New England TOs and EEI that the Commission should dismiss the Complaint because the New England TOs' base ROE continues to fall within the zone of reasonableness. The Commission has repeatedly rejected the assertion that every ROE within the zone of reasonableness must be treated as an equally just and reasonable ROE."[10] Further, the FERC rejected arguments as to the propriety of allowing a fourth complaint against the TOs' ROE after three previous complaints have been filed since 2011. As it did when it allowed Complaints II and III to go forward, the FERC found that Complaint IV was properly set for hearing as it is based on newer, more current data than prior Complaints subsequent

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[7] *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*").

[8] "EMCOS" are: Belmont Mun. Light Dept., Braintree Elec. Light Dept., Concord Mun. Light Plant, Georgetown Mun. Light Dept., Groveland Elec. Light Dept., Hingham Mun. Lighting Plant, Littleton Elec. Light & Water Dept., Middleborough Gas & Elec. Dept., Middleton Elec. Light Dept., Reading Mun. Light Dept. ("Reading"), Rowley Mun. Lighting Plant, Taunton Mun. Lighting Plant, and Wellesley Mun. Light Plant.

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

[10] *Id.* at P 38.

hearings.[11] The FERC is "initiating an entirely new proceeding, based on an entirely separate factual record, that may or may not reach the same conclusions as those reached in the earlier ROE proceeding."[12] The FERC estimated that, if this case does not settle and goes to hearing, the Commission's ultimate decision would be issued on or before June 30, 2018.[13] 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.

Settlement Judge Procedures. On October 4, Chief Judge Cintron designated Judge Jennifer Long as the Settlement Judge. Settlement conferences have thus far been held on November 8 and December 20, 2016. Following a request of the parties (who continue to wait for a decision in *Emera Maine v. FERC* (DC Cir. case No. 15-1118), a third settlement conference was rescheduled to May 3, 2017. On March 6, Settlement Judge Long issued a status report again indicating that the parties remain open to settlement and recommending that settlement judge procedures be continued concurrently with the hearings described below.

Concurrent Hearing Procedures. 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 can proceed *concurrently* with settlement judge procedures still underway before Judge Long. Absent a settlement, these hearing procedures will be conducted under the FERC's "Track II" procedural time standards, which requires that an initial decision be issued within 47 weeks, or by November 15, 2017. Judge Glazer scheduled a preliminary conference for January 17, 2017, noting that hearing has been set for August 2, 2017 (with September 27, 2017 as the deadline for reply briefs). At the January 17 conference, Participants proposed the remaining procedural schedule, which was adopted by Judge Glazer in an order issued January 23. In addition, Judge Glazer has issued orders adopting rules for the conduct of the hearing (December 21, 2016) and the discovery plan (January 17). Direct and Answering Testimony and Exhibits have been filed. Hearings are scheduled for August 2-8, with an initial decision to be issued on or before November 15, 2017.

If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Jamie Blackburn (202-218-3905; jblackburn@daypitney.com).

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

Settlement discussions in this proceeding are on-going. As previously reported, the FERC instituted this Section 206 proceeding on December 28, 2015, finding that the ISO Tariff is unjust, unreasonable, and unduly discriminatory or preferential because the Tariff "lacks adequate transparency and challenge procedures with regard to the formula rates" for Regional Network Service ("RNS") and Local Network Service ("LNS").[14] The FERC also found that the RNS and LNS rates themselves "appear to be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful" because (i) "the formula rates appear to lack sufficient detail in order to determine how certain costs are derived and recovered in the formula rates" and "could result in an over-recovery of costs" due to the "the timing and synchronization of the RNS and LNS rates".[15] Accordingly, the FERC established hearing and settlement judge procedures to develop just and reasonable formula rate protocols to be included in the ISO-NE Tariff and to examine the justness and reasonableness of the RNS and LNS rates. The FERC encouraged the parties to make every effort to settle this matter before hearing procedures

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

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

[13] *Id.* at P 44.

[14] *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).

[15] *Id.* at P 8.

are commenced.[16] Hearings are being held in abeyance pending the outcome of settlement judge procedures underway.[17] The FERC-established refund date is January 4, 2016.[18]

Settlement Judge Procedures. As previously reported, John P. Dring was designated the Settlement Judge in these proceedings. Five settlement conferences were held in 2016: January 19, March 24, April 28, August 30, and November 18 (telephonically). A 6th settlement conference was held on April 5. Judge Dring's most recent status report was issued on February 7, indicating that the parties are making progress toward settlement and recommending that the settlement procedures be continued. The Transmission Committee is being kept apprised of settlement efforts. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

Judge Sterner's findings and Initial Decision, and pleadings in response thereto, remain pending before the FERC. As previously reported, the FERC, in response to second (EL13-33)[19] and third (EL14-86)[20] complaints regarding the TOs' 11.14% Base ROE, issued orders establishing trial-type, evidentiary hearings and separate refund periods. The first, in EL13-33, was issued on June 19, 2014 and established a 15-month refund period of December 27, 2012 through March 27, 2014;[21] the second, in EL14-86, was issued on November 24, 2014, established a 15-month refund period beginning July 31, 2014,[22] and, because of "common issues of law and fact", consolidated the two proceedings for purposes of hearing and decision, with the FERC finding it "appropriate for the parties to litigate a separate ROE for each refund period."[23] The TOs requested rehearing of both orders. On May 14, 2015, the FERC denied rehearing of both orders.[24] On July 13, 2015, the TOs appealed those orders to the DC Circuit Court of Appeals (*see* Section XIV below), and that appeal remains pending.

Hearings and Trial Judge Initial Decision. Initial hearings on these matters were completed on July 2, 2015. In mid-December 2015, Judge Sterner reopened the record for the limited purpose of having the discounted cash flow ("DCF") calculations re-run in accordance with the FERC's preferred approach and re-submitted. A limited hearing on that supplemental information was held on February 1, 2016. On March 22,

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[16] *Id.* at P 11.

[17] *Id.*

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

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

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

[21] *Environment Northeast, 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).

[22] *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).

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

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

2016, Judge Sterner issued his 939-paragraph, 371-page Initial Decision, which lowered the base ROEs for the EL13-33 and EL14-86 refund periods from 11.14% to 9.59% and 10.90%, respectively.[25] The Decision also lowered the ROE ceilings. Judge Sterner's decision, if upheld by the FERC, would result in refunds totaling as much as $100 million, largely concentrated in the EL13-33 refund period. Briefs on exceptions were filed by the TOs, Complainant-Aligned Parties ("CAPs"), EMCOS, and FERC Trial Staff on April 21, 2016; briefs opposing exceptions, on May 20, 2016. Judge Sterner's findings and Initial Decision, and pleadings in response thereto, remain pending, and will be subject to challenge, before the FERC. The *2012/14 ROE Initial Decision* and its findings can be approved or rejected, in whole or in part.

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

II. Rate, ICR, FCA, Cost Recovery Filings

- **FCA11 Results Filing (ER17-1073)**

As previously reported, the ISO filed the results of the February 6 eleventh FCA ("FCA11") on February 28. The ISO reported the following highlights:

- FCA11 Capacity Zones were the Southeastern New England ("SENE") Capacity Zone (the Northeastern Massachusetts ("NEMA")/Boston, Southeastern Massachusetts, and Rhode Island Load Zones), the Northern New England ("NNE") Capacity Zone (the Maine, New Hampshire and Vermont Load Zones) and the Rest-of-Pool Capacity Zone (the Connecticut and Western/Central Massachusetts Load Zones)
- FCA11 commenced with a starting price of $18.624/kW-mo. and concluded for the SENE, NNE and Rest-of-Pool after five rounds.
- Resources will be paid as follows:
    - $5.297/kW-mo. – all Capacity Zones
    - $5.297/kW-mo. – NY AC Ties imports (539.4 MW), HQ interfaces (441 MW) and Highgate (55 MW)
    - $3.381/kW-mo. – New Brunswick imports (200 MW)
- No resources cleared as Conditional Qualified New Generating Capacity Resources
- No Long Lead Time Generating Facilities secured a Queue Position to participate as a New Generating Capacity Resource
- No de-list bids were rejected for reliability reasons

The ISO asked the FERC to accept the FCA11 rates and results, effective June 28, 2017. Comments on this filing are due on or before April 14, 2017. Doc-less interventions have been filed by Dominion, Eversource, Exelon, National Grid, NESCOE, and NRG. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Exelon Request for Additional Cost Recovery (ER17-933)**

On February 3, pursuant to Section III.A.15 of Appendix A to Market Rule 1,[26] Exelon Generation Company ("Exelon") requested that the FERC authorize recovery of $1,495,171 of actual fuel costs for Mystic Generating Station Units 8 and 9 ("Mystic 8 and 9") that were not recovered due to market power

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[25] *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*").

