NEW ENGLAND POWER POOL

David T. Doot
Secretary

February 27, 2020

VIA ELECTRONIC MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of March 5, 2020 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 **Thursday, March 5, 2020 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.

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

The room block at the Colonnade Hotel for the March 5 meeting is now closed. If you need a room and have not yet made arrangements, please contact Pat Gerity (pmgerity@daypitney.com / 860-275-0533).

Respectfully yours,

/s/
David T. Doot, Secretary

FINAL AGENDA

1. To approve the preliminary minutes of the Participants Committee teleconference meeting held on February 6, 2020. The preliminary minutes of the February 6 meeting are included with this supplemental notice and posted with the meeting materials.

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

3. To receive an ISO Chief Executive Officer Report.

4. To receive an ISO Chief Operating Officer Report.

5. To receive input on plans for future discussions on issues related to New England's transition to a future grid. Background materials are included with this supplemental notice and posted with the meeting materials.

6. To consider and take action, as appropriate, on a recommendation by the Membership Subcommittee to approve Advanced Energy Economy as a Fuels Industry Participant and NEPOOL member. Background material and draft resolutions are included with this supplemental notice and posted with the meeting materials.

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

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

   - Markets Committee
   - Reliability Committee
   - Transmission Committee
   - Budget & Finance Subcommittee
   - GIS Agreement Working Group
   - Joint Nominating Committee
   - Others

9. Administrative matters.

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

PRELIMINARY

A meeting of the NEPOOL Participants Committee was held via teleconference beginning at 10:00 a.m. on Thursday, February 6, 2020, 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.

Ms. Nancy Chafetz, Chair, presided and Mr. David Doot, Secretary, recorded.

APPROVAL OF DECEMBER 6, 2019 MINUTES

Ms. Chafetz referred the Committee to the preliminary minutes of the December 6, 2019 annual meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of the December 6, 2019 annual meeting were unanimously approved as circulated, with an abstention by Mr. Michael Kuser noted.

CONSENT AGENDA

Ms. Chafetz referred the Committee to the Consent Agenda that was circulated and posted in advance of the meeting. Following motion duly made and seconded, the Consent Agenda was unanimously approved without comment, with an abstention by Mr. Kuser noted.

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 December 6, 2019 Participants Committee meeting, which had been circulated and posted in advance of the meeting. There were no questions or comments on the summaries.

In response to questions preceding and at the meeting, Mr. Van Welie requested that Ms. Anne George, ISO Vice President, External Affairs and Corporate Communications, summarize the ISO comments provided at Connecticut's January 22, 2020 Integrated Resource Plan

Technical Meeting. She noted that the ISO also provided written comments, which were publicly available on the ISO's website and filed with Connecticut's regulators.

Ms. George summarized her comments as follows:

The ISO respected the states' rights to prioritize public policies and would strive to assist in addressing those policies consistent with the ISO's jurisdictional and legal mandates. She summarized the cost, reliability and environmental benefits that Connecticut and the other New England states experienced through participation in the regional system. She noted that competitive forces, which had driven system efficiencies, could also be used to achieve the states' clean energy goals. In addition, Ms. George noted that Connecticut appeared focused on the capacity market. She stressed the integration and interdependence of all of the ISO markets.

Ms. George also stated that the ISO disagreed with Connecticut's perspective on the effectiveness of Competitive Auctions with Sponsored Policy Resources (CASPR). She identified carbon pricing as a possible mechanism to efficiently address State concerns in the wholesale market framework. She said that the ISO was open to discussing other alternatives as discussions ensued on the future of the wholesale markets.

In response to questions regarding the FERC's recent order on PJM's capacity market, she stated that the ISO did not believe that the effects of that order presented an immediate risk to New England's capacity market. Connecticut regulators also asked about self-supply options, like those discussed in PJM. Ms. George noted in response to these questions that the New England arrangements did not provide for the self-supply Connecticut was inquiring about and changes would need to be worked through the Tariff if the region sought such an outcome. Ms. George again emphasized that the ISO was committing resources for exploring changes to the regional arrangements and studying the potential implications to the region of those changes.

ISO COO REPORT

Dr. Chadalavada reviewed highlights from the February COO report, which was circulated in advance of the meeting and posted on the NEPOOL and ISO websites. He noted that, based on data through January 29, 2020: (i) Energy Market value was $280 million, down $188 million from December 2019 and down $319 million from January 2019; (ii) average natural gas prices over the period were 38 percent lower than December average values; (iii) average Real-Time Hub LMPs ($26.29/MWh) were 39 percent lower than December averages; (iv) average daily (peak hour) Day-Ahead cleared physical Energy, as a percent of forecasted load, was 99.5 percent in January, up from 98.7 percent in December; and (v) daily Net Commitment Period Compensation (NCPC) for January totaled $1.6 million, down $3.1 million from December 2019 and down $600,000 from January 2019. January 2020 NCPC, which was 0.6 percent of total Energy Market value, was comprised of (a) $1.5 million in first contingency payments, down $500,000 from December, and (b) $108,000 in second contingency payments, down $168,000 from December.

Dr. Chadalavada noted that January was a very mild month with record high temperatures and correspondingly lower loads. He reported that Real-Time loads averaged about 14,000 MWh. Further, natural gas prices averaged about $3.00/MMBtu. He also noted that NCPC payments were at record lows, which continued a trend from 2019.

Dr. Chadalavada provided two reminders. First, the Public Policy Process was initiated on January 14, 2020. Stakeholder input on federal, state and local Public Policy Requirements must be submitted by February 28, 2020. Second, proposals in response to the Boston 2028 Phase One request for proposals (RFP) must be submitted by 11:00 p.m. on March 4, 2020.

Dr. Chadalavada then turned to the forward capacity auctions (FCA). He stated that preparations for FCA15 were underway and a press release on the results of FCA14 had been published earlier that week. He confirmed, in response to a question, that no Capacity Supply Obligations were transferred by way of substitution auction in FCA14.

Dr. Chadalavada then addressed questions received ahead of the meeting in four areas. First, he commented on the historic low loads that the region had experienced during December and January. He explained those loads directly correlated to the region's mild weather (temperature seasonally 4.5º higher, and for January, 8º higher, than normal; and little snow coverage increasing the efficiency of photovoltaic (PV) resources). He said that there had been only two very cold days in January -- one at the beginning of the month and the other in the middle -- which had not happened in a very long time.

Second, he responded to a question on the emissions exhibit in his report, which highlighted two ISO analysis efforts underway. The first effort was to produce load-weighted and a non-load-weighted emissions analyses of marginal resources. The ISO planned to review its preliminary findings from this effort at the February Environmental Advisory Group meeting. The second effort was an effort to assess the emissions intensity of imports into New England. The ISO was working to obtain data for this effort and hoped to begin discussion of that effort with stakeholders in April.

A third question related to planned refinements to the ISO's Installed Capacity Requirement (ICR) and load forecast models to recognize contributions of behind-the-meter PV resources and to improve the modeling of intermittent power resources. Dr. Chadalavada noted on-going ISO efforts to evaluate and improve upon its models, and reported that changes would be reviewed with NEPOOL beginning in the second quarter, with the Participants Committee to be apprised ahead of time on the details of how those discussions would be structured and where and how they would be scheduled.

Finally, in response to questions concerning the potential change of the deadline for Day-Ahead Energy Market bids from 10:00 a.m. to 10:30 a.m., Dr. Chadalavada confirmed that the ISO would propose such a change in the second quarter following the Energy Security Improvements (ESI) filing. He stated, in response to a question, that the ISO was targeting to implement such a change late in 2020.

FURTHER *ORDER 841* (ELECTRIC STORAGE) TARIFF REVISIONS

Ms. Chafetz referred the Committee to Tariff changes proposed in response to the FERC's November 22, 2019 order requiring further revisions to New England's *Order 841* compliance filing (the Order).

Ms. Mariah Winkler, Markets Committee Chair, summarized the Markets Committee-recommended changes and provided the procedural background for that Committee's consideration of the changes. She reported that, at its January 28, 2020 meeting, the Markets Committee unanimously recommended Participants Committee support for the changes, with an abstention noted.

The following motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports the revisions to Tariff Section III.1.10.6 to address certain requirements set forth in the FERC's November 22, 2019 Order in Docket No. ER19-470, as recommended by the Markets Committee at its January 28, 2020 meeting and as circulated to this Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

A Generation Group Seat representative expressed concern with the timing of the revisions addressing the Order's directives related to the state of charge and duration characteristics of an energy storage facility in the Day-Ahead Energy Market. The specific concern was the indication that such a change would not be implemented until January 1, 2026. She noted that about 2,500 MW of storage resources were already positioned in the interconnection queue and delaying such a change until 2026 could adversely impact those resources. She requested that efforts to address this issue be scheduled for later in 2020, with the hope that any required software changes could be integrated with or facilitated by the Day-Ahead Market changes to be developed in connection with the ESI proposal. Others, recognizing those concerns, nonetheless supported the ISO's proposed revisions, and opposed any linkage to the ESI changes.

The Committee then voted and approved the motion with no opposition and the following Participants abstaining: Generation Group Member and Mr. Michael Kuser.[1]

LITIGATION REPORT

Mr. Doot referred the Committee to the February 4 Litigation Report circulated and posted in advance of the meeting. He highlighted the following developments: (i) the more than 50 requests for rehearing of the FERC's December 19, 2019 order addressing PJM's Minimum Offer Price Rule; (ii) denial of two pending FCA14-related waiver requests and rejection of the Mystic cost-of-service agreement amendment that could have impacted FCA14; and (iii) the denial of the requests for rehearing of the FERC orders addressing membership by and treatment of press reporters in NEPOOL.

COMMITTEE REPORTS

Markets Committee (MC). Mr. William Fowler, the MC Vice-Chair, reported that the MC was scheduled to meet three days from February 11–13, 2020, and two days on March 10–11, 2020, all in Westborough. He also reminded members that the Committee was meeting again

[1] Secretary's note: following the meeting, Calpine's member, who's abstention had not been communicated in the teleconference call, requested that Calpine be noted as abstaining on the revisions for the same reason articulated when the revisions were considered by the Markets Committee. Specifically, at the Markets Committee Calpine objected to the ISO's use of two-hour capability, rather than Effective Load Carrying Capability (ELCC), in the determination of the capacity value of energy limited resources, which Calpine indicated it would pursue following consideration of the ESI proposal.

on March 24, 2020 in Worcester, at which it was scheduled to vote on the ISO's ESI proposal. Mr. Fowler asked Participants to provide any ESI-related amendments as soon as possible.

Reliability Committee (RC). Mr. Robert Stein, the RC Vice-Chair, reported that the next RC meeting would be February 18, 2020. On March, 17, 2020, the RC would have an ISO-led presentation on FCA14.

Transmission Committee (TC). Mr. José Rotger, the TC Vice-Chair, reported that the next TC meeting was scheduled for Wednesday, February 26, 2020, and would be held by teleconference, if not cancelled. He urge members to pay attention to further notices.

Budget & Finance Subcommittee (B&F). Ms. Michelle Gardner, B&F Chair, reported that the first B&F meeting of the year (following cancellation of the January 28 meeting) would be held February 10. Agenda items would include consideration of the ISO's fourth quarter capital funding tariff filing, NEPOOL year end results and a preview of upcoming items for 2020.

Membership Subcommittee. On behalf of the Subcommittee Chair, Mr. Patrick Gerity, NEPOOL Counsel, reported that, at its December 9, 2019 meeting, the Subcommittee members present recommended that the Participants Committee approve Advanced Energy Economy as a Fuels Industry Participant. That recommendation would be taken up at the next in-person Participants Committee meeting. He encourage all those interested to participate in the Subcommittee's next meeting scheduled for February 14, 2020.

Joint Nominating Committee (JNC). Mr. Doug Hurley reported that the JNC was scheduled to meet in mid-March to review and to narrow the list of candidates for the one open Board seat to be interviewed in-person in early May. Mr. Hurley also advised members to watch for the set of documents to be circulated by NEPOOL counsel that would describe the areas of

Board expertise, the retirement schedule for each Board member, and a brief description of the role of the ISO Board of Directors.

GIS Agreement Working Group. Mr. Dave Cavanaugh reported that the GIS Agreement Working Group had been re-formed to address the upcoming (December 31, 2020) expiration of the amended and restated GIS Administration Agreement between NEPOOL and APX. The first meeting was scheduled for February 18, 2020, and all those interested were encouraged to join.

OTHER BUSINESS

There being no further business, the meeting adjourned at 10:47 a.m.

Respectfully submitted,

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David Doot, Secretary

ATTACHMENT 1

**PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
FEBRUARY 6, 2020 TELECONFERENCE MEETING**

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
American Petroleum Institute	Fuels Industry Part.	Zoe Cadore		
AR Small Load Response (LR) Group Member	AR-LR		Brad Swalwell	
AR Small Renewable Generation (RG) Group Member	AR-RG	Erik Abend		
American PowerNet Management	Supplier			Mary Smith, Mike Macrae
Ashburnham Municipal Light Plant	Publicly Owned		Brian Thomson	
AVANGRID: CMP/UI	Transmission		Alan Trotta	
Belmont Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Block Island Utility District	Publicly Owned	Dave Cavanaugh		
Boylston Municipal Light Department	Publicly Owned		Brian Thomson	
BP Energy Company	Supplier			Nancy Chafetz
Braintree Electric Light Department	Publicly Owned			Dave Cavanaugh
Brookfield Renewable Trading and Marketing	Supplier	Aleksandar Mitreski		
Calpine Energy Services, LP	Supplier			Bill Fowler
Central Rivers Power	AR-RG		Dan Allegretti	
Chester Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned		Brian Thomson	
Concord Municipal Light Plant	Publicly Owned		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned	Brian Forshaw		
Connecticut Office of Consumer Counsel	End User		Dave Thompson	
Conservation Law Foundation (CLF)	End User	Jerry Elmer		
CPV Towantic, LLC	Generation	Dan Pierpont		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned		Dave Cavanaugh	
Direct Energy Business, LLC	Supplier			Nancy Chafetz
Dominion Energy Generation Marketing, Inc.	Generation	Mike Purdie		
DTE Energy Trading, Inc.	Supplier			Nancy Chafetz
Dynegy Marketing and Trade, LLC	Supplier	Andy Weinstein		Bill Fowler
Emera Maine	Transmission	Lisa Martin		
Enel X North America, Inc.	AR-LR		Herb Healy	
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Entergy Nuclear Power Marketing LLC	Supplier			Bill Fowler
Eversource Energy	Transmission	James Daly	Cal Bowie	Vandan Divatia
Excelerate Energy LP	Fuels Industry Part.			Gary Ritter
Exelon Generation Company	Supplier	Steve Kirk	Bill Fowler	
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	Nancy Chafetz		
Generation Group Member	Generation			Susan Muller; Bob Stein
Georgetown Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Great River Hydro	AR-RG			Bill Fowler
Groton Electric Light Department	Publicly Owned		Brian Thomson	
Groveland Electric Light Department	Publicly Owned		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc.	Supplier	Louis Guibault	Bob Stein	Susan Muller
Harvard Dedicated Energy Limited	End User	Mary Smith	Mike Macrae	Doug Hurley
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned		Brian Thomson	
Holyoke Gas & Electric Department	Publicly Owned		Brian Thomson	
Hull Municipal Lighting Plant	Publicly Owned		Brian Thomson	
Industrial Energy Consumer Group (IECG)	End User	Kevin Penders		

ATTACHMENT 1

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PARTICIPATING IN
FEBRUARY 6, 2020 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Ipswich Municipal Light Department	Publicly Owned		Brian Thomson	
Jericho Power LLC (Jericho)	AR-RG	Mark Spencer		
Littleton (MA) Electric Light and Water Department	Publicly Owned		Dave Cavanaugh	
Littleton (NH) Water & Light Department	Publicly Owned	Craig Kieny		Dave Cavanaugh
Long Island Power Authority (LIPA)	Supplier		Bill Killgoar	
Maine Power LLC	Supplier	Jeff Jones		
Maine Public Advocate's Office	End User			Erin Camp
Maine Skiing, Inc.	End User	Kevin Penders		
Mansfield Municipal Electric Department	Publicly Owned		Brian Thomson	
Maple Energy LLC	AR-LR			Doug Hurley
Marblehead Municipal Light Department	Publicly Owned		Brian Thomson	
Mass. Attorney General's Office (MA AG)	End User	Christina Belew	Benjamin Griffiths	
Mass. Bay Transportation Authority	Publicly Owned		Dave Cavanaugh	
Mass. Municipal Wholesale Electric Company	Publicly Owned	Brian Thomson		
Mercuria Energy America, LLC	Supplier			Nancy Chafetz
Merrimac Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Michael Kuser	End User	Michael Kuser		
Middleborough Gas & Electric Department	Publicly Owned		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned		Dave Cavanaugh	
National Grid	Transmission		Tim Martin	
Natural Resources Defense Council	End User	Bruce Ho		
Nautilus Power, LLC	Generation		Bill Fowler	
New Hampshire Electric Cooperative	Publicly Owned			B. Forshaw; D. Cavanaugh; B. Thomson
New Hampshire Office of Consumer Advocate				Erin Camp
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
North Attleborough Electric Department	Publicly Owned		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned		Dave Cavanaugh	
NRG Power Marketing LLC	Generation		Pete Fuller	
Pascoag Utility District	Publicly Owned		Dave Cavanaugh	
Paxton Municipal Light Department	Publicly Owned		Brian Thomson	
Peabody Municipal Light Department	Publicly Owned		Brian Thomson	
PowerOptions, Inc.	End User			Erin Camp
Princeton Municipal Light Department	Publicly Owned		Brian Thomson	
PSEG Energy Resources & Trade LLC	Supplier	Joel Gordon		
Reading Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Repsol Energy North America Company	Fuels Industry Part.		Nancy Chafetz	
Rowley Municipal Lighting Plant	Publicly Owned		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned		Brian Thomson	
Shrewsbury Electric & Cable Operations	Publicly Owned		Brian Thomson	
South Hadley Electric Light Department	Publicly Owned		Brian Thomson	
Sterling Municipal Electric Light Department	Publicly Owned		Brian Thomson	
Stowe Electric Department	Publicly Owned		Dave Cavanaugh	
Sunrun Inc.	AR-DG			Pete Fuller
Taunton Municipal Lighting Plant	Publicly Owned		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned		Brian Thomson	
The Energy Consortium	End User		Mary Smith	Doug Hurley; Mike Macrae
Vermont Electric Coop.	Publicly Owned	Craig Kieny		Dave Cavanaugh
Vermont Energy Investment Corp (VEIC)	AR-LR		Doug Hurley	

ATTACHMENT 1

**PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
FEBRUARY 6, 2020 TELECONFERENCE MEETING**

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Vermont Public Power Supply Authority	Publicly Owned			Brian Forshaw
Village of Hyde Park (VT) Electric Department	Publicly Owned		Dave Cavanaugh	
Wakefield Municipal Gas & Light Department	Publicly Owned		Brian Thomson	
Wallingford DPU Electric Division	Publicly Owned		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned		Brian Thomson	
Westfield Gas & Electric Department	Publicly Owned		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler	

CONSENT AGENDA

Reliability Committee

From the previously-circulated notice of actions of the Reliability Committee's February 19, 2020 meeting, dated February 19, 2020:[1]

1. **OP-18 Revisions (Station Frequency Telemetering Requirement; Equipment Requirements; Section 1 Revisions)**

   Support revisions to ISO Operating Procedure (OP) No. 18 (Metering and Telemetering Criteria), which add a requirement to telemeter station frequency, identify equipment requirements, specify which requirements apply to existing and new equipment, and revise Section I (Purpose) to reflect current practice, all as recommended by the Reliability Committee at its February 19, 2020 meeting, together 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. **OP-23, Appendix I Revisions (Non-Generator Resource Asset ID Clarification)**

   Support revisions to OP-23 Appendix I (Reactive Capability Audit Data Recording Form), which clarifies the asset id entry for certain Reactive Resources without an ISO-NE-assigned asset id, as recommended by the Reliability Committee at its February 19, 2020 meeting, together 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. **OP-3 Revisions (Extension of Opportunity Outage from 96 to 108 Hours)**

   Support revisions to OP-3 (Transmission Outage Scheduling), which extends the maximum duration for an Opportunity Outage from 96 hours to 108 hours, as recommended by the Reliability Committee at its February 19, 2020 meeting, together 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. **PP-3 Revisions (I.3.9 Conforming Changes – Use of Terms Market Participant and Transmission Owner)**

   Support revisions to Planning Procedure (PP) No. 3 (Reliability Standards for the New England Area Pool Transmission Facilities), which replace the term "Governance Participant" with the terms "Market Participant" and/or "Transmission Owner", together 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 https://www.iso-ne.com/committees/reliability/reliability-committee/?document-type=Committee Actions.

Summary of ISO New England Board and Committee Meetings

March 5, 2020 Participants Committee Meeting

Since the last update, the Compensation and Human Resources Committee met by teleconference on February 4. On February 13, the Audit and Finance Committee, the Markets Committee, the Nominating and Governance Committee, the Special Committee on IT and Cyber Security, and the Board of Directors each met in Holyoke.

The Compensation and Human Resources Committee convened in executive session and reviewed updated survey data regarding employers' proposed 2020 budgets for executive compensation. The Committee then discussed the Company's corporate performance for 2019 and officer compensation for 2020.

The Audit and Finance Committee met with the investment advisors for the Company's benefits plan assets and 401(k) plan and received an analysis of investment options and details regarding the mix, cost, and performance of offerings. The investment performance continues to be strong across all asset classes, and investment performance costs continue to be reasonable with a competitive weighted average expense ratio. The Committee then reviewed significant accounting estimates used in the Company's budgeting and financial statements, including earnings and discount rates, health care trends, and depreciation. After considering the impact of the accounting estimates, the Committee approved the rates. Finally, the Committee met in executive session to review Internal Audit Department results for 2019 and considered the performance and 2020 compensation for the Director of Internal Audit.

The Markets Committee was provided with an update on the results of the Annual Forward Capacity Auction, including the clearing of new generation and the participation of renewable technology resources. The Committee then received an update on the Energy Security Improvements ("ESI") project and the work leading to the April ESI market design filing with FERC. The Committee discussed the External Market Monitor's view on day-ahead market power mitigation. The Committee also reviewed a summary of potential stakeholder amendments to the ESI design filing, and noted areas of concern expressed by stakeholders related to issues of cost, mitigation and efficacy.

The Nominating and Governance Committee discussed the Company's annual communications and outreach plan, including the use of various media tools and ways in which to emphasize the main messages and themes for the current year. The Committee also discussed plans intended to apply in specific situations, such as preparedness to respond to crisis or emergency events.

The Special Committee on IT and Cyber Security discussed its objectives and outlined a schedule to achieve those goals. The Committee also briefly reviewed the Company's current information technology structure, and discussed the importance of cyber and information technology governance.

The Board of Directors received reports from the standing committees and the Chief Executive Officer who, with the General Counsel, discussed recent developments at FERC. Last, in executive session, the Board approved corporate performance results for 2019 and officer compensation for 2020.

2020 Regional Electricity Outlook

ISO new england

New England can achieve its clean-energy goals at the least cost, while keeping the power system reliable, by harnessing competitive market forces.

Our Mission

Through innovation and collaboration, ISO New England ensures that New England has reliable, competitively priced wholesale electricity today and into the future.

The company's engineers, economists, computer scientists, and other professionals fulfill this mission through three interconnected responsibilities:

- Managing 24/7 operation of the region's high-voltage power grid
- Administering the region's billion-dollar competitive markets for buying and selling wholesale electricity
- Planning for the future power needs of 15 million New Englanders

The ISO is an independent not-for-profit—none of its board members, officers, or employees has any financial interest in any company doing business in the region's wholesale electricity marketplace. The Federal Energy Regulatory Commission (FERC) regulates the ISO.

About This Report

ISO New England's unique role gives it an objective, bird's-eye view of trends that could affect the region's power system. The *Regional Electricity Outlook* is one of the many ways the ISO keeps stakeholders informed about the current state of the grid, issues affecting its future, and ISO initiatives to ensure a modern, reliable power system for New England. Please also see our Annual Work Plan at www.iso-ne.com/work-plan for information on the ISO's major projects for the year to improve our services and performance. Contact ISO New England's Corporate Communications and External Affairs teams at (413) 535-4309 for copies of this report.

Visit www.iso-ne.com/reo.

ISO new england

One Sullivan Road, Holyoke, MA 01040

From the Board Chair and CEO:

The Clean-Energy Transition: How to Get There from Here

Kathleen Abernathy
Board Chair

Gordon van Welie
President and Chief Executive Officer

New England is unquestionably on a path to a clean-energy future. From large-scale offshore wind procurements to the smallest rooftop solar arrays, the New England states are turning to a wide range of renewable resources to fulfill their clean-energy goals. And now, as the states ramp up their goals to achieve up to 100% renewable resources in the electricity sector and move to decarbonize the entire economy in the coming decades, the question for us here at ISO New England has become: how do we get there from here?

For more than a decade, ISO New England has been preparing for this transition. Through the creation of vibrant, competitive electricity markets, the ISO and New England stakeholders have brought about one of the cleanest, most efficient fleets of power generating resources in the country, achieved very low wholesale energy prices that reflect the efficiency of the market design, and facilitated a dramatic reduction in emissions—all while successfully maintaining reliable 24/7 bulk power system operations.

While the path to decarbonizing the electricity industry is well underway, the journey to decarbonize the other sectors has really only just begun. As the transportation sector and the heating and cooling industry turn to carbon-free electricity, the ISO firmly believes that the region can achieve its clean-energy goals at the least cost, while keeping the power system reliable, by harnessing competitive market forces.

The region currently does this using a suite of competitive markets—the energy, ancillary, and capacity markets—that attract and sustain the resources needed to operate the grid reliably and deliver economic and environmental benefits to the region. But, as the number of renewable resources increase, the market architecture will need to be updated so wholesale prices remain competitive and all resources get paid a fair price for providing their products and services. We see the introduction of two sets of market innovations, the CASPR (Competitive Auctions for Sponsored Policy Resources) auction platform and the Energy-Security Improvements, as the next steps toward achieving the region's long-term, carbon-free goals.

In 2019, coal and oil-fired resources produced less than half a percent of New England's electricity—only 0.1% of New England's electricity came from oil-fired power plants and 0.4% from coal plants. And New England had the lowest annual average wholesale electricity price on record.

Where We Are Today: CASPR and ESI Market Mechanisms

CASPR was designed as a solution that should, over time, enable a reliable and efficient turnover in New England's power fleet—moving the power system away from fossil fuel resources to serving the region's electricity needs using renewables—all done by achieving a fair, market-based price. In the coming years, we anticipate that, as they become more cost-competitive, renewable resources will enter the wholesale market directly and the need for CASPR will diminish.

Carbon pricing would work to more quickly change the overall economics of all resources in the market, making renewable and low-carbon resources more cost-competitive than high-carbon-emitting resources. The ISO is ready to introduce such a mechanism on the wholesale level; however, this will require support of the New England states or federal legislation.

In addition to CASPR, the ISO and New England stakeholders are working on market enhancements called the Energy-Security Improvements (ESI) initiative. ESI is a critical market enhancement designed to keep the system reliable during energy-limited conditions, such as extreme cold weather. Furthermore, ESI will also provide the market structure needed as the New England system makes the change from fossil fuel to renewable resources that are inherently intermittent and may be energy-limited during extended periods of inclement weather. ESI will introduce stronger, market-based compensation for electric energy and reserve services and will select the least-cost resources to provide electrical energy when called on by the ISO. ESI is expected to be in place by mid-2024.

For ISO New England, a broadened scope for the region's power grid is expected to increase both the power system planning and operational complexity—and this will drive a need for more investment in staff skills, training, and software development.

Today, Tomorrow, and Beyond: Our Work Together Continues

As we move forward in the coming years, New England's wholesale markets must continue to adapt to the region's changing resource mix and the changing needs of its power system. This adaptation will be necessary because of the anticipated impact to the power system should the states fully decarbonize other carbon-based sectors. As the states' plans become more formalized and the transportation and heating sectors decarbonize, they will turn to the region's power grid for electricity: to keep our plug-in electric vehicles moving and to keep the temperature in our houses and businesses comfortable. As a result, the demand for carbon-free electricity will likely increase over the coming decades and the power grid will become even more important than it is today because every sector of the economy will be dependent on it.

The states, stakeholders, and the ISO will need to continue to collaborate to understand what the period beyond 2030 may look like, including the forecasted demand for clean electricity from other sectors, and the likely market-based pathways to supplying this demand. Analyzing future pathways for decarbonization will also allow the region to have an informed discussion about whether, and where, additional transmission investments will be required to enable the vast quantities of grid-scale renewable energy.

ISO New England respects the environmental policy objectives of the New England states and believes that a strong, competitive wholesale market provides the best structure for achieving these objectives in a cost-effective and reliable way. By working with the states and other industry stakeholders, we together will determine if there are better market design solutions or needed adjustments to the markets. ISO New England is dedicating market-development and planning resources in 2020, and beyond, to discuss potential future market frameworks that are consistent with state decarbonization goals, as outlined in the summary of our strategic plan presented later in this report.

ISO New England has worked tirelessly for the past two decades to ensure the region's power system is there to serve New England and its consumers every day—today, tomorrow, and for decades to come. We are proud of our accomplishments to date in ensuring the region's power system reliability through competitive wholesale markets, and we pledge to continue this dedication as the region transitions to a clean-energy future. We also know that, based on our history, collaboration with all industry and government stakeholders will be paramount to achieve this successful transition. The next phase of our region's energy journey has begun—and we are excited by the prospects.

Sincerely,

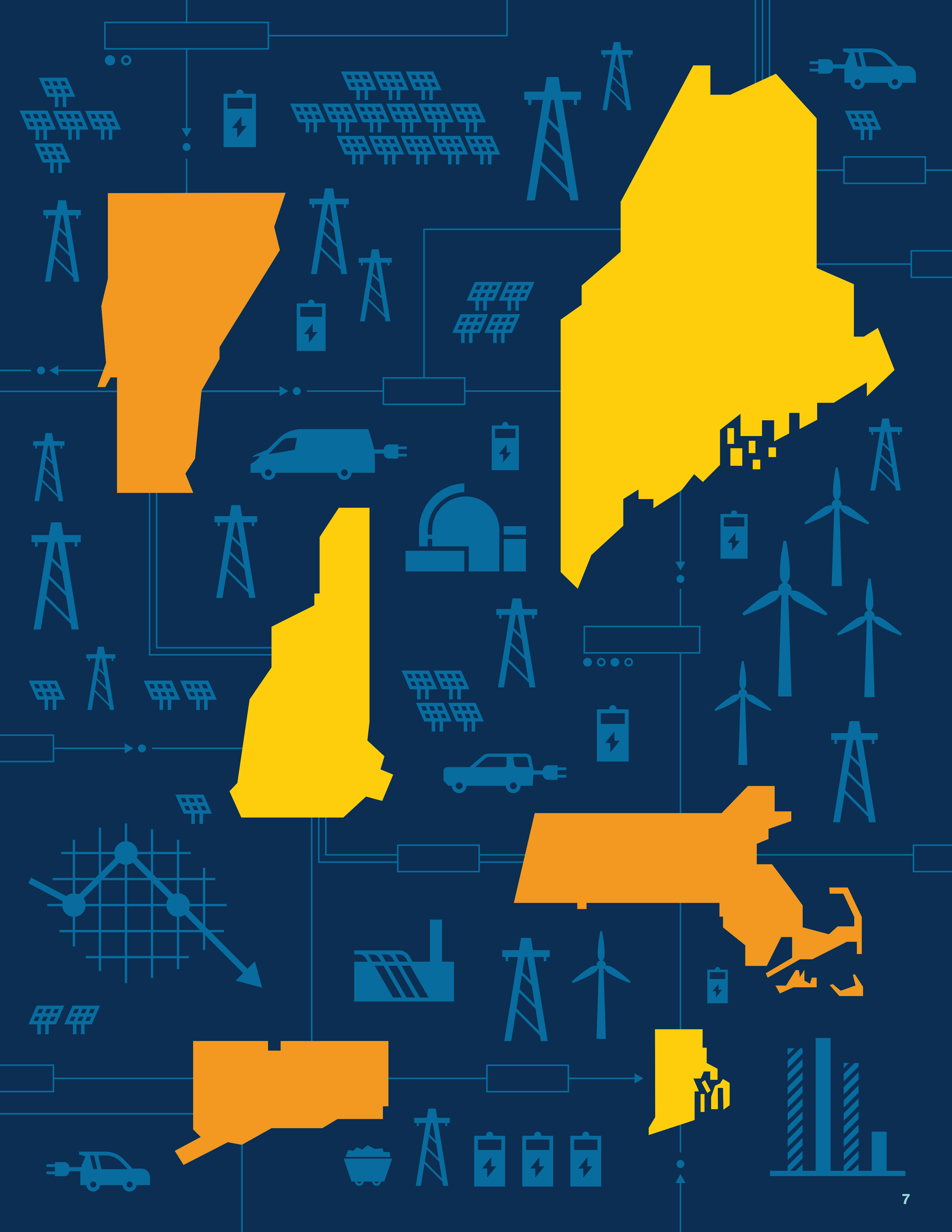
Kathleen Abernathy
Board Chair

Gordon van Welie
President and Chief Executive Officer

Focusing on State Goals:

Achieving Cleaner, Lower-Cost Power

New England restructured its electricity industry more than 20 years ago, driven by state and federal initiatives that were guided by the principle that a reliable supply of competitively priced electricity is fundamental to a thriving society and economy. Specifically, the overarching goals of introducing wholesale competitive markets were to lower costs, encourage innovation, and shield consumers from unwise investments.



For decades before restructuring, the region's utilities operated as vertically integrated, rate-payer-funded, regulated monopolies that generated, transmitted, and distributed electricity. Dissatisfied with investments that increased consumer rates while limiting funds for needed infrastructure, the federal government, with support from the New England states, introduced wholesale markets where privately developed resources would compete with each other to provide the *least-cost, reliable* wholesale electricity supply, regardless of the fuel or technology used to generate the electricity.

Through a cooperative effort, federal, state, and industry officials agreed to create ISO New England in 1997 as the independent administrator of the region's wholesale electricity markets and operator of the regional power grid. In this role, the ISO is bound by its regulator, the Federal Energy Regulatory Commission, to allow participation in the highly competitive markets by all resources. The FERC and the ISO carry out laws created by Congress, which set US federal policy related to power. The ISO does not set policy and does not select the mix of resources being developed in the region. Congress has reserved the right to site generation to the states.

While the states were focused on markets driving efficiency and innovation, they also began introducing clean-energy incentives and emission-reduction goals, focusing first on reducing greenhouse gas (GHG) emissions from the electric power industry. Emissions regulations work well with the wholesale markets by making higher-polluting power plants more expensive to operate and providing a reliable means for cleaner resources to come on line in their place.

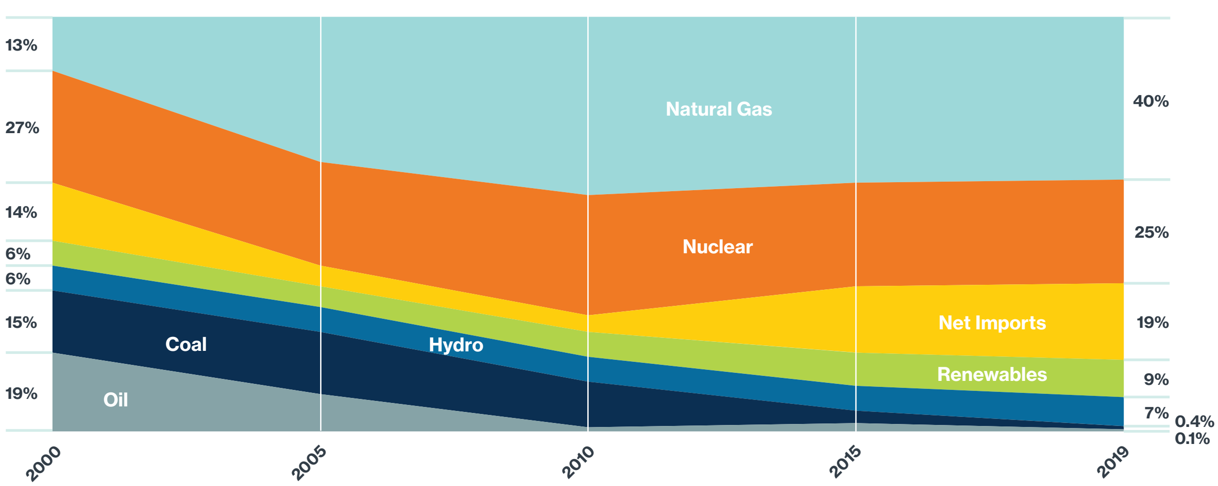
Over two decades, the market and policy approach has driven change in the direction the states have been seeking: around $16 billion in private investment in some of the most efficient, lowest-emitting power resources in the country, shifting investment costs and risks away from consumers, lowering wholesale prices, reducing carbon emissions, and enabling the transition to an even lower-carbon system. This is evidenced by the following:

Lower-Emitting Sources of Energy Supply Almost All of New England's Electricity

Sources of Grid Electricity in New England (Annual Net Energy for Load)

In 2019, efficient natural-gas-fired generation, nuclear, other low- or no-emission sources, and imported electricity (mostly hydropower) provided roughly 99.5% of the region's electricity.

Source: ISO New England, generation data, and *Net Energy and Peak Load by Source Report*



The Rapid Development of a Cleaner, Cheaper, More Efficient Power Fleet in New England

When the wholesale markets opened to competition, private investors pursued the development of natural-gas-fired power plants because they used advanced technology that made them run efficiently; were relatively inexpensive to build, site, and interconnect; and their lower carbon emissions compared to coal and oil helped the region meet state environmental policies. As nearby shale gas emerged as an inexpensive and plentiful fuel resource in the 2008 timeframe, natural gas generators became the go-to resource for New England, clearing as the largest resource type in the market year after year.