[26] Under Appendix A Section III.A.15, a Market Participant has the right to make a Section 205 filing seeking additional cost recovery if, as a result of mitigation applied under Appendix A or the Energy Offer Cap, it will not recover the fuel and variable operating and maintenance ("O&M") costs of a Resource for all or part of one or more Operating Days.

mitigation applied during the months of October and November 2016, as well as associated regulatory costs (estimated by Exelon to be roughly $60,000). Comments on Exelon's request were due on or before February 24. The ISO answered the Exelon request on February 24, requesting that the FERC "reject [Exelon]'s request for additional cost recovery for October 1, 3 and 4, and, to the extent it accepts the remainder of [Exelon]'s Cost Recovery Request, affirm that the amount recovered is justified by the IMM's correct application of the ISO Tariff provisions for calculating cost-based Reference Levels." On March 13, Exelon and NEPGA (which also moved to intervene out-of-time) answered the ISO's February 24 answer. Exelon asked that the FERC strike the portions of the IMM's pleading related to issues Exelon is not seeking/ contesting -- Exelon's recovery of additional fuel costs incurred under a Shoulder Period Agreement with ENGIE and the IMM's request that the FERC "find that the IMM has properly applied the ISO Tariff in establishing the Reference Levels for the Mystic 8 and 9 units . . . ." NEPGA, which also moved to intervene out-of-time, also asked the FERC to deny the IMM's requested Reference Level finding. Additional parties to the proceeding include NEPOOL and Direct Energy Business. On March 29, the IMM responded to the March 13 Exelon and NEPGA answers.

On March 30, 2017, the Director of Office of Energy Market Regulation ("OEMR")-East, pursuant to the FERC's February 3 *Absence of a Quorum Delegation Order* (*see* Section XII, AD17-10 below), issued an order accepting Exelon's Cost Recovery Filing for filing, suspended for a nominal period, to become effective March 30, 2017, subject to refund and further Commission order. As a practical matter, however, the letter order punts to a later date a final FERC decision on this matter. The letter order stated that "preliminary analysis indicates that Exelon's filing has not been shown to be just and reasonable and may be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful … Protests and comments will be addressed in a further Commission order as appropriate."

This matter remains subject to further FERC proceedings and/or action. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **ISO Securities: Authorization for Future Drawdowns (ES17-15)**

On March 31, the ISO requested the necessary continued FERC authorization for drawdowns under its previously authorized $20 million Revolving Credit Line and $4 million line of credit supporting the Payment Default Shortfall Fund.[27] (ISO authorization would otherwise terminate on June 30, 2017).[28] Comments on this filing are due on or before April 21. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

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

- **Waiver Request: FCM Qualification for FCA8 MRAs (Emera ESS6) (ER17-1031)**

On February 23, Emera Energy Service Subsidiary No. 6 ("Emera ESS6") requested waiver of the FCM qualification rules to allow EES6 to qualify Bayside Station for participation in the summer 2017 Monthly Reconfiguration Auctions ("MRAs") associated with the FCA8 2017/18 Capacity Commitment Period. Absent waiver,[29] the ISO has determined EES6 cannot be qualified, notwithstanding market rule changes recently

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[27] *See ISO New England Inc.*, 139 FERC ¶ 62,248 (June 22, 2012) (initially authorizing borrowings through June 30, 2014); *ISO New England Inc.*, 147 FERC ¶ 62,091 (May 6, 2014) (continuing authorization through June 30, 2015); *ISO New England Inc.*, 151 FERC ¶ 62,185 (June 15, 2015) (continuing authorization through June 30, 2017).

[28] *See ISO New England Inc.*, 151 FERC ¶ 62,185 (June 15, 2015).

[29] Among the Market Rules Emera identified as needing to be waived to allow Bayside Station the opportunity to secure a CSO in the FCA8 MRAs are: Section III.13.4.2.1.2.2.3.2 (recently adopted rule allowing early sales by Import Capacity Resources and setting the ARA3 Qualified Capacity for imports backed by a generator); Section III.13.1.3.5.1(b) (the rule stating that early sales must submit contracts by the New Capacity Qualification Deadline); Section III.13.1.3.5.2 (the rule describing the documentation that must be submitted for imports backed by existing

accepted in the *FCM Enhancements Order*[30] (*see* below), since Emera ESS6 did not submit during the FCA11 qualification process (and before the FCM Enhancements were accepted) contracts to provide capacity in the New England Control Area from outside of the New England Control Area. Comments on Emera ESS6's waiver request were due on or before March 16, 2017; none were filed. A doc-less intervention was filed by NEPOOL. 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) or Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Active Demand Resource Type Removal (ER17-925)**

On March 15, the FERC accepted changes that remove Real-Time Demand Response ("RTDR") and Real-Time Emergency Generation ("RTEG") resource types from the Tariff. The changes were accepted as filed to allow for two effective dates: (i) February 24, 2017 (for the revisions which make RTEG Resources no longer qualified to participate in Forward Capacity Auctions ("FCAs") starting with FCA12; and (2) requiring the ISO to convert any RTEG Resources that remain in the FCM into Demand Response Capacity Resources ("DRCRs")) and (ii) June 1, 2018 (for the deletion of all provisions associated with RTDR Resources and RTEG Resources entirely – coincident with the full integration of Demand Response Resources). Unless the March 15 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)**

The ISO's January 13 filing of updated FCM Cost of New Entry ("CONE"), Net CONE and Offer Review Trigger Price ("ORTP") values remains pending. With respect to CONE and Net CONE, the ISO will use a gas-fired simple cycle combustion-turbine ("CT") as the reference technology for the updated values, $11.35 and $8.04, respectively. The ISO will use a Capacity factor of 32%, resulting in a $11.02 ORTP for on-shore wind resources. The ISO requested a March 15, 2017 effective date for the new values to coincide with the beginning of the administrative cycle for FCA12. The CONE & ORTP Updates were not supported by the Participants Committee when considered at the January 6 meeting. Comments on this filing were due on or before February 3. Doc-less interventions were filed by Avangrid, Brookfield, Calpine, ConEd, Dominion, Eversource, Exelon, FirstLight, LSPower, National Grid, NextEra, NRG, PSEG, and Cogentrix[31] (out-of-time). Comments were filed by NEPOOL (identifying concerns and alternatives presented and reviewed in the course of the stakeholder process preceding the filing) and NESCOE (supporting the CONE/Net CONE values as overall reasonable updates reflecting changed market outcomes and market designs). NEPGA filed a protest (challenging the ISO's proposal to base Net CONE for FCA12 on a greenfield simple-cycle combustion turbine). The ISO answered the NEPGA protest on February 17. NEPGA answered the ISO's February 17 answer on March 6 and the ISO answered NEPGA's March 6 answer on March 21.

In further developments since the last Report, the ISO submitted, in light of the contested nature of this proceeding and the lack of a FERC quorum, an amendment-type filing to extend indefinitely the date by which the FERC would otherwise have been required to act on the January 13 filing or have the filing become effective by operation of law. The ISO committed to submit a further amendment-type filing, triggering a new 60-day statutory action date, "at the appropriate time" (presumably once the FERC has a quorum). In the meantime, the ISO stated that the proposed March 15, 2017 effective date for the CONE and ORTP Updates

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external resources, including a description of the MWs and confirmation that the capacity is currently unobligated to others); and Section III.13.4.2.1.4 (the rule that equates MRA qualification with the ARA3 Qualified Capacity).

[30] Of pertinent relevance, the FCM Enhancements permit Import Capacity Resources backed by one or more External Resources to be granted the option to participate for certain reconfiguration auctions in Capacity Commitment Periods prior to the Capacity Commitment Period associated with the first FCA in which it qualified. Bayside has an FCA10 CSO.

[31] Cogentrix Energy Power Management, LLC ("Cogentrix") intervened on behalf of its Participant affiliates Rhode Island State Energy Center, LP, Essential Power Newington, LLC, and Essential Power Massachusetts.

remains unchanged and will be used for the administration of FCA12. Comments on the ISO's March 6 filing were due on or before March 27. NEPOOL filed limited comments seeking acknowledgement in any final order that the ISO's actions not be construed to have any precedential effect in future contested Section 205 proceedings where the FERC does have a quorum.

This matter will remain pending before the FERC until such time as the ISO makes its further filing re-starting the 60-day clock. Until then, if you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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

The FERC's *FCM Enhancements Order*[32] remains subject to a request for rehearing by Indicated NYTOs.[33] As previously reported, the FERC accepted changes to the Tariff to increase liquidity in the FCM by increasing Market Participant opportunities to enter into reconfiguration auctions and bilateral contracts for the exchange of CSOs ("FCM Enhancements"). Specifically, the FCM Enhancements (i) modify certain FCM qualification rules to facilitate the ability of New Capacity Resources to supply capacity beginning four months after participating in their first FCA; (ii) provide Import Capacity Resources backed by one or more External Resources the opportunity (currently available to generators and demand response) to provide capacity beginning one or two years after participating in their first FCA; and (iii) establish a new form of bilateral contracting in which Market Participants can, as the Capacity Commitment Period approaches, trade CSOs for a seasonal strip of CSOs. The FCM Enhancements included several smaller improvements as well, including the elimination of a requirement that the ISO make a FERC filing in order to terminate the CSO of a resource that has voluntary withdrawn from the FCM resource development process. The FCM Enhancements were accepted, effective as of October 19, 2016, as requested.