In contrast, aging coal-fired, oil-fired, and nuclear power plants have been closing largely because their operating, fuel, and environmental-compliance costs make them too expensive to compete against lower-cost resources. Consumers have benefited from this least-cost resource mix created through competitive markets. Since 2013, roughly 7,000 megawatts (MW) of mostly coal, oil, and nuclear generation have retired or have announced plans for retirement in the coming years. Another 5,000 MW of oil and coal, which now run only during peak demand or periods of gas pipeline constraints, are likely to retire soon. (The region's remaining two zero-carbon-emitting nuclear facilities, Millstone and Seabrook, supply a quarter of the electricity New England consumes in a year). Competition in the markets brought about this change at a faster pace than under the traditional industry model. Under wholesale markets, private companies have carried the risks of uneconomic investments, not utilities and their customers.

A Major Reduction in Emissions from the Power System

The shift to cleaner, more efficient generation and strong regional investment in transmission improvements to move this power to consumers that demand it has resulted in a striking decrease in annual generator air emissions, compared here between 2001 and 2018. Emissions rose slightly between 2017 and 2018 because oil- and coal-fired plants, which typically don't run often, became critical during a winter cold spell when fuel for natural-gas-fired generators was limited and expensive.

Regional Power Plant Emissions Have Plummeted with Changes in Resource Fleet

New England Generator Air Emissions, 2001 vs. 2018

The **80 million short tons of carbon dioxide emissions** avoided regionally between 2001 and 2018 is like taking more than **17 million passenger vehicles off the road** for a year. For comparison, in 2016, roughly 5.1 million vehicles were registered in New England.

Carbon Dioxide (CO_2) ↓ **36%**
major driver of climate change

Nitrogen Oxide (NO_x) ↓ **74%**
adds to smog

Sulfur Dioxide (SO_2) ↓ **98%**
with NO_x, leads to acid rain

Source: ISO New England and the US Environmental Protection Agency's Greenhouse Gas Equivalencies Calculator

Remarkably Low Wholesale Electricity Prices

Markets reveal a resource's operating cost, and a primary driver of operating costs is fuel. As lower-cost, highly efficient natural gas plants displaced older oil and coal plants, wholesale electricity prices declined. After plummeting almost 50% a decade ago, average wholesale energy prices have remained consistently low since then. The average annual price was $42.02 in 2009 and $30.67 in 2019.

Lower wholesale prices translate into lower power-supply charges for consumers. These charges are just one part of an electric customer's bill: retail electricity prices also reflect a state's longer-term, fixed-price contracts for energy; the recovery of the costs to pay for the transmission and distribution systems; stranded costs from legacy, vertically integrated utility investments; and various policy-driven adders, such as funding energy efficiency (EE) and solar photovoltaic (PV) incentive programs. So while wholesale market costs have been consistent over time and across the New England states in recent years (ranging from 7.48 cents/kilowatt-hour (kWh) to 7.81 cents/kWh in 2018), retail power supply rates vary significantly across the New England states (ranging from 8.92 cents/kWh to 13.51 cents/kWh in effect on January 1, 2019), due in large part to the different laws and power procurement practices of each state and the utilities within each state.

In 2019, New England experienced a mild winter that moderated natural gas prices, a cool summer that tempered air conditioning use, and surging amounts of solar power and energy efficiency that lessened electricity demand from the grid. The markets responded in-kind, and New England had the second lowest

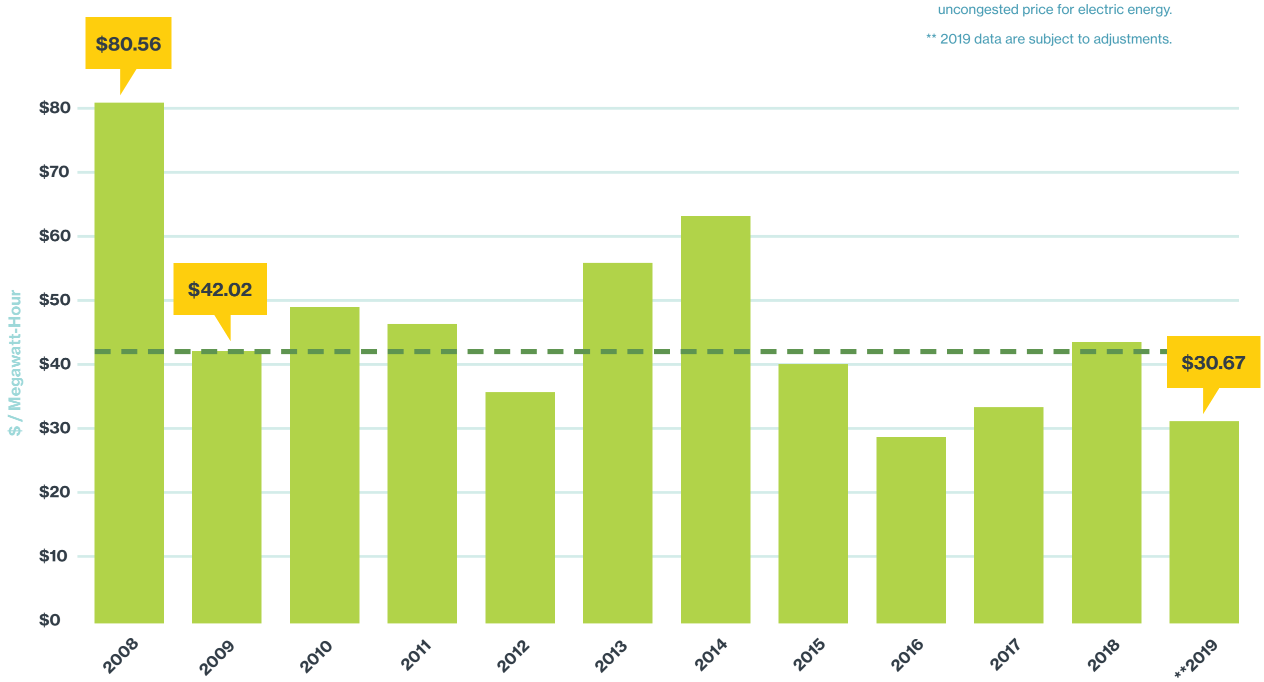
The Average Annual Wholesale Electricity Price Has Remained Consistently Low Over the Past Decade

Average Annual Price of Wholesale Electricity (Average Real-Time Hourly Price at the Hub*)

Note: Higher prices in 2013 and 2014 were largely due to spikes in natural gas prices during wintertime fuel-delivery constraints.

* The Hub is a collection of 32 locations in New England used to represent an uncongested price for electric energy.

** 2019 data are subject to adjustments.



annual average price since the introduction of the current market structure in 2003. Higher real-time power prices in 2013 and 2014 were largely due to spikes in natural gas prices during wintertime natural gas delivery constraints.

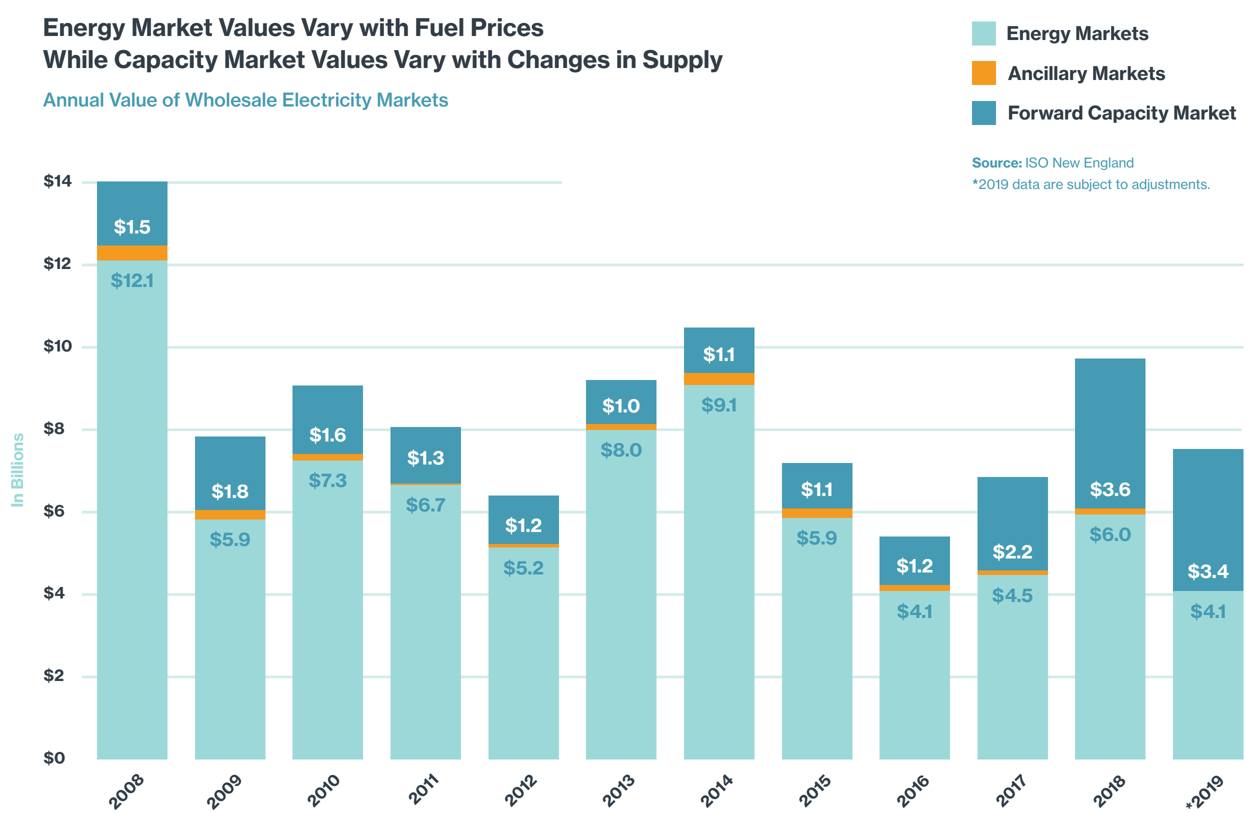
Whereas the energy market value varies with fuel prices, the capacity market value varies with changes in amounts of electricity-producing resources. Strong competition has generally kept capacity market auction prices low for most years, but when generation started to retire, the capacity market value over the past few years has increased. The capacity market works in tandem with the energy and ancillary service markets to provide revenue that attracts and sustains power resources needed today and into the future.

Robust transmission system enables region to move low-cost, clean power

Before industry restructuring, New England saw little investment in transmission infrastructure. Over the past 20 years, the ISO's continuous study of the transmission system has helped guide cooperative regional investment that not only improves reliability but enables the competitive markets to work as designed. Transmission system upgrades allow the ISO to dispatch the most economic resources throughout the region, allow less-efficient resources to retire, and enable the interconnection of power plants with lower emissions. Upgrades have nearly eliminated congestion costs in the New England energy market and, with the aid of low natural gas prices and other factors, have helped drive down and mitigate "uplift" payments to run specific generators to meet local reliability needs.

Energy Market Values Vary with Fuel Prices While Capacity Market Values Vary with Changes in Supply

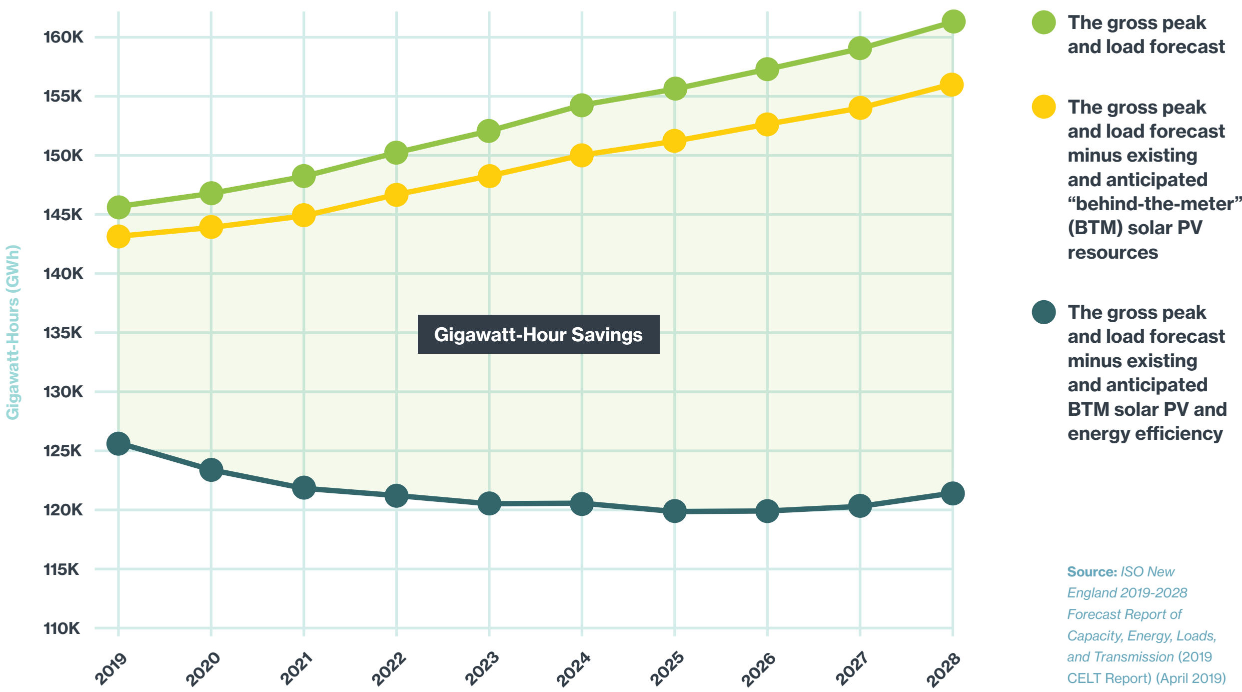
Annual Value of Wholesale Electricity Markets



Source: ISO New England
*2019 data are subject to adjustments.

Energy Efficiency and Behind-the-Meter Solar Are Forecasted to Significantly Reduce Grid Electricity Use Over the Next 10 Years

Projected Annual Energy Use (GWh) With and Without EE and PV Savings



Source: *ISO New England 2019-2028 Forecast Report of Capacity, Energy, Loads, and Transmission* (2019 CELT Report) (April 2019)

In a system that traditionally saw load grow every year, EE and BTM solar are reducing peak demand growth and overall grid electricity use over the next 10 years.

The Steep Growth of Energy Efficiency and Solar Power that Are Driving Down Annual Grid Use

New England's 7.2 million retail electricity customers used over 119,000 gigawatt-hours (GWh) of electricity from the grid in 2019, down from the record 136,355 GWh consumed in 2005. Today, 20% of total system capacity is provided by distributed energy resources that reduce demand from the grid and the need to turn on or build expensive power plants.

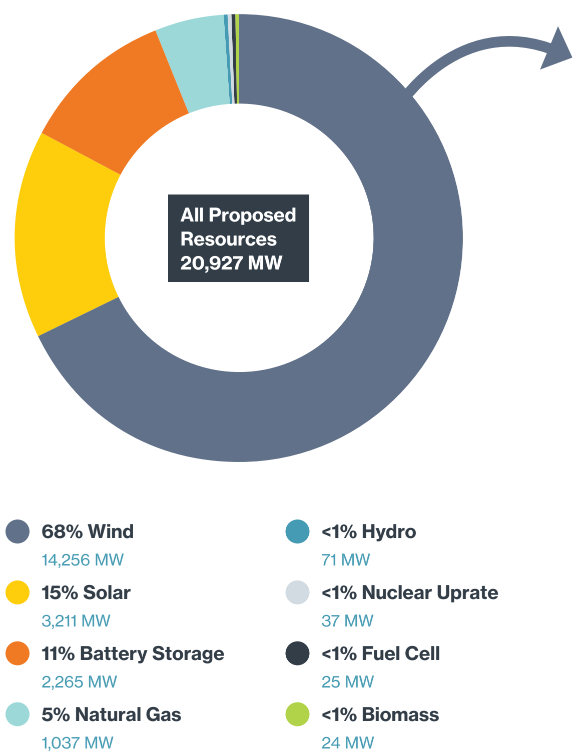
State policies and wholesale market revenues are stimulating the rapid growth of energy efficiency and demand response. New England states invest billions of dollars on EE programs that promote the use of energy-efficient appliances and lighting and advanced cooling and heating technologies (nearly $5.4 billion on EE programs from 2013–2018 and another $10.7 billion between 2021 and 2029). Nearly 3,000 MW of EE measures and 500 MW of demand response can reduce electricity demand from New England's power grid—that's 10% of system capacity acquired in the Forward Capacity Auction. And New England is first in the nation to innovate and enable demand resources to fully participate in the energy and reserve markets.

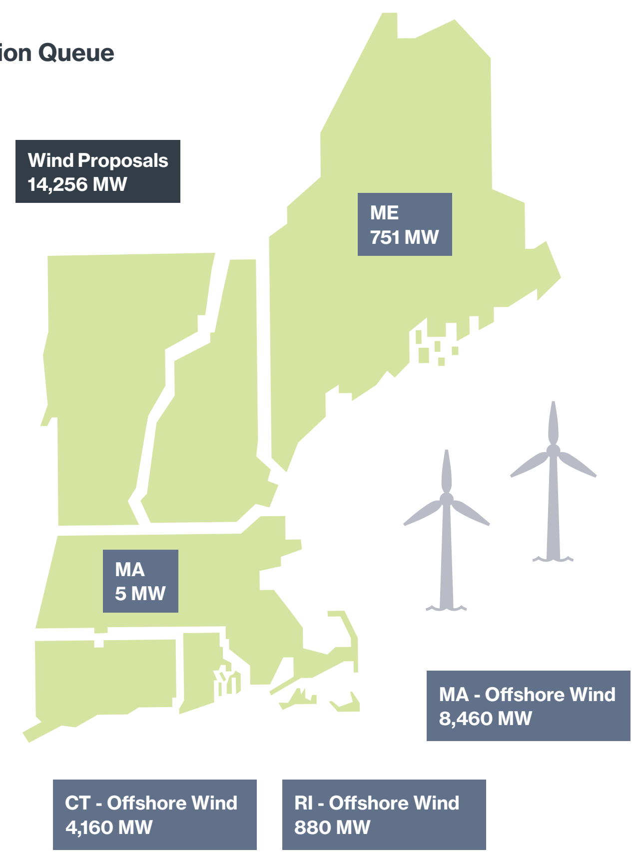
Incentivizing local/residential solar power is also a top priority for New England policymakers, with the states spending billions of dollars on making solar energy affordable for consumers. New England started the decade with 40 MW of behind-the-meter (BTM) solar photovoltaic resources. Today, more than 183,000 installations span the six states, with a combined nameplate generating capability of more than 3,400 MW. The region is on track to reach nearly 8,000 MW over the next decade. Though these resources don't participate in the markets, the markets are flexible to changes in grid demand, so grid electricity is not over produced—or over purchased.

Wind, Grid Solar, and Battery Projects Dominate New Resource Proposals

Developers of clean-energy resources are taking advantage of state incentives, declining technology costs, and revenues from the wholesale markets. About 95% of resources currently proposed for the region are grid-scale wind, solar, and battery projects.

Wind Power Comprises More Than Two Thirds of New Resource Proposals in the ISO Interconnection Queue





Note: Some natural gas proposals include dual-fuel units (with oil backup). Some natural gas, wind and solar proposals include battery storage.

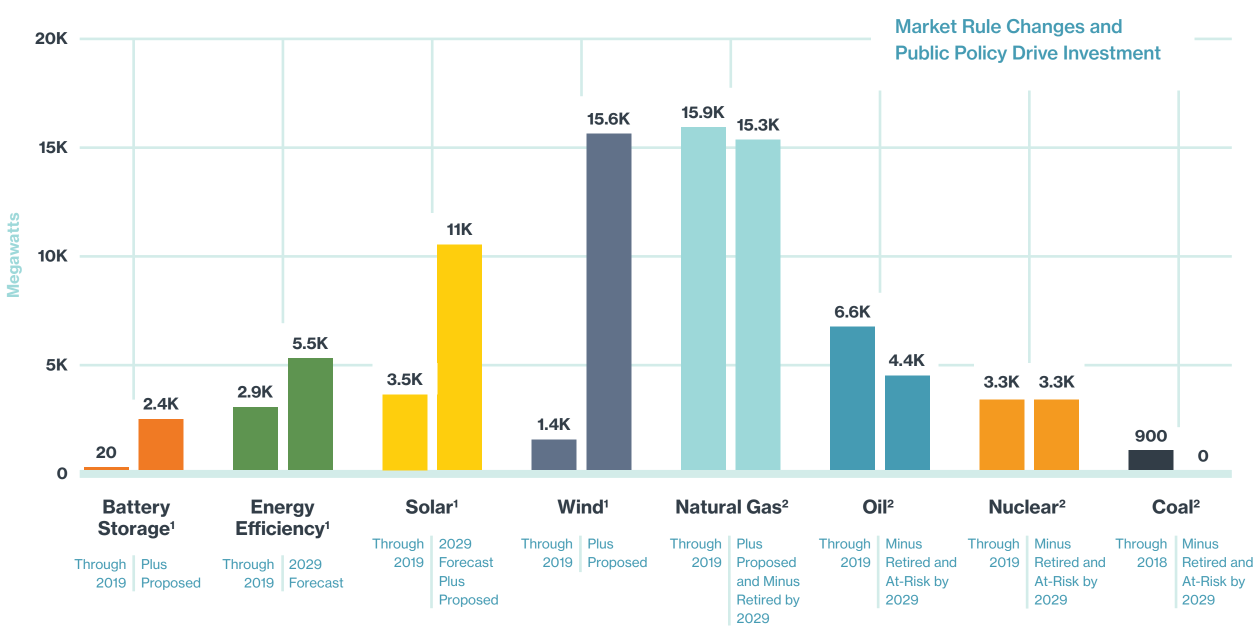
Source: ISO Interconnection Request Queue (January 2020) FERC and Non-FERC Jurisdictional Proposals; Nameplate Capacity Ratings

ISO New England has more than 14,000 MW of wind interconnections under study, which is by far the largest group of resources seeking to connect to the region's electricity grid (as of January 2020). The New England coast offers prime conditions for offshore wind, and about 13,500 MW of proposed wind is located offshore of Massachusetts, Rhode Island, and Connecticut, with most of the remaining located onshore in Maine. In 2016, the wind turbines at the Block Island Wind Farm began putting power onto the electricity grid, making the 30 MW project the first offshore wind farm in the United States.

Solar and battery storage now rank second and third in the ISO Interconnection Request Queue, both surpassing natural gas. New storage technologies are emerging, driven by technological advances, falling costs, support from the states, and changes to the markets that enable storage participation. About 20 MW of grid-scale battery-storage projects have come on line since 2015; nearly 2,300 MW of grid-scale stand-alone energy-storage projects are requesting interconnection. Grid-scale and behind-the-meter energy storage can contribute a number of benefits: provide grid operators with short-term reliability services, maximize the output from wind and solar resources by storing their excess energy, defer transmission and distribution system upgrades when strategically placed, shave the peak during times of high system demand, provide backup power during localized power outages, and enable the development of microgrids.

Battery Storage, Energy Efficiency, and Renewables Are Trending Up in New England

Projected Changes in Key New England Power Resources and EE

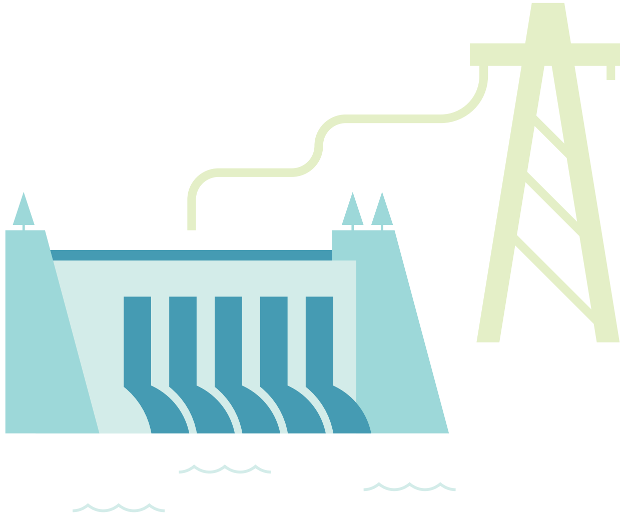


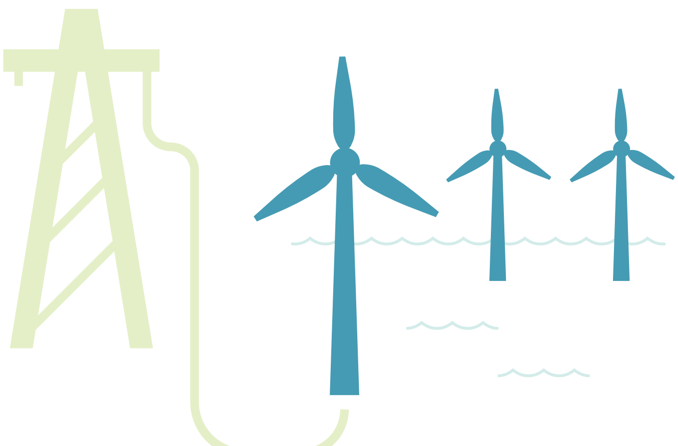
Notes: Numbers are rounded. Not all proposed new projects are built; historically, almost 70% of proposed new megawatts in the ISO Interconnection Request Queue have ultimately withdrawn.

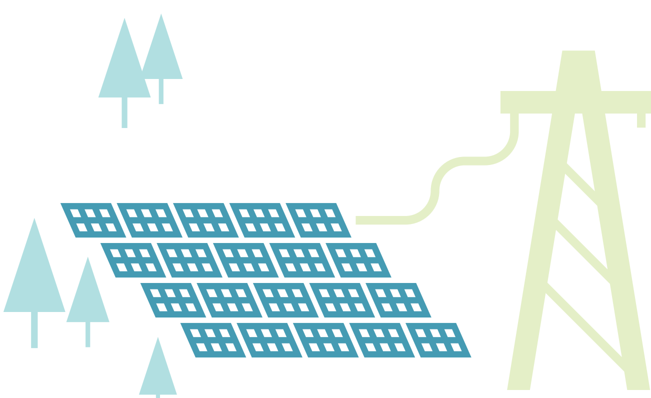
1. Nameplate capacity. Battery storage includes existing and proposed grid-connected resources; some wind and solar projects also include batteries. Solar includes existing and proposed grid-connected resources, as well as existing and forecasted BTM resources. EE includes resources in the capacity market, as well as forecasted future capacity.

2. Nameplate capacity for proposed projects; summer seasonal claimed capability for existing units based on primary fuel type. Some oil units can also burn natural gas and vice versa. The 2028 at-risk values are hypothetical, reflecting retirement delist bids, plus the possible loss of nearly 2,100 MW of generation.

Source: ISO New England, *ISO Interconnection Request Queue* (January 2020), *2019 CELT Report, Draft 2020 Solar PV Forecast* (February 2020), *2020 Draft Energy-Efficiency Forecast* (February 2020), *Seasonal Claimed Capability Monthly Report* (January 2020), *Status of Nonprice Retirement Requests and Retirement Delist Bids* (August 2019), and *2016 Economic Studies Phase I Assumptions* (2016)







Region will need investment in the superhighway for moving clean-energy

Even with substantial investment made to modernize the transmission system and enable the free flow of low-cost power, additional transmission (and distribution) system upgrades will be needed to accommodate large amounts of diverse clean-energy sources—from large-scale offshore wind, remote Canadian hydropower, and hundreds of thousands of distributed solar and storage sources. Think of the grid as the superhighway for moving the clean-energy that ultimately will be fundamental to reliably converting millions of vehicles and heating systems in buildings to electricity.

ISO New England has no authority over siting processes or permits, and because of local opposition and other factors, transmission investments can take a long time to come to fruition in New England. To achieve decarbonization goals, the region must be proactive in developing infrastructure that aligns with supply growth and is available when needed. Regional coordination may not alleviate local opposition but may help make the siting process more successful.

Focusing on Our Role:

Planning, Innovating, and Enabling a Reliable, Clean-Energy Grid

ISO New England is a leader in operational and market innovation to get the grid ready for the future—one that will primarily use clean-energy resources to meet consumer demand. The ISO team of highly skilled technical staff have the unique responsibility, independent of any technological, financial, or other interests, to minimize risk to the reliable operation of the power system and ensure that the competitive markets can continuously provide sufficient revenues for all resources needed for grid reliability.

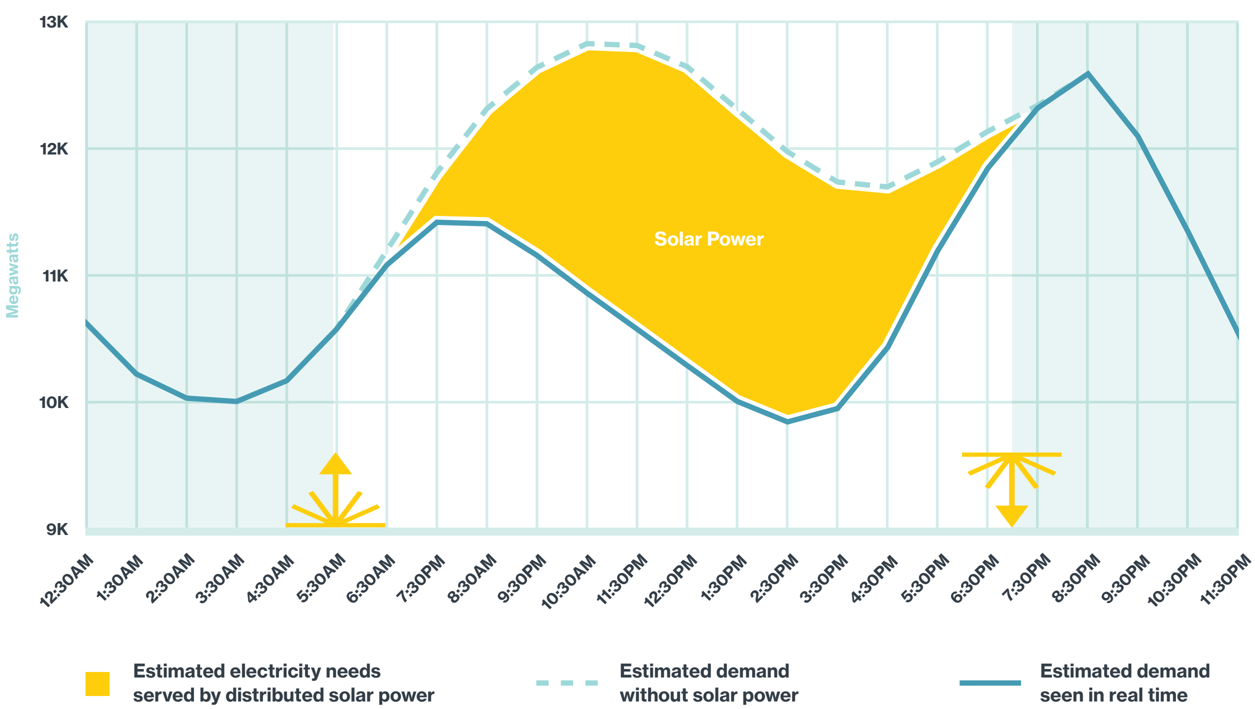
Year after year, the ISO's experts have been working steadily and intensively to integrate high levels of renewable and distributed resources—**energy efficiency, demand-response resources, energy storage, wind,** and **solar**—into system operations, wholesale electricity market design, and power system planning. This includes innovating ways to help the states achieve their climate and energy goals while maintaining the integrity of the region's grid and competitive markets. These efforts have been developed through countless hours of stakeholder discussion, with their differing interests, leveraging the region's strong history of collaboration.

Innovations in Forecasting Enable Grid Operators to Continuously Balance Supply and Demand

Although not connected to the bulk power grid, hundreds of thousands of behind-the-meter solar installations are in operation across the six states, which the ISO must plan for in terms of the extreme changes in electricity demand they create on the grid. When the sun is shining and conditions are optimal, the ISO sees a significant reduction in regional electricity demand from the grid due to BTM solar. These resources are reducing thousands of megawatts of grid demand during heatwaves in the summer, and on cool sunny spring days, the region sometimes uses less grid electricity in the middle of the day than in the middle of the night—something that never happened before. In 2018, grid electricity demand on Thanksgiving Day did not peak as usual in the morning as New Englanders turned on their ovens; the use of BTM solar pushed the peak to after sunset.

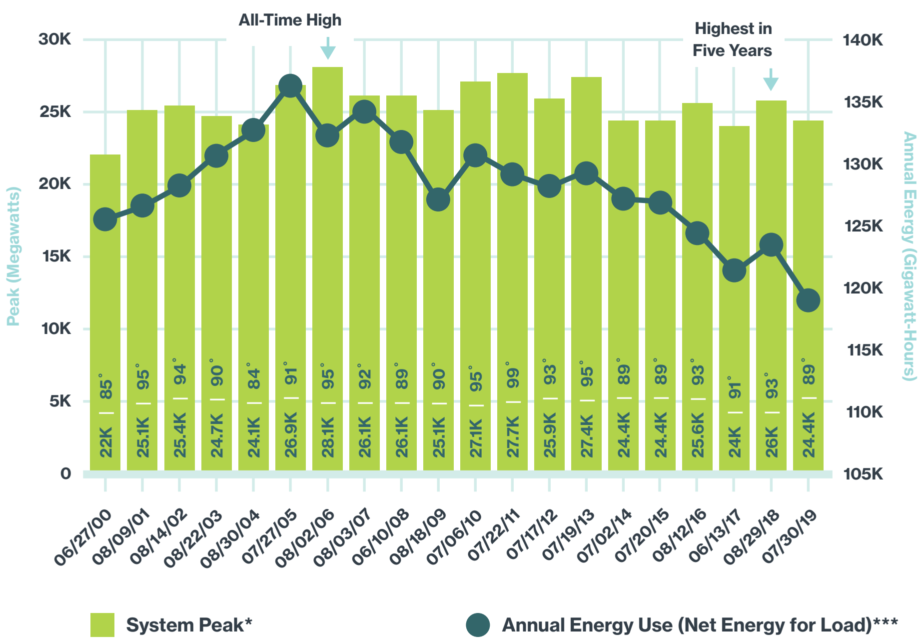
For the First Time, in 2018, New England Used Less Grid Electricity During the Day than in the Middle of the Night

On April 28, 2018, at 1:30 p.m., behind-the-meter solar reduced grid demand by more than 2,300 MW



New England's Power System Must Be Prepared to Meet Peak Demand Even If Peaks Aren't Historically High

Peak Demand vs. Annual Energy Use on New England Power System as of January 24, 2020



* The sum of metered generation and metered net interchange, less demand from pumped storage units. Starting with full market integration of demand response on June 1, 2018, this total also includes the grossed-up demand-response value.

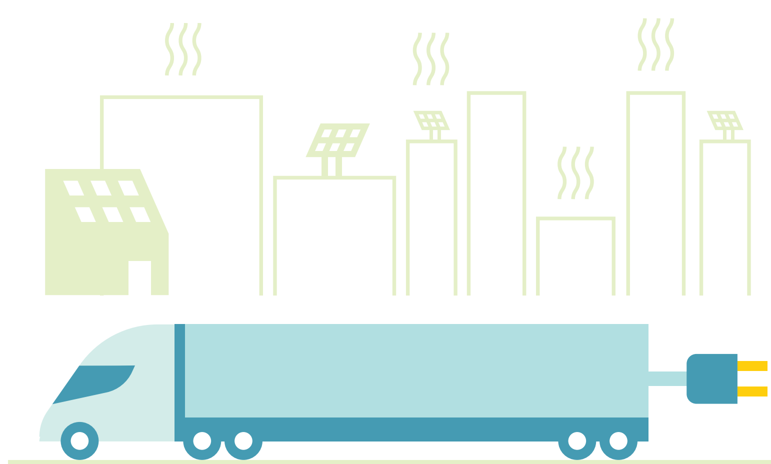
**Annual peak, as of January 24, 2020. Values are preliminary and subject to adjustment.

***Net energy for load (NEL) is the total amount of grid electricity produced by generators in New England and imported from other regions during the year to satisfy all residential, commercial, and industrial customer demand.

Source: ISO New England, *Seasonal Peaks since 1980 Report*, *Net Energy and Peak Load Report* and *Annual Generation and Load Data for ISO NE and the Six New England States Report*.

Despite significant declines in annual electricity use from the grid, weather can still drive spikes in demand, for which the grid must be prepared. For example, when the dew point is above 70° Fahrenheit, every one-degree increase can cause demand to rise by about 500 MW—the amount produced by a medium-sized power plant. Summer 2018 was marked by spells of hot and humid weather that drove electricity demand on the power grid to peaks not seen in five years, and New England reached its highest Labor Day peak ever recorded. Conversely in 2019, other than one hot weekend in July when both days reached all-time, top-10 peak weekend demand days, New England experienced relatively cool average temperatures, leading to the lowest summer-season grid demand and the second-lowest wholesale pricing since 2003.

Now, to fully meet climate goals, the states are looking to convert the transportation and heating sectors to run on cleaner electricity. Electrification initiatives will ramp up aggressively over the next few decades, and by midcentury, these efforts likely will introduce considerable new demand for electricity across the region.



Predicting the unpredictable

The ISO's grid operators can no longer rely on historical patterns of electricity use or traditional weather forecasts to accurately predict how much electricity must be generated to meet second-to-second demand. The proliferation of distributed resources that drastically reduce (or someday increase) electricity demand from the grid make long-term planning challenging. The ISO is continuously innovating both long-term and daily forecasting processes to accurately predict grid demand levels.