In accepting the FCM Enhancements, the FERC noted that "protestors do not challenge the justness and reasonableness of the specific tariff revisions … the concerns raised by NYISO are not the result of ISO-NE's proposed tariff revisions, but result from NYISO's treatment of generators that export capacity from within a constrained locality under its current market rules."[34] Accordingly, the FERC was "not persuaded that the potential behavior of New York suppliers provides a sufficient basis to reject ISO-NE's filing in this case, and deferring the effective date of an otherwise just and reasonable proposal would be inconsistent with the notice provision in section 205 of the FPA."[35] The FERC did acknowledge NYISO's concerns about a potential flaw in its market rules, and encouraged NYISO stakeholders to timely complete discussions underway to address that flaw.

As noted above, on November 17, 2016, Indicated TOs' requested rehearing of the *FCM Enhancements Order*. On December 19, 2016, the FERC issued a tolling order affording it additional time to consider Indicated TOs' rehearing request, which remains pending before the FERC.

NYISO Tariff Revisions in Response to FCM Enhancements (ER17-446). On January 27, the FERC conditionally accepted in part, and rejected, in part, NYISO tariff revisions proposed in response to the acceptance of the FCM Enhancements, to correct a pricing inefficiency in NYISO's Installed Capacity ("ICAP") market design related to capacity exports from certain zones in the New York Control Area.[36] Specifically, the FERC accepted NYISO's proposed locality exchange factor methodology to be implemented

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

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

[34] *Id.* at P 31.

[35] *Id.*

[36] *NY Indep. Sys. Op., Inc.*, 158 FERC ¶ 61,064 (Jan. 27, 2017), *reh'g requested*.

immediately but rejected NYISO's proposed one-year transitional mechanism.[37] In accepting the immediate implementation of NYISO's Locality Exchange Factor methodology, the FERC found the proposed methodology "just and reasonable because it corrects a pricing inefficiency in NYISO's ICAP market design. NYISO's proposed methodology will now recognize that an exporting generator continues to operate within its Locality, which would be reflected in the ICAP Spot Market Auction clearing prices by accounting for the portion of exported capacity that can be replaced by capacity located in Rest of State. Therefore, NYISO's proposal will ensure that prices within the Localities reflect actual market conditions and prices."[38] In rejecting the transition mechanism, the FERC found that "that the mechanism lacks analytical basis and will delay efficient market signals … because it could overstate the extent to which the capacity export will unencumber NYISO's transmission capability into Southeast New York."[39] NYISO was directed to submit, and submitted on February 6 and corrected on February 10, a compliance filing removing the one-year transition mechanism provisions.[40] NRG requested rehearing of the January 27 order on February 24. The FERC issued a tolling order on March 27, 2017, affording it additional time to consider NRG's request for rehearing, which remains pending before the FERC.

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

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

The NEGPA, NextEra and Exelon request for rehearing of the FERC's *Resource Retirement Reforms Order*[41] remains pending. As previously reported, the FERC conditionally accepted, effective March 1, 2016, changes to the FCM rules for resource retirements proposed by the ISO and its Internal Market Monitor ("IMM") (the "ISO/IMM Proposal"). The FERC conditioned its acceptance of the ISO/IMM Proposal on the filing of Tariff revisions "establishing a materiality threshold for determining whether or not a particular proxy de-list bid will replace a Retirement Bid in an FCA,"[42] which were filed with and later accepted by the FERC.[43] NEPGA, Exelon and NextEra jointly requested rehearing of the *Resource Retirement Reforms Order*. On June 13, the FERC issued a tolling order affording it additional time to consider the joint rehearing request, which remains pending before the FERC. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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

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

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[37] *Id.* at P 20.

[38] *Id.* at P 35.

[39] *Id.* at P 55.

[40] *Id.* at P 61.

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

[42] *Id.* at P 62.

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

[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

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, 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." Comments on the ISO's report were due on or before February 13. 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 protest. 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 (Public Policy Transmission Studies Timeline Modifications and Clean-Up/Admin Changes to Section 6.3 and Appendices 2 & 3) (ER17-857)**

On March 10, the FERC accepted revisions to Attachment K of the OATT to modify the timeline associated with the Public Policy Transmission Study Process and to reflect clean-up changes to Section 6.3(Interregional Coordination) and to Appendices 2 (List of Entities Enrolled in the Transmission Planning Region) and 3 (List of Qualified Transmission Project Sponsors). The changes were accepted effective as of March 27, 2017, as requested. Unless the March 10 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).

V. Financial Assurance/Billing Policy Amendments

- **Financial Assurance Policy FCM Capacity Charge Calculation Changes (ER17-1103)**

On March 6, the ISO and NEPOOL jointly filed changes to modify how FCM Capacity Charge Requirements are calculated. A June 1, 2017 effective date was requested. These changes were supported unanimously by the Participants Committee at its March 3, 2017 meeting (Item #5). Comments on this filing are due on or before March 27; none were filed. Doc-less interventions were filed by Eversource and National Grid. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

VI. Schedule 20/21/22/23 Changes

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

As previously reported, the FERC accepted Eversource's November 22 offer of settlement[46] to resolve the issues in this proceeding (principally, whether the $38.9 million in FERC-jurisdictional, merger-related transmission costs incurred as the result of the April 10, 2012 NU/NSTAR merger that Eversource

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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. et al.*, 158 FERC ¶ 61,096 (Jan. 31, 2017).

sought to recover through changes to Schedule ES-21 were just and reasonable).[47] Eversource was directed to file revised tariff records in eTariff format to reflect the FERC's approval of the settlement. Eversource filed those tariff sheets on March 2, 2017. Comments on the March 1 filing were due on or before March 22; none were filed. Pending acceptance of the March 1 filing, this proceeding will be concluded. If you have any questions concerning these proceedings, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

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

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

Settlement Judge Procedures. ALJ John Dring is the settlement judge for these proceedings. A first settlement conference was held on June 29; a second settlement conference, October 25. A third settlement conference, scheduled for November 22, 2016, was cancelled and subsequently held on December 1. In a March 16 status report, Judge Dring indicated that the parties had reached a settlement in principal and were memorializing their agreement. He reported that the parties intend to file that agreement in late April or early May. He recommended that settlement procedures be continued. If you have any questions concerning these matters, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

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

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

[49] *Id.* at P 24.

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

[51] *Id.* at P 27.

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

VIII. Regional Reports

- **Capital Projects Report - 2016 Q4 (ER17-963)**

On March 31, the FERC accepted the ISO's 2016 fourth quarter ("Q4") Capital Projects Report and Unamortized Cost Schedule (the "Report"). Report highlights included the following new projects: (i) Situational Awareness – Video Wall Expansion Phase I ($854,000); (ii) 2017 Issue Resolution Phase I ($840,000); (iii) Information Technology ("IT") Asset Workflow ($794,500); (iv) Cyber Security Network Segmentation Phase I ($655,500); (v) Case Snapshot Market Operator Interface ($619,600); (vi) Cyber Security Network Segmentation Phase II ($565,000); (vii) Asset Characteristic Database Re-Design ($549,300); (viii) Update Enhanced Energy Scheduling Technical Architecture ($500,000); (ix) Corporate Performance Management and Budget Forecast System ($385,000); (x) 2016 Market System Corrective Action / Preventative Action ("CAPA") ($208,000); and (xi) Demand Response Resources ("DRR") Baseline Methodology Modification ($185,000). Projects with significant changes were: (i) Price Responsive Demand (2016 budget increase of $416,200); (ii) market enhancements for DARD pumps (2016 budget decrease of $878,700; 2017 budget decrease of $25,000); (iii) Real-Time Fast-Start Pricing (2016 budget decrease of $798,900; 2017 budget decrease of $45,000); (iv) FCA11 (2016 budget decrease of $245,300; 2017 budget increase of $14,500); (v) Operations Document Management System (2016 budget decrease of $300,000); (vi) IMM data needs (2016 budget decrease of $204,100); (vii) Transmart Technical Architecture Update (2016 budget decrease of $177,300; 2017 budget decrease of $25,000); (viii) Energy Management Platform 3.1 Upgrade and Customs Reduction (2016 budget decrease of $159,700); and (ix) Sub-Hourly Settlements (2016 budget decrease of $157,300). Unless the March 28 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*[53] *and 531-B*[54] 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).

- **Reserve Market Compliance (22nd) Semi-Annual Report (ER06-613)**

As directed by the original ASM II Order,[55] as modified,[56] the ISO submitted its 22nd semi-annual reserve market compliance report on April 3, 2017. In the 22nd report, the ISO explained, as in its prior

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

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

[55] *See NEPOOL and ISO New England Inc.*, 115 FERC ¶ 61,175 (2006) ("*ASM II Order*") (directing the ISO to provide updates on the implementation of a forward TMSR market), *reh'g denied* 117 FERC ¶ 61,106 (2006).

compliance reports, that work on the forward TMSR market issues continues to be on hold due to its efforts on other priority projects. The ISO reported that it does not contemplate revisiting this issue until at least 2018. If there are questions on this matter, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com).

- **ISO-NE FERC Form 715 (not docketed)**

On April 1, the ISO submitted its 2017 Annual Transmission Planning and Evaluation Report. These filings are not noticed for filing.

IX. Membership Filings

- **April 2017 Membership Filing (ER17-1364)**

On March 31, as corrected on April 4, NEPOOL requested that the FERC accept (i) the membership of GridAmerica Holdings Inc. (National Grid Related Person); and (ii) the name changes of ENGIE Energy Marketing NA, Inc. (f/k/a GDF SUEZ Energy Marketing NA, Inc.) and Verso Energy Services LLC (f/k/a Verso Maine Energy LLC). Comments on this filing are due on or before April 21.

- **March 2017 Membership Filing (ER17-1048)**

On March 28, The FERC accepted (i) the membership of Rubicon NYP Corp. and TransCanada Hydro Northeast Inc.; (ii) the termination of the Participant status of Duke Energy Commercial Enterprises, Inc. and CinCap V, LLC (Supplier Sector) and South Jersey Energy ISO2, LLC (Related Person to remaining South Jersey Energy Companies); and (iii) the name changes of McGill St-Laurent Inc. (f/k/a Canadian Wood Products – Montreal, Inc.) and St. Anselm College (f/k/a The Order of St. Benedict of New Hampshire).

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

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

- **Revised Reliability Standards: IRO-002-5; TOP-001-4 (RD17-4)**

On March 6, NERC filed for approval changes to Reliability Standards TOP-001-4 (Transmission Operations) and IRO-002-5 (Reliability Coordination - Monitoring and Analysis), and approval of their associated Implementation Plans, Violation Risk Factors ("VRFs"), Violation Severity Levels ("VSLs"), and retirement of the currently-effective versions of the revised Standards. Specifically, TOP-001-4 Requirement R10 was revised to require a Transmission Operator to monitor non-BES facilities for determining System Operating Limit ("SOL") exceedances within its Transmission Operator Area and TOP-001-4 was further revised to require that Real-Time data exchange capabilities needed for Real-Time monitoring and analysis have redundant and diversely routed data exchange infrastructure within the primary Control Center and that those capabilities are tested for redundant functionality on a regular basis. Similar revisions were reflected in IRO-002-5. NERC sated that these revisions will help ensure that all facilities that can adversely impact reliability are monitored and to prevent a single point of failure in primary Control Center data exchange infrastructure from halting the flow of Real-Time data used by operators to monitor and control the Bulk Electric System. Comments on this filing are due on or before April 10.

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

On March 3, NERC filed for approval changes to Reliability Standard CIP-003 (Cyber Security - Security Management Controls), approval of the 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

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[56] *See NEPOOL and ISO New England Inc.*, 123 FERC ¶ 61,298 (2008) (continuing the semi-annual reporting requirement with respect to the consideration and implementation of a forward market for Ten-Minute Spinning Reserve ("TMSR")).

Connectivity" and "Low Impact BES Cyber System Electronic Access Point". 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; 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. 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. As of the date of this Report, the FERC has not noticed a proposed rulemaking proceeding or otherwise invited public comment.

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

On September 2, 2016, NERC filed for approval (i) two new Reliability Standards -- PRC-027-1 (Coordination of Protection Systems for Performance During Faults) and PER-006-1 (Specific Training for Personnel), (ii) associated Glossary definitions, (iii) an implementation plan, (iv) VRFs and VSLs, and (v) the retirement of PRC-001-1.1(ii) (together, the "Protection System Changes"). NERC stated that the purpose of the Protection System Changes is to: (1) maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System ("BES") Elements, such that those Protection Systems operate in the intended sequence during Faults; and (2) require registered entities to provide training to their relevant personnel on Protection Systems and Remedial Action Schemes ("RAS") to help ensure that the BES is reliably operated. NERC requested that the new Standards and definitions become effective on the first day of the first calendar quarter that is 24 months following the effective date of the FERC's order approving the Standards. As of the date of this Report, the FERC still has not noticed a proposed rulemaking proceeding or otherwise invited public comment.

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

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

On March 7, the FERC issued a data request seeking additional information about the current back-up power supply practices of a representative sample of entities potentially affected by the Frequency Control Changes. Responses to the FERC's data request are due on or before April 10.

- ***Order 835*: Revised Reliability Standard: BAL-002-2 (RM16-7)**

On January 19, the FERC approved revised Reliability Standard -- BAL-002-2 (Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event), and eight associated Glossary definitions, implementation plan, VRFs and VSLs (together, the "BAL Changes").[59] *Order 835* also directed NERC: (1) to collect and report on data regarding additional MW losses following Reportable Balancing

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

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

[59] *Disturbance Control Standard - Contingency Reserve for Recovery from a Balancing Contingency Event Reliability Standard*, Order No. 835, 158 FERC ¶ 61,030 (Jan. 19, 2017) ("*Order 835*").

Contingency Events during the Contingency Reserve Restoration Period; and (2) to study and report on the reliability risks associated with MW losses above the most severe single contingency ("MSSC") that do not cause energy emergencies. As previously reported, BAL-002-2 is intended to ensure that balancing authorities and reserve sharing groups are able to recover from system contingencies by deploying adequate reserves to return their ACE to defined values and by replacing the capacity and energy lost due to generation or transmission equipment outages. *Order 835* will become effective on April 3, 2017.[60]

- **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[61] 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[62] 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,[63] 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.

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

On February 22, NERC submitted a compliance filing reviewing the progress of its risk-based Compliance Monitoring and Enforcement Program ("CMEP") program. In this filing, NERC identified and proposed two enhancements to the risk-based CMEP: (1) providing minimal risk Compliance Exceptions ("CEs") identified through self-logging to FERC non-publicly; and (2) expanding the use of CEs to include certain moderate risk noncompliance currently processed through Find, Fix, Track and Report ("FFTs"). Comments on this filing were submitted by the ISO/RTO Council ("IRC"), AEP, EEI, PPL, and jointly by the American Public Power Association ("APPA"), the Electricity Consumers Resource Council ("ELCON"), the National Rural Electric Cooperative Association ("NRECA"), and the Transmission Access Policy Study Group ("TAPS"). This filing is pending before the FERC.

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[60] *Order 835* was published in the *Fed. Reg.* on Feb 2, 2017 (Vol. 82, No. 21) pp. 8,994-9,004.

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

[62] 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.

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

XI. Misc. - of Regional Interest

- **203 Application: Green Mountain Power/VT Transco (Highgate) (EC17-86)**

On March 1, Green Mountain Power ("GMP") and Vermont Transco ("VT Transco") filed an application requesting FERC authorization for GMP to sell its undivided ownership share in the Highgate Transmission Facility to VT Transco and for VTransco to acquire GMP's undivided ownership share, as well as certain undivided ownership shares of other joint owners of the Highgate Transmission Facility. Comments on the application were due on or before March 22, 2017; none were filed. This matter is pending before the FERC.

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

On February 3, Green Mountain Power filed an application requesting FERC authorization to acquire 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. ("EGPNA"): Hoague-Sprague, Kelley's Falls, Lower Valley, Glen, Rollinsford, South Berwick, Somersworth, and Woodsville. Comments on the application were due on or before February 24, 2017; none were filed. This matter is pending before the FERC.

- **203 Application: Helix Generation/TransCanada (EC17-38)**

On March 31, 2017, the FERC authorized a transaction whereby Helix Generation, LLC ("Helix"), an affiliate of LSPower, will indirectly acquire all of the interests in a number of TransCanada-owned projects, including TransCanada's non-hydro generating assets in New England (i.e. the Kibby wind project and Ocean State facility).[64] Among other conditions, the *Helix/TransCanada Order* required notice within 10 days of the consummation of the transaction. As of the date of this report, that notice has not been provided.

- **203 Application: NSTAR/WMECO 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.[65] 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.

- **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. 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).

- **IAs: WMECO/Nautilus Hydros (ER17-1340 et al.)**

On March 28, Eversource, on behalf of WMECO ("Eversource"), filed five two-party Interconnection Agreement ("TGIAs") with Nautilus Hydro, LLC ("Nautilus") to govern the continuing interconnection of the following hydro facilities: Dwight Hydro (1.7 MW); Gardners Falls (3.7 MW); Indian Orchard (3.7 MW); Puss Bridge (4.1 MW); and Red Bridge (4.5 MW). Since the TGIAs continue the existing interconnection arrangements between Eversource and the hydro facilities, previously covered by an Interconnection and

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[64] *Helix Generation, LLC et al.*, 158 FERC ¶ 62,268 (Mar. 31, 2017) ("*Helix/TransCanada Order*").