2012: Developed the first multistate, long-term **energy-efficiency** forecast in the nation.

2013: Developed a highly accurate **hourly wind** forecast for the region and each individual wind farm to help manage the fluctuating output of **wind resources**; these forecasts integrated into control room operations in 2014.

2013: Launched the regional Distributed Generation Forecast Working Group to collect data on **solar** and **storage** policies and implementation and to forecast long-term incremental growth in distributed generation (≤ 5 MW, connected to the distribution system, and not directly visible to the ISO).

2014: Developed the first multistate, long-term forecast for BTM **solar** installations.

2015: Prototyped a short-term **solar** power forecast based on the sun's strength (irradiance) to help estimate how much electricity demand will be reduced by BTM solar resources.

2017: Hired a full-time meteorologist on staff to help with more precise weather forecasting. Cloud cover, haze, humidity, rain, and snow conditions can vary widely across the six New England states—leading to a range of outputs from the region's **solar** installations. New England has erratic weather conditions, and every New Englander knows how hit or miss weather forecasts can be—even from town to town.

2018: Improved its innovative **energy-efficiency** forecast methodology to more accurately forecast the amount of EE installed on the distribution systems operated by local utilities across the region.

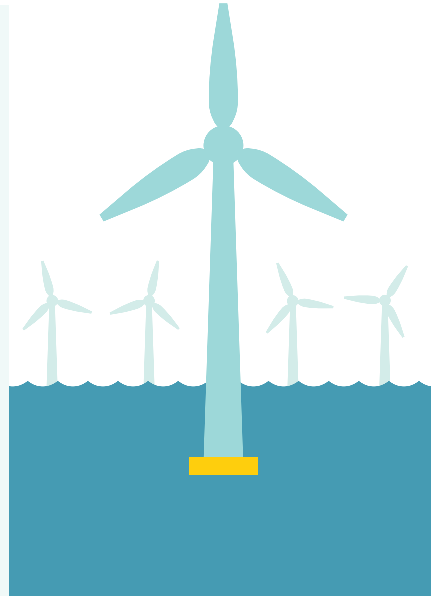
2019: Launched a new method of predicting **solar** PV output regionally that is integrated into the existing day-ahead and seven-day operational load forecasts. Given that the ISO cannot feasibly collect performance data directly from all 183,000 individual PV systems, these efforts will enhance visibility and help the ISO grid operators forecast variations in system demand with the higher degree of accuracy needed to operate the grid reliably and efficiently.

2019: Incorporated improved modeling of BTM **solar** in the calculations that help determine the amount of capacity to procure through the Forward Capacity Market. A more accurate forecast of future loads helps avoid excessive costs to load for capacity that isn't needed.

2020: Expanding 10-year planning forecast to quantify the impact that the increases in **electric vehicles** and **electric heat pumps** will have on long-term grid electricity demand.

Expediting the reliable interconnection of distributed resources

A number of BTM solar resources are being proposed for areas without corresponding consumer demand or infrastructure to support it. Although these systems are interconnected to the distribution system, in large numbers, they can affect the bulk power system. The ISO is required to conduct reliability analyses, and in some cases, may identify upgrades needed for integrating these systems reliably. Delaying projects can be frustrating for developers, policymakers, and consumers. The ISO is serving as an informational resource on distributed-generation interconnection for state officials, developers, and other stakeholders as they consider changes to their state interconnection processes.



Wholesale Markets Enable the Proliferation of Renewable and Distributed Energy Resources

Renewable resources like wind are variable, inverter-based generators that operate differently from conventional power resources. For a decade, the ISO has been developing the ability of renewable and distributed energy resources to participate and earn revenue in the wholesale markets and implementing operational tools to efficiently manage the grid with increasing amounts of these resources.

2010: Studied the potential impacts of integrating large amounts of **wind** resources into the New England system.

2013: Integrated into our operations, power system data from phasor measurement units (PMUs) and associated computer systems installed across the region to increase the observability of system conditions, enable new applications, and improve oscillation detection, which help manage the variability of demand from **BTM solar** and the variability of supply from **wind** resources. The ISO has also worked with leading universities to demonstrate how cloud computing can be used to create a reliable, secure, resilient, and affordable platform for managing PMU data and sharing it with neighboring grid operators.

2014: Introduced the ability to offer negative prices (i.e., pay to operate) in the energy market, enabling primarily **wind** but also **solar** power to continue operating during low-load conditions when they otherwise could be curtailed.

2014: With scientists from the Lawrence Livermore National Laboratory, studied how high-performance computing can be used to model and simulate a new robust unit-commitment solution for dispatching variable **wind**.

2015: Introduced an "energy-neutral" dispatch signal to integrate new **energy-storage** technologies, such as batteries and flywheels, into the regulation market to provide real-time frequency-regulation services.

2015: Improved the interconnection study process for elective transmission upgrades (ETUs) and introduced new rules that ensure that renewable resources can deliver capacity and energy into the wholesale electricity markets. Today, private developers are competing in state procurements to build transmission projects that would enable the delivery of thousands of megawatts from mostly **wind** resources in northern Maine and hydro resources in Canada.

2016: Included **wind and intermittent hydro** resources into real-time dispatch, enabling them to set real-time prices for the first time.

2017: Improved real-time fast-start pricing to help incentivize power resources that can quickly ramp up their output to bridge the steep increase in grid demand that occurs when **solar** PV shuts off quickly as the sun sets or clouds roll in.

2017: To accommodate high interest from new **wind** projects in Maine, implemented a new methodology that enables the ISO to study multiple interconnection requests from the same area together in a "cluster." This helps more quickly advance projects seeking to interconnect to the regional grid and participate in the markets and allows resources to share interconnection costs.

2018: Fully integrated **demand-response resources** into the energy and reserve markets, rounding out their participation in the capacity market.

2018–2020: Ahead of federal requirements mandated by FERC Order 841, implemented and planned for a number of market enhancements for **storage**, which have the physical capability to act as generators, demand, or both, providing a means for simultaneous participation in the energy, reserves, and regulation markets.

2019: Enable **wind** resources with capacity supply obligations to begin participating in the Day-Ahead Energy Market.

Lead the smart grid application of high-voltage direct-current (HVDC) facilities and flexible alternating-current transmission systems (FACTS), which improve the controllability and transfer capability of transmission infrastructure—key factors in the connection of more **renewable energy resources**.

ISO-NE trail blazes demand resources in markets

Unlike EE and behind-the-meter PV, demand-response resources can be dispatched by the ISO. They reduce their electricity consumption from the regional grid by shifting the time of their demand (such as changing the operating times of machines, adjusting times of water use, or modifying temperatures), by switching to an on-site generator (distributed generation), or by switching to a storage device such as a battery. This has paved the way for the full integration of storage, microgrids, and other small-scale distributed energy resources, which will also rely on aggregators to integrate them into the market like demand-response resources do. The region has received national and international recognition for the extent to which demand resources have been fully integrated into the wholesale markets.

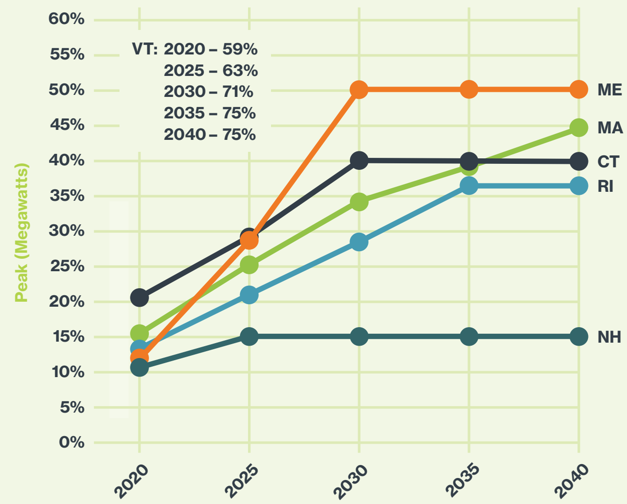
Helping the states accelerate the clean-energy transition to fulfill their GHG goals

Despite significantly reduced emissions from the power system, action toward meeting economywide GHG goals set by the states is just getting underway. There is a growing desire to accelerate actions needed to meet the climate goals. With deadlines looming, the states are eager for the quicker transformation of the power grid to renewables and for electrification of the broader economy.

Because large-scale renewable resources typically have higher up-front capital costs and different financing opportunities than more conventional resources, they have had

State Renewable Portfolio Standards Are Rising

Class I or New Renewable Energy Resource (%)



All six New England states have renewable energy standards

Electricity suppliers are required to provide customers with increasing percentages of renewable energy to meet state requirements

- Vermont's standard recognizes new and existing renewable energy and is unique in classifying large-scale hydropower as renewable.

To Meet Their Public Policy Goals, the States Are Seeking to Develop (or Retain) Clean-Energy Resources Through Large-Scale Procurement Efforts

States Accelerate Clean-Energy Procurements

Note: Nameplate MW may be higher than qualified FCM capacity MW.

State(s)	State Procurement Initiatives for Large-Scale Clean-Energy Resources	Resources Eligible/Procured	Target MW (nameplate)
CT	**2019:** Offshore Wind RFP	Offshore Wind	400–2,000 MW
MA	**2019:** Section 83C II Offshore Wind RFP	Offshore Wind	800 MW
RI	**2018:** Renewable Energy RFP	Solar, Wind, Biomass, Small Hydro, Fuel Cells and Other Eligible Resources	400 MW
CT	**2018:** Zero-Carbon Resources RFP	Nuclear, Hydro, Class I Renewables, Energy Storage	Approx. 1,400 MW (11,658,080 MWh)
CT	**2018:** Clean-Energy RFP	Offshore Wind, Fuel Cells, Anaerobic Digestion	252 MW
MA, RI	**2017:** Section 83C I Offshore Wind RFP	Offshore Wind	800 MW (MA) 400 MW (RI)
MA	**2017:** Section 83D Clean-Energy RFP	Hydro Import	Approx. 1,200 MW (9,554,000 MWh)
MA, CT, RI	**2015:** Multi-State Clean-Energy RFP	Solar, Wind	390 MW

difficulty competing in the wholesale markets. Therefore, the New England states are promoting, at varying levels and speed, the development of specific clean-energy resources to meet their public policy goals.

Several states have established public policies that direct electric power companies to enter into rate-payer-funded, long-term contracts for large-scale carbon-free energy that would cover most, if not all, of the resource's costs. Long-term contracts carry risk given the rapid development and falling costs of new technologies—and this risk of stranded costs is placed back on consumers. As policymakers seek to convert the transportation and heating sectors to carbon-free electricity to fully meet climate goals, this public policy trend is expected to continue.

Pricing carbon within the competitive market structure is the simplest, easiest, and most efficient way to rapidly reduce GHG emissions in the electricity sector. Moreover, placing a realistic price on carbon would enable consumers to pay accurate, competitive prices without the risk of paying for stranded costs. However, New England state policymakers and other stakeholders responsible for putting this approach into motion have not pursued a carbon-pricing option that effectively reflects decarbonization goals, neither economywide nor in the electricity sector.

In the absence of a regional strategy for realistic carbon pricing, ISO New England designed and implemented Competitive Auctions for Sponsored Policy Resources (CASPR) to enable the resource transition to take place in a manner that does not compromise reliability. CASPR is a state-of-the-art solution that allows state-sponsored clean-energy resources (such as state-contracted offshore wind) into the capacity market without artificially depressing prices for all other resources. Unrestricted entry of state-sponsored resources into the capacity market could lead to economic distortions, undermine the competitiveness of the market, and cause retirements to happen too quickly. Or, it could deter new investment in other resources that don't have a contract but are needed to operate the grid reliably (such as merchant investment in grid-scale storage technologies).

Pricing carbon within the competitive market structure is the simplest, easiest, and most efficient way to rapidly reduce GHG emissions in the electricity sector.

It is important to note that CASPR does not prevent potential capacity resources from clearing in the primary auction if they are economic. Rather, it provides an opportunity for state-sponsored resources unable to clear in the primary auction to trade with a capacity resource seeking to retire, thereby avoiding the expensive and inefficient acquisition of more resources than required for reliability.

The ISO conducted the first substitution auction in conjunction with Forward Capacity Auction #13 in 2019. CASPR will work over time, depending on the timing and buildup of the economic incentives for buyers and sellers. While CASPR is a second-best solution for reducing (or eliminating) carbon from the power sector, the market design demonstrates ISO New England's consideration of the region's climate goals and adherence to our mission to ensure reliability through a competitive wholesale market structure.

Regional cap-and-trade GHG reduction initiatives work well with markets

In addition to their individual state goals and laws, all six New England states have been members of the Regional Greenhouse Gas Initiative (RGGI) since 2007. The first mandatory cap-and-trade program in the United States to limit carbon dioxide (CO_2) in the power sector, RGGI is a tool for some of the states to invest in efforts, such as energy efficiency and renewable energy, via the revenue-generating auction mechanism of CO_2 allowances. However, the caps on allowances to date have not been restrictive enough to raise prices to a level that spurs development of renewable resources without other incentives or power purchase agreements. The New England states have also participated in discussions with the Transportation and Climate Initiative, a regional collaboration of Northeast and Mid-Atlantic states and the District of Columbia that seeks to improve transportation, develop the clean-energy economy, and reduce carbon emissions from the transportation sector. The goal of the initiative is the design of a proposal for a regional low-carbon transportation policy using a cap-and-invest program or other pricing mechanism to reduce carbon emissions from transportation fuels.

What is the capacity market?

Power resources compete in the Forward Capacity Market to take on a commitment to be available to meet projected demand for electricity three years out. The FCM works in tandem with the energy and ancillary services markets to provide revenue that attracts and sustains power resources needed today and into the future. Over the years, the FCM has enabled the entry of nearly 12,000 MW from energy efficiency, demand response, renewable resources and natural gas plants. And it has provided an orderly process for the retirement of almost 7,000 MW from older fossil units and nuclear plants.

Focusing on Energy Security:

Reliably Operating a Future Power Grid with a High Penetration of Renewable and Energy-Limited Resources

The New England power grid is no longer comprised mostly of conventional, thermal generation that stores fuel on site. Instead, the system is increasingly made up of generating facilities that run on *just-in-time* energy sources: natural gas (from pipelines and LNG deliveries), wind, and solar energy.

Natural Gas, Wind, and Solar Are Especially Variable in Winter

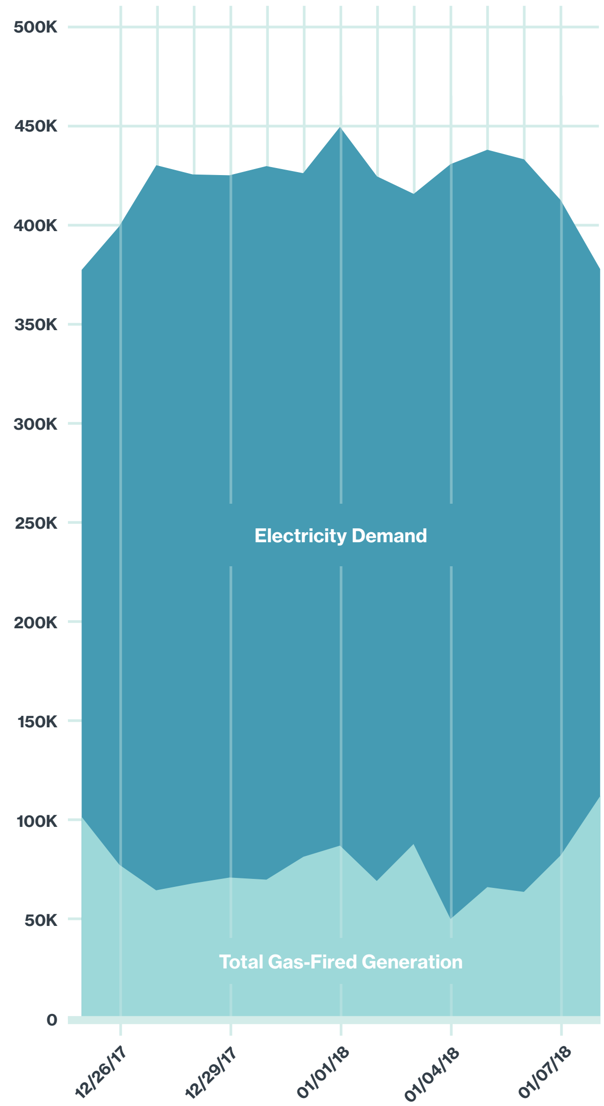
With limited options for storing natural gas, most natural-gas-fired plants rely on just-in-time fuel delivered to New England through interstate pipelines. However, interstate pipeline infrastructure has only expanded incrementally over the last several decades, even as reliance on natural gas for home heating and for power generation has grown significantly.

During cold weather, most natural gas is committed to local utilities for residential, commercial, and industrial heating. As a result, we are finding that during severe winter weather, many power plants in New England cannot obtain fuel to generate electricity. Liquefied natural gas (LNG), brought to New England by ship from overseas, can help fill the gap—but regional LNG storage and sendout capability is limited, and its timely arrival depends on long-term weather forecasts, global market prices, and other logistical challenges.

Winter also imposes the most challenges for solar output in New England due to snow, clouds, and shortened daylight hours. In addition, shortened winter days means consumers use the most electricity after sunset, and therefore solar doesn't reduce winter peak demand. While offshore wind experiences its highest production during winter, winter storms that limit solar power can also significantly limit the output of wind generation. This type of variability is an understandable challenge in meeting the states' decarbonization goals through greater renewable, weather-dependent technologies, and it poses new technical challenges to the grid's reliability.

During Cold Weather, Natural-Gas-Fired Generation Supplies a Small Fraction of the Region's Electricity

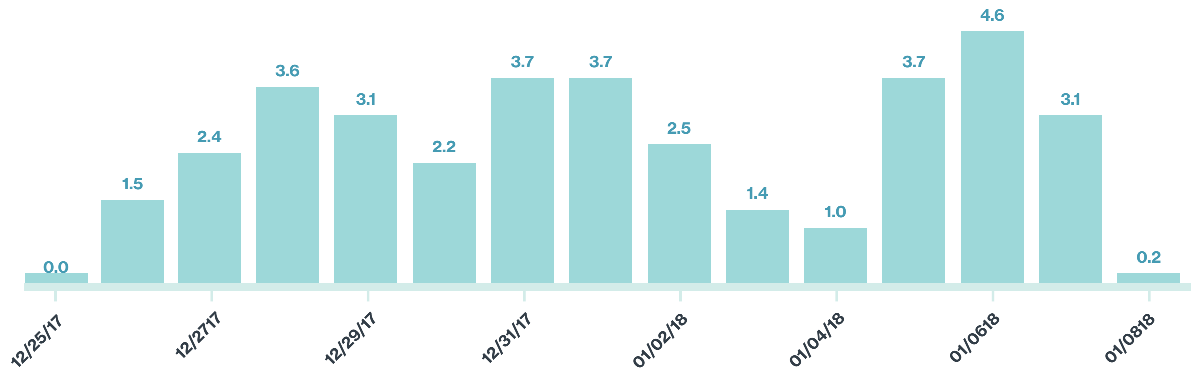
Electricity Demand and Total Gas-Fired Generation
December 26, 2017–January 9, 2018



Gas-fired generation plummets during extended cold weather. Remaining oil-fired and coal units presently cover that 'energy supply gap.' But these resources are likely to retire in the coming years.

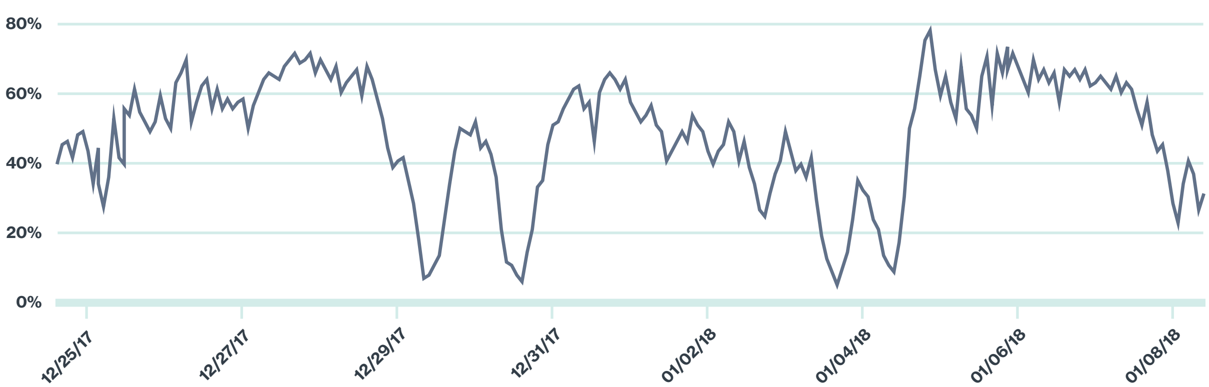
Cold Weather Exposes New Reliability Risks

Estimated Unavailable Natural Gas Generation Capacity (GW) | December 25, 2017–January 8, 2018



Natural gas generation is severely limited due to infrastructure constraints. During extended cold weather, renewable energy output can be highly variable. Both technologies rely on just-in-time delivery of their energy sources.

Output from Wind Fleet Generation | December 25, 2017–January 8, 2018 *(Share of Nameplate)*



Sources: *ISO New England Cold Weather Operations* (2/2018, p.50); *ISO-NE Seven Day Capacity Forecast, Anticipated Cold Weather Outages* (12/25/2017–1/8/2018)

From storing fossil fuel to storing clean energy: flexible resources will be required

Although New England currently enjoys the benefit of almost 2,000 MW of large-scale hydroelectric energy-storage facilities (that can pump water uphill at night to generate power the next day), future storage technologies that can offer longer-term and even seasonal electricity-storage capability are becoming important to balancing electricity supply and demand. The region is in the nascent stages of developing new grid-scale lithium-ion batteries, and much more grid-scale, clean-energy storage capability may ultimately be needed, including clean fuels.

The synergies between renewable energy sources and flexible energy storage is already evident in the grid's operation. Consumers' demand for power can be low on many days when the sun is shining and the wind is blowing steadily. Yet, without greater capabilities to convert and store that zero-carbon electricity, much of that power may simply go unused. And conversely, if the region experiences high electricity demand on days when the output from renewable resources falters (due to adverse weather), the grid requires a considerable amount of flexible-resource capacity that can promptly respond—and sustain output for as long as needed—to fill the gap.

Until storage technologies can supply much more energy for extended periods, the system's existing fleet of modern, flexible natural gas resources will remain essential for meeting energy demand and, critically, filling the "energy gap" when the weather is uncooperative for wind and solar and the system's existing grid-scale storage facilities run low.

Storage also consumes energy and may not provide assistance once depleted

Energy-storage resources draw electricity from the power system or directly from a generating resource (such as a colocated solar or wind facility) as they "stockpile" energy, and then send electricity to the grid at a later time. Overall, they consume more energy than they supply, as operations and losses during energy conversion consume some of their "inventory" of stored energy. If these resources are already depleted during a system emergency, they would not be able to provide help but would instead sit idle, making their "inventory management" and optimization a key technical challenge for the grid's reliability.

Managing Energy Security to Date

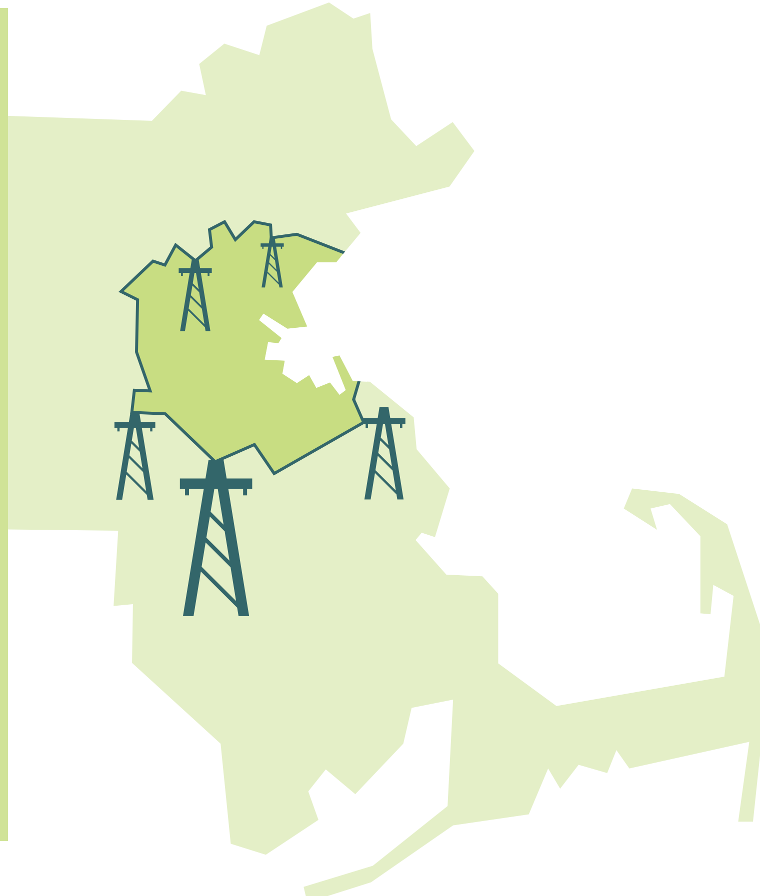
In New England, interstate natural gas pipeline constraints, combined with the retirement of many older (oil and coal-fired) power plants, have heightened the region's energy-security concerns. The ISO doesn't have authority over pipelines or other fuel infrastructure that supply New England's power plants. Instead, the ISO has the ability to develop market rules that result in accurate pricing signals that incentivize power suppliers to make investments in their generation facilities and fuel-supply arrangements to operate reliably and profitably.

Over nearly two decades, the ISO has made many successful market and operational enhancements to improve gas system and electric power system coordination; boost power plants' performance; and lead generation owners to make more resilient fuel-supply arrangements across all system conditions (and, at times, working to delay the retirement of key facilities still needed for reliability). The most recent changes, since the publication of the 2019 REO, include:

- Temporarily retaining the Mystic Generation Station in Everett, MA from retiring, using a special cost-of-service contract. ISO New England was given federal approval to retain resources from retiring for a limited period based on the region's fuel-security reliability challenges in winter.
- Developing a temporary Inventoried Energy Program, a short-term, stop-gap program to be in effect for the winters of 2023/2024 and 2024/2025. This mechanism provides revenues to resources with inventoried energy that contribute to reliable operations during cold winter conditions and reduce the potential for these resources to retire prematurely for uneconomic reasons.

Competitive solution for the Boston area's anticipated transmission needs

In late 2019, the ISO issued its first request for proposals (RFP) to address transmission system upgrades needed in the Boston area with the coming retirement of the Mystic Generating Station—one of the largest power plants in New England and located in the region's largest city. The issuance of the RFP marks a milestone as ISO New England's first competitive transmission solicitation under FERC Order 1000, which created a competitive selection process for transmission upgrades and enables the potential for more creative transmission engineering and technology solutions. Prospective developers have until March 4, 2020, to submit their initial applications; the ISO expects to make a final selection in the summer of 2021.



The Next Step Forward: Ensuring Enough Flexible Supply Each Day to Manage the Uncertainties in an Increasingly Energy-Limited Power System

The design of the wholesale energy markets is based on the physics of the power system. Generators with stored fuel provide enough flexibility for the daily energy market to balance electricity supply and demand over the course of the day, reliably and at least cost. However, a system predominantly comprised of generating facilities with just-in-time fuel supplies—wind, solar, or natural gas—loses flexibility.

In the coming years, the ISO must ensure that the grid has sufficient energy "on demand" to power New England if these just-in-time gas-fired and renewable technologies are unavailable simultaneously. Grid electricity will need to balance supply and demand over time spans from *fractions of a second to several weeks*—to operate through both instantaneous disturbance and throughout sustained variation in demand, availability of resources, and weather conditions.

To solve this challenge, ISO New England and regional stakeholders are proactively developing long-term market enhancements known as **Energy-Security Improvements (ESI)**, to be put in place in 2024. ESI introduces strong market-based compensation for new energy and reserve services that will reward the lowest-cost resources that can firm-up their energy sources and deliver electricity reliably when unforeseen grid operating challenges arise. These new competitive market mechanisms create powerful incentives that will help ensure that enough flexible resources are on line or available in the region during energy-limited conditions.

New England is the first in the nation to bring forward a market design that will directly recognize and compensate resources for the reliable, flexible, and responsive attributes they provide and will thereby help accelerate the transition to reliable zero-carbon, renewable resources and storage technologies.

For example, a solar facility with battery storage has the same opportunity to provide these reliability services as a natural gas plant with a contract for liquefied natural gas or an offshore wind farm that operates at a high capacity factor during winter. All may be rewarded under the ESI design.

ESI does not favor fossil fuels—rather, it focuses on promoting reliable energy output instead of compensating for specific production inputs such as fossil fuel. By contrast, direct subsidies to selected generators to procure additional fuel would benefit only those selected resource owners, providing no incentive for the systems' other resources—or for potential new technologies, such as current and future storage technologies—that may ultimately comprise the most cost-effective long-term solutions.

The design maintains New England's transparent, technology-neutral principles of competition and a familiar framework for resources:

1. **Reliability.** Minimize the heightened risk of unserved electricity demand
2. **Cost Effectiveness.** Leverage established markets and efficiently use the region's infrastructure
3. **Sustainability.** Facilitate innovation that can reduce energy-security risk as technology continues to evolve

ESI is comprised of two conceptual components:

1 *File with FERC: April 15, 2020; Take Effect: June 1, 2024:* Create new option-based services in the day-ahead markets that compensate for the flexibility of energy "on demand" to manage uncertainties each operating day. The ESI design will firm up and formalize the option to call on 3,500 to 5,000 MW of potential energy "in reserve" each day, as follows, with a range of specific delivery-response times, to help ensure reliable operations—capabilities previously relied on but not properly compensated:

- **Generation Contingency Reserves (GCR):** Three new day-ahead ancillary services that ensure operating reserve energy (GCR 10-minute spinning reserve, GCR 10-minute nonspinning reserve, and GCR 30-minute reserve)
- **Replacement Energy Reserves (RER):** Two new day-ahead ancillary services that ensure energy through the balance of the day to cover any "supply gap" that may arise if scheduled energy suppliers' falter (RER 90-minute and RER 4-hour reserve)
- **Energy Imbalance Reserves (EIR):** A day-ahead means to ensure energy to cover any "gap" between forecast consumer demand the next day and the supplies scheduled from both fossil and forecasted renewable resources

2 *In development 2020–2021:* Develop a **new, seasonal forward market auction** that awards competitive, resource-neutral forward contracts to reduce both investors' and consumers' risks of achieving any combination of more reliable energy supplies or longer-term (multimonth) energy-storage arrangements.

Designing and implementing long-term winter energy-security improvements is a large, complex, multiyear project to develop the rules, complete quantitative and qualitative analyses on the design, and review the details with stakeholders. After filing a proposal with FERC in April 2020 and awaiting its response, implementing market administration processes and developing new software and IT systems is expected to take another three to four years.

Focusing on the Future:

Sustaining a Power Grid that Can Reliably Support a Carbon-Free Economy and Society

Future Market Analyses: Thinking Even Longer Term

In 2019, the ISO received requests from the New England States Committee on Electricity, New England Power Generators Association, and other participants, that we dedicate time and staffing in 2020 and beyond to discuss potential future market frameworks that will help them achieve their state decarbonization goals.

According to Energy Information Administration data, almost 75% of New England's GHG emissions come from the transportation sector and residential, commercial, and industrial buildings, with the remaining 25% from the electricity sector. Regional policymakers are considering which policy instruments will best incentivize New Englanders to adopt electric vehicles and convert their homes and businesses to electric heat.

As the region moves toward these goals, we must ensure that the wholesale markets and regional planning process can bring to fruition a power system that continuously and reliably supports the electrification of millions of vehicles, homes, and buildings with low-to-no-carbon energy.

The New England power system will look very different in that future world, and the "electrification of everything" raises important questions about where the region is heading in the coming decades in terms of the overall architecture of the regional power system and wholesale market structure. We are committed to working with the states and industry stakeholders to evaluate how wholesale markets can sustain a power grid that can reliably support decarbonization across New England's economy and society.

ISO-NE Strategic Planning

ISO New England is guided by a purposeful and integrated business planning approach to assist the organization in thinking strategically about the future and drive focus toward a common target for years to come. Our strategic planning framework aligns the organization's purpose with measurable goals and objectives that are a direct reflection of ongoing input from states and stakeholders. The framework provides the foundation for the development of our annual work plans and associated budgets.

The strategic plan provides clarity and focus for the company during this time of change. As the region moves along its decarbonization journey, ISO New England's goal is to collaborate with the New England states and industry stakeholders to ensure that competitive markets and reliability stay aligned and keep pace with environmental policies and rapid technological changes.

Discussions with the states on the future of New England's market framework are included as part of our 2020 Annual Work Plan (www.iso-ne.com/work-plan).

STRATEGIC PLAN SUMMARY

Objective:
Provide Reliable Operations and Robust Planning

Strategy:
Meet regional and national reliability standards

INITIATIVES

Participate in and influence national reliability and cybersecurity standards

Maintain and invest in robust operator training and compliance monitoring program

Implement state-of-the-art cyberdefense posture through cybersecurity investments

Provide improved situational awareness of fuel constraints to marketplace

Strategy:
Manage robust planning process to identify needed infrastructure investments

INITIATIVES

Study and publish 10-year power system needs with emphasis on role/impact of emerging technologies and evolving grid

First Order 1000 RFP to address retirement of Mystic Power Station

Study on- and offshore wind interconnections on timely basis using cluster study process

Strategy:
Develop innovative approaches for reliable transition to hybrid grid

INITIATIVES

Work with stakeholders to integrate regional policy actions into operations and planning

Improve long- and short-term forecasting of EE/PV/wind profiles

Implement state-of-the-art energy-storage models

Objective:
Ensure Open, Competitive Wholesale Markets

Strategy: Achieve resource adequacy

INITIATIVES

Maintain effective Forward Capacity Market and support stakeholder discussion on the future of the wholesale market structure

Continue to evaluate the efficacy of the Forward Capacity Market, including CASPR

Implement improved incentives for new commercial resources to be operational on time

Objective:
Run Efficient, Cost Effective, High Quality Business

Strategy: Create transparent, accountable budgets

INITIATIVES

Require robust internal and external review of annual budget requirements

Deliver capital portfolio, on budget and schedule, with high quality

Employ active risk management of operating and capital budgets

Strategy: Prepare workforce for evolving industry

INITIATIVES

Recruit high-quality candidates for organization's current and future needs; ensure ongoing training and development

Maintain competitive compensation and benefits

Ensure up-to-date leadership succession plans and development for internal leadership candidates

Maintain a positive work environment, enabling employees to deliver their best results

Strategy: Be trusted, independent source of information

INITIATIVES

Make accurate information accessible and transparent to marketplace via easy-to-use tools

Foster open communication and support robust stakeholder process

Publish ongoing studies to inform region of economic outcomes of different resource portfolios

Strategy: Ensure proper design and price formation

INITIATIVES

Design and implement new ancillary products to address energy security (ESI)

Co-optimize energy and ancillary products in Real-Time and Day-Ahead Energy Markets to improve price formation (ESI)

Strategy: Ensure markets enable and accommodate hybrid grid

INITIATIVES

Support regional discussions on valuing environmental attributes in wholesale markets

Evaluate new ancillary products to operate system reliably with increasing intermittent resources (ESI and other)

ISO Metrics:

Measuring ISO New England's Performance, Accountability, and Transparency

Accountability and Transparency

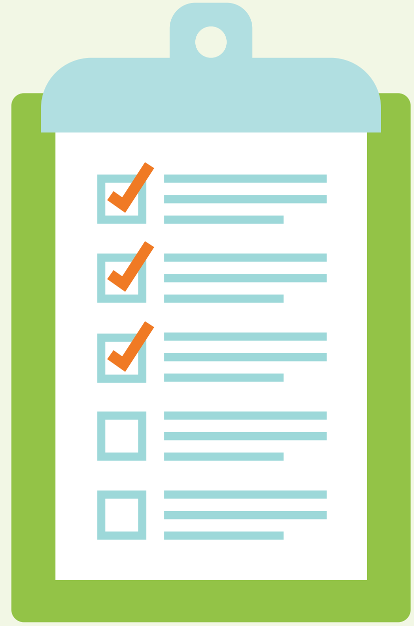
$1.01 per Month

The services and benefits the ISO provides to keep competitively priced power flowing will cost the average New England residential electricity consumer $1.01 per month in 2020, based on 750 kilowatt-hours per month usage. The ISO's 2020 operating budget is $201.7 million, which is $3.7 million more than 2019, or a 1.9% increase. This includes $1.3 million of special purpose funds for work related to FERC Order 1000, which, if underutilized, will be returned in a following year. Other increases are for funding (other than to maintain current operations): **cybersecurity, NERC Critical Infrastructure Protection (CIP) compliance, and energy security market improvements**. The FERC-approved budget is the result of a robust stakeholder discussion to set priorities. Full financial statements are available at www.iso-ne.com/about.

97% Satisfaction

The latest survey of market participants (2019) revealed high overall satisfaction levels with the information and services the ISO provides. Positive satisfaction among respondents with an opinion was 97%. Responses help the ISO identify and prioritize improvements in system operations, market administration, the website, and other information products.

9,600 Issues Resolved



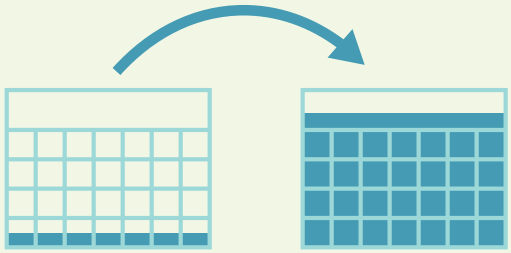
The ISO has a strong culture of responsiveness and outreach to keep market participants and other stakeholders well informed. In 2019:

- ISO Customer Support resolved over 9,600 issues submitted via phone call, email, and Ask ISO self-service.
- We held classroom or web-conference trainings for over 800 stakeholders and made over 79 e-learning modules and 163 presentations available on the ISO website for stakeholders.
- Our extensive website was accessed over 1.1 million times by more than 350,000 unique visitors.
- ISO senior management, subject matter experts, and other staff met well over 500 requests from stakeholders and the media for presentations, panel discussions, technical answers, and interviews.