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

Operating Agreement ("IOA") with Essential Power Massachusetts ("Essential Power"), without modification to the any of facilities' capability or operating characteristics. Accordingly, new 3-party party Interconnection Agreements ("IA") that would include the ISO were not required. A March 29, 2017 effective date was requested. Comments on this filing are due on or before April 19, 2017. Nautilus Hydro moved to intervene on April 3. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **IA: WMECO/Essential Power (ER17-1322)**

On March 28, Eversource, on behalf of WMECO, filed an amended IOA with Essential Power to remove the hydro facilities transferred to Nautilus (*see* ER17-1340 et al. immediately above) and to amend provisions that remain applicable to certain Essential Power fossil-fueled assets (West Springfield, Doreen Street and Woodland Road. A March 29, 2017 effective date was requested. Comments on this filing are due on or before April 19, 2017. Essential Power moved to intervene on April 3. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **SGIA: ISO-NE/GMP (ER17-1296)**

On March 24, 2017, the ISO and GMP filed a non-conforming Small Generator Interconnection Agreement ("SGIA") to allow the interconnection of GMP's Small Generating Facility to the Administered Transmission System at GMP's Huntington Falls Substation. The Small Generating Facility is an existing facility located in Weybridge, VT, constructed in 1910, that has been interconnected to GMP's system, and following modifications, will be rated at 6.58 MW. The SGIA is non-conforming in that GMP is both the Interconnection Customer and the Interconnecting Transmission Owner. A March 8, 2017 effective date was requested. Comments on this filing are due on or before April 14, 2017. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **IA: Eversource/Covanta (Preston, CT) (ER17-1038)**

On February 24, 2017, Eversource filed a non-conforming Interconnection Agreement ("IA") with Covanta Southeastern Connecticut Company ("Covanta") to govern the continuing interconnection of Covanta's 18.5 MW generating facility located in Preston, Connecticut. Since the IA continues the existing interconnection arrangements between Eversource and Covanta, without modification to the facility's capability or operating characteristics, a new three-party IA that would include the ISO was not required. A February 18, 2017 effective date was requested. Comments on this filing were due on or before March 17, 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).

- **LSA: CL&P/Wallingford, CT Transmission Line Separation Agreement (ER17-967)**

On February 13, 2017, CL&P filed a Transmission Line Separation Agreement with the Town of Wallingford, CT Department of Public Utilities Electric Division ("Wallingford"). The purpose of the Agreement is to set forth the terms and conditions under which CL&P will assist Wallingford in separating transmission lines 1630 and 1640, a required upgrade following an ISO-NE post-FCA re-study. A February 13, 2017 effective was requested. Comments on this filing were due on or before March 6, 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).

- **LGIA: CMP/Wight Brook (ER17-938)**

On March 30, the FERC accepted the non-conforming Large Generation Interconnection Agreement ("LGIA") between CMP and Wight Brook Hydro ("Wight Brook"), which governs the continuing interconnection of Wight Brook's 30 MW hydro generating facility located in Newry, Maine. Since the LGIA continues the existing interconnection arrangements between CMP and Wight Brook, without modification to the facility's capability or operating characteristics, a new three-party IA that would include the ISO was not required. The LGIA was accepted, effective as of February 1, 2017, as requested. Unless the March 30 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **LGIA: CMP/Stony Brook (ER17-937)**

Also on March 30, the FERC accepted the non-conforming LGIA between CMP and Stony Brook Hydro ("Stony Brook"), which governs the continuing interconnection of Stony Brook's 30 MW hydro generating facility located in Hanover, Maine. Like Wight Brook, a new three-party IA with the ISO was not required because the LGIA continues the existing interconnection arrangements between CMP and Stony Brook, without modification to the facility's capability or operating characteristics. A February 1, 2017 effective was requested. The LGIA was accepted, effective as of February 1, 2017, as requested. Unless the March 30 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **LGIA: CMP/ReEnergy Livermore Falls (ER17-909)**

On March 15, the FERC accepted a non-conforming LGIA between CMP and ReEnergy Livermore Falls that governs the interconnection of ReEnergy's 39 MW biomass-fueled generating facility located in Livermore Falls, Maine. Since the LGIA continues the existing interconnection arrangements between CMP and Livermore Falls, without modification to the facility's capability or operating characteristics, a new three-party IA was not required. The LGIA was accepted effective as of January 1, 2017, as requested. Unless the March 15 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

As previously reported, the FERC conditionally accepted, on December 7, 2015, changes to the Maine Public District ("MPD") Open Access Transmission Tariff ("MPD OATT"), including to the rates, terms, and conditions set forth in MPD OATT Attachment J.[66] However, the FERC found, ultimately, that the changes to the MPD OATT had not been shown to be just and reasonable, may be unjust and unreasonable, instituted a Section 206 proceeding (in EL16-13) to examine the provisions, and set the matter for a trial-type evidentiary hearing, to be held in abeyance pending the outcome of settlement judge procedures (*see* below).

Background (ER15-1429). Emera Maine, as successor to Maine Public Service Company ("Maine Public"), provides open access to Emera Maine's transmission facilities in northern Maine (the "MPD Transmission System") pursuant to the MPD OATT. Emera Maine stated that the changes to the MPD OATT were needed to ensure that, in light of the filing by Emera of consolidated FERC Form 1 data (data comprising both the former Bangor Hydro and Maine Public systems), charges for service under the MPD OATT reflect only the costs of service over the MPD Transmission System. Emera Maine also proposed additional, limited changes to the MPD OATT. A June 1, 2015 effective date was requested. The "Maine Customer Group"[67] filed a motion to reject ("Motion to Reject") the April 1 Filing, asserting the April 1 Filing was deficient because, rather than actual rates, it included proxy rates that MPD said would be replaced with 2014 Form 1 numbers when MPD's 2014 Form 1 was available. On April 22, the Maine PUC and the Maine Customer Group protested the filing. The MPUC challenged three aspects of the filing: (i) the proposed increase of ROE from 9.75% to 10.20% based on anomalous economic conditions; (ii) the change from a measured loss factor calculation to a fixed loss factor; and (iii) the use of end-of-year account balances, rather than average 13-month account balances, for determination of facilities that are included in rate base. In addition to those aspects, the Maine Customer Group further challenged: (iv) inclusion of an out-of-period adjustment to rate base for forecasted transmission; (v) the proposed capital structure, which they assert is artificially distorted to accommodate a requirement resulting from the merger of Emera Maine's predecessor companies; and (vi) the proposed new cost allocation scheme. On April 24, Emera Maine answered the Maine Customer Group's Motion to Reject. On April 29, the Maine Customer Group answered Emera Maine's April 24 answer. On May 1, Emera Maine filed an amendment and errata to its April 1 filing,

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

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

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

On June 2, 2016, the FERC granted Maine Customer Group's Motion to Compel, and set the remaining issues with respect to Emera Maine's 2014 and 2015 Annual Updates for hearing and settlement judge procedures.[68] The FERC also consolidated ER12-1650 with this proceeding. In addition, the FERC directed that Emera Maine to make a compliance filing, on or before July 5, that (1) revises its 2014-2015 formula rate charges to correct the errors the Maine Customer Group raised with respect to amortization of long-term debt costs and post-retirement benefits other than pensions, and (2) imputes the retired debt balance for the tax-free Maine Public bonds ($22.6 million) into the capital structure calculation for the 2014-2015 Rate Year. Emera Maine requested rehearing of the June 2 order on July 5. On January 6, 2017, the FERC denied rehearing and Emera Maine's alternative request for consolidation with the ongoing proceedings in Docket Nos. EC10-67-002, *et al*.[69]

Compliance Filing (ER12-1650). The *January 6 Order* also conditionally accepted Emera Maine's July 5, 2016, pending compliance filing. submitted in response to the June 2 Order described above. The compliance filing was contested by the Maine Customer Group, which asserted that Emera's compliance filing was incorrect as to two of the three refund issues, and Emera should be ordered to pay immediate refunds in accordance with the corrected revised formula rate it proposed. While the FERC sided with Emera Maine on the refund issues, it agreed with the Maine Customer Group that immediate refunds were in order. Accordingly, the FERC directed Emera Maine to make adjustments during the 2014-2015 Rate Year and refund the nearly $400,000 of excess revenue requirement as shown in its compliance filing, demonstrating in a refund report 6 how the excess charges will be refunded.[70] Emera Maine submitted that report on February 9, indicating the amounts to be refunded by February 28, 2017 to each customer that took either point-to-point or network service under the MPD OATT. The FERC accepted the Report on March 15, 2017.

Hearing and Settlement Judge Procedures. The FERC encouraged the parties to make every effort to settle their disputes before hearing procedures are commenced, and is holding the hearing in abeyance pending the outcome of settlement judge procedures. As previously reported, Chief Judge Cintron substituted ALJ Dring in place of ALJ Johnson in mid-September as the settlement judge for these proceedings. Settlement conferences before Judge Johnson were held on January 5, March 3, and April 26, 2016 and on October 25 before Judge Dring. A fifth settlement conference, scheduled for November 22, was held on December 1. Since the last Report, Judge Dring issued on March 24 an eighth status report (i) indicating that the parties have reached a settlement in principal and are memorializing their agreement (which now is to be filed in late April or early May), and (ii) recommending that settlement judge procedures be continued. If you have any questions concerning these matters, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **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.

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[68] *Emera Maine*, 155 FERC ¶ 61,233 (June 2, 2016), *reh'g denied*, 158 FERC ¶ 61,012 (Jan. 6, 2017).

[69] *Emera Maine*, 158 FERC ¶ 61,012 (Jan. 6, 2017) ("*January 6 Order*").

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

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

- **FERC 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

- **IDs for Visitors to FERC (not docketed)**

On February 2, all parties on service lists subject to settlement judge and hearing procedures were notified that, pursuant to new security procedures for entry onto FERC premises implemented pursuant to the REAL ID Act,[71] driver's licenses and state-issued ID cards from certain states, including the state of Maine, will no longer be accepted by security. Visitors from those states must use alternative forms of identification.[72]

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

On March 3, FERC issued a notice of a 2-day (May 1-2) technical conference 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. Specifically, FERC staff seeks 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". Further details regarding the agenda, speakers and organization of the technical conference will be identified in supplemental notices to be issued prior to the technical conference. All interested may attend. Though registration is not required, in-person attendees are encouraged to register on-line at: https://www.ferc.gov/whats-new/registration/05-01-17-form.asp. There will also be a free webcast of the conference.

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[71] Congress passed the REAL ID Act in 2005 in response to the 9/11 Commission's recommendation that the Federal Government "set standards for the issuance of sources of identification, such as driver's licenses." The Act established minimum security standards for state-issued driver's licenses and identification cards and prohibits Federal agencies from accepting, for official purposes, licenses and identification cards from states that do not meet these standards. Visitors seeking access to FERC and other Federal facilities using their state-issued driver's licenses or identification cards must present proper identification issued by REAL ID compliant states or a state that has received an extension. Connecticut and Vermont are REAL ID compliant. Massachusetts, New Hampshire and Rhode Island have received an extension until October 17, 2017. The REAL ID status of other states is available at https://www.dhs.gov/real-id-enforcement-brief.

[72] Other TRA-approved IDs include: US passports or passport cards; DHS trusted traveler cards; US military IDs; and permanent resident or border crossing cards. For a complete list, see https://www.ferc.gov/security-requirements-for-visitors-to-FERC.pdf.

- **Agency Operations in the Absence of a FERC Quorum (AD17-10)**

On February 3, the FERC issued an order delegating additional authority to agency staff to continue certain agency operations in the absence of a quorum of FERC Commissioners.[73] The *Absence of a Quorum Delegation Order* also affirmed that all pre-existing delegations of authority by the FERC to its staff continue to be effective. The *Absence of a Quorum Delegation Order* took effect February 4, 2017, and the additional authority granted to agency staff will last until the earlier of FERC action lifting the *Order* or 14 days following the date a quorum is re-established. The specific delegation of agency authority permits (i) the Director of OEMR to accept and suspend rate filings, and make them effective subject to refund and further order of the FERC, or accept and suspend them, make them effective subject to refund, and set them for hearing and settlement judge procedures (for initial rates or rate decreases submitted under section 205 of the FPA, for which suspension and refund protection are unavailable, FERC staff was granted authority under section 206 to institute proceedings in order to protect the interests of customers);[74] (ii) FERC staff to extend the time for action on matters where it is permitted by statute; and (iii) the Director of OEMR to take appropriate action on uncontested waiver and settlement filings. Although the *Delegation Order* was initially challenged by the Wyoming Pipeline Authority ("WPA"), the WPA withdrew its challenge and, with no other party challenging it, the *Delegation Order* is final and unappealable.

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

On February 10, the FERC issued a notice that it will hold a June 22, 2017 technical conference to discuss policy issues related to the reliability of the Bulk-Power System ("BPS"). The FERC will issue an agenda at a later date.

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

On November 9, 2016, the FERC held a technical conference to discuss the utilization of electric storage resources as transmission assets compensated through RTO/ISO transmission rates, for grid support services that are compensated in other ways, and for multiple services. On November 14, the FERC invited all those interested to file, on or before December 14, 2016, post-technical conference comments on the topics discussed in the November 1 Supplemental Notice of Technical Conference. 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. On August 3, the FERC issued a notice inviting post-technical conference comments on questions listed in the attachment to the notice. Following requests by Utility Trade Associations[75] and the New Jersey BPU, the deadline for comments was extended to October 3, 2016 and 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.

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[73] Agency Operations in the Absence of a Quorum ,158 FERC ¶ 61,135 (Feb. 3, 2017) ("*Absence of a Quorum Delegation Order*").

[74] The acceptance for filing and suspension and making effective subject to refund and to further FERC order of these filings is without prejudice to any further action of the FERC with respect to these filings once the FERC again has a quorum.

[75] The "Utility Trade Associations" are APPA, EEI, Large Public Power Council, NRECA, and TAPS.

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

A workshop to discuss compensation for Reactive Supply and Voltage Control (Reactive Supply) in RTO/ISO markets was held on June 30, 2016. The workshop explored the types of costs incurred by generators for providing Reactive Supply capability and service; whether those costs are being recovered solely as compensation for Reactive Supply or whether recovery is also through compensation for other services; and different methods by which generators receive compensation for Reactive Supply (e.g., FERC-approved revenue requirements, market-wide rates, etc.). The workshop also explored potential adjustments in compensation based on changes in Reactive Supply capability and potential mechanisms to prevent overcompensation for Reactive Supply. Technical conference materials are available on the FERC's e-Library. Written comments were due on or before July 28, 2016, and were filed by, among others, NYISO, PJM, the PJM IMM, AWEA, EEI, EPSA, EDF Renewables, Talen, Essential Power, and Exelon. EDF Renewables filed reply comments on August 19; 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. On September 6, the FERC issued a notice inviting post-technical conference comments to be filed. Such comments may address (1) the use of the "one-mile rule" to determine the size of an entity seeking certification as a small power production qualifying facility ("QF"); and (2) minimum standards for PURPA-purchase contracts. Comments were due on or before November 7, 2016 and were filed by over 40 parties, including AWEA, Covanta, CT PURA/MA AG, Duke, EDP, EEI, ELCON, NARUC, and NRECA.

- **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:[76] (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 and uplift allocation 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.[77] The NOI follows the D.C. Circuit's *United Airlines*[78] 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".[79] In response to requests for an extension of the comment and reply comment deadlines, and objections to those requests, the FERC extended the comment and reply comment deadlines to March 8 and April 7, 2017, respectively. Comments were submitted by over 25 parties, including a particularly ebullient pleading by a former general counsel of FERC's predecessor, the Federal Power Commission. As noted immediately above, replies to the comments submitted, if any, are due on or before April 7.

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

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

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

[79] *Id.* at 137.

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

As previously reported, the FERC issued a NOPR[80] on December 15, 2016 proposing reforms designed to improve certainty,[81] promote more informed interconnection,[82] and enhance interconnection processes.[83] 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 has identified proposed reforms which it states could remedy potential shortcomings in the existing interconnection processes. The FERC also seeks comment on whether any of its proposed reforms should be applied to the *pro forma* SGIP/SGIA.[84] Following a request from the ISO/RO Council ("IRC"), supported by NEPOOL and a coalition of trade associations (APPA, LPPA, NRECA), for a 30-day extension of the comment deadline granted by the FERC on February 23, comments on the *LGIP/LGIA Reforms NOPR* are now due April 13, 2017. Draft NEPOOL Comments will be considered at the April 7 Participants Committee meeting. Since the last Report, Industrial Energy Consumers of America submitted comments.

- **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.[85] The FERC stated that these reforms should lead to prices that more transparently reflect the marginal cost of serving load, which will

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[80] *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.

[81] 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.

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

[83] 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.

[84] *Id.* at P 11.

[85] *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*").

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 offline 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 due on or before February 28, 2017[86] and were filed by numerous parties, including NEPOOL, ISO-NE and EEI. Reply comments were filed by MISO and he PJM IMM. The *Fast-Start Pricing NOPR* is pending before the FERC.

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

On January 19, 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.[87] 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 on the *Uplift/Transparency NOPR* are due on or before April 10, 2017.[88]

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

On November 23, the FERC issued a NOPR proposing to require each RTO and ISO to revise its tariff "to (1) establish a participation model consisting of market rules that, recognizing the physical and operational characteristics of electric storage resources, accommodates their participation in the organized wholesale electric markets and (2) define distributed energy resource aggregators as a type of market participant that can participate in the organized wholesale electric markets under the participation model that best accommodates the physical and operational characteristics of its distributed energy resource aggregation."[89] Comments on the *Storage NOPR* were initially due on or before January 30, 2017,[90] but following requests for an extension of time, were due February 13, 2017. Comments 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, IPKeys, MA DPU,

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[86] The *Fast-Start Pricing NOPR* was published in the *Fed. Reg.* on Dec. 30, 2016 (Vol. 81, No. 251 pp. 96,391-96,404.

[87] *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*").

[88] The *Uplift/Transparency NOPR* was published in the *Fed. Reg.* on Feb. 7, 2017 (Vol. 82, No. 24 pp. 9,539-9,555.

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

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

MIT, MMWEC, NARUC, NERC, NESCOE, NextEra, NRG, SEIA, UCS. This matter is 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.[91] The *Data Collection NOPR* presents substantial revisions from what the FERC proposed in the *Connected Entity NOPR*, and responds to the comments and concerns submitted by NEPOOL in that proceeding. Among other things, the changes proposed in the *Data NOPR* include: (i) a different set of filers; (ii) a reworked and substantially narrowed definition of Connected Entity; and (iii) a different submission process. With respect to the MBR program, the proposals include: (i) adopting certain changes to reduce and clarify the scope of ownership information that MBR sellers must provide; (ii) reducing the information required in asset appendices; and (iii) collecting currently-required MBR information and certain new information in a consolidated and streamlined manner. The FERC also proposes to eliminate MBR sellers' corporate organizational chart submission requirement adopted in *Order 816*. Comments on the *Data Collection NOPR* were due on or before September 19, 2016[92] and were filed by over 30 parties, including: APPA, Avangrid, Brookfield, EPSA, Macquarie/DC Energy/Emera Energy Services, NextEra, and NRG.