70+ Stakeholder Meetings

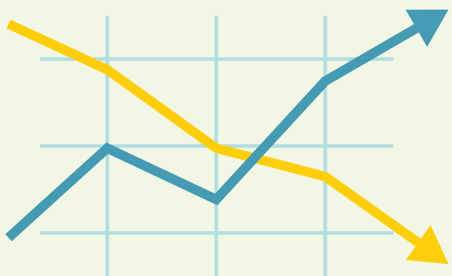
The ISO's stakeholders are a wide-ranging group, from **market participants** to **regulators** to **policymakers** to **environmental advocates** and **retail consumers**. Their diverse perspectives help inform discussions and generate solutions to regional challenges and ensure a collaborative process in the administration of New England's wholesale electricity markets and power system. Changes to the *ISO New England Inc. Transmission, Markets, and Services Tariff* and associated procedures, which govern the administration of the region's wholesale electricity markets and the operation of the bulk power system, are all vetted through the New England Power Pool (NEPOOL) stakeholder process. Stakeholders also interact regularly with ISO staff and participate in committees and working groups. In 2019, the ISO coordinated or participated in 73 meetings of the Markets, Reliability, Transmission, and Participants Committees and the Planning Advisory Committee (PAC). The Consumer Liaison Group (CLG) also met quarterly to share information about the power system and wholesale electricity markets' impacts on consumers. The PAC and CLG are open to the public, while the rules governing NEPOOL, the association of regional market participants, determines attendance for the other committees.

2019 Improvements for a Better Stakeholder Experience



Forward Capacity Market Delayed Commercial Resource Treatment

This new monthly “failure-to-cover” charge incentivizes market participants unable to fulfill their capacity supply obligation to take action to cover their obligation or assume a charge.

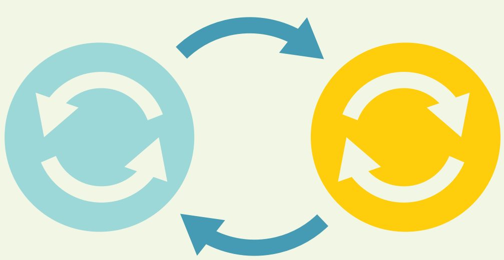


Annual Reconfiguration Transactions (ARTs)

ARTs were introduced to provide the equivalent of a bilateral transfer of a capacity supply obligation at a fixed price. By entering into an ART and participating in an annual reconfiguration auction, a capacity supplier can achieve price-quantity assurance (to the extent the capacity is substitutable) when either acquiring or shedding an obligation.

Financial Transmission Rights—Balance of Planning Period

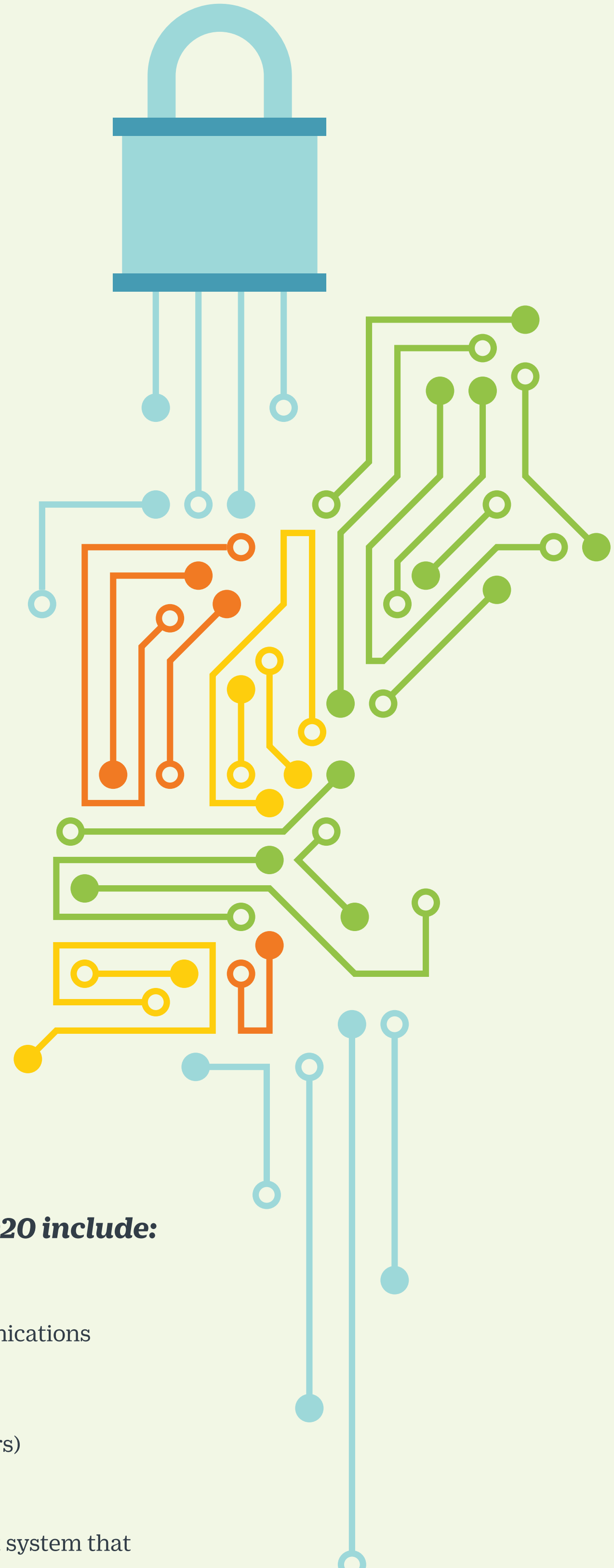
The FTR BoPP augments the FTR bidding process by implementing multiple on-peak and off-peak auctions for the months remaining in the annual period. This provides market participants with more opportunities to configure their FTR portfolio.



New Software for Scheduling External Transactions

The 16-year-old Enhanced Energy Scheduling software was replaced by the New England External Transaction Tool (NEXTT), a new software application for market participants to submit external transactions in the Day-Ahead and Real-Time Energy Markets. Numerous improvements allow customers to better manage their external transactions, with the tool being an important part of the day-to-day operation of the electricity grid.

Cybersecurity to Protect the Grid and Marketplace



A successful cyberattack on ISO New England would result in loss of control over critical IT systems, jeopardizing the reliable operation of the power system. The energy sector faces significant risk of attempted cyberintrusion, and the bulk power system is the only industry subject to mandatory and enforceable cybersecurity standards. Violation of the North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection standards can result in fines of up to $1 million per violation per day.

The ISO continuously works internally and with stakeholders and regulators to meet evolving threats and build on our already extensive 24/7 systems of process controls, advanced detection and response, redundancy in systems and control centers, and intensive employee training. These help us detect, respond to, and recover from any cyberattacks, as well as to comply with mandatory standards. And more than 100 employees participated in GridEx V, hosted by NERC and designed to exercise coordinated responses to cyber and physical attacks.

The ISO's cybersecurity initiatives for 2020 include:

- Enhancing network security and building a new network to safeguard control center communications
- Complying with all NERC standards, including:
  - CIP-012 (communications between control centers)
  - CIP-013 (supply chain risk management)
- Implementing an Identity and Access Management system that automates and secures access to CIP and non-CIP assets and, going forward, will serve as a foundation for the ISO's cybersecurity program

ISO Board of Directors

as of January 2020

1. **Kathleen Abernathy**
   Board Chair
2. **Gordon van Welie**
   President and Chief Executive Officer
3. **Brook Colangelo**
4. **Michael J. Curran**
5. **Roberto R. Denis**
6. **Cheryl LaFleur**
7. **Barney Rush**
8. **Philip N. Shapiro**
9. **Vickie VanZandt**
10. **Christopher Wilson**

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ISO Senior Management

as of January 2020

1. **Gordon van Welie**
   President and Chief Executive Officer
2. **Vamsi Chadalavada**
   Executive Vice President
   and Chief Operating Officer
3. **Jamshid A. Afnan**
   Vice President, Information
   and Cyber Security Services
4. **Peter T. Brandien**
   Vice President, System Operations
   and Market Administration
5. **Janice S. Dickstein**
   Vice President, Human Resources
6. **Robert Ethier**
   Vice President, System Planning
7. **Anne C. George**
   Vice President, External Affairs
   and Corporate Communications
8. **Maria Gulluni**
   Vice President, General Counsel,
   and Corporate Secretary
9. **Mark Karl**
   Vice President, Market Development
   and Settlements
10. **Robert C. Ludlow**
    Vice President and Chief Financial
    and Compliance Officer
11. **Jeffrey McDonald**
    Vice President, Market Monitoring

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ISO new england

ABOUT ISO NEW ENGLAND

ISO new england

The ISO was established to ensure that a not-for-profit, independent organization with no financial stake in the energy industry would design and administer New England's competitive wholesale electricity markets and guide the development of a reliable and efficient power grid.

The ISO is the regional energy expert in power system operations, wholesale electricity market design and development, and power system planning.

ISO New England delivers value to the region by being a stable presence in a changing and challenging industry.

For more than 20 years, ISO New England has been an effective manager, with proven experience and expertise to handle evolving industry challenges.

The ISO recognizes the environmental policy imperative within the region and is working hard to facilitate the integration of renewable energy while continuously ensuring that electric power reliability is delivered through competitive wholesale markets.

ISO New England is synonymous with innovation. The ISO will continue to innovate advances in markets, operations, and planning as the region transitions to a low-to-no carbon power grid that will be used to electrify millions of vehicles and building heating systems across the region.

The ISO successfully collaborates with market participants and regulatory commissions and is committed to working with the states to ensure that wholesale markets can bring to fruition a power grid that reliably supports decarbonization across New England's economy and society.

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NEPOOL Participants Committee Report

March 2020

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Energy market value was $212M, down $86M from January 2020 and down $154M from February 2019
    - February natural gas prices over the period were 21% lower than January average values
    - Average RT Hub Locational Marginal Prices ($20.37/MWh) over the period were 22% lower than January averages
      - DA Hub Avg: $23.40/MWh
    - Average February 2020 natural gas prices and RT Hub LMPs over the period were down 46% and 45%, respectively, from February 2019 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 100% during February, up from 99.6% during January*
    - The minimum value for the month was 95.4% on Monday, February 3rd

DATA THROUGH FEBRUARY 26, EXCEPT WHERE NOTED.

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

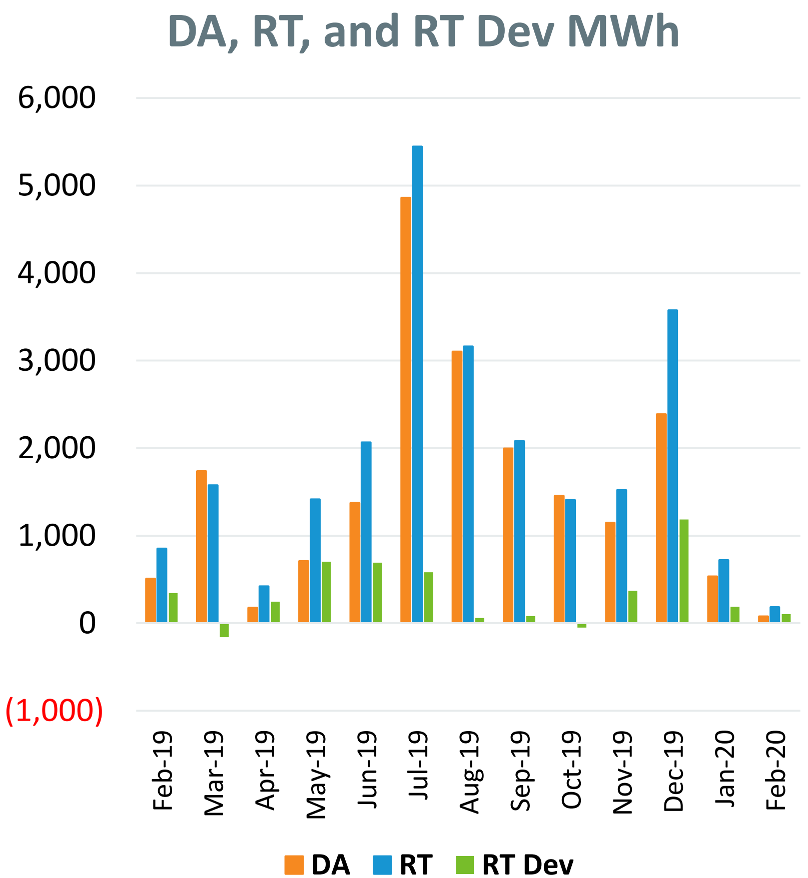
***DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market**

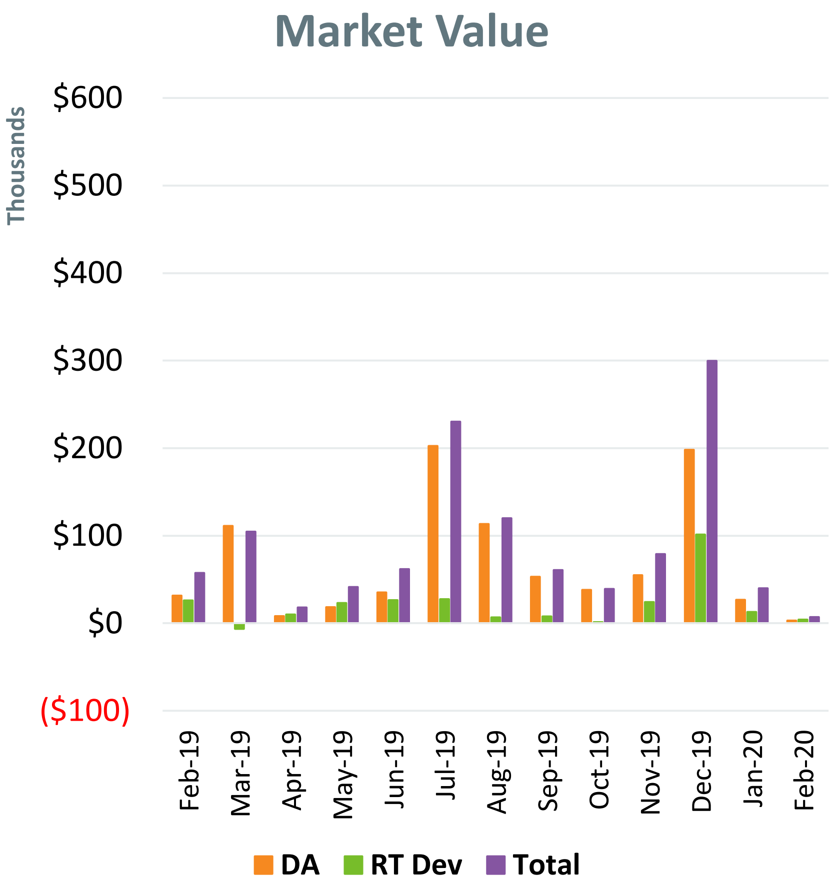
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - February NCPC payments totaled $883K over the period, down $791K from January 2020 and down $1M from February 2019
    - First Contingency* payments totaled $825K, down $791K from January
      - $815K paid to internal resources, down $799K from January
        - » $180K charged to DALO, $428K to RT Deviations, $216K to RTLO
      - $10K paid to resources at external locations, up $7K from January
        - » $10K to RT Deviations
    - Second Contingency payments totaled $58K, down $50K from January
        - » Planned transmission work in SEMA area
      - Voltage and Distribution payments were both zero
  - NCPC payments over the period as percent of Energy Market value were 0.4%

*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $121K; Rapid Response Pricing (RRP) Opportunity Cost - $84K; Posturing - $0K; Generator Performance Auditing (GPA) - $12K**

Price Responsive Demand (PRD) Energy Market Activity by Month





Note: DA and RT (deviation) MWh are settlement obligations and reflect appropriate gross-ups for distribution losses.

Highlights

- Boston 2028 RFP Phase One Proposals must be submitted by 11:00 p.m. on March 4
- The ISO has developed forecasts of the anticipated energy and demand impacts of electrification of the transportation and heating sectors for incorporation into the 2020 CELT forecast and ICR for FCA 15
  - This forecast will be discussed with PAC in March
- Results of the stakeholder survey regarding the content and format of the RSP will be discussed with PAC later this spring
- Transmission portion of the NESCOE Economic Study is anticipated to be presented to PAC in the March-April timeframe
- 2020 economic study requests are due by April 1

Forward Capacity Market (FCM) Highlights

- CCP 10 (2019-2020)
  - Late, new resources (regardless of size) are being monitored closely
- CCP 11 (2020-2021)
  - Third and final annual reconfiguration auction (ARA3) was held March 2-4 and results to be posted no later than April 1
- CCP 12 (2021-2022)
  - Second reconfiguration auction (ARA2) will be August 3-5 and results to be posted by September 2

CCP – Capacity Commitment Period
ICR – Installed Capacity Requirement

Forward Capacity Market (FCM) Highlights

- CCP 13 (2022-2023)
  - First reconfiguration auction (ARA1) will be June 1-3, and results to be posted by July 1
- CCP 14 (2023-2024)
  - Auction results were filed with FERC on February 18, and comments are due on April 3
  - Informational filing was approved by FERC on February 21

FCA – Forward Capacity Auction

FCM Highlights, cont.

- CCP 15 (2024-2025)
  - The qualification process has started, and training materials are under development
  - Topology certifications were sent to the TOs on October 9, 2019
    - Approved projects were shared with the RC at their January meeting
  - Capacity zone development discussions began in November 2019 at the PAC meeting
    - All subsequent reconfiguration auctions model the same zones as the FCA
  - ICR & Related Values development will commence in April with a presentation to the RC, and detailed discussions will begin in May with the PSPC

Load Forecast

- The 2020 load forecast process continues, and the near-final forecast will be discussed with PAC members in April. Supporting working group meetings include:
  - Energy-Efficiency Forecast Working Group WebEx - March 19
  - Distributed Generation Forecast Working Group - March 20
  - Load Forecast Committee Meeting - March 23
- New this year, the ISO has developed forecasts of the anticipated energy and demand impacts of electrification of the transportation and heating sectors for incorporation in the 2020 CELT forecast and ICR for FCA 15. This forecast will be discussed with PAC in March.
  - Methodologies and supporting assumptions are being discussed as part of the annual Load Forecast Committee stakeholder process.
- Efforts continue to enhance load forecast models and tools to improve day-ahead and long-term load forecast performance.

FERC Order 1000

- Qualified Transmission Project Sponsor (QTPS)
  - 25 companies have achieved QTPS status
- The ISO issued the Boston 2028 request for proposal (RFP) on 12/20/2019, which is its first RFP for a competitively-selected transmission solution
  - Phase One Proposals must be submitted by 11:00 p.m. on 3/4/2020
- The ISO filed a response on 12/27/2019 to a 10/17/2019 FERC Section 206 Proceeding regarding the ISO's implementation of Order 1000 time-sensitive needs for immediate need reliability projects (i.e., projects needed to meet reliability needs that are determined to exist three years or less from the completion of a Needs Assessment)
  - The ISO filed an answer to comments on 2/11/2020
- The Public Policy Process was initiated on 1/14/2020
  - Stakeholder input on federal, state, and local Public Policy Requirements (PPRs) was required to be submitted by 2/28/2020
  - Two PPR submittals were received
  - NESCOE may submit a communication to the ISO regarding PPRs by 5/1/2020

Highlights

- The lowest 50/50 and 90/10 Spring Operable Capacity Margins are projected for week beginning May 9, 2020.

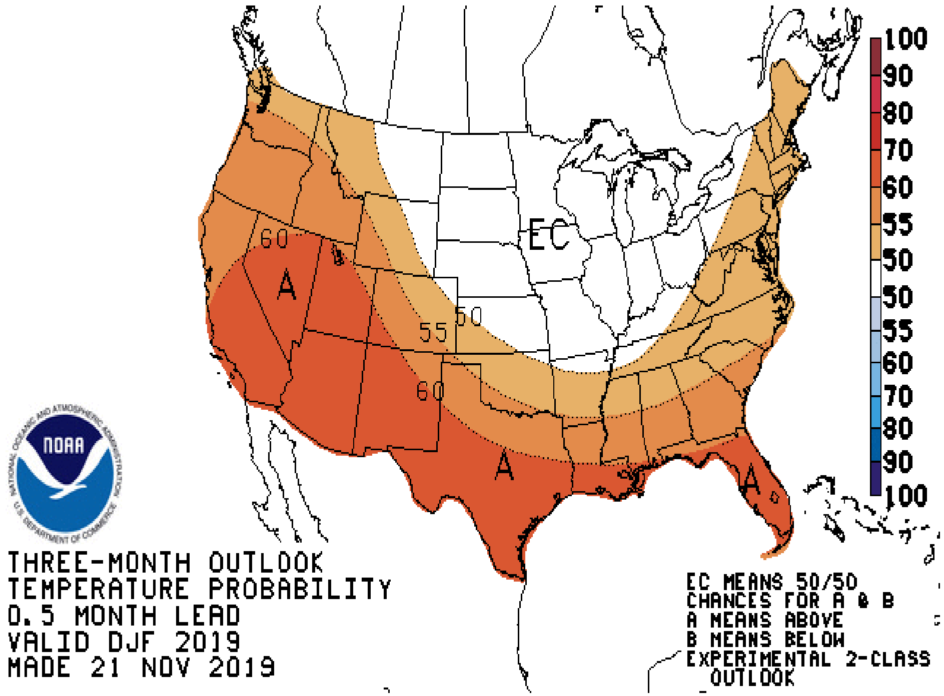
- The lowest 50/50 and 90/10 Preliminary Summer Operable Capacity Margins are projected for week beginning May 30, 2020.

WINTER 2019/20 OPERATIONS

Highlights

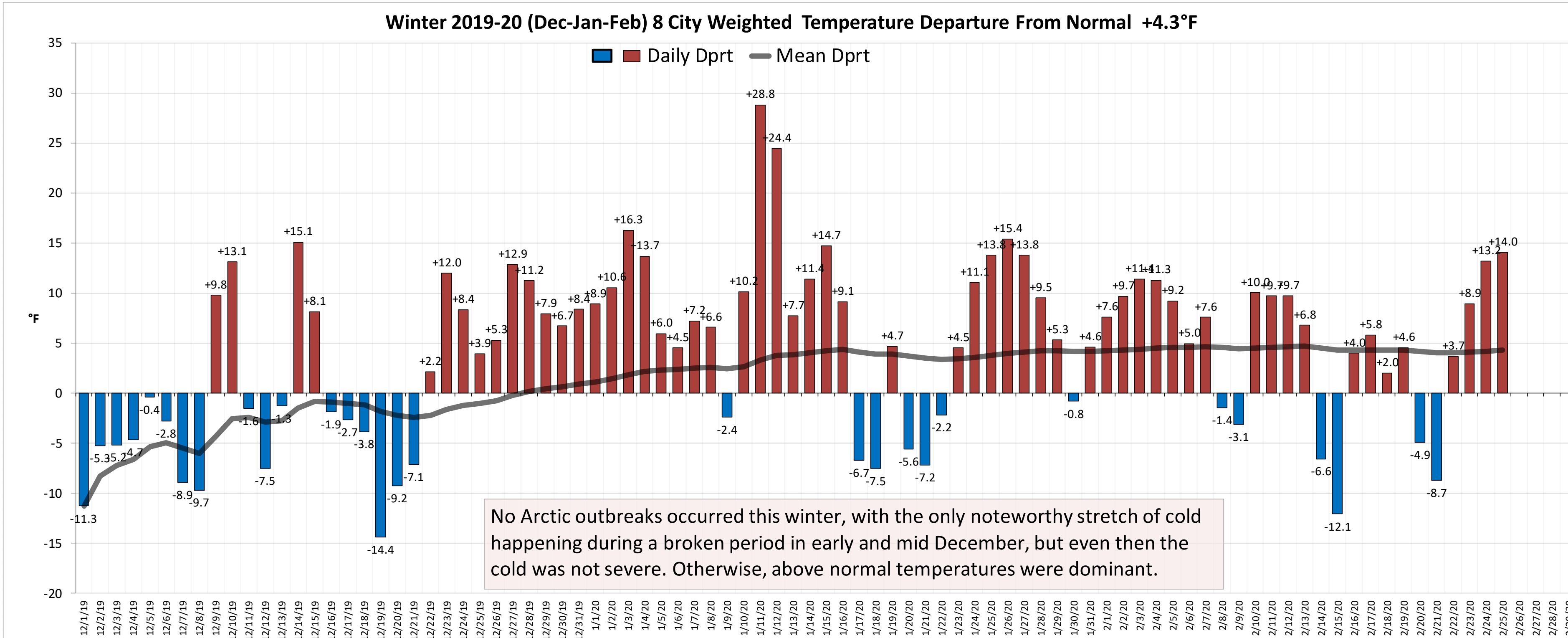
- The New England winter average temperature of +4.3°F was consistent with NOAA's seasonal outlook issued November 21, 2019 of above normal temperatures
- Minimal reductions in natural gas availability to generation
- Fuel oil usage was minimal and supplies remained steady throughout the winter
- Generation fleet and transmission system performed well
- Surplus generation capacity was available throughout the winter
- No MLCC-2 (Abnormal Conditions Alert) or OP-4 (Capacity Deficiency) actions were implemented

Observed Winter Temperatures (Dec-Feb)



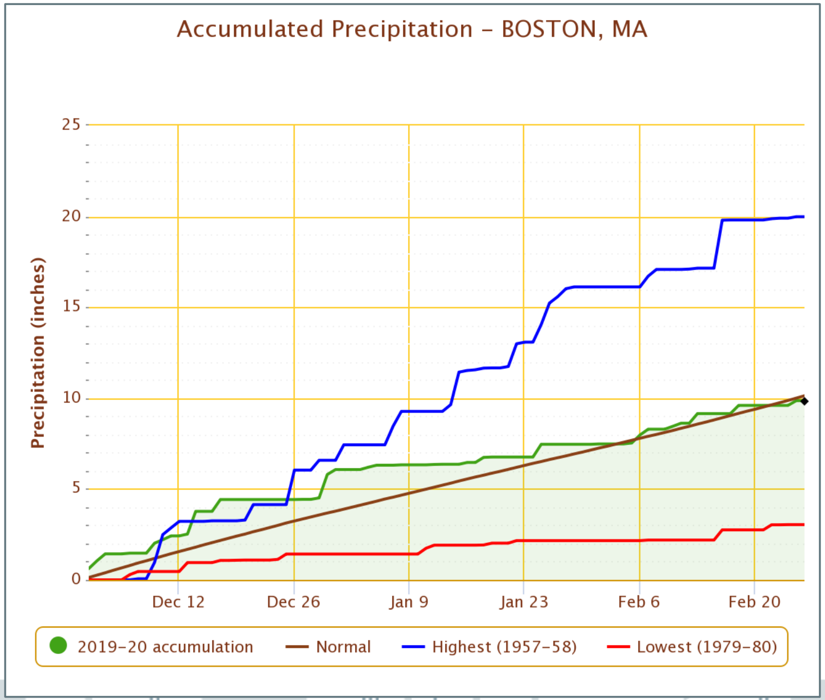
- 17 out of the first 21 days in December were below normal, which was the longest cold stretch of the winter
- That cold stretch was not severe however, as only two of the days were at least 10°F below normal

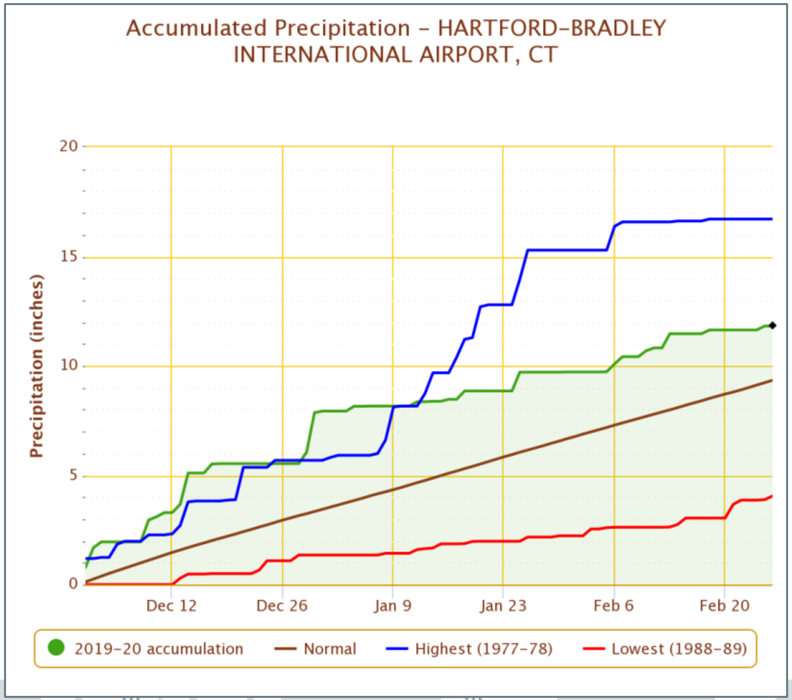
Winter Temperatures



Observed Winter Precipitation (Dec-Feb)

- Boston
  - Total precipitation was 0.1 inches below normal
  - 15.1” of snowfall recorded, which was 16.6” below normal
- Hartford
  - Total precipitation was 2.6 inches above normal
  - 25.7” of snowfall recorded, which was 4.2” below normal





Winter Observations

- Winter Demand Forecast
  - 50/50 winter peak demand forecast was 20,476 MW
  - 90/10 winter peak demand forecast was 21,173 MW
  - Actual winter peak demand was 18,913 MW on December 19, 2019

- Transmission System & Transfer Capability
  - New England transmission system performed well
  - Transfer capability on the New York Northern AC ties was increased from 1400 to 1500 MW for the winter period

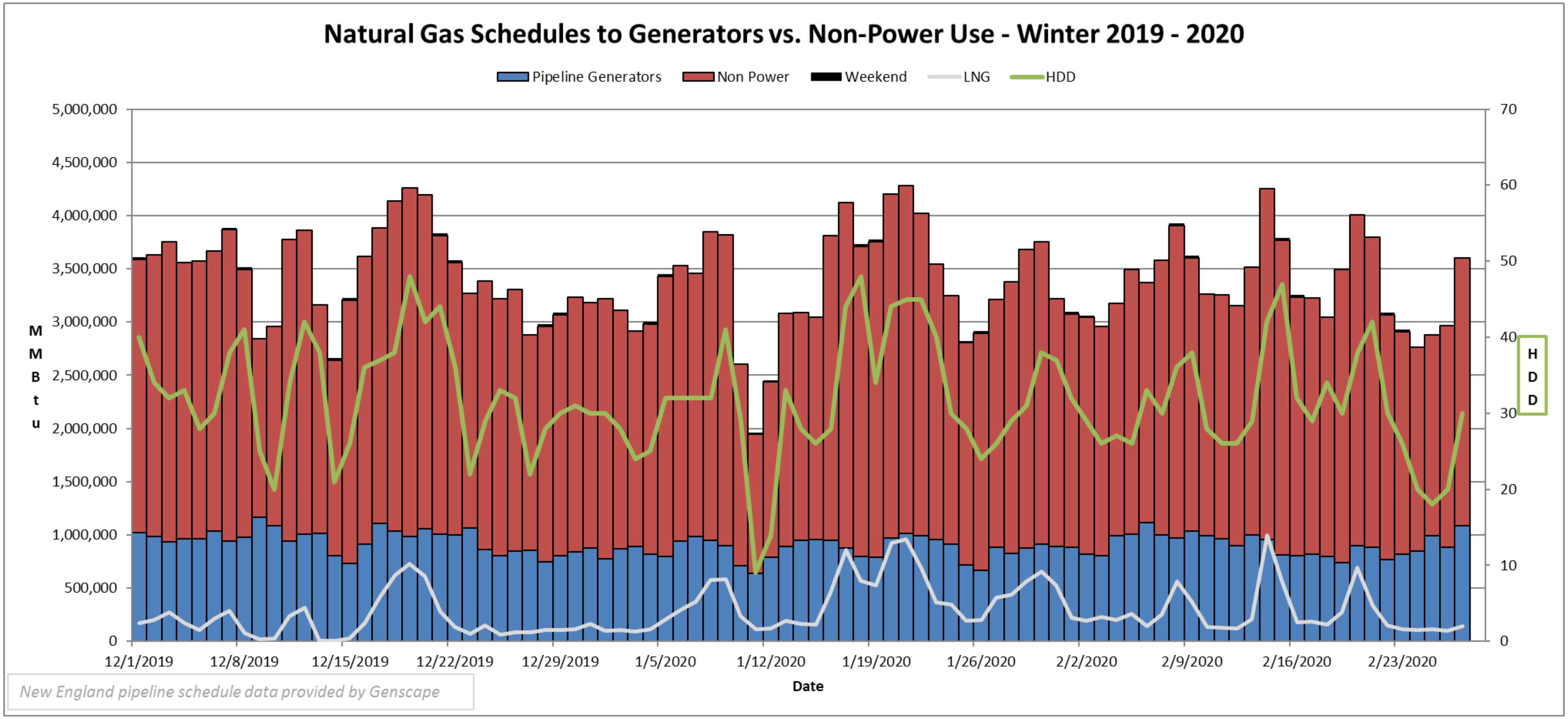
Winter Observations, cont.

- Natural Gas Supply and Demand
  - Overall, peak natural gas demand was slightly lower than previous years
  - Scheduled LNG injections were less than last winter by approximately 4 Bcf
    - No Excelerate LNG ship this winter
- Algonquin pipeline pressure restrictions
  - Reductions lifted in early December
  - Minimal impact on generation

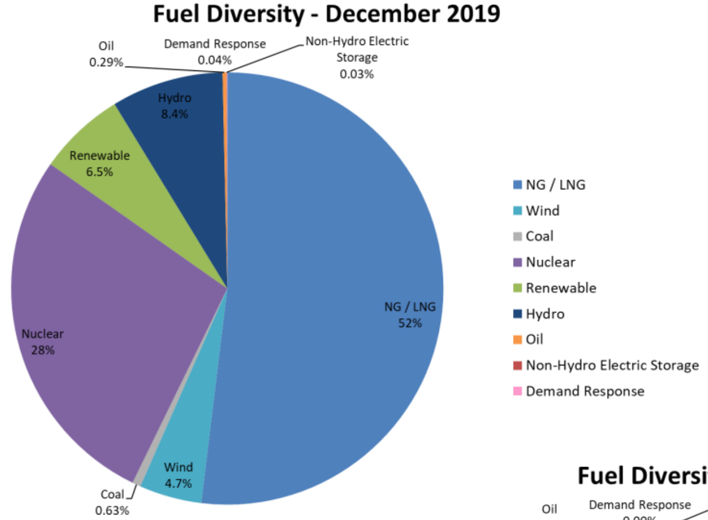
Winter Observations, cont.