Technical Workshops. The FERC held two technical workshops. The first technical workshop was held on August 11 and focused on the *Data Collection NOPR's* draft data dictionary. The second technical workshop was held on December 7, 2016 and focused on the submittal process, with case studies serving as a platform for discussion of (i) the steps to submit data; (ii) data review and validation processes; and (iii) the notifications to be provided through the data validation and receipt process. Staff also provided a high-level update on proposed technical refinements to the data dictionary based on input received during the first workshop and additional outreach.

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

The FERC issued *Order 833*[93] on November 16, 2016. *Order 833* amended FERC regulations to implement provisions of the Fixing America's Surface Transportation ("FAST") Act that pertain to the designation, protection and sharing of Critical Electric Infrastructure Information ("CEII") and amend other regulations that pertain to CEII. The amended procedures will be referred to as the Critical Energy/Electric Infrastructure Information (CEII) procedures. *Order 833* became effective February 21, 2017.[94] On December 19, 2016, EEI requested rehearing of *Order 833*. The FERC issued a tolling order on January 17, 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)**

On November 17, 2016, the FERC issued a NOPR proposing to require all newly interconnecting large and small generating facilities, both synchronous and non-synchronous, to install and enable primary

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

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

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

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

frequency response capability as a condition of interconnection.[95] 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*[96] from early 2016. Comments on the *Primary Frequency Response NOPR* were due on or before January 24, 2017[97] and were filed by over 30 parties, including AWEA, EEI, ELCON, EPSA, ESA, First Solar, the IRC, NRECA, and UCS. Since the last Report, supplemental comments were filed by ELCON. This matter is pending before the FERC.

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

On November 17, 2016, the FERC issued *Order 831*[98] requiring each RTO/ISO: (i) to cap each resource's incremental energy offer at the higher of $1,000/MWh or that resource's verified cost-based incremental energy offer; and (ii) cap verified cost-based incremental energy offers at $2,000/MWh when calculating locational marginal prices ("LMP"). In addition, the FERC clarified that the verification process 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.[99] Market Rule changes implementing *Order 831* are required to be filed within 75 days of that effective date, or by May 8, 2017.[100] On December 19, 2017, American Municipal Power Inc. ("AMP") and APPA, Exelon, NYISO, and TAPS requested rehearing and/or clarification of *Order 831*. The FERC issued a tolling order on January 17, affording it additional time to consider the requests for rehearing, which remain pending. On January 4, the PJM Market Monitor opposed Exelon's motion for clarification and/or rehearing. On January 13, MISO submitted comments supporting NYISO request for rehearing.

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

As previously reported, *Order 825*[101] revises FERC regulations to require that each RTO/ISO (i) settle (a) energy transactions in its real-time markets at the same time interval it dispatches energy; (b) operating reserves transactions in its real-time markets at the same time interval it prices operating reserves; and (c) intertie transactions in the same time interval it schedules intertie transactions; and (ii) trigger shortage pricing for any dispatch interval during which a shortage of energy or operating reserves occurs. The FERC stated that adopting these reforms will align prices with resource dispatch instructions and operating needs, providing appropriate incentives for resource performance. *Order 825* will become effective September 13, 2016.[102]

Compliance. Each RTO/ISO was required to submit a compliance filing with the tariff changes needed to implement this Final Rule within 120 days of the Final Rule's September 13, 2016 effective date (on or before January 11, 2017). As noted in Section III above, New England's *Order 825* compliance filing was submitted on

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

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

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

[98] *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 requested*.

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

[100] The 75-day period ends on Saturday, May 6. Pursuant to Rule 2007 of the FERC's Rules of Practice & Procedure, if the last day of a time period falls on a weekend, the time period does not end until the close of the next day on which the FERC remains open. See 18 CFR 385.2007(a)(2).

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

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

January 11. The FERC will allow a further 12 months from the compliance filing date for the tariff changes implementing reforms to settlement intervals to be effective, and 120 days from that same compliance filing date for the tariff changes implementing shortage pricing reforms to be effective. As previously noted, the ISO's and NEPOOL's jointly filed Sub-Hourly Settlement Changes, which changed to five minutes the settlement interval in the Real-Time Energy and Reserves Markets, was filed and accepted by the FERC.

XIII. Natural Gas Proceedings

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

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

On March 31, 2016, the FERC conditionally accepted Algonquin tariff modifications and request for waiver that provided an exemption from capacity release bidding requirements for certain types of firm transportation capacity releases by Electric Distribution Companies ("EDCs") that are participating in state-regulated electric reliability programs.[103] 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.[104] 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.[105] 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.[106] 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.[107] 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

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

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

[105] *Id.* at P 27.

[106] *Id.* at P 34.

[107] *Id.* at P 35

Marketing Ventures filed answers to the requests for clarification on October 17. Those requests are pending before the FERC.

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

- **Natural Gas-Related Enforcement Actions**

The FERC continues to closely monitor and enforce compliance with regulations governing open access transportation on interstate natural gas pipelines:

BP (IN13-15). On July 11, 2016, the FERC issued *Opinion 549*[108] 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").[109] 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."[110] 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.[111] BP was directed to pay the civil penalty and disgorgement amount within 60 days of the *BP Penalties Order*. On August 10, BP requested rehearing of the *BP Penalties Order*. On September 8, the FERC issued a tolling order, affording it additional time to consider BP's request for rehearing of the *BP Penalties Order*, which remains pending.

On September 7, BP submitted a motion for modification of the *BP Penalties Order's* disgorgement directive because it cannot comply with the disgorgement directive as ordered. BP explained that the entity to which disgorgement was to be directed, the Texas Low Income Home Energy Assistance Program ("LIHEAP"), is not set up to receive or disburse amounts received from any person other than the Texas Legislature. In response, on September 12, the FERC stayed the disgorgement directive (until an order on BP's pending request for rehearing is issued), but indicated that interest will continue to accrue on unpaid monies during the pendency of the stay.[112]

Total Gas & Power North America, Inc. et al. (IN12-17). On April 28, 2016, the FERC issued a show cause order[113] 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

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

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

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

[111] *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).

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

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

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.[114]

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

- **New England Pipeline Proceedings**
  The following New England pipeline projects are currently under construction or before the FERC:
  - ***Atlantic Bridge Project (CP16-9)***
    - Algonquin Gas Transmission filed for Section 7(b) and 7(c) certificate on Oct. 22, 2015.
    - 132,700 Dth/d of firm transportation to new and existing delivery points on the Algonquin system and 106,276 Dth/d of firm transportation service from Beverly, MA to various existing delivery points on the Maritimes & Northeast system.
    - 6.3 miles of replacement pipeline along Algonquin in NY and CT; new 7,700-horsepower compressor station in Weymouth, MA; more horsepower at existing compressor stations in CT and NY.
    - Seven firm shippers: Heritage Gas Limited, Maine Natural Gas Company, NSTAR Gas Company d/b/a Eversource Energy, Exelon Generation Company, LLC (as assignee and asset manager of Summit Natural Gas of Maine), Irving Oil Terminal Operations, Inc., New England NG Supply Limited, and Norwich Public Utilities.
    - Certificate of public convenience and necessity granted Jan. 25, 2017.[115]
    - Authorization to proceed with construction of certain Projects segments requested Mar. 14, 2017 and granted on Mar. 27, 2017.
  - ***Connecticut Expansion Project (CP14-529)***
    - Tennessee Gas Pipeline filed for Section 7(c) certificate July 31, 2014.
    - 72,100 Dth/d of firm capacity.
    - 13.26 miles of three looping segments & facility upgrades/modifications in NY, MA & CT.
    - Three firm shippers: Conn. Natural Gas, Southern Conn. Gas, and Yankee Gas.
    - Notice of Schedule issued Sept. 1 with FERC EA to be issued Oct. 23 and 90-day Federal Authorization Decision Deadline set at Jan. 21, 2016.

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

[115] Order Issuing Certificate and Authorizing Abandonment, *Algonquin Gas Transmission LLC and Maritimes & Northeast Pipeline, LLC*, 158 FERC ¶ 61,061 (Jan. 25, 2017), *reh'g requested*.

  - Environmental Assessment (EA) issued on Oct. 23, 2015.
  - Certificate of public convenience and necessity granted Mar. 11, 2016.[116]
  - Construction began 4th Quarter 2016.
  - In-service: Nov. 2017 (anticipated).