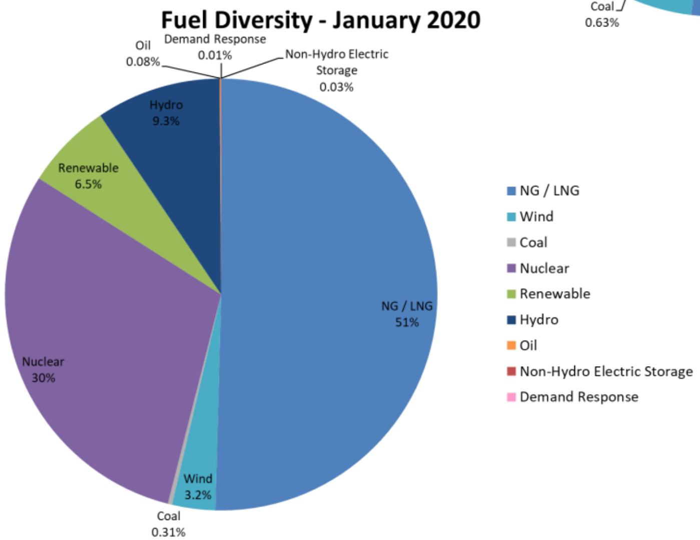
- Fuel and Emissions Availability
  - Fuel inventories and potential emissions restrictions of oil, coal, and natural-gas fired resources were monitored throughout the winter via weekly surveys
  - Oil tanks entered Winter 2019-2020 at approximately 52% full and ended at approximately 54% full
- Winter Capacity
  - Generation fleet performed well overall throughout the winter
  - The lowest 50/50 capacity margins were projected to be 2,448 MW (50/50) and 1,284 MW (90/10) for the week beginning January 11, 2020
  - Actual lowest observed margin was 530 MW on December 20, 2019

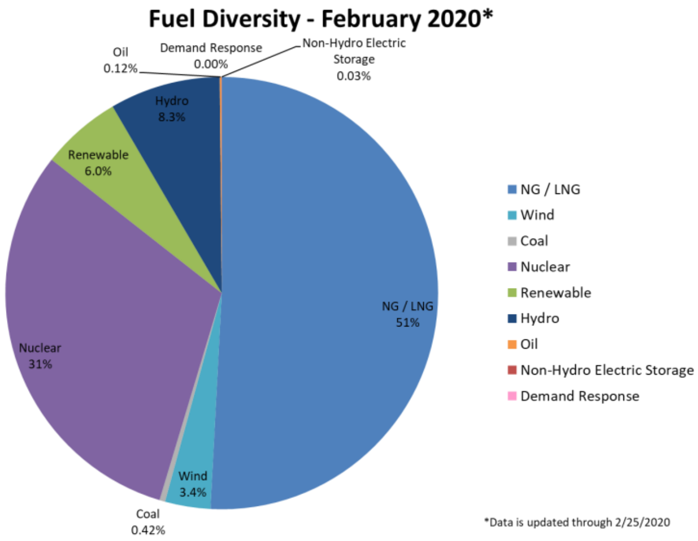
Winter Natural Gas Schedules



Winter Fuel Diversity







Winter Initiatives 2019-2020

- Initiatives for Winter 2019-2020
  - Winter Readiness Seminar: Generator Winter Readiness Seminar with Market Participants was held on November 4, 2019
  - Pay for Performance (PFP)
    - Provides incentives for resources to perform under scarcity conditions
    - No PFP events occurred this winter
  - Opportunity Cost Enhancements (first implemented in 2018)
    - Enhances ability of resources to include fuel-related opportunity costs in energy supply offers
    - Extended cold weather did not occur this winter, as a result there was no need to utilize the opportunity cost mechanisms
  - OP-21 Enhancements
    - Provided market participants with a weekly 21-day look ahead of forecasted system conditions, and therefore an opportunity for Market Participants to take action in advance of an Energy Emergency
    - Forecasted energy surplus did not drop below 5,000 MW for any hour in any of the 21-day forecasts this winter

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (6.1°F) Max: 64°F, Min: 12°F Precipitation: 3.30" – Above Normal Normal: 3.25" Snow: 0.5"	Hartford	Temperature: Above Normal (4.5°F) Max: 63°F, Min: 6°F Precipitation: 3.19" - Above Normal Normal: 2.89" Snow: 0.4"

Peak Load:	16,824 MW	February 14, 2020	19:00 (ending)

Emergency Procedure Events (OP-4, M/LCC 2, Minimum Generation Emergency)

Procedure	Declared	Cancelled	Note
None for February, 2020			

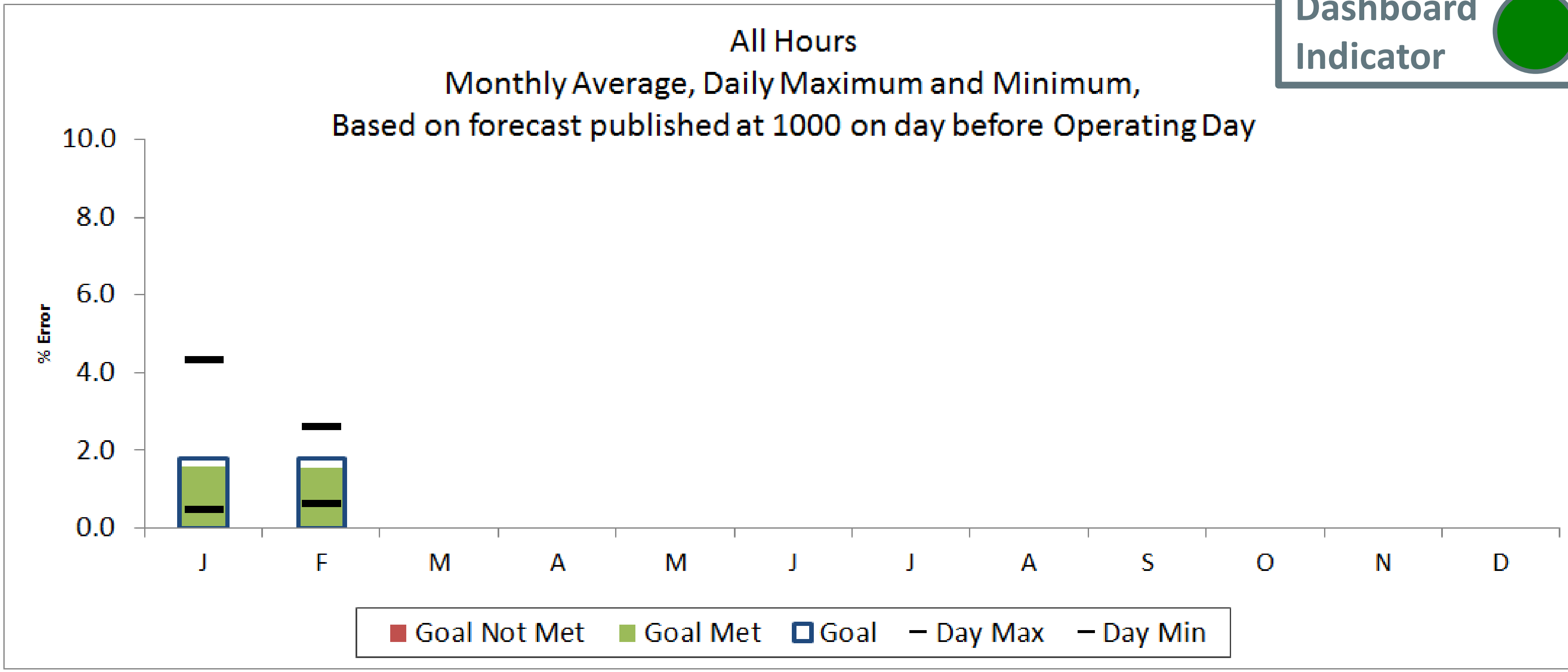
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
2/3	IESO	830
2/18	PJM	1100
2/26	NYISO	750

2020 System Operations - Load Forecast Accuracy

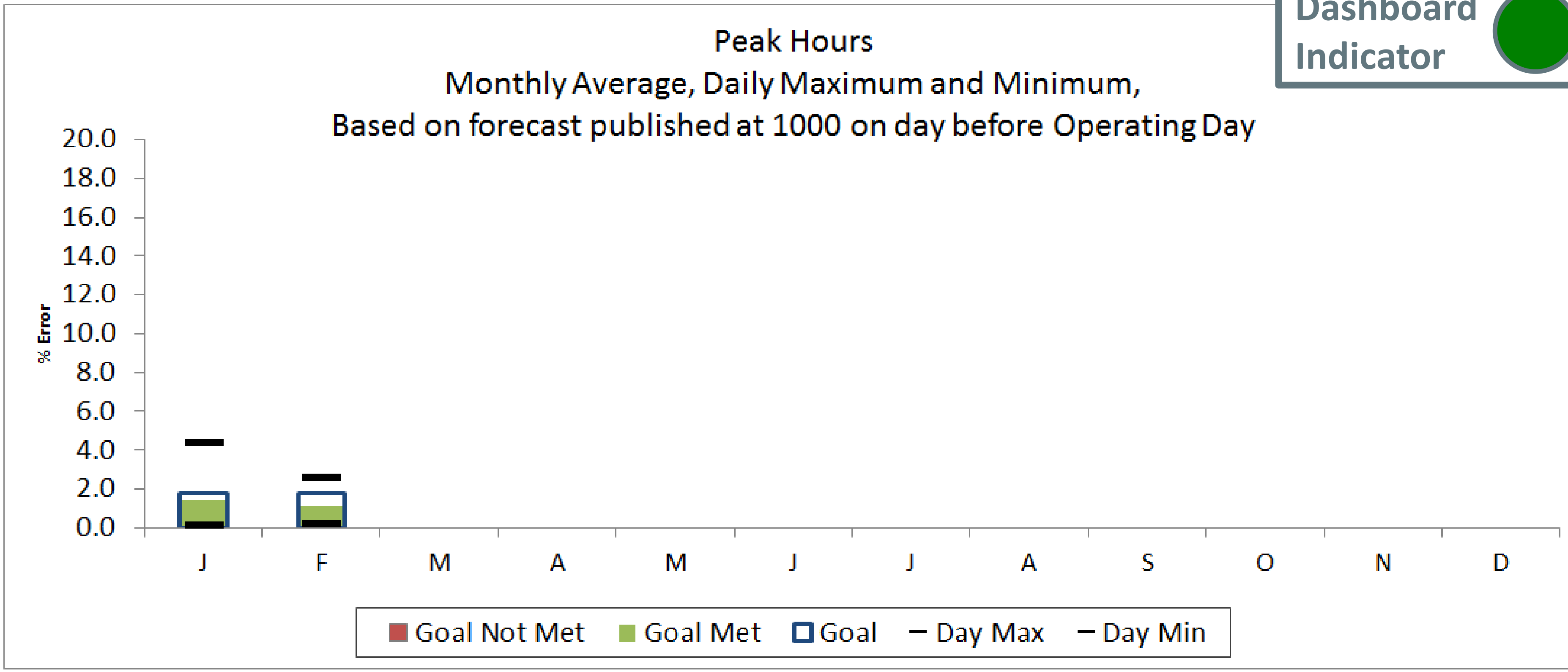
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.31	2.59											4.31
Day Min	0.46	0.61											0.46
MAPE	1.57	1.54											1.56
Goal	1.80	1.80											

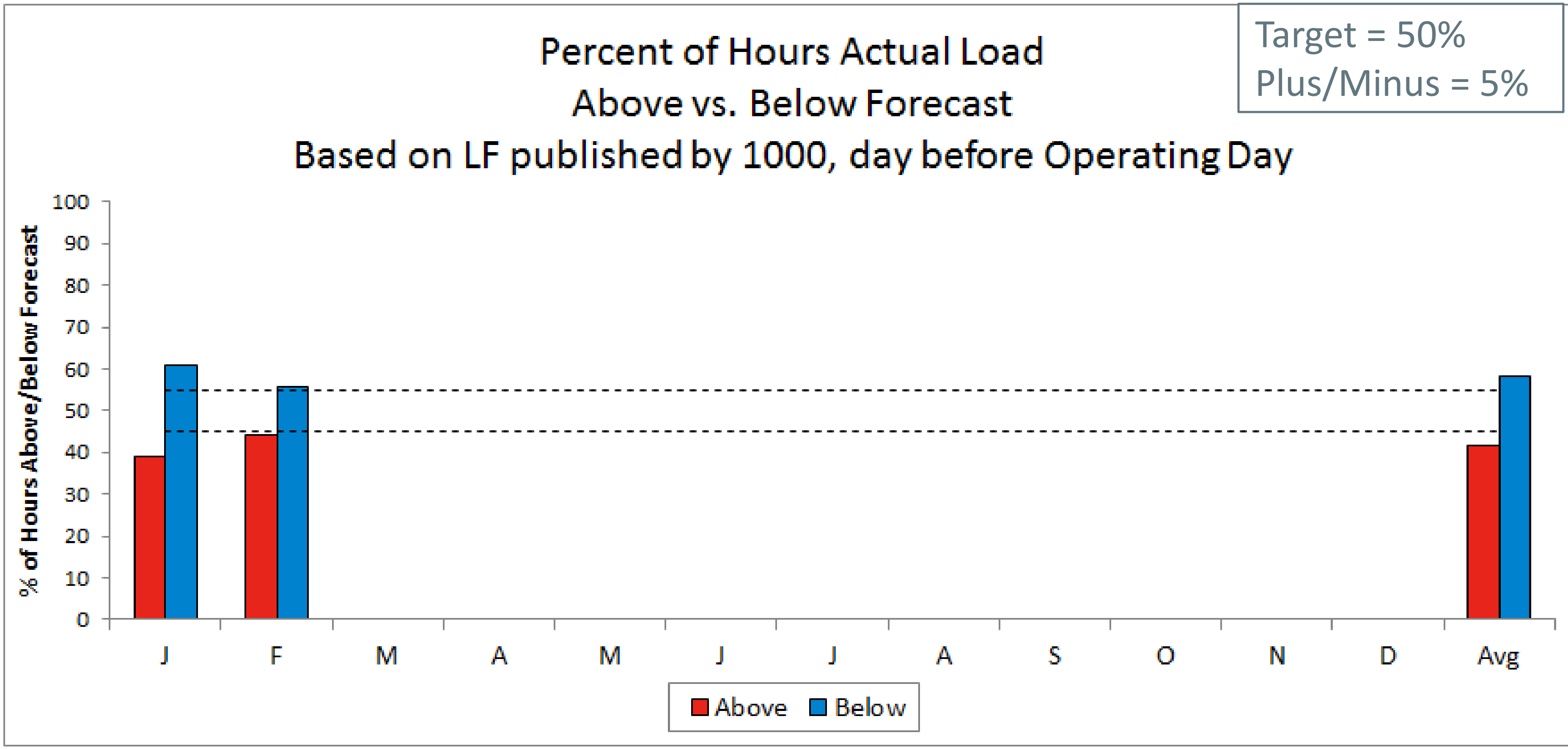
2020 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



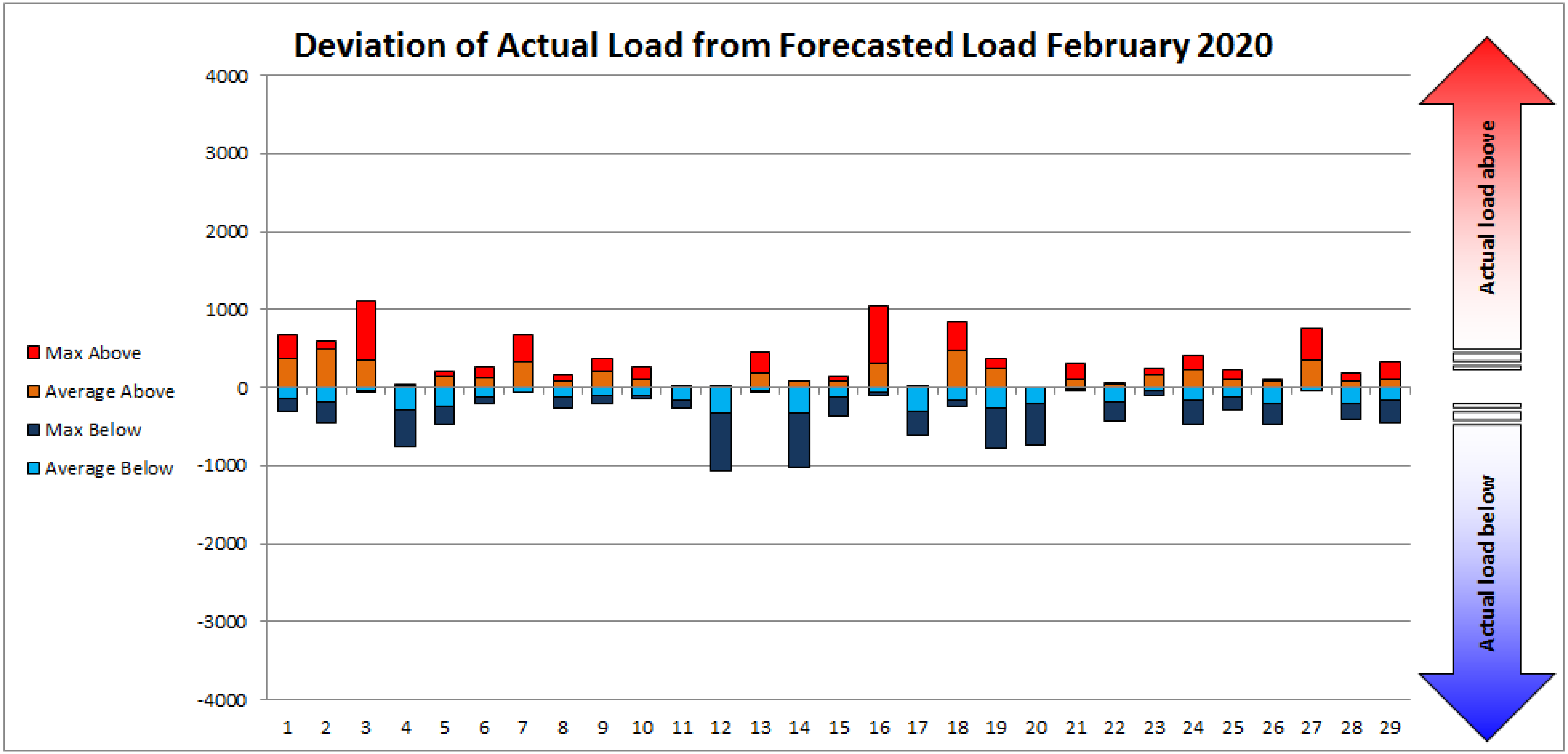
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.33	2.59											4.33
Day Min	0.07	0.19											0.07
MAPE	1.41	1.12											1.27
Goal	1.80	1.80											

2020 System Operations - Load Forecast Accuracy cont.

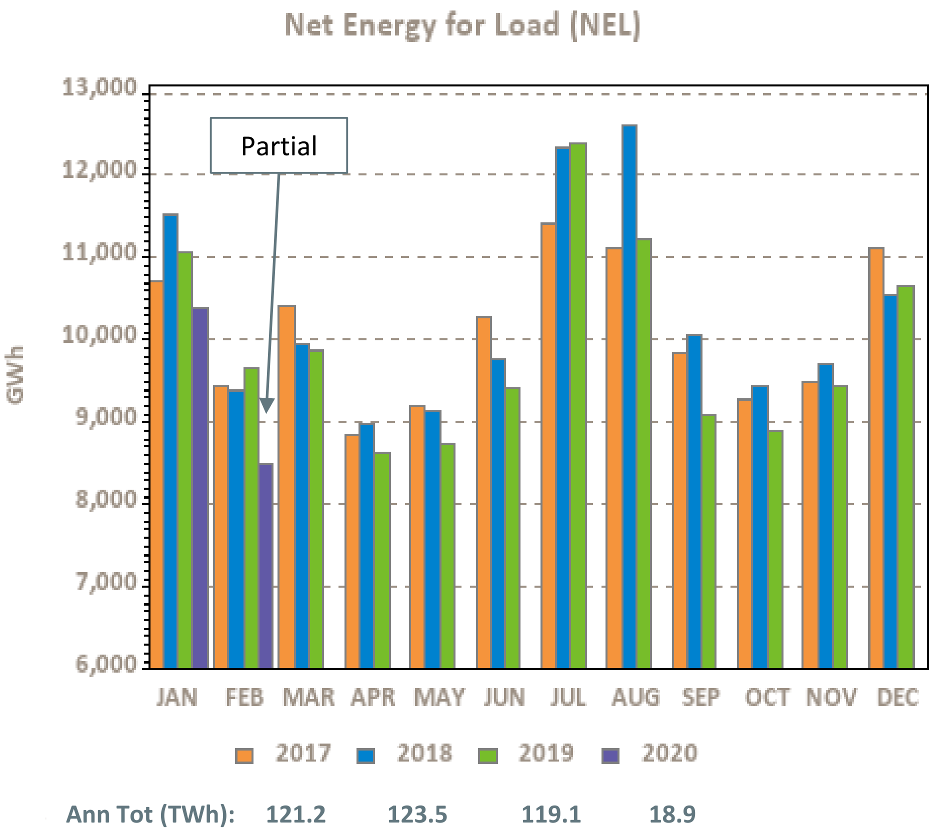


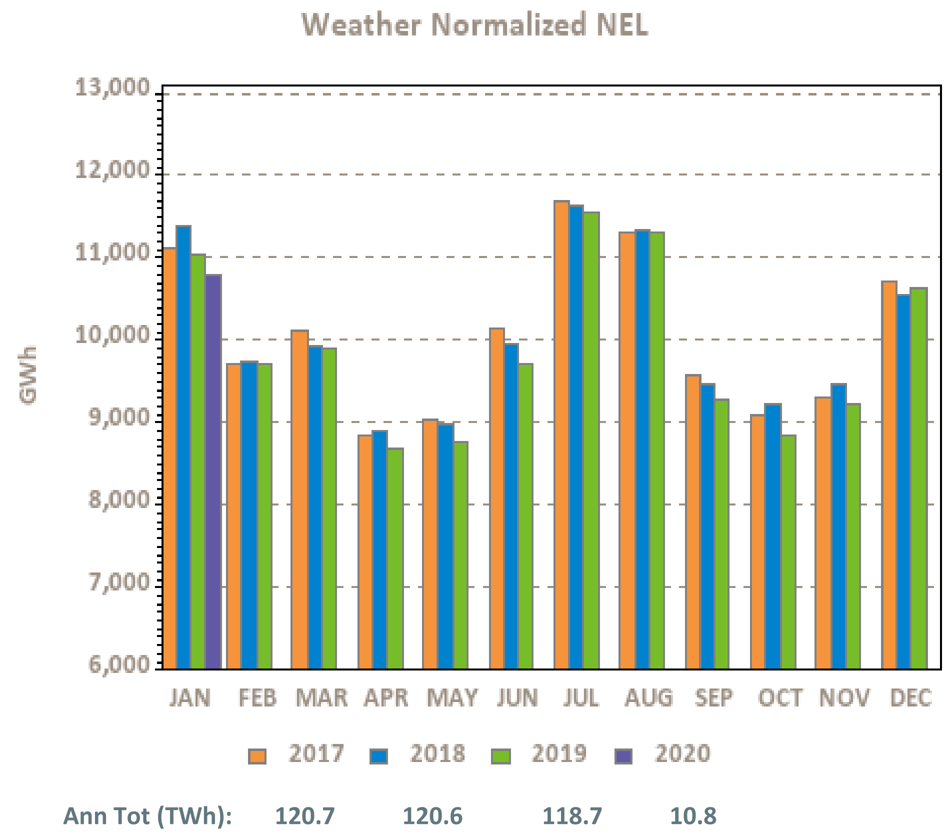
	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	39	44.3											42
Below %	61	55.7											58
Avg Above	136.2	169.9											170
Avg Below	-192.4	-157.6											-192
Avg All	-65	-13											-40

2020 System Operations - Load Forecast Accuracy cont.



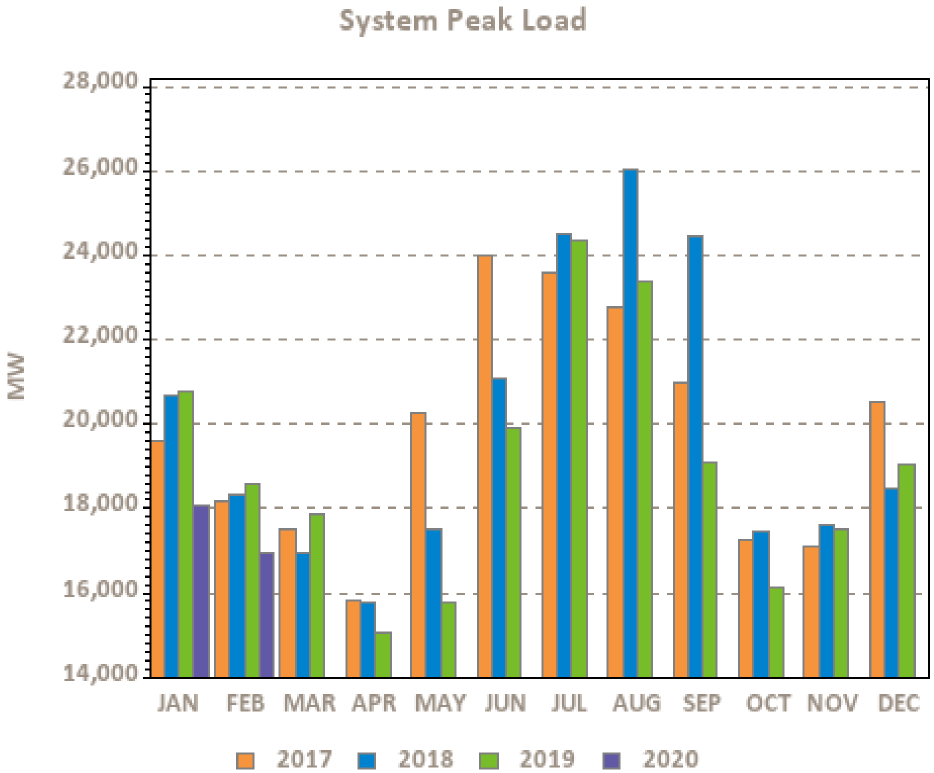
Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL



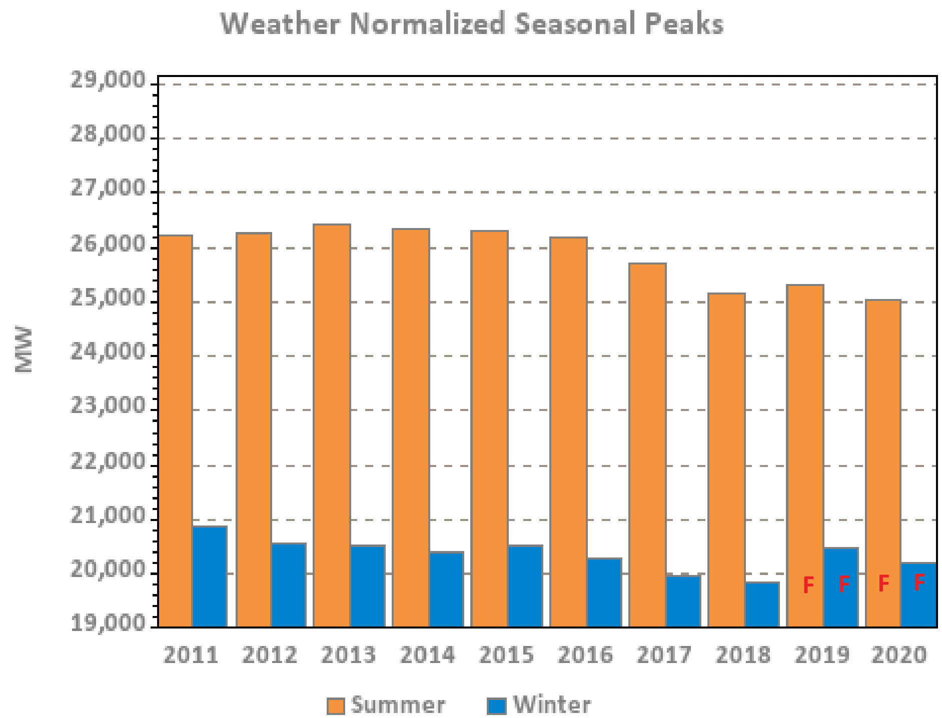


NEPOOL NEL is the total net revenue quality metered energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation – pumping load + net interchange where imports are positively signed. Current month's data may be preliminary. Weather normalized NEL may be reported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

Monthly Peak Loads and Weather Normalized Seasonal Peak History



Revenue quality metered value

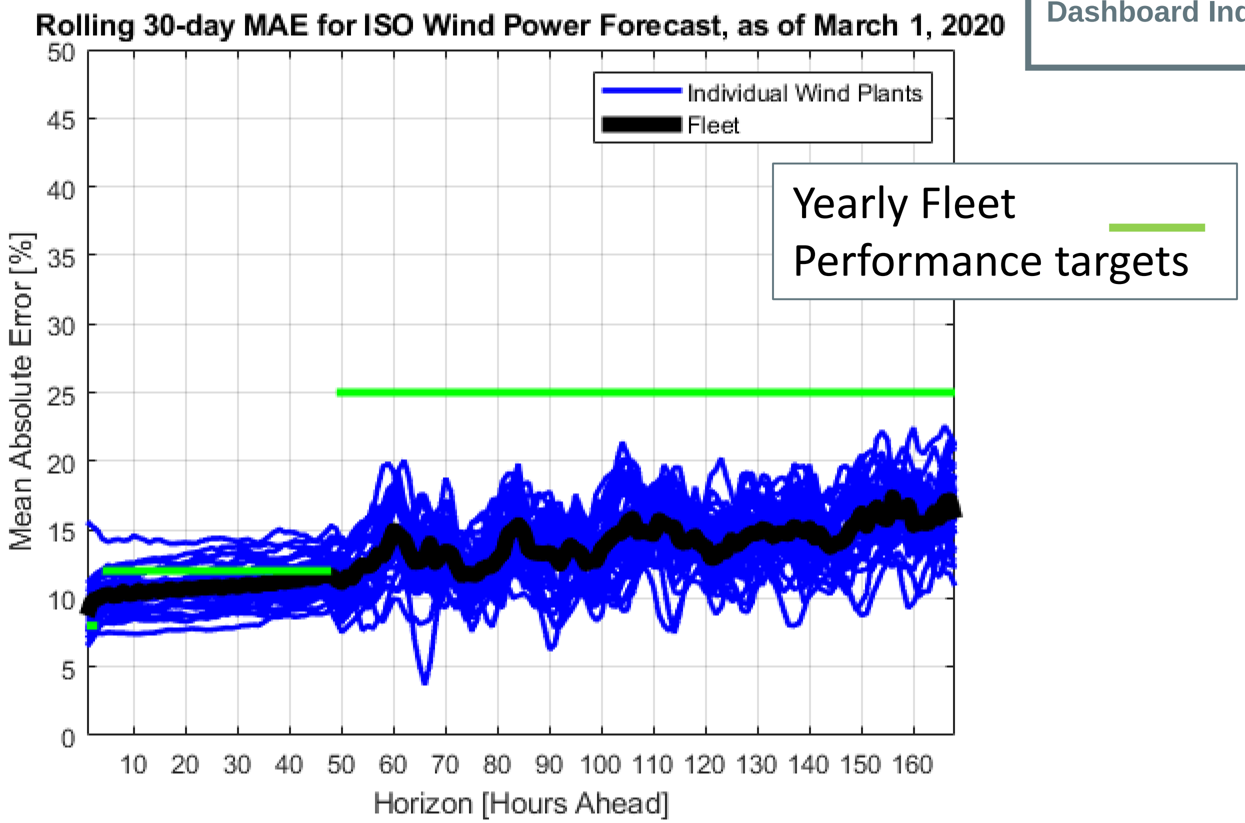


Winter beginning in year displayed

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

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

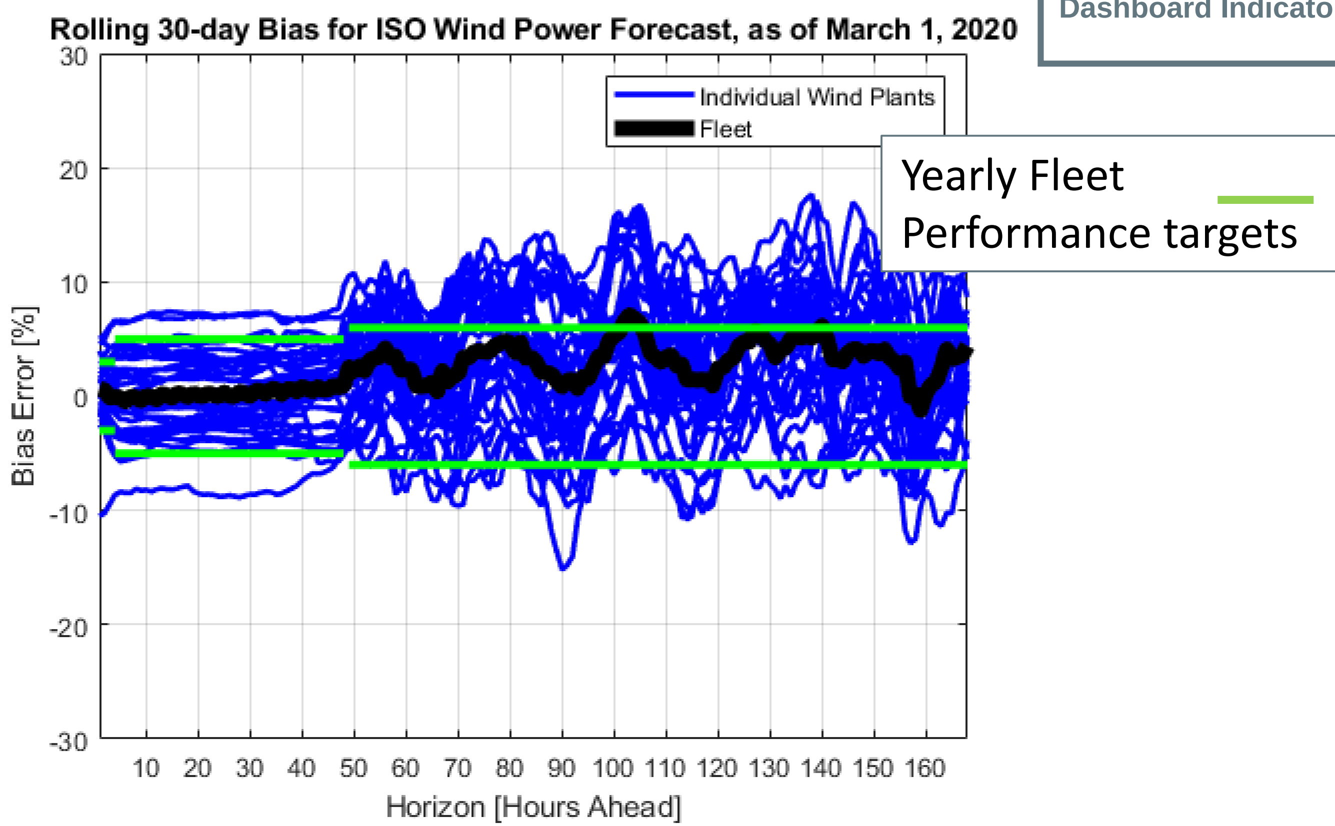
Dashboard Indicator



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

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

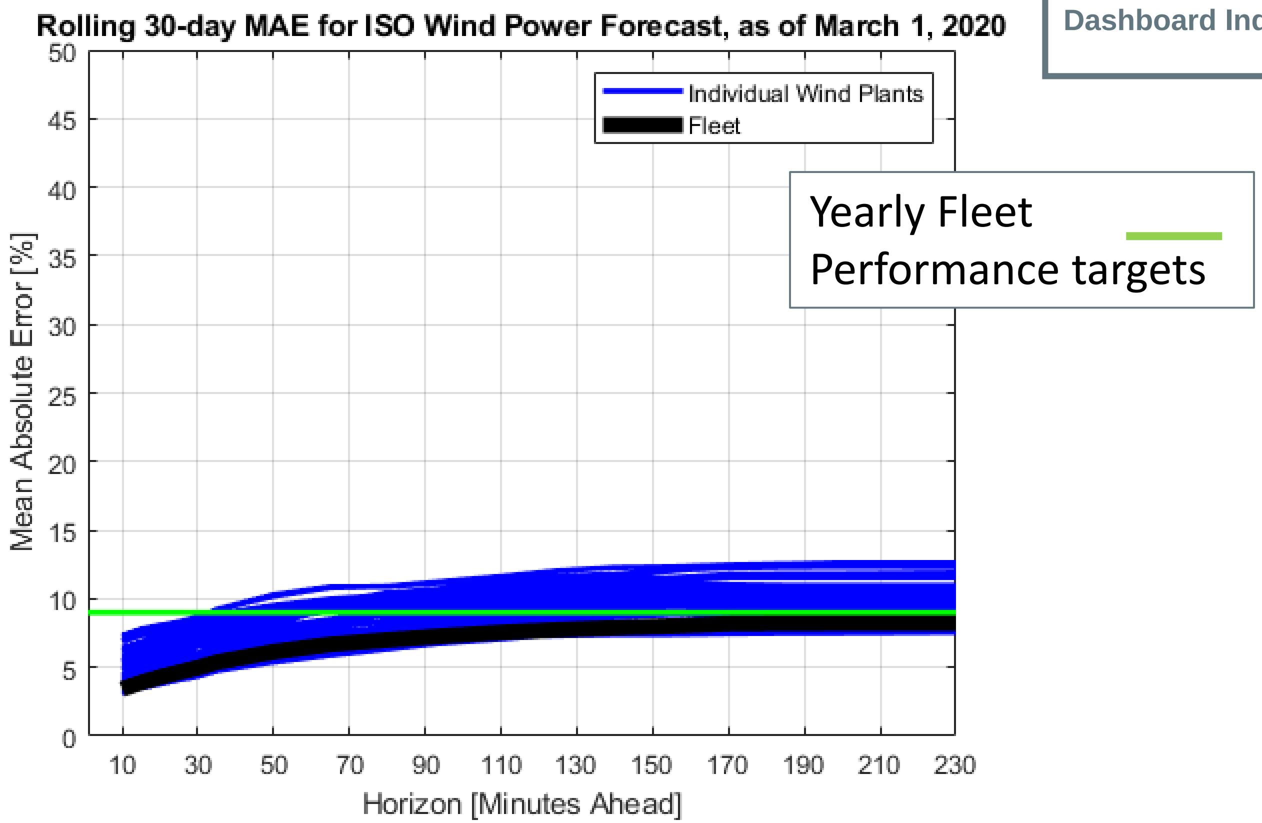
Dashboard Indicator



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

Wind Power Forecast Error Statistics: Short Term Forecast MAE

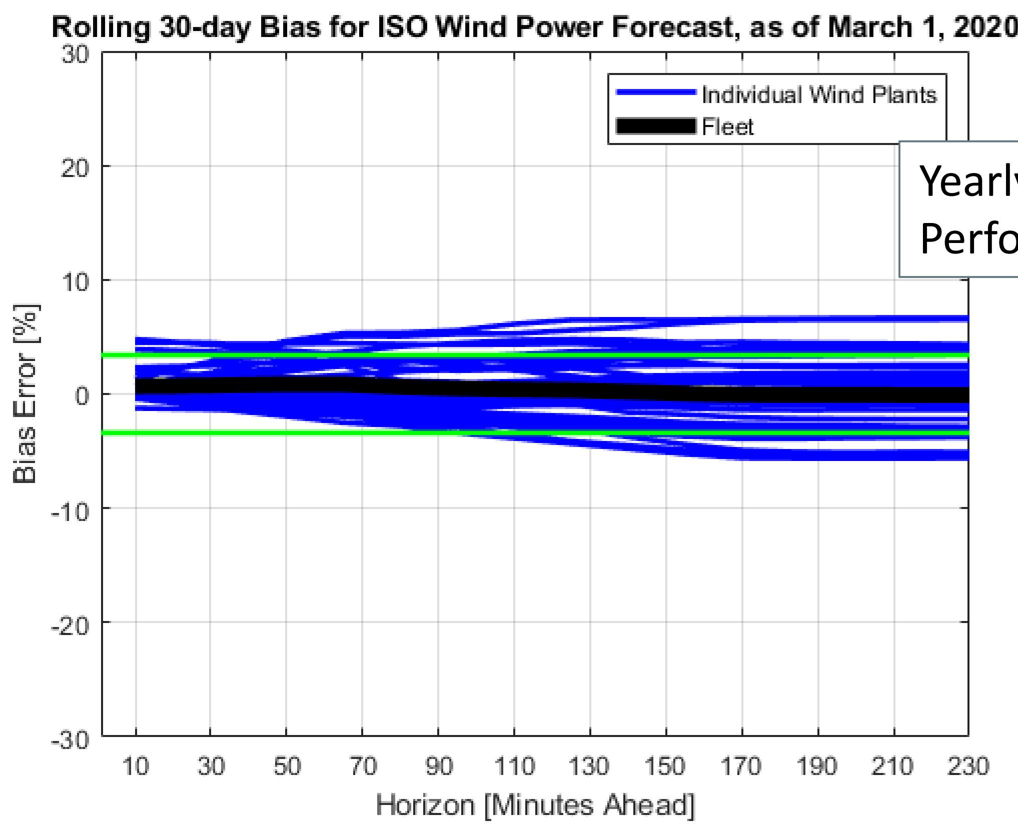
Dashboard Indicator



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

Wind Power Forecast Error Statistics: Short Term Forecast Bias

Dashboard Indicator

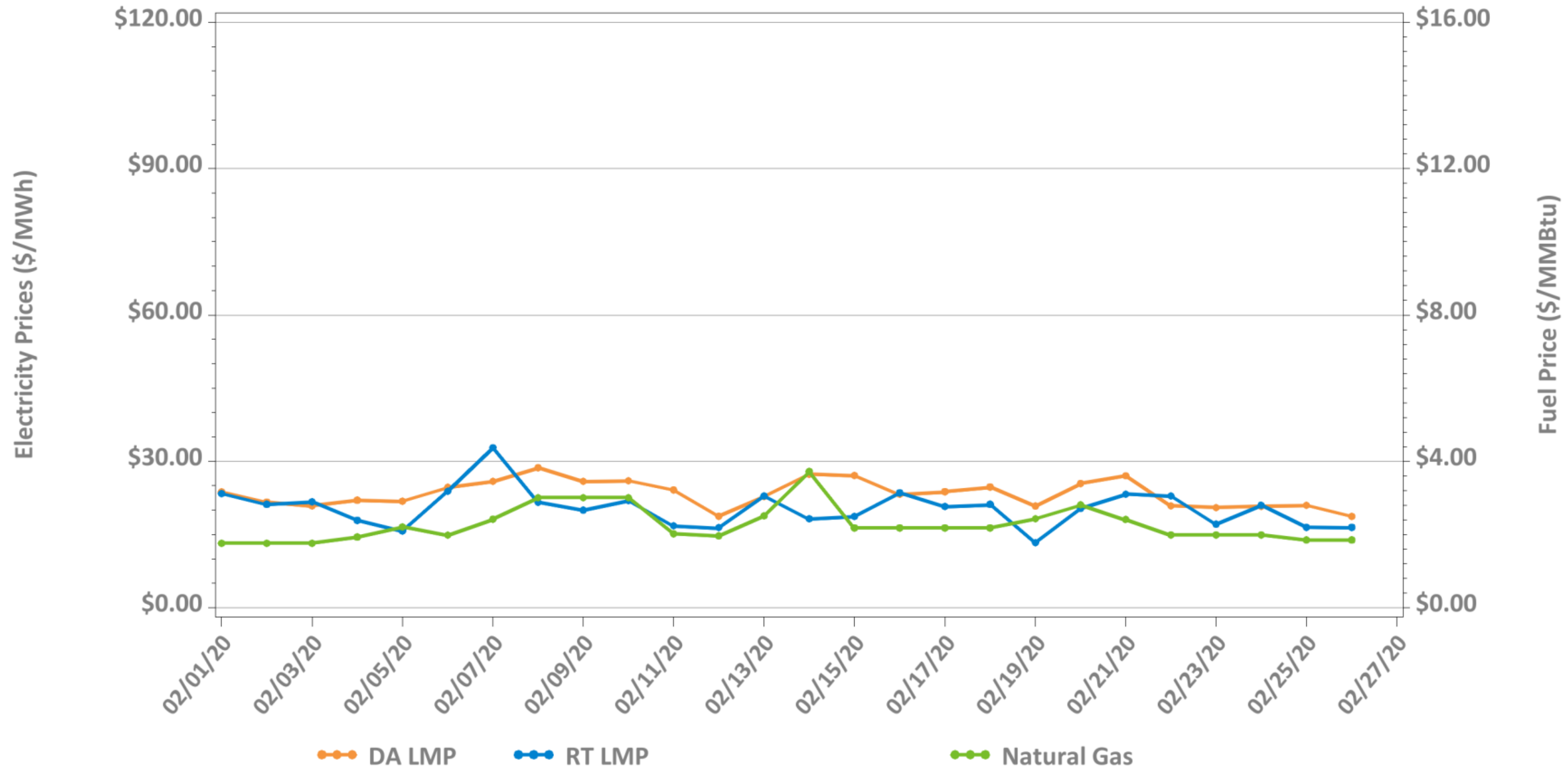


Yearly Fleet Performance targets

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.

MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: February 1-26, 2020

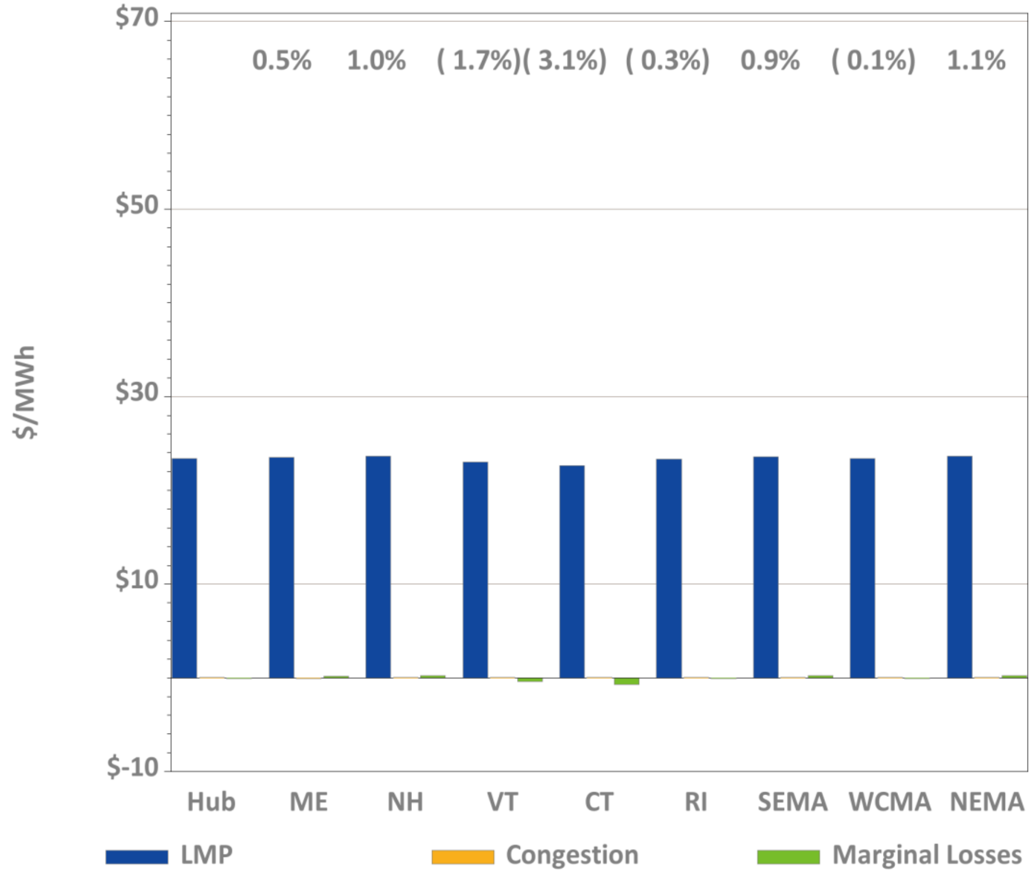


Underlying natural gas data furnished by:

ICE Global markets in clear view

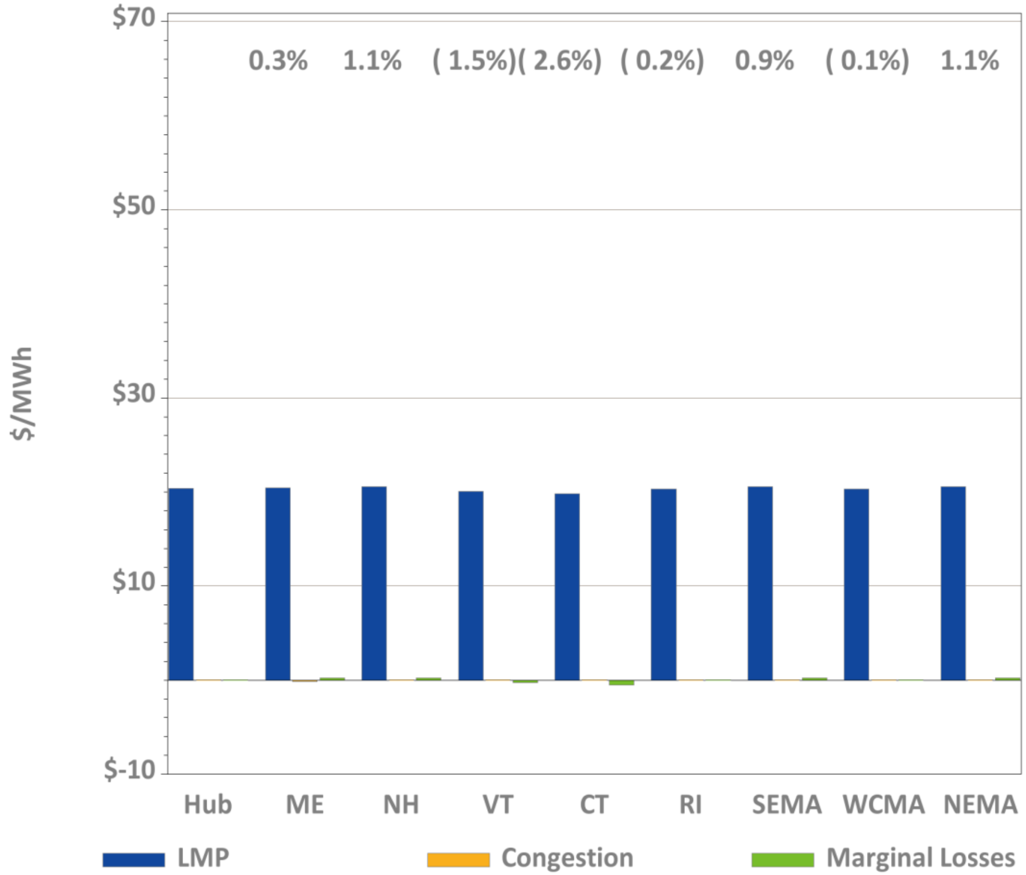
Average price difference over this period (DA-RT): $3.03
Average price difference over this period ABS(DA-RT): $3.84
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 19%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, February 2020



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

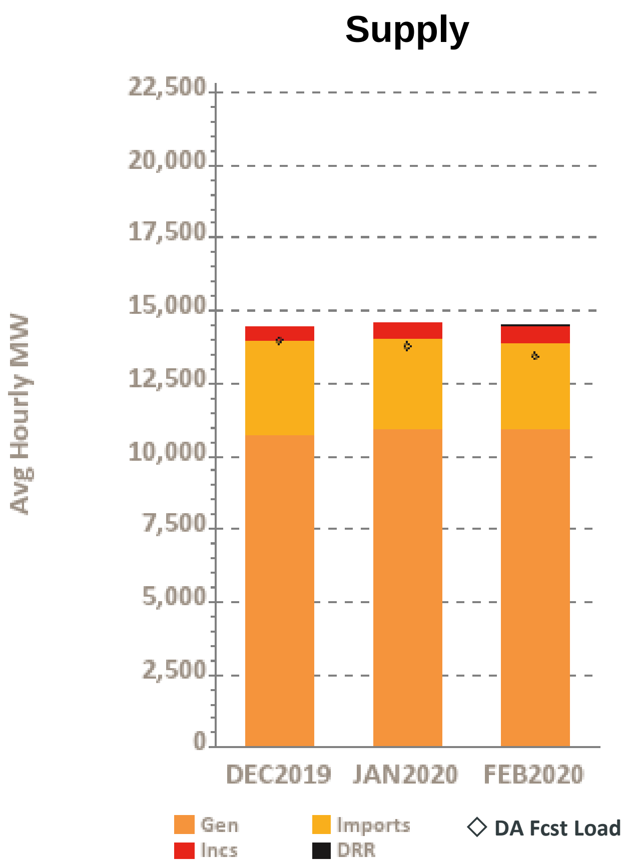
RT LMPs Average by Zone & Hub, February 2020



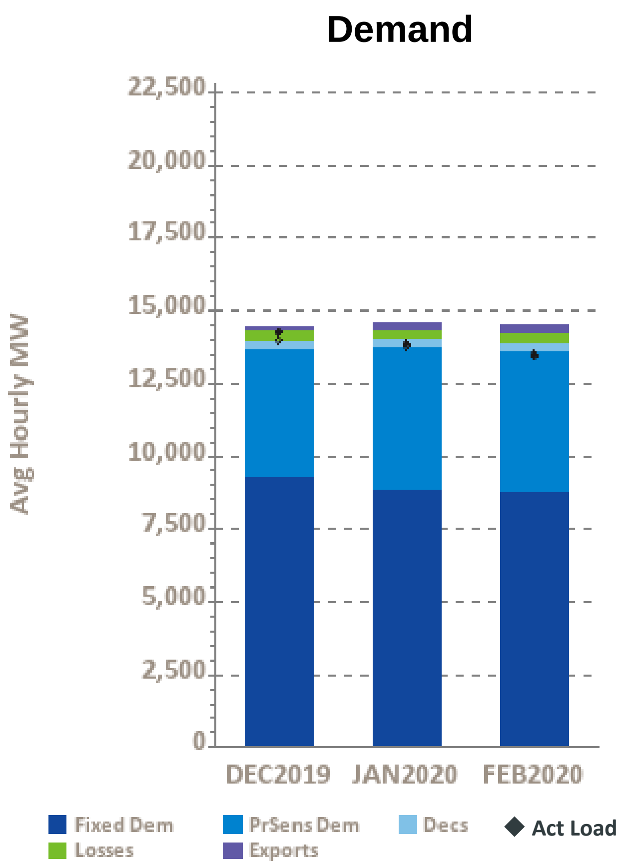
Definitions

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

Components of Cleared DA Supply and Demand – Last Three Months

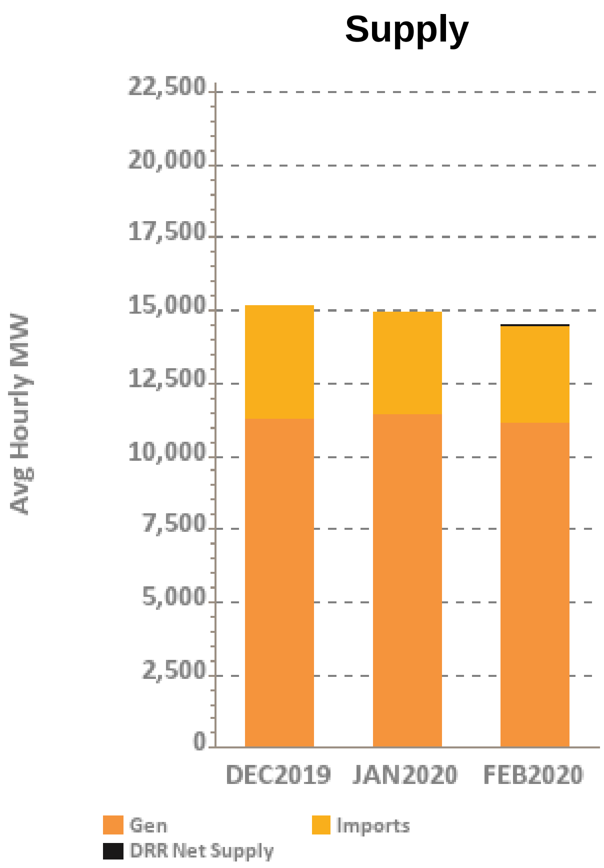


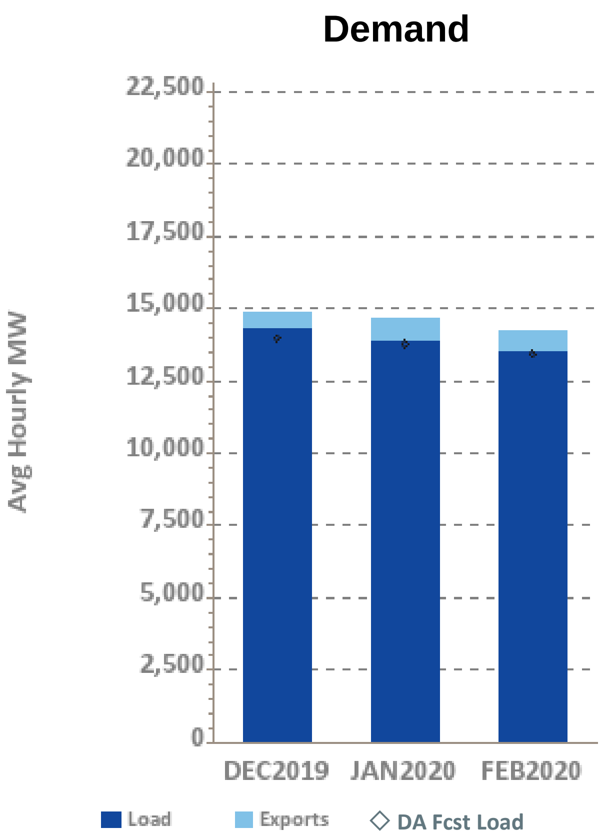
Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load



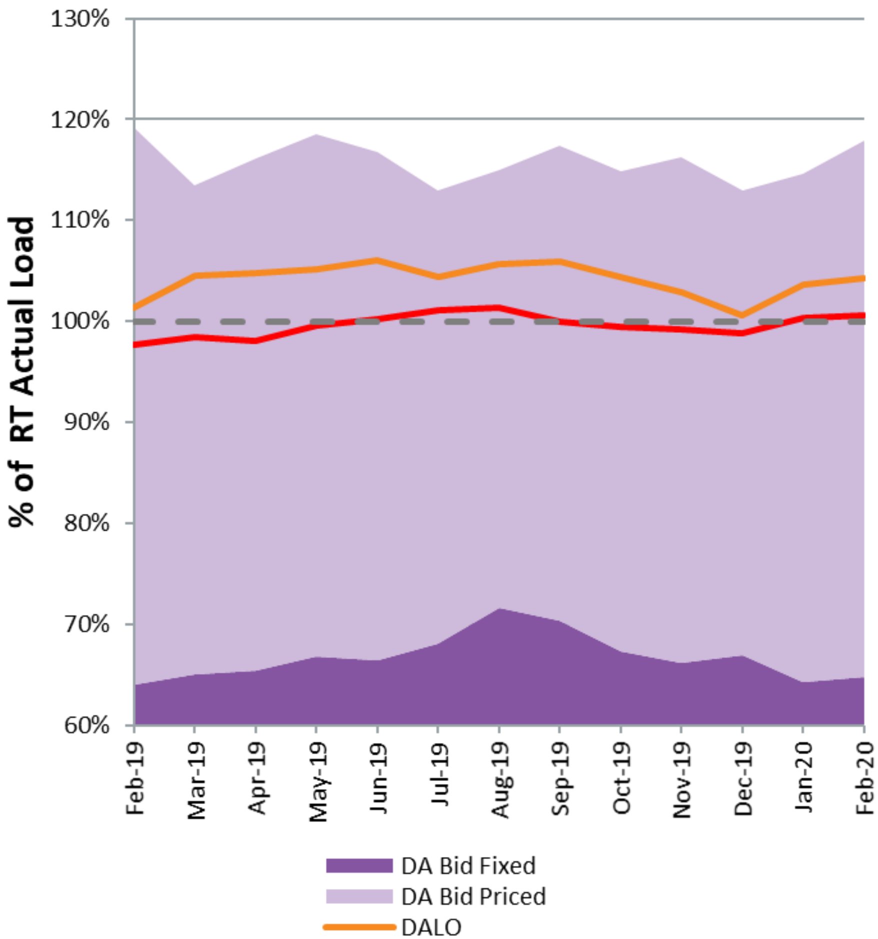
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

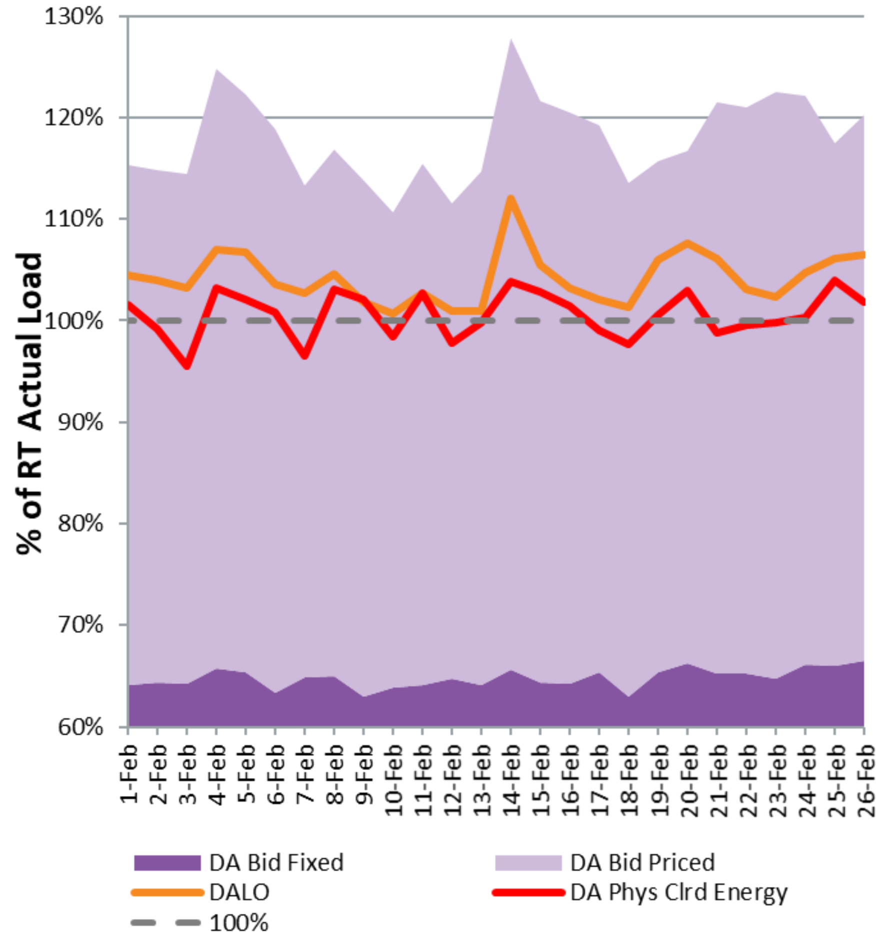
Components of RT Supply and Demand – Last Three Months





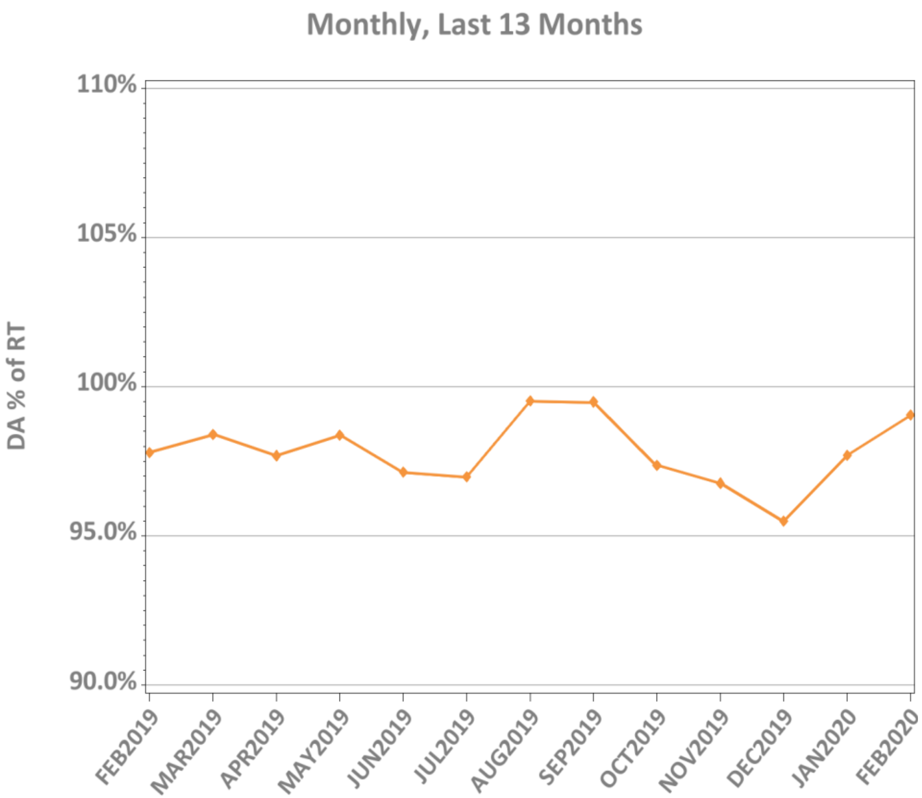
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

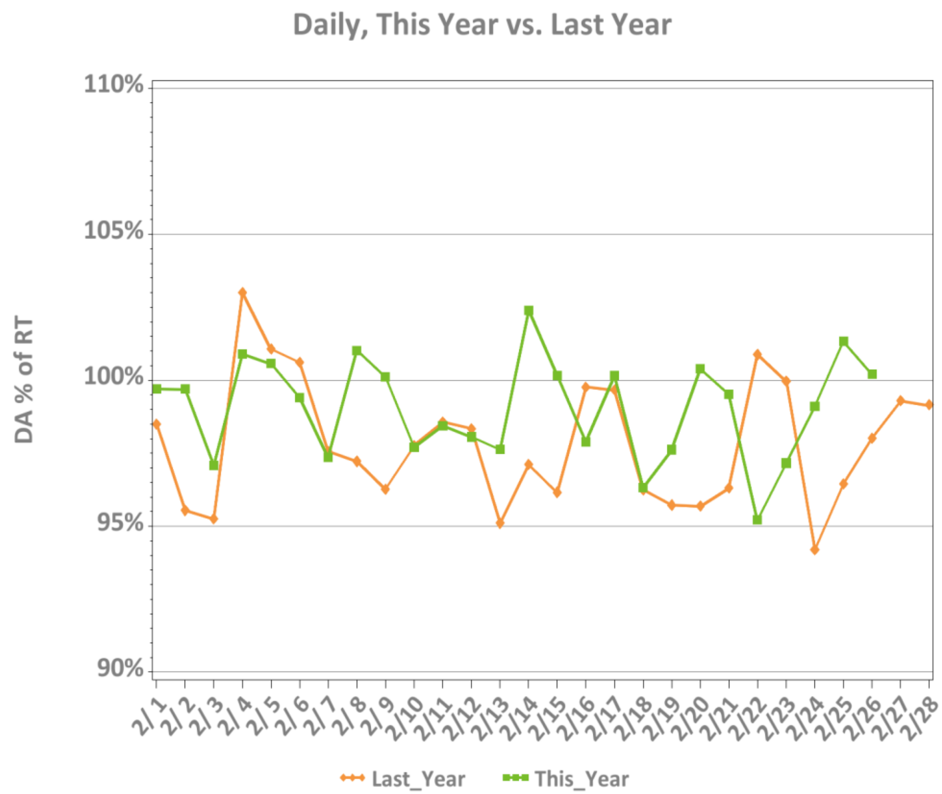




Note: Percentages were derived for the peak hour of each day (shown on right), then averaged over the month (shown on left). Values at hour of forecasted peak load. DA Bid categories reflect internal load asset bidding behavior (Virtual demand and export bid behavior not reflected).

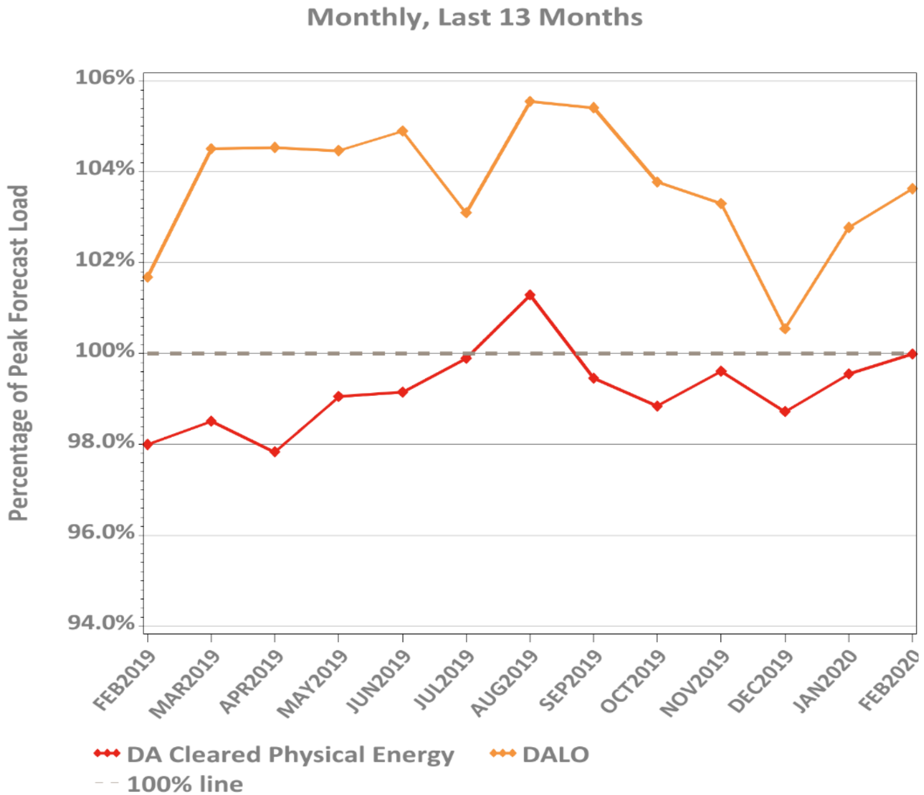
DA vs. RT Load Obligation: February, This Year vs. Last Year

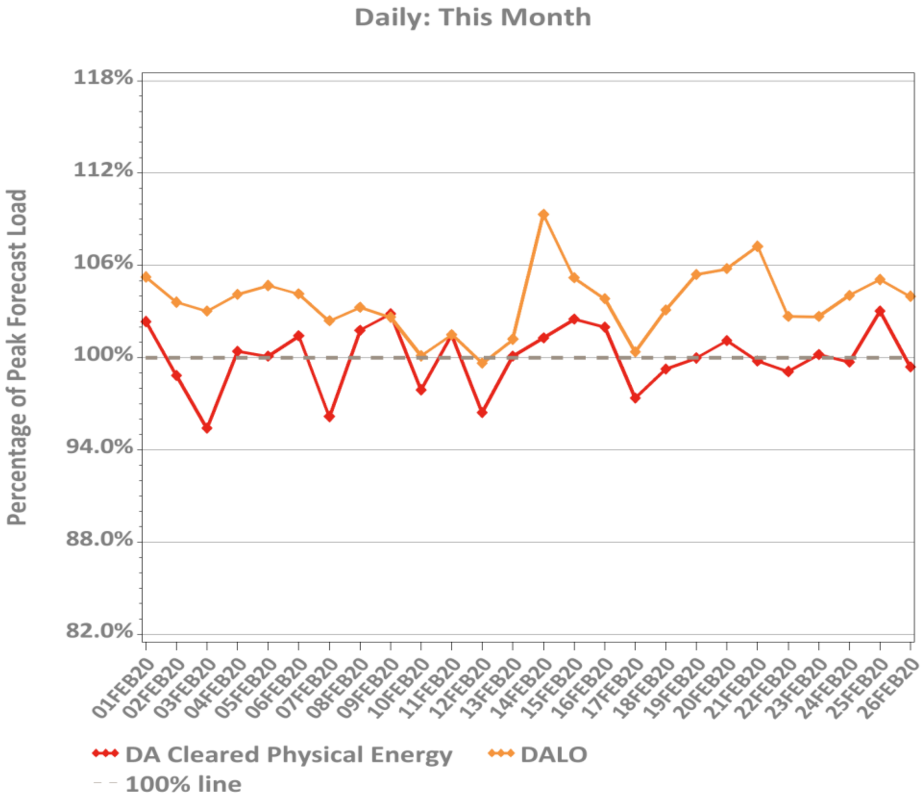




*Hourly average values

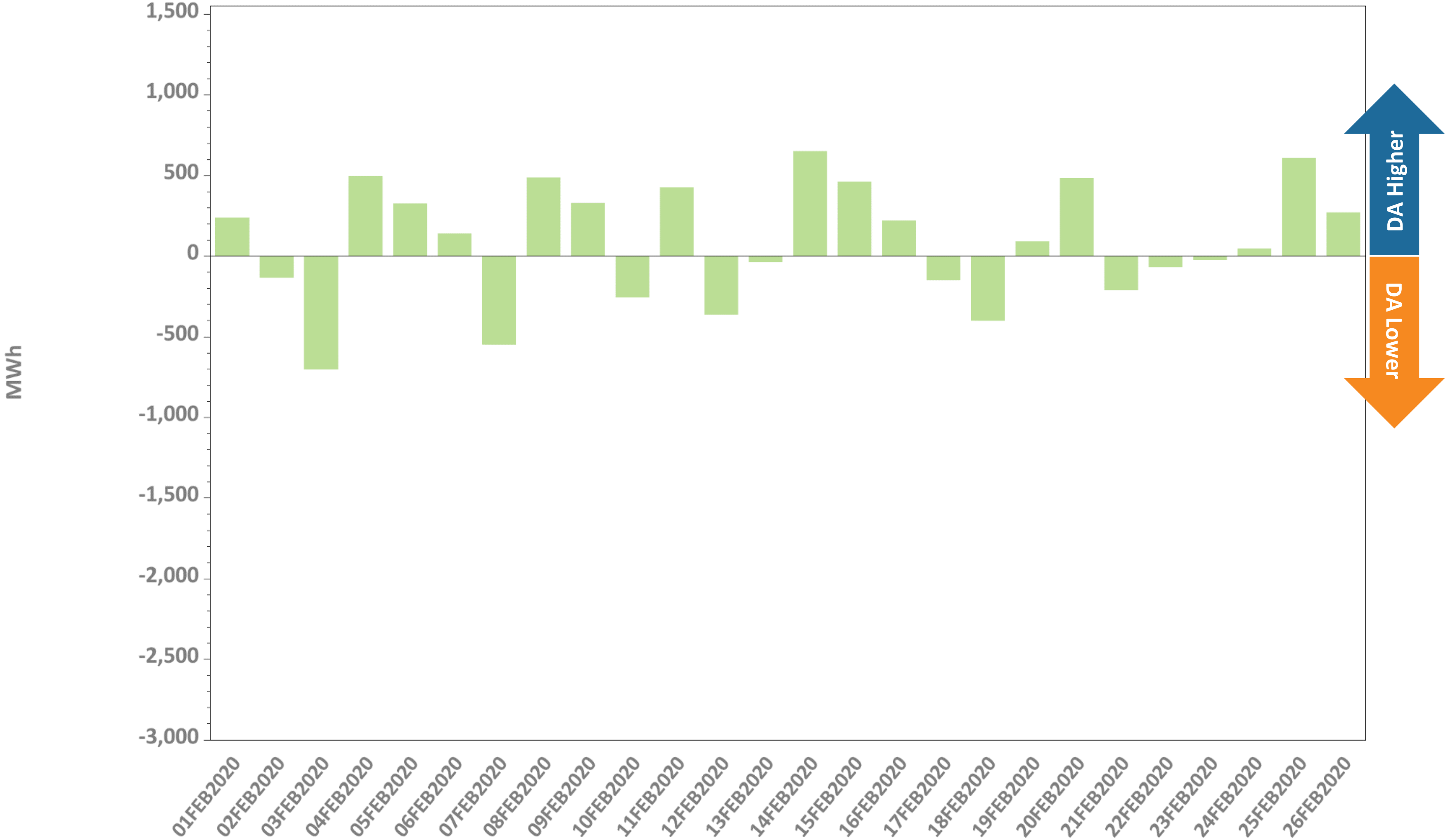
DA Volumes as % of Forecast in Peak Hour





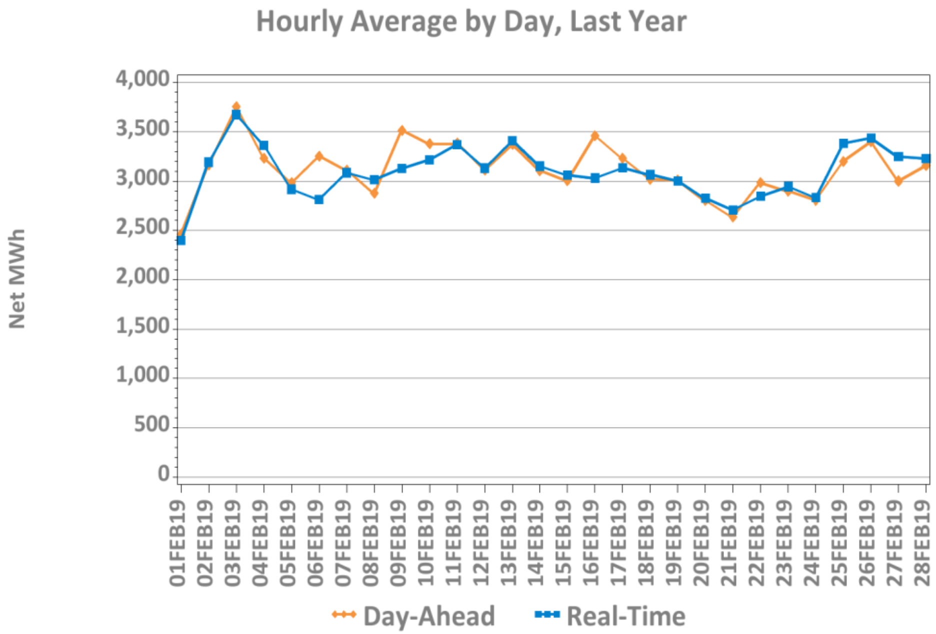
* There were *no* system-level supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) during February.