- ***Constitution Pipeline (CP13-499) and Wright Interconnection Project (CP13-502)***
  - Constitution Pipeline Company and Iroquois Gas Transmission (Wright Interconnection) concurrently filed for Section 7(c) certificates on June 13, 2013.
  - 650,000 Dth/d of firm capacity from Susquehanna County, PA (Marcellus Shale) through NY to Iroquois/Tennessee interconnection (Wright Interconnection).
  - New 122-mile interstate pipeline.
  - Two firm shippers: Cabot Oil & Gas and Southwestern Energy Services.
  - Final EIS completed on Oct 24, 2014.
  - Certificates of public convenience and necessity granted Dec 2, 2014.
  - On April 22, 2016, New York State Department of Environmental Conservation denied Constitution's application for a Section 401 permit under the Clean Water Act. The decision effectively guarantees that the Constitution Pipeline project will, at best, be delayed by several years.
  - On May 16, 2016, the New York Attorney General filed a complaint against Constitution at the FERC (CP13-499) seeking a stay of the December 2014 order granting the original certificates, as well as alleging violations of the order, the Natural Gas Act, and the Commission's own regulations due to acts and omissions associated with clear-cutting and other construction-related activities on the pipeline right of way in New York.
  - Construction was expected to begin Spring 2016 (after final Federal Authorizations), but has been plagued by delays.
    - On October 13, 2016, the FERC approved Constitution's request to proceed to remove the felled trees in Pennsylvania.

XIV. State Proceedings & Federal Legislative Proceedings

No Activity to Report.

XV. Federal Courts

The following are matters of interest, including petitions for review of FERC decisions in NEPOOL-related proceedings, that are currently pending before the federal courts (unless otherwise noted, the cases are before the U.S. Court of Appeals for the District of Columbia Circuit). An "**" following the Case No. indicates that NEPOOL has intervened or is a litigant in the appeal. The remaining matters are appeals as to which NEPOOL has no organizational interest but that may be of interest to Participants. For further information on any of these proceedings, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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[116] *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).

- **Demand Curve Changes (17-1110)**
  Underlying FERC Proceedings: ER14-1639[117]
  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. A briefing order will follow.

- **FCA10 Results (16-1408) and FCA9 Results (16-1068)**
  Underlying FERC Proceedings: ER16-1041[118] **ER15-1137**[119]
  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. On March 14, Petitions filed Petitioners' Brief . The briefing schedule calls for the following: Respondent's Brief to be filed by May 15, 2017; Intervenor for Respondent's Brief, May 22, 2017; Petitioners' Reply Brief, June 5, 2017; Deferred Appendix, June 12, 2017; and Final Briefs, June 26, 2017.

- **NEPGA PER Complaint and FCM Jump Ball and Compliance Proceedings (16-1023/1024)**
  Underlying FERC Proceeding: ER14-1050;[120] **EL14-52;121 EL15-25**[122]
  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 and this matter remains pending before the DC Circuit.

- **Base ROE Complaints II & III (2012 & 2014) (15-1212)**
  Underlying FERC Proceedings: EL13-33; EL14-86[123]
  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 sixth such report filed, was filed on February 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.

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[117] 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*).

[118] 155 FERC ¶ 61,273 (June 16, 2016); 157 FERC ¶ 61,060 (Oct. 27, 2016).

[119] 153 FERC ¶ 61,378 (Dec. 30, 2015); 151 FERC ¶ 61,226 (June 18, 2015).

[120] 153 FERC ¶ 61,224 (Nov. 19, 2015); 153 FERC ¶ 61,223 (Nov. 19, 2015); 147 FERC ¶ 61,172 (May 30, 2014).

[121] 153 FERC ¶ 61,222 (Nov. 19, 2015); 150 FERC ¶ 61,053 (Jan. 30, 2015).

[122] 153 FERC ¶ 61,222 (Nov. 19, 2015); 150 FERC ¶ 61,053 (Jan. 30, 2015).

[123] 147 FERC ¶ 61,235 (June 19, 2014); 149 FERC ¶ 61,156 (Nov. 24, 2014); 151 FERC ¶ 61,125 (May 14, 2015).

- **Order 1000 Compliance Filings (15-1139, 15-1141**) (consolidated)**
  Underlying FERC Proceedings: ER13-193; ER13-196[124]
  Appellants: New England Transmission Owners (NETOs); NESCOE/CT DEEP/CT PURA, *et al*.

As previously reported, NETOs[125] and NESCOE, *et al*., filed a petition for review of the FERC's orders in the *Order 1000* Compliance Filing proceeding on May 15, 2015. Briefing has been completed and oral argument was held on January 13, 2017 before a panel comprised of Judges Brown, Wilkins and Edwards. This matter is now pending before the DC Circuit.

- **Base ROE Complaint I (2011) (15-1118, 15-1119, 15-1121**) (consolidated)**
  Underlying FERC Proceeding: EL11-66[126]
  Appellants: NETOs

On April 30, 2015, NETOs filed a petition for review of the FERC's orders in the 2011 Base ROE Complaint Proceeding. All briefing was completed and oral argument was held on December 6 before Judges Millett, Sentelle and Randolph. This matter is now pending before the DC Circuit.

- **FCM Pricing Rules Complaints (15-1071**, 16-1042) (consol.)**
  Underlying FERC Proceeding: EL14-7,[127] **EL15-23**[128]
  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. On May 22, the Court granted NEPGA's motion to hold the case in abeyance pending a decision in EL15-23 and, following the FERC's decision in EL15-23 and Exelon's appeal of that case (16-1042), Exelon's motion to consolidate this proceeding with 16-1042. All briefing in the consolidated proceeding has now been completed and this matter is now before the Court.

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

In this proceeding, an appeal from an unsuccessful challenge of Connecticut's actions under the 2015 multi-state clean energy RFP ("Clean Energy RFP") in Connecticut District Court, Allco continues its challenges to Connecticut's actions under the Clean Energy RFP. Allco asserts that Connecticut's actions are inconsistent with PURPA and constitutional principles recently addressed by the Supreme Court in *Hughes v Talen Energy Marketing* and summarized in prior Reports. As reported at the November Participants Committee meeting, the Second Circuit Court of Appeals on November 2 granted Allco's motion for an emergency injunction. The emergency injunction enjoined Connecticut (but not Massachusetts or Rhode Island) from "awarding, entering into, executing, or approving any wholesale electricity contracts in connection with the [Clean Energy RFP] during the pendency of this appeal." The injunction did "not apply retroactively to any wholesale electricity contract that has been entered into, executed, and approved" as of November 2, 2016. Briefs and Amicus Briefs were filed. Oral argument was held on December 9, 2016. On December 12, 2016 the Court vacated the November 2 injunction, indicating that an opinion would follow in due course. That opinion has not yet been issued.

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[124] 150 FERC ¶ 61,209 (Mar. 19, 2015); 143 FERC ¶ 61,150 (May 17, 2013).

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

[126] 150 FERC ¶ 61,165 (Mar. 3, 2015); 149 FERC ¶ 61,032 (Oct. 16, 2014); 147 FERC ¶ 61,234 (June 19, 2014).

[127] 150 FERC ¶ 61,064 (Jan. 30, 2015); 146 FERC ¶ 61,039 (Jan. 24, 2014).

[128] 154 FERC ¶ 61,005 (Jan. 7, 2016); 150 FERC ¶ 61,067 (Jan. 30, 2015).

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NEPOOL PARTICIPANTS COMMITTEE
APR 7, 2017 MEETING, AGENDA ITEM #10A

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Paul Belval and John Shriver, NEPOOL Counsel

DATE: April 5, 2017

RE: Report on status of GIS Agreement Working Group discussions concerning future GIS Arrangements

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You will receive a report at the April 7, 2017 meeting of the NEPOOL Participants Committee on the status of GIS Agreement Working Group (the "Working Group") discussions concerning future NEPOOL Generation Information System ("GIS") arrangements. This memorandum summarizes that status. The report is for information and, at this point, no action on your part is necessary.

Since convening in June of 2016, the Working Group has explored various options regarding the continued development and administration of the GIS. Among other options, the Working Group considered issuing a request for proposals for the development and administration of the GIS, as well as extending and restating the agreement with the current GIS administrator, APX, Inc. ("APX"). During this exploration and evaluation process, the existing agreement with APX automatically renewed for a twelve-month term, which now runs through December 31, 2017.

After evaluating various options, the Working Group has concluded, based on preliminary agreement in principle with APX, that the desired course of action is to pursue amendment and restatement of the existing GIS Development and Administration Agreement, with current discussions of a three-year term running from January 1, 2018 through December 31, 2020. Under the preliminary agreement, NEPOOL Load Serving Entities (LSEs) will benefit from lower APX administrative fees along with improved functionality, security and data integrity. Importantly, these benefits can be realized without risk of interruption in the operation and availability of the GIS. The preliminary agreement also includes new annual subscriptions for Large (more than 10MW in aggregate nameplate capacity registered), Medium (1MW up to 10MW in aggregate nameplate capacity registered) and Trader (no registered generators) account holders, Absent alternative direction from the Participants Committee, the Working Group will dedicate its efforts between now and the Participant's Committee's summer meeting to negotiating an agreement consistent with this preliminary agreement in principle, and cease its exploration of alternative GIS providers for now. If members wish to provide the Working Group additional direction with respect to those negotiations, the Participants Committee may decide to go into executive session for those strategic discussions.

If you have any questions about this memo or the GIS Agreement Working Group's efforts in advance of Friday's meeting, please contact Paul Belval (860-275-0831, pnbelval@daypitney.com).