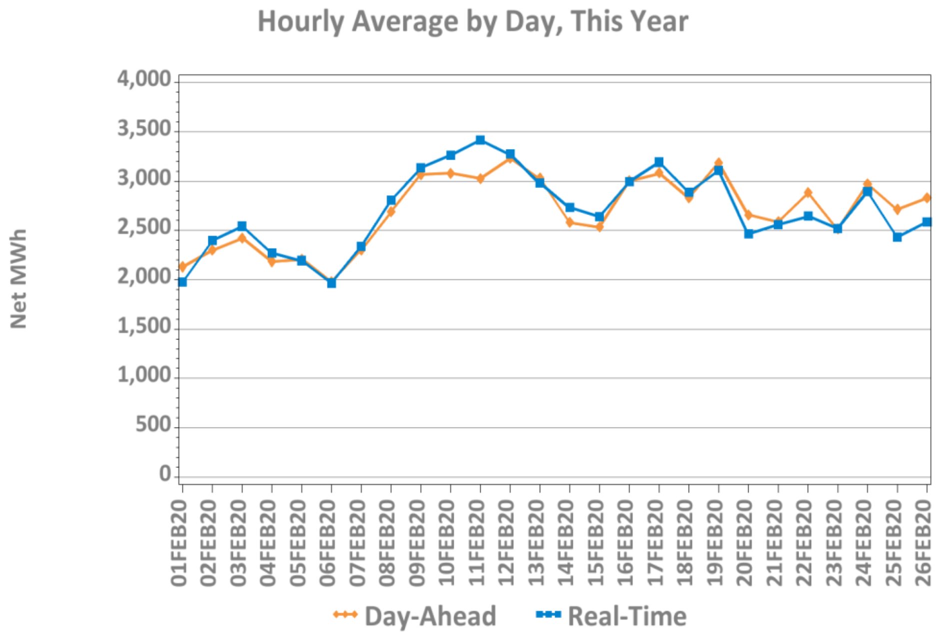
DA Cleared Physical Energy Difference from RT System Load at Peak Hour*



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

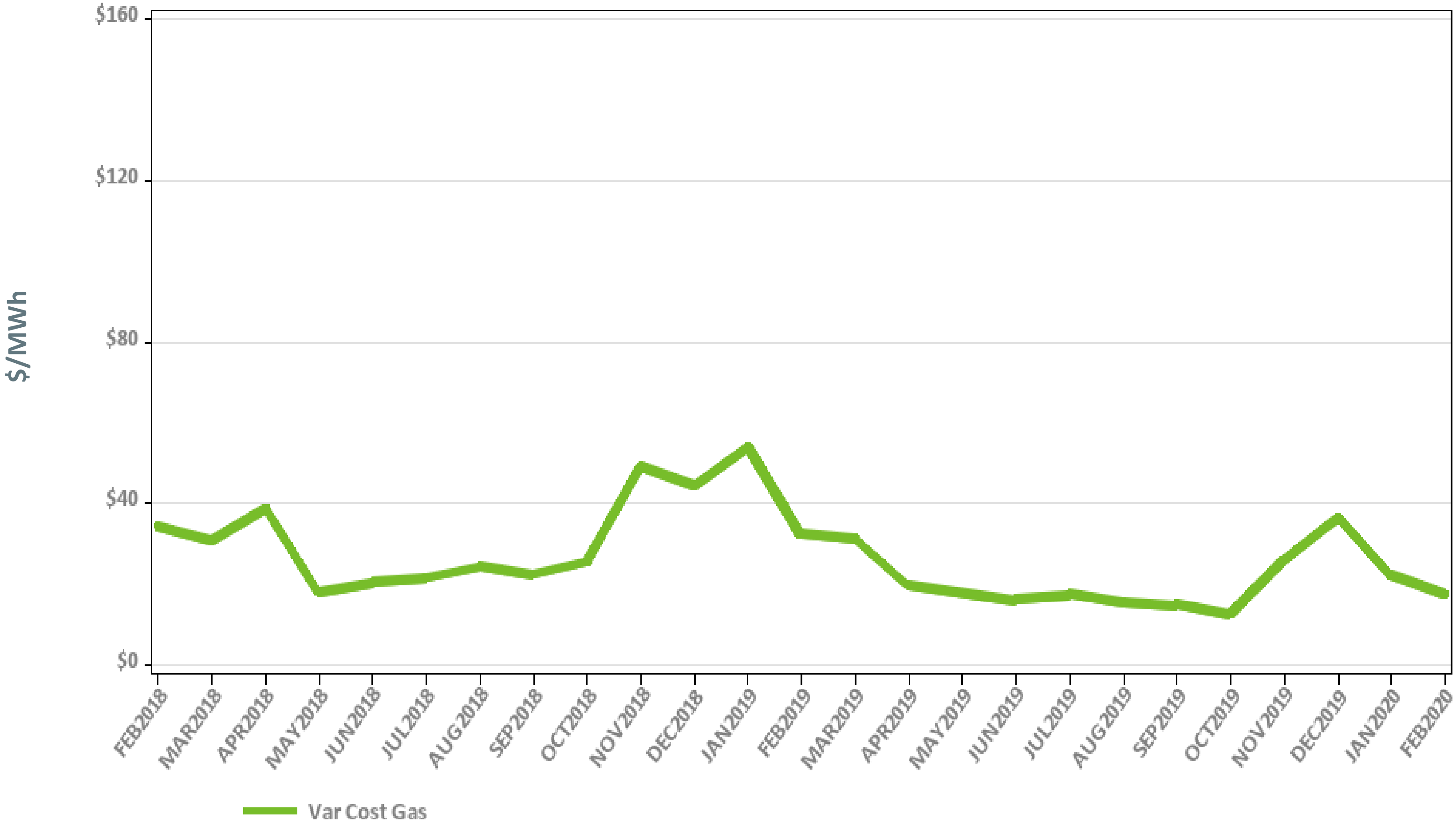
DA vs. RT Net Interchange
February 2019 vs. February 2020





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

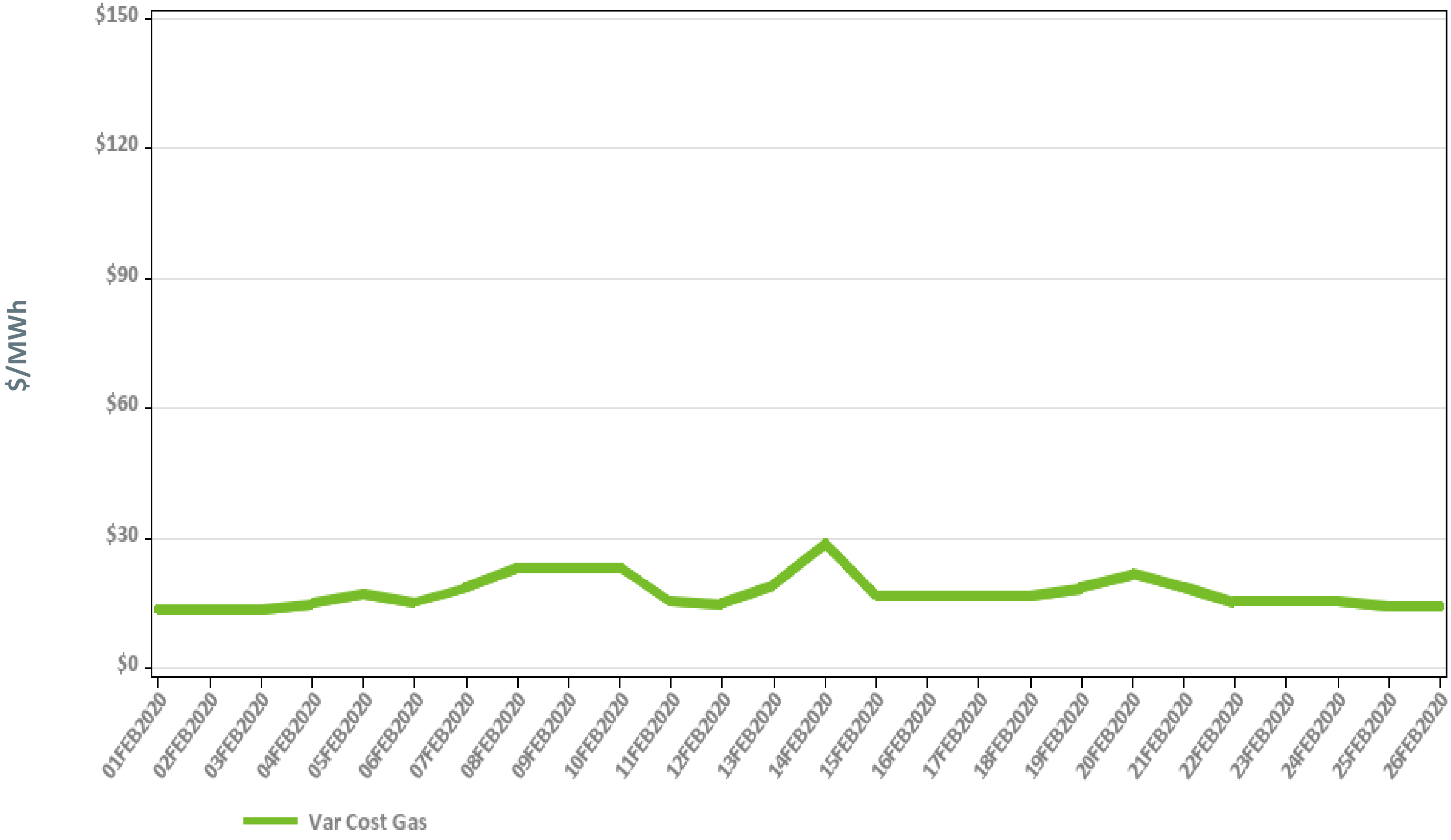
Variable Production Cost of Natural Gas: Monthly



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

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

Variable Production Cost of Natural Gas: Daily

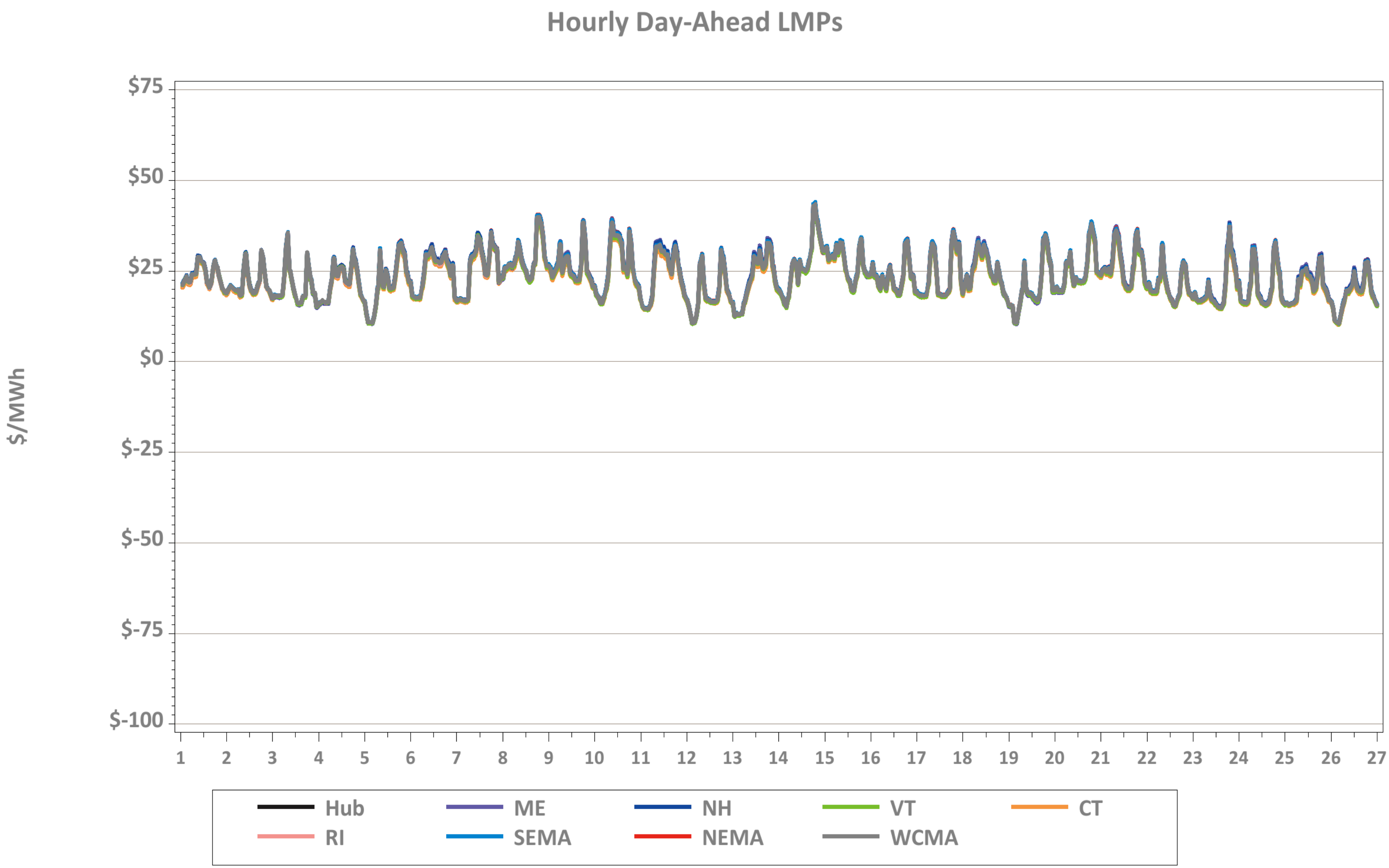


Underlying natural gas data furnished by:

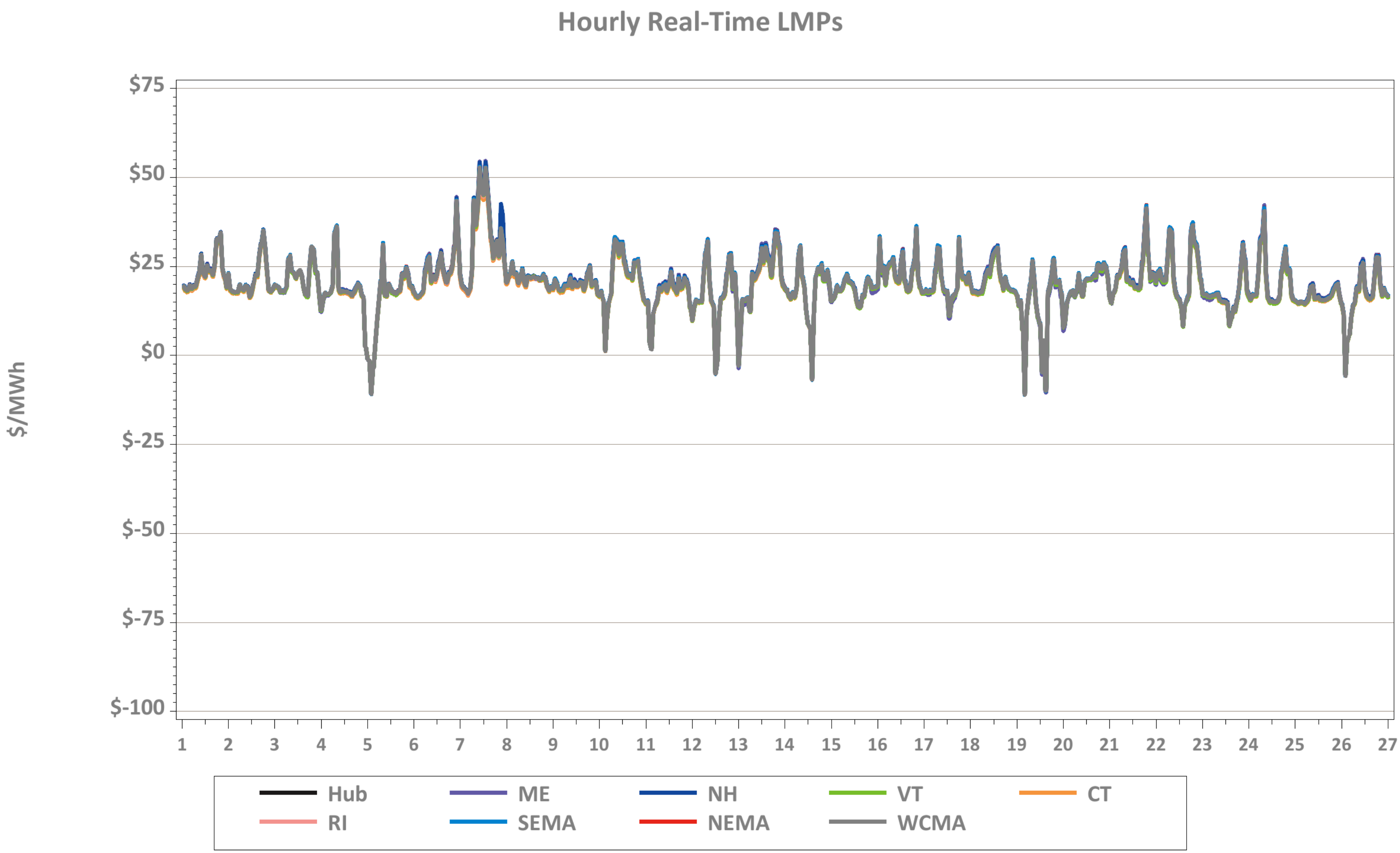
ICE Global markets in clear view

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

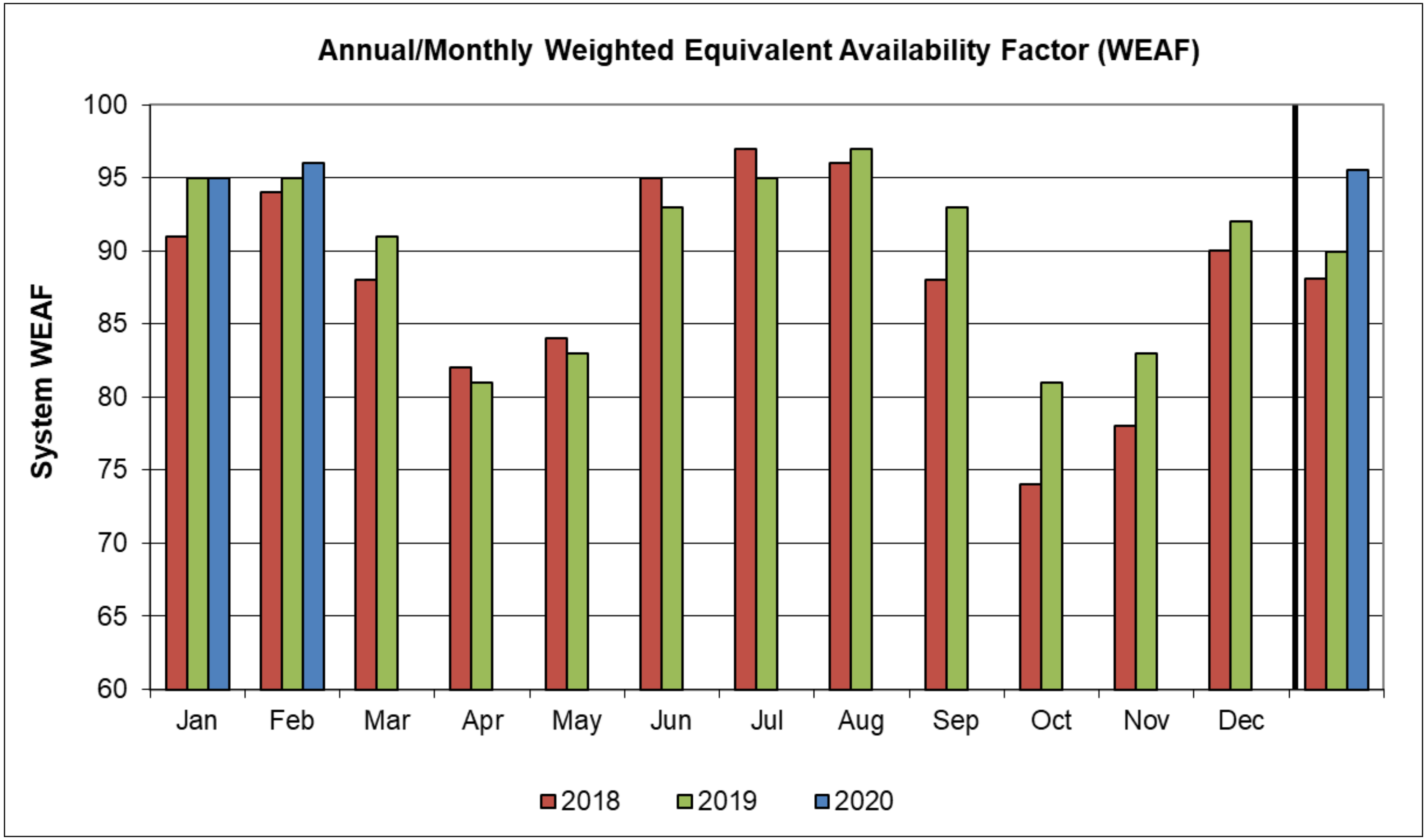
Hourly DA LMPs, February 1-26, 2020



Hourly RT LMPs, February 1-26, 2020



System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2020	95	96											96
2019	95	95	91	81	83	93	95	97	93	81	83	92	90
2018	91	94	88	82	84	95	97	96	88	74	78	90	88

Data as of 2/25/2020

BACK-UP DETAIL

DEMAND RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for March 2020

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	107.0	168.0	0.0	275.0
NH	23.9	115.4	0.0	139.4
VT	31.2	174.4	0.0	205.6
CT	96.0	76.7	437.6	610.3
RI	31.4	261.9	0.0	293.3
SEMA	41.0	410.3	0.0	451.3
WCMA	56.1	453.7	33.9	543.7
NEMA	46.4	637.1	0.0	683.5
Total	**433.1**	**2,297.4**	**471.5**	**3,202.1**

*** Active Demand Capacity Resources**

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

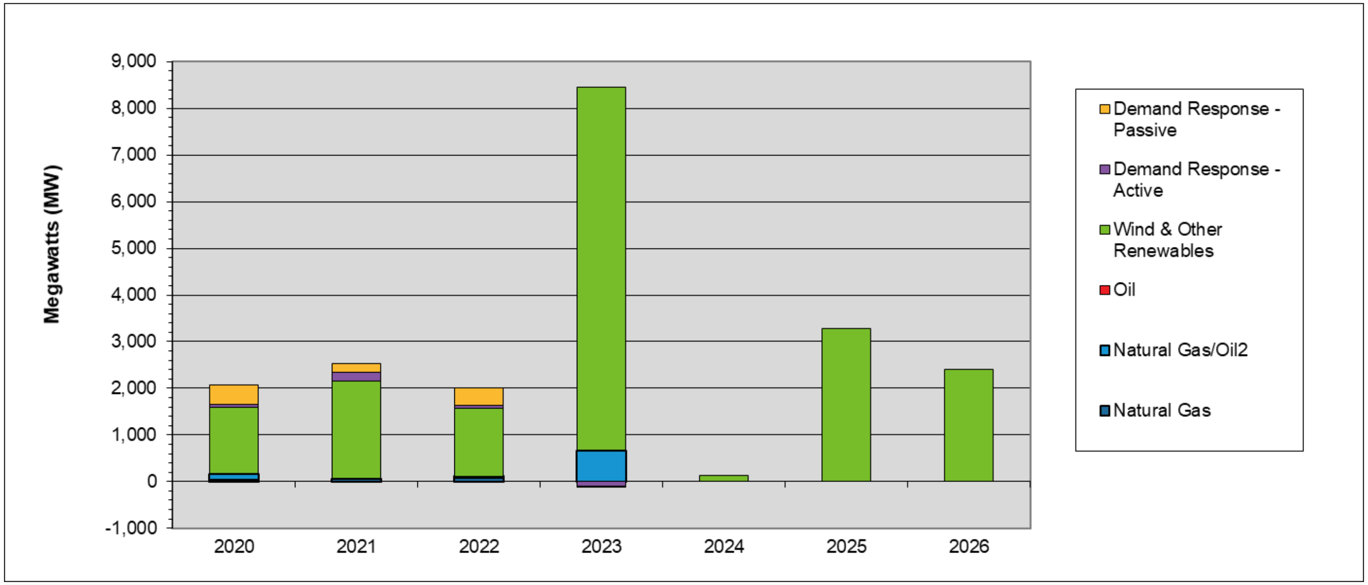
NEW GENERATION

New Generation Update
Based on Queue as of 2/28/20

- 3 projects totaling 53 MW applied for interconnection study since the last update
- No projects went commercial, 8 withdrew, and net decreases in project capacities resulted in a net decrease in new generation projects of 545 MW
- In total, 178 generation projects are currently being tracked by the ISO, totaling approximately 19,574 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



	2020	2021	2022	2023	2024	2025	2026	Total MW	% of Total[1]
Demand Response - Passive	422	184	380	-28	0	0	0	958	4.6
Demand Response - Active	42	204	62	-94	0	0	0	214	1.0
Wind & Other Renewables	1,437	2,086	1,450	7,791	130	3,276	2,400	18,570	89.5
Oil	0	0	0	0	0	0	0	0	0.0
Natural Gas/Oil[2]	121	0	39	672	0	0	0	832	4.0
Natural Gas	43	61	73	0	0	0	0	177	0.9
Totals	**2,066**	**2,535**	**2,004**	**8,341**	**130**	**3,276**	**2,400**	**20,752**	**100.0**

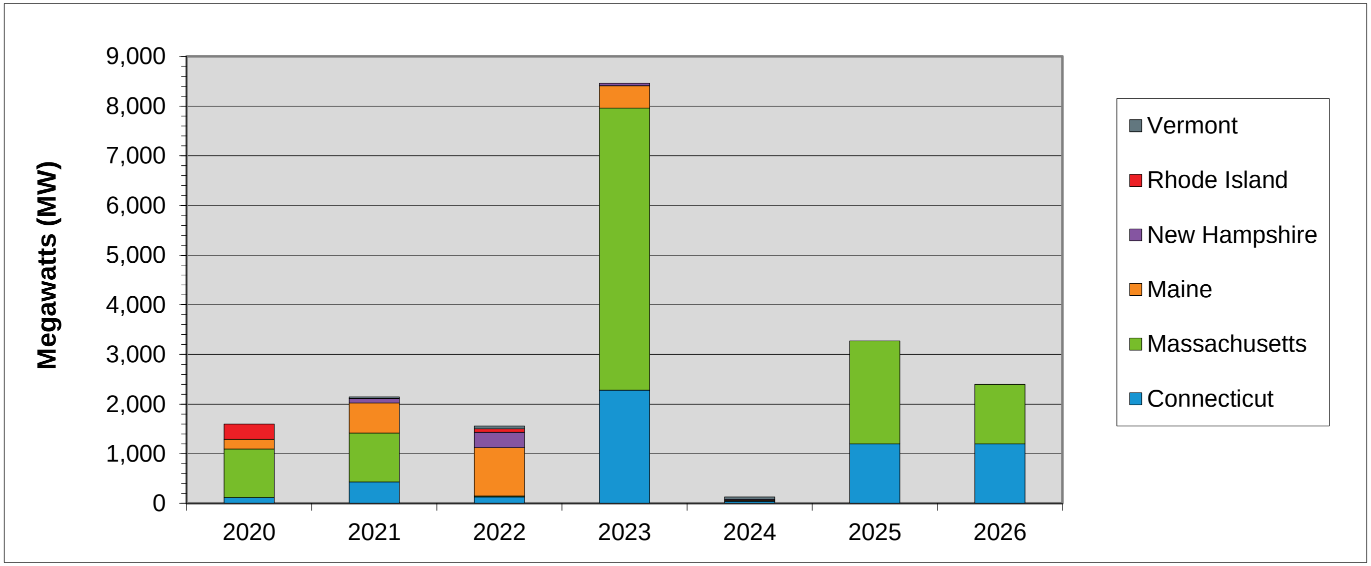
[1] Sum may not equal 100% due to rounding

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

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

Actual and Projected Annual Generator Capacity Additions

By State



	2020	2021	2022	2023	2024	2025	2026	Total MW	% of Total[1]
Vermont	0	35	60	0	50	0	0	145	0.7
Rhode Island	312	6	73	0	0	0	0	391	2.0
New Hampshire	0	83	306	50	20	0	0	459	2.3
Maine	193	601	972	451	20	0	0	2,237	11.4
Massachusetts	976	990	16	5,680	0	2,076	1,200	10,938	55.9
Connecticut	120	432	135	2,282	40	1,200	1,200	5,409	27.6
Totals	**1,601**	**2,147**	**1,562**	**8,463**	**130**	**3,276**	**2,400**	**19,579**	**100.0**

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

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	2	57	0	0	2	57
Battery Storage	13	1,835	0	0	13	1,835
Hydro	3	99	1	66	2	33
Landfill Gas	0	0	0	0	0	0
Natural Gas	7	177	0	0	7	177
Natural Gas/Oil	6	832	2	59	4	773
Nuclear	1	37	0	0	1	37
Oil	0	0	0	0	0	0
Solar	125	3,313	4	111	121	3,202
Wind	21	13,224	0	0	21	13,224
Total	178	19,574	7	236	171	19,338

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

New Generation Projection

By Operating Type

Operating Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	9	182	0	0	9	182
Intermediate	2	116	0	0	2	116
Peaker	146	6,052	7	236	139	5,816
Wind Turbine	21	13,224	0	0	21	13,224
Total	178	19,574	7	236	171	19,338

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

New Generation Projection

By Operating Type and Fuel Type

	Total		Baseload		Intermediate		Peaker		Wind Turbine	
Fuel Type	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	2	57	2	57	0	0	0	0	0	0
Battery Storage	13	1,835	0	0	0	0	13	1,835	0	0
Hydro	3	99	2	33	0	0	1	66	0	0
Landfill Gas	0	0	0	0	0	0	0	0	0	0
Natural Gas	7	177	4	55	2	116	1	6	0	0
Natural Gas/Oil	6	832	0	0	0	0	6	832	0	0
Nuclear	1	37	1	37	0	0	0	0	0	0
Oil	0	0	0	0	0	0	0	0	0	0
Solar	125	3,313	0	0	0	0	125	3,313	0	0
Wind	21	13,224	0	0	0	0	0	0	21	13,224
Total	178	19,574	9	182	2	116	146	6,052	21	13,224

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 10

Resource Type	Resource Type	FCA	Annual Bilateral for ARA 1		ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	377.525	367.227	-10.298	464.715	97.488	460.55	-4.165	459.928	-0.622	457.966	-1.962	493.5	35.534
	Passive Demand	2,368.631	2,366.783	-1.848	2,363.949	-2.834	2,363.789	-0.16	2,527.244	163.46	2,529.014	1.77	2594.08	65.066
Demand Total		**2,746.156**	**2,734.01**	**-12.146**	**2,828.664**	**94.654**	**2,824.339**	**-4.325**	**2,987.172**	**162.83**	**2,986.98**	**-0.192**	**3,087.58**	**100.6**
Generator	*Non-Intermittent*	30,520.433	30,462.67	-57.763	30,048.398	-414.272	30,103.684	55.286	30,093.142	-10.54	30,081.64	-11.502	30,146.76	65.115
	Intermittent	850.143	893.189	43.046	904.311	11.122	831.251	-73.06	798.958	-32.293	800.387	1.429	733.668	-66.719
Generator Total		**31,370.576**	**31,355.86**	**-14.716**	**30,952.709**	**-403.151**	**30,934.935**	**-17.774**	**30,892.1**	**-42.84**	**30,882.027**	**-10.073**	**30,880.42**	**-1.604**
Import Total		**1,449.8**	**1,449.8**	**0**	**1,451**	**1.2**	**1,451**	**0**	**1,451**	**0**	**1,459**	**8**	**1,428**	**-31**
****Grand Total**		**35,566.532**	**35,539.668**	**-26.864**	**35,232.373**	**-307.295**	**35,210.274**	**-22.099**	**35,330.272**	**120.00**	**35,328.007**	**-2.265**	**35,396**	**67.996**
Net ICR (NICR)		**34,151**	**33,755**	**-396**	**33,755**	**0**	**33,407**	**-348**	**33,407**	**0**	**33,390**	**-17**	**33,390**	**0**

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

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

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

Capacity Supply Obligation FCA 11

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		*CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	419.928	441.221	21.293	594.551	153.33		
	Passive Demand	2,791.02	2,835.354	44.334	2,883.767	48.413		
Demand Total		**3,210.95**	**3,276.575**	**65.625**	**3,478.318**	**201.743**		
Generator	*Non-Intermittent*	30,494.80	30,064.23	-430.569	30,159.891	95.661		
	Intermittent	894.217	823.796	-70.421	809.571	-14.225		
Generator Total		**31,389.02**	**30,888.027**	**-500.993**	**30,969.462**	**81.435**		
Import Total		**1,235.40**	**1,622.037**	**386.637**	**1,609.844**	**-12.193**		
****Grand Total**		**35,835.37**	**35,786.64**	**-48.731**	**36,057.624**	**270.984**		
Net ICR (NICR)		**34,075**	**33,660**	**-415**	**33,520**	**-140**		

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

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

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

Capacity Supply Obligation FCA 12

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		*CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	624.445	659.137	34.692				
	Passive Demand	2,975.36	3,045.073	69.713				
Demand Total		**3,599.81**	**3,704.21**	**104.4**				
Generator	*Non-Intermittent*	29,130.75	29,244.404	113.654				
	Intermittent	880.317	806.609	-73.708				
Generator Total		**30,011.07**	**30,051.013**	**39.943**				
Import Total		**1,217**	**1,305.487**	**88.487**				
****Grand Total**		**34,827.88**	**35,060.710**	**232.83**				
Net ICR (NICR)		**33,725**	**33,550**	**-175**				

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

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

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

Capacity Supply Obligation FCA 13

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		*CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	685.554						
	Passive Demand	3,354.69						
Demand Total		**4,040.244**						
Generator	*Non-Intermittent*	28,586.498						
	Intermittent	1,024.792						
Generator Total		**2,9611.29**						
Import Total		**1,187.69**						
****Grand Total**		**34,839.224**						
Net ICR (NICR)		**33,750**						

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

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

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

Capacity Supply Obligation FCA 14

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		*CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	592.043						
	Passive Demand	3,327.071						
Demand Total		3,919.114						
Generator	*Non-Intermittent*	27,816.902						
	Intermittent	1,160.916						
Generator Total		28,977.818						
Import Total		1,058.72						
****Grand Total**		33,955.652						
Net ICR (NICR)		32,490						

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

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

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

Active/Passive Demand Response

CSO Totals by Commitment Period

Commitment Period	Active/ Passive	Existing	New	**Grand Total**
2019-20	Active	357.221	20.304	377.525
	Passive	2,018.20	350.43	2,368.63
	Grand Total	2375.422	370.734	2746.156
2020-21	Active	334.634	85.294	419.928
	Passive	2,236.73	554.292	2,791.02
	Grand Total	2571.361	639.586	3210.947
2021-22	Active	480.941	143.504	624.445
	Passive	2,604.79	370.568	2,975.36
	Grand Total	3085.734	514.072	3599.806
2022-23	Active	598.376	87.178	685.554
	Passive	2,788.33	566.363	3,354.69
	Grand Total	3386.703	653.541	4040.244
2023-24	Active	560.55	31.493	592.043
	Passive	3,035.51	291.565	3,327.07
	Grand Total	3596.056	323.058	3919.114

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

What are Daily NCPC Payments?

- Payments made to resources whose commitment and dispatch by ISO-NE resulted in a shortfall between the resource's offered value in the Energy and Regulation Markets and the revenue earned from output during the day
- Typically, this is the result of some out-of-merit operation of resources occurring in order to protect the overall resource adequacy and transmission security of specific locations or of the entire control area
- NCPC payments are intended to make a resource that follows the ISO's operating instructions "no worse off" financially than the best alternative generation schedule

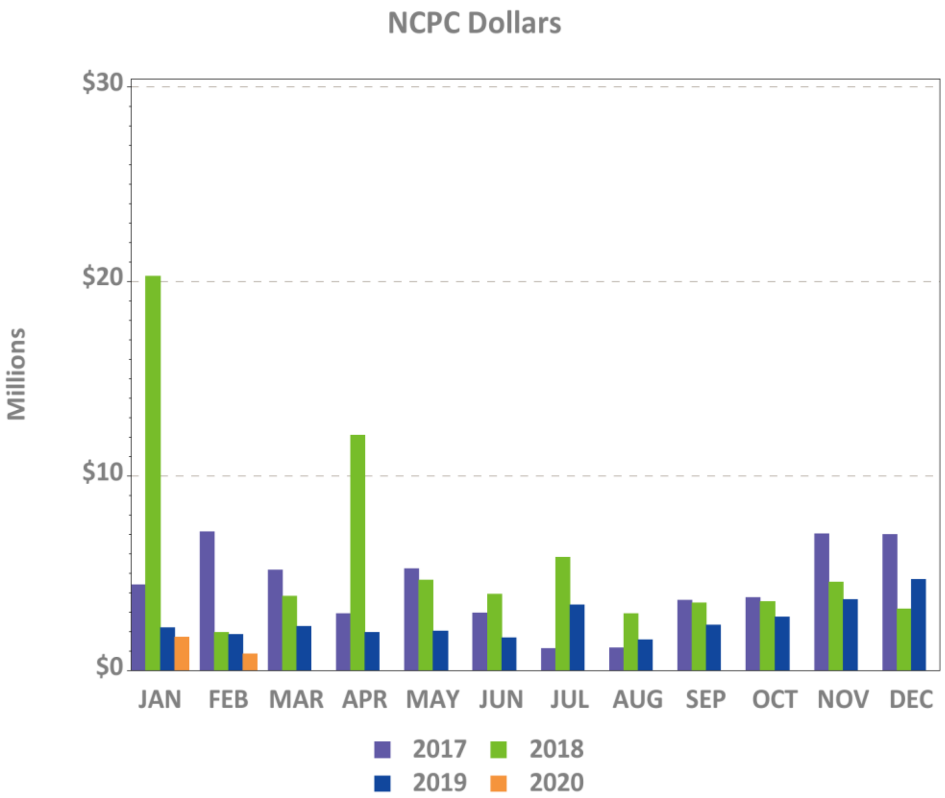
Definitions

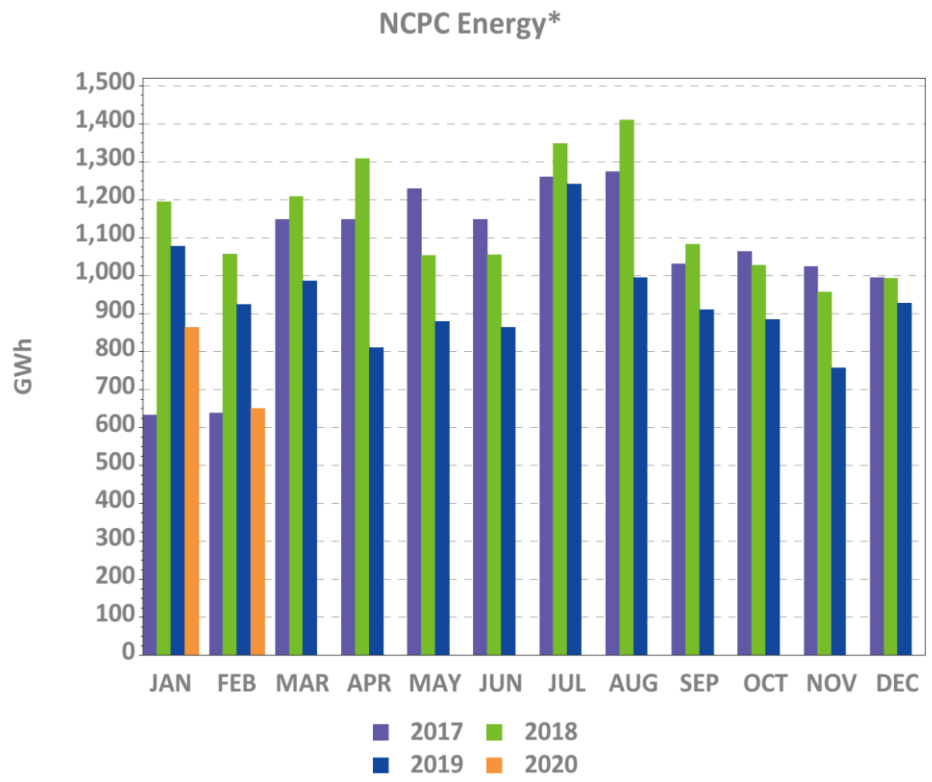
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing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

Charge Allocation Key

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

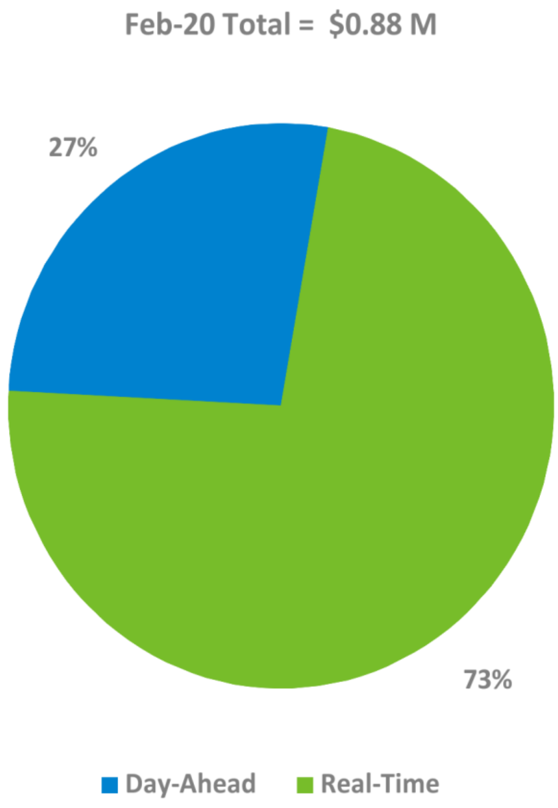
Year-Over-Year Total NCPC Dollars and Energy

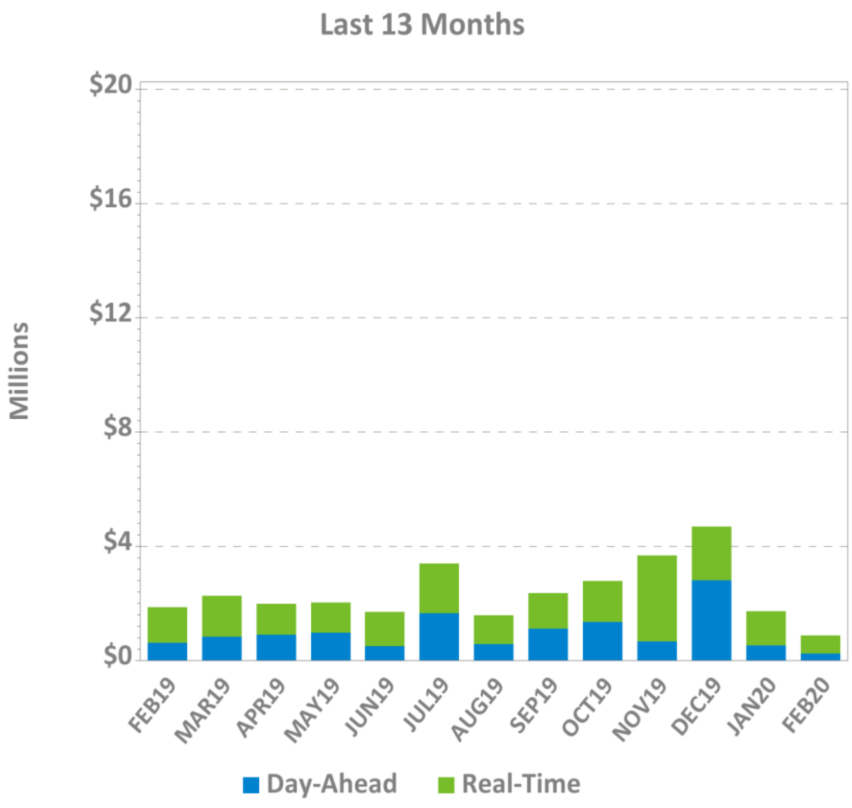




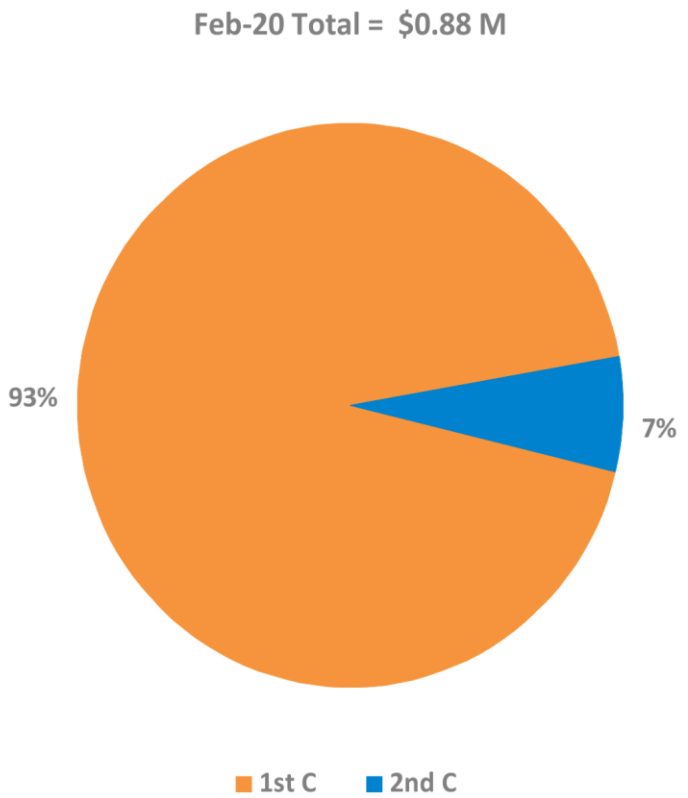
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

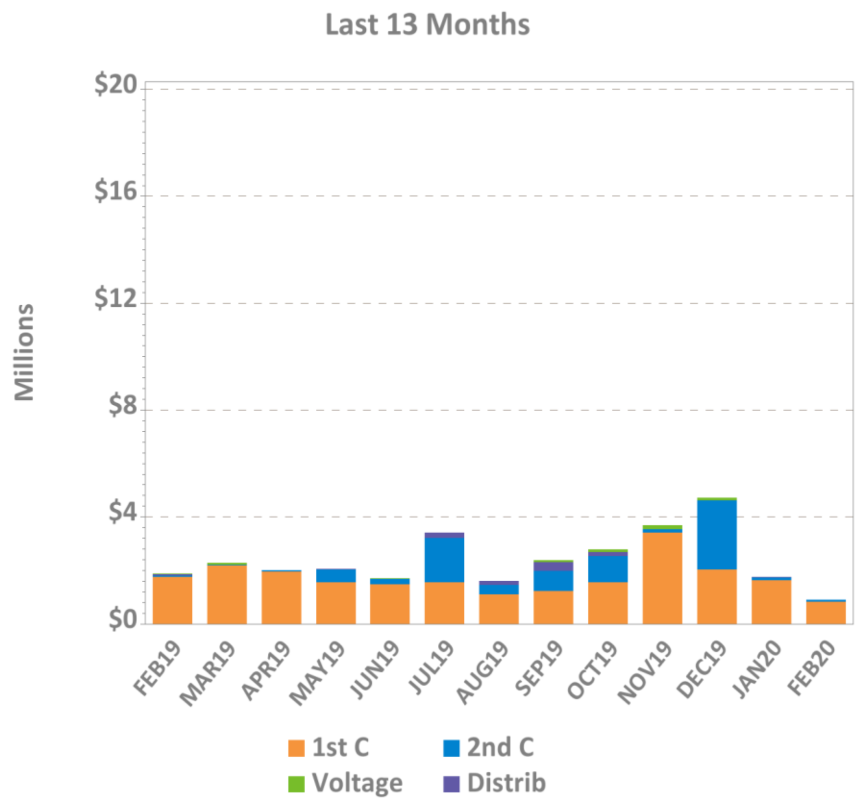
DA and RT NCPC Charges





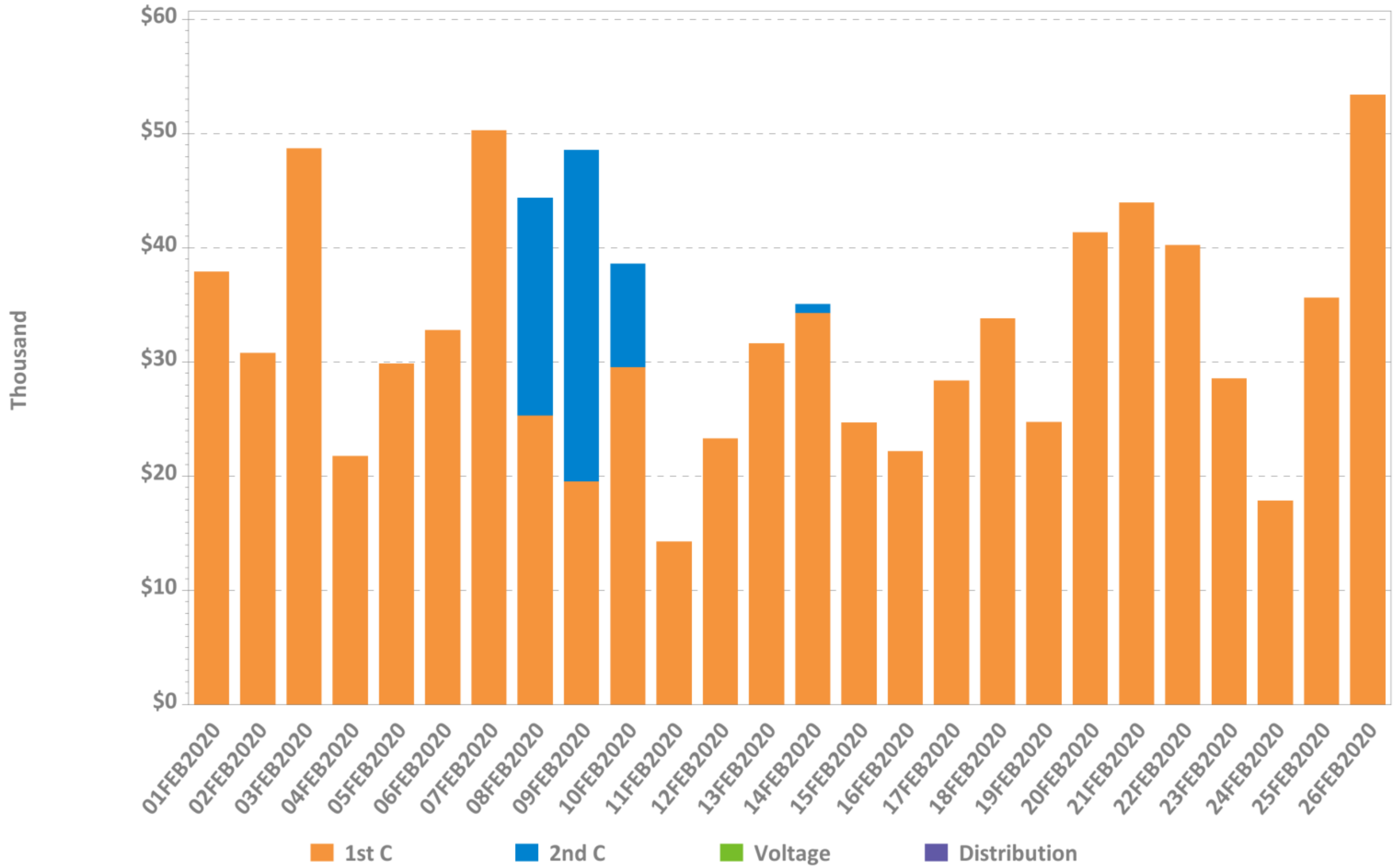
NCPC Charges by Type



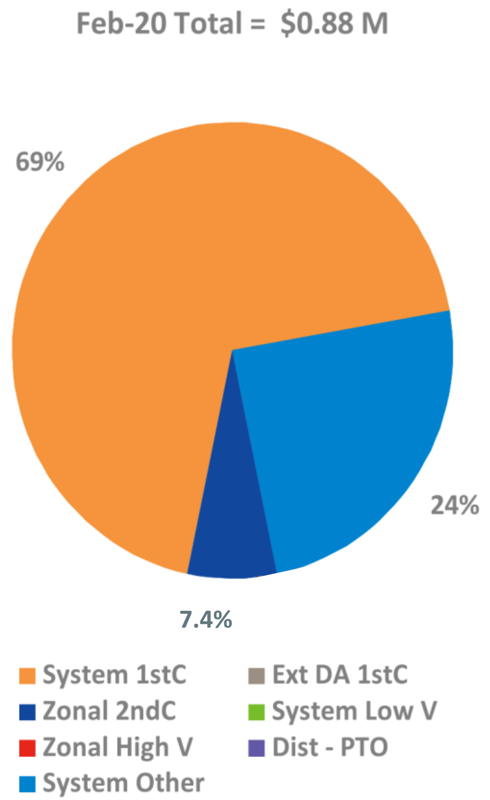


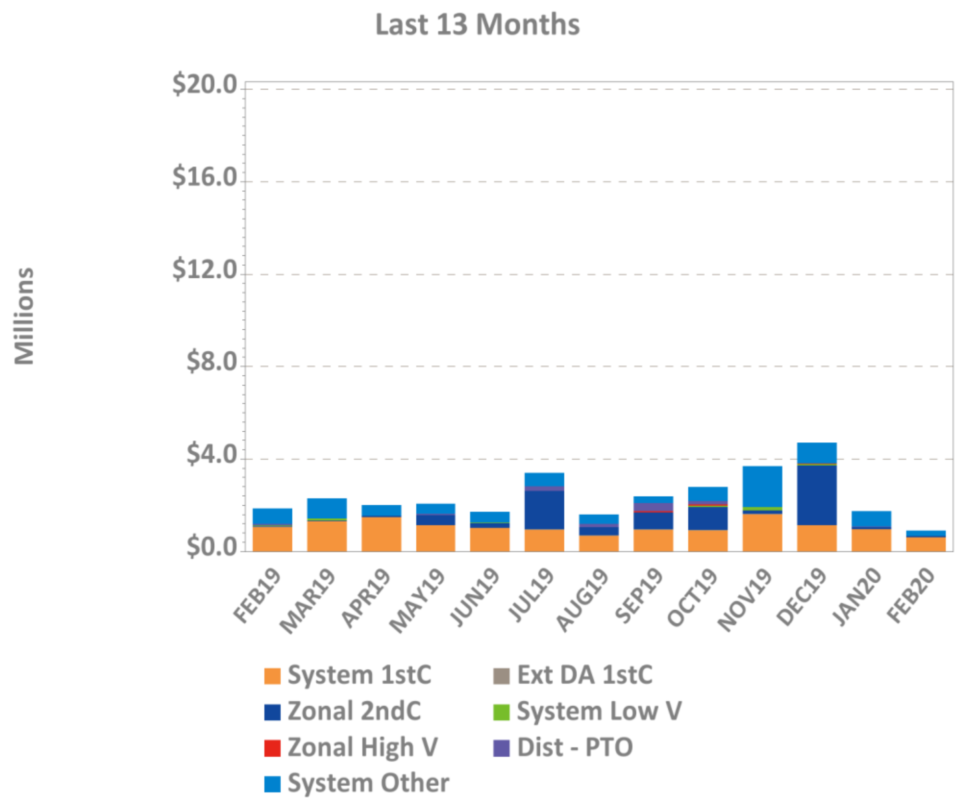
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



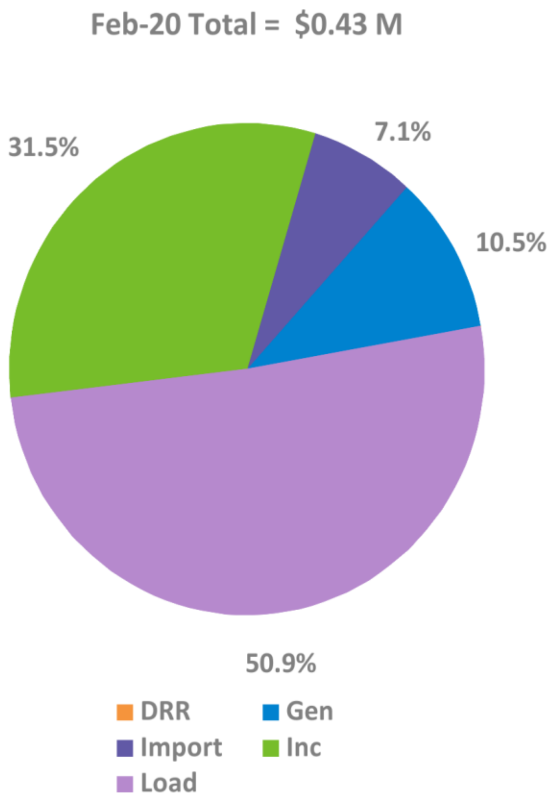
NCPC Charges by Allocation

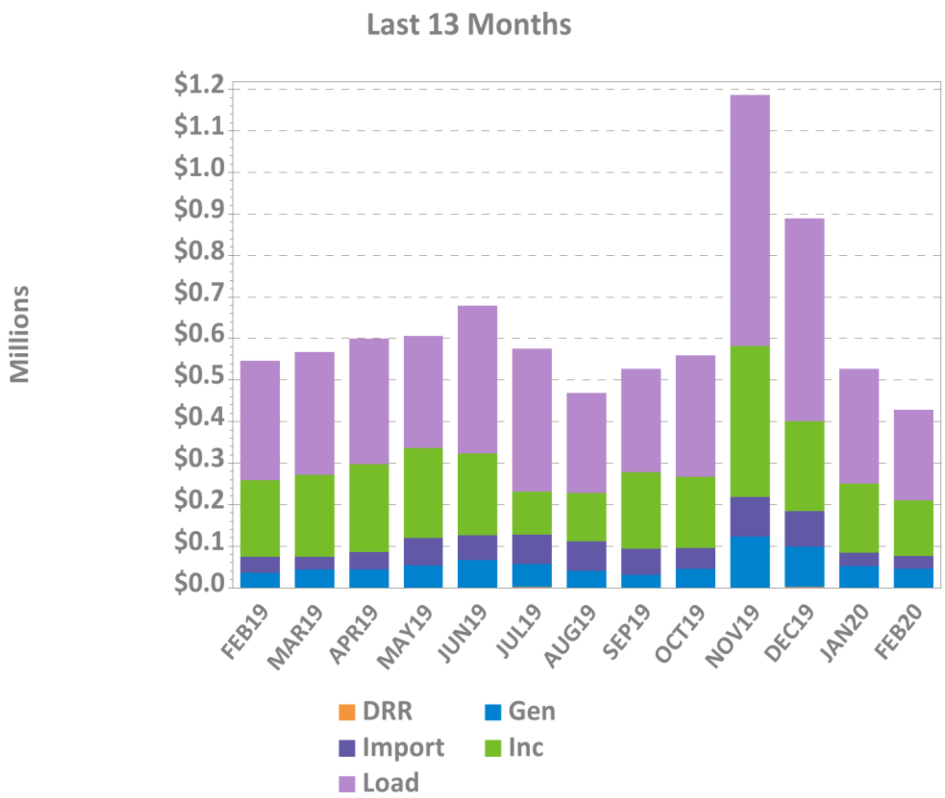




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

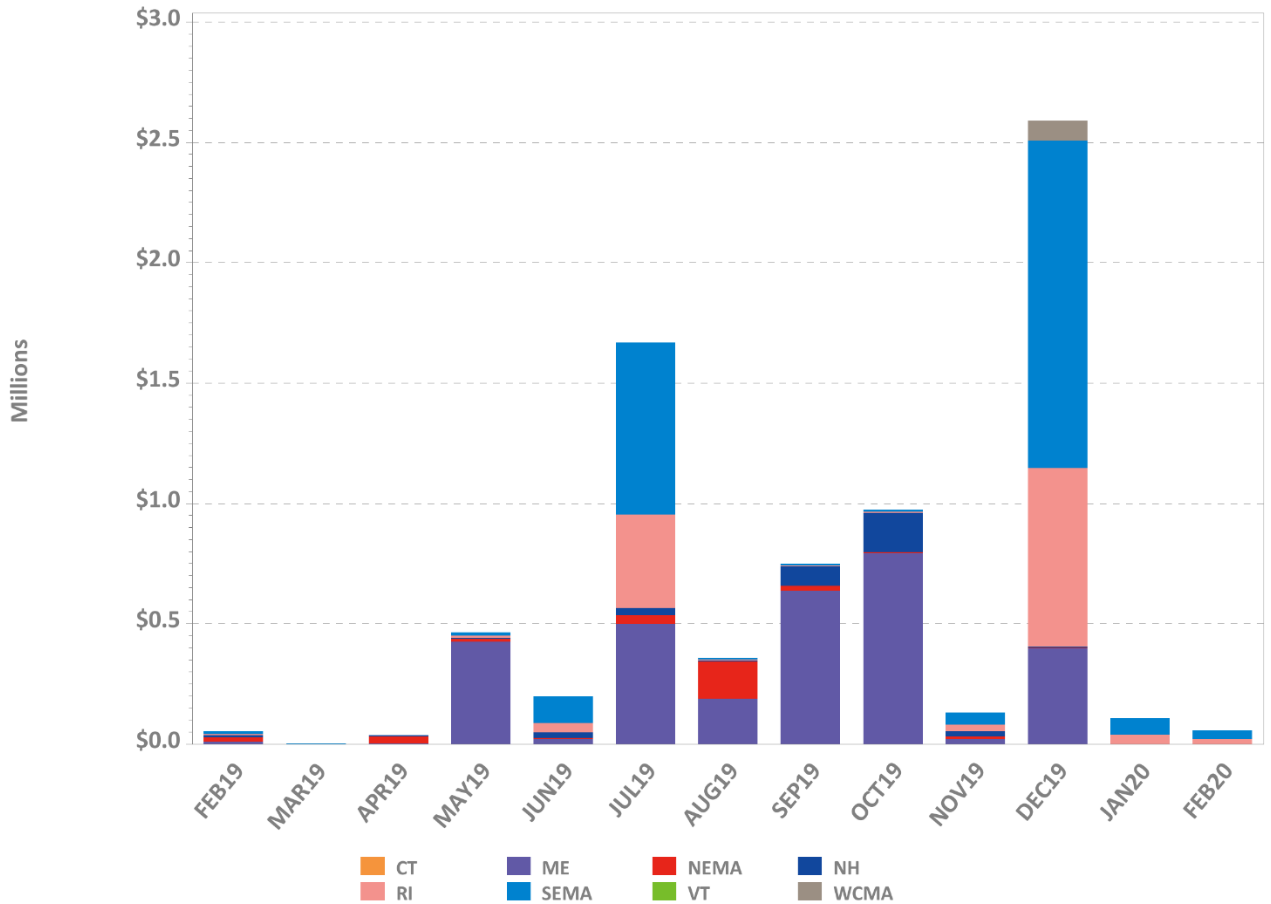
RT First Contingency Charges by Deviation Type





DRR – Demand Response Resource deviations
Gen – Generator deviations
Inc – Increment Offer deviations
Import – Import deviations
Load – Load obligation deviations

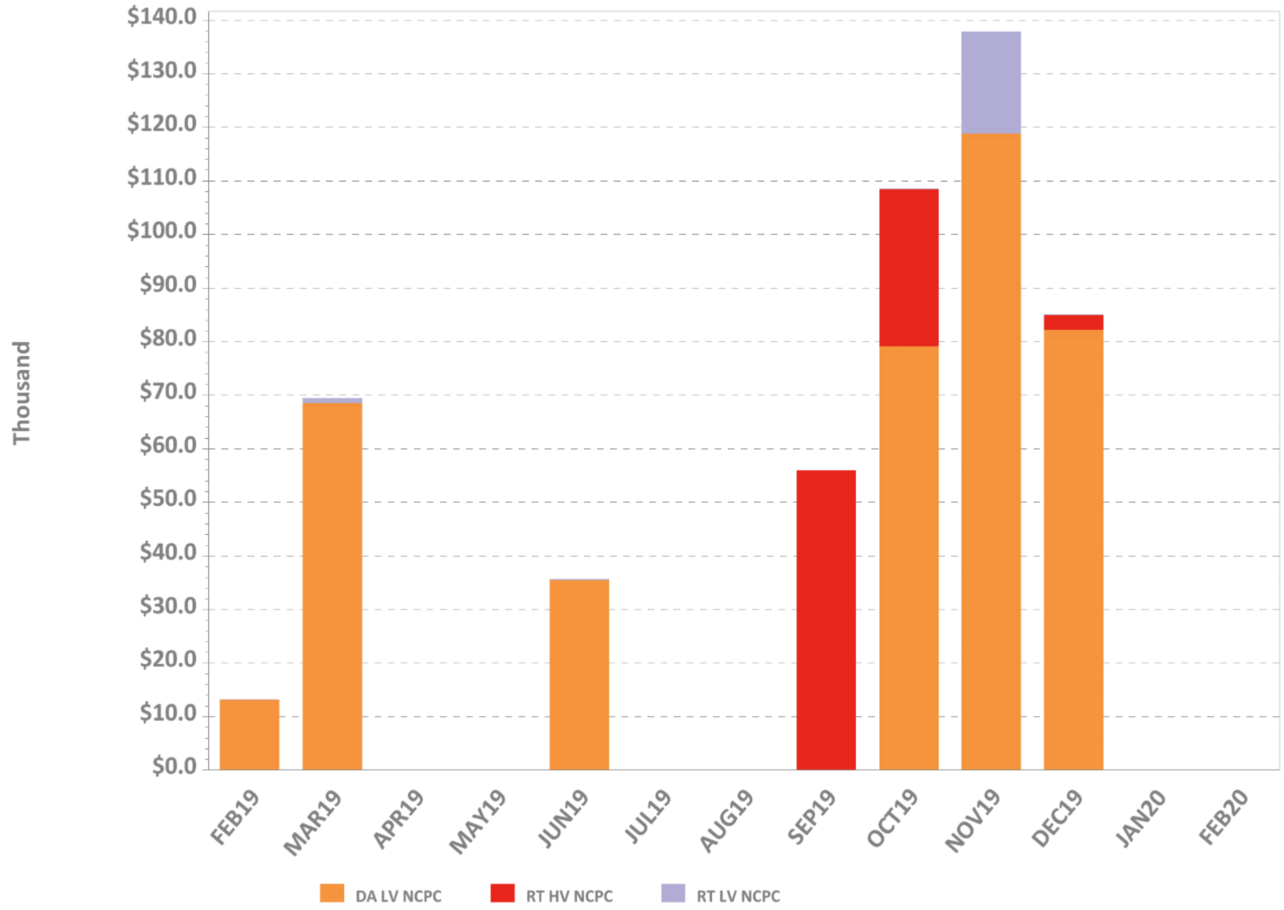
LSCPR Charges by Reliability Region



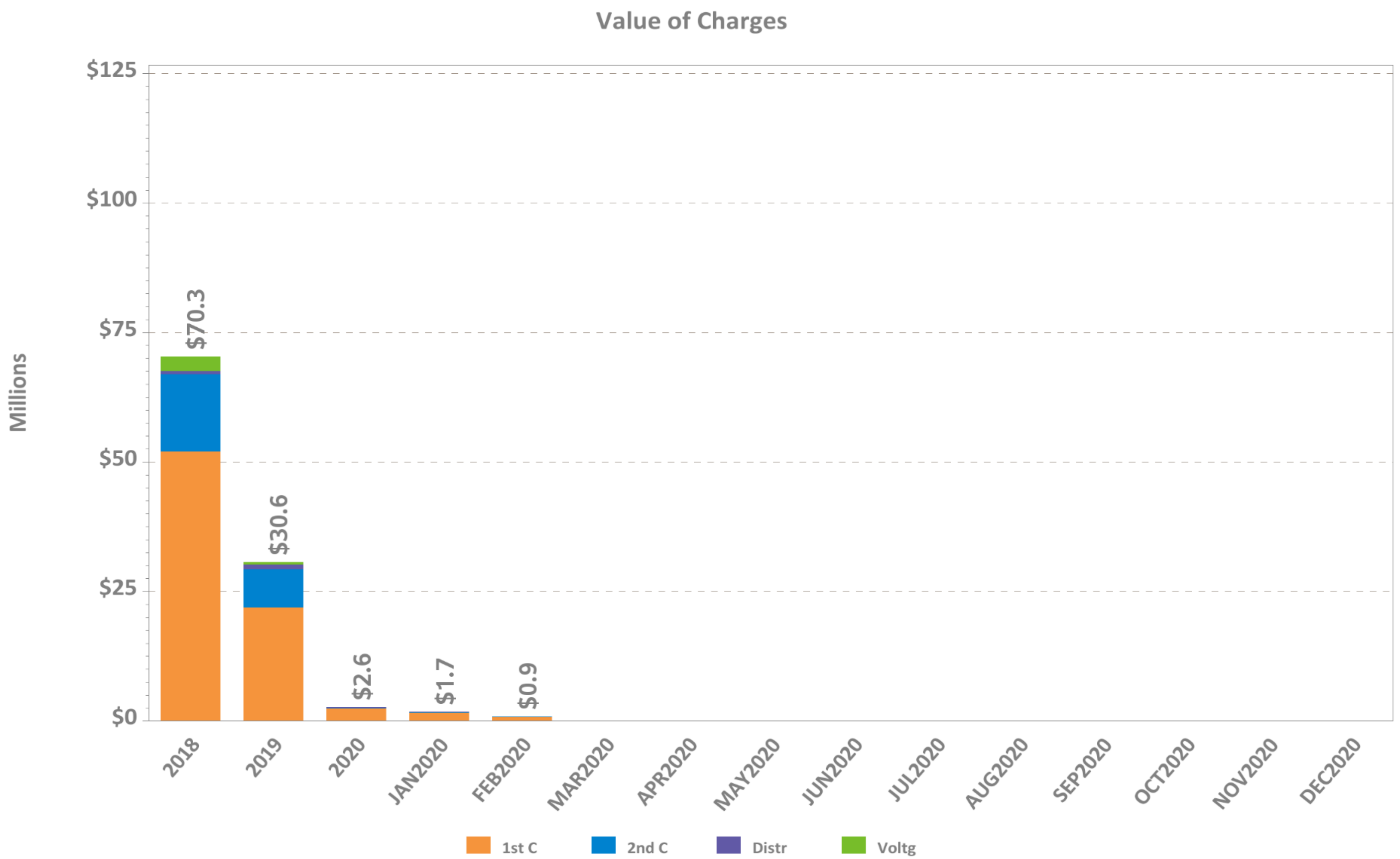
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

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

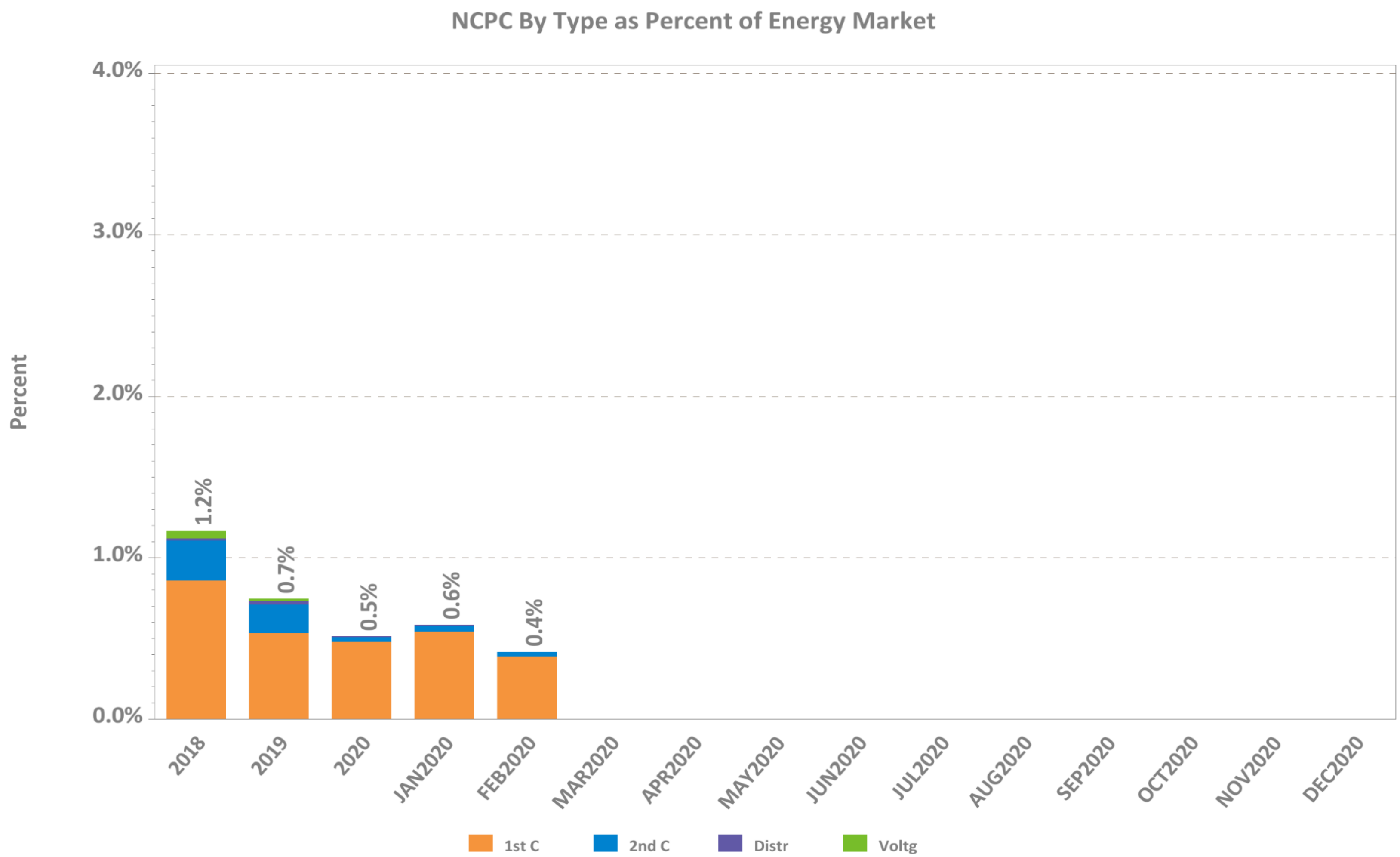
NCPC Charges for Voltage Support and High Voltage Control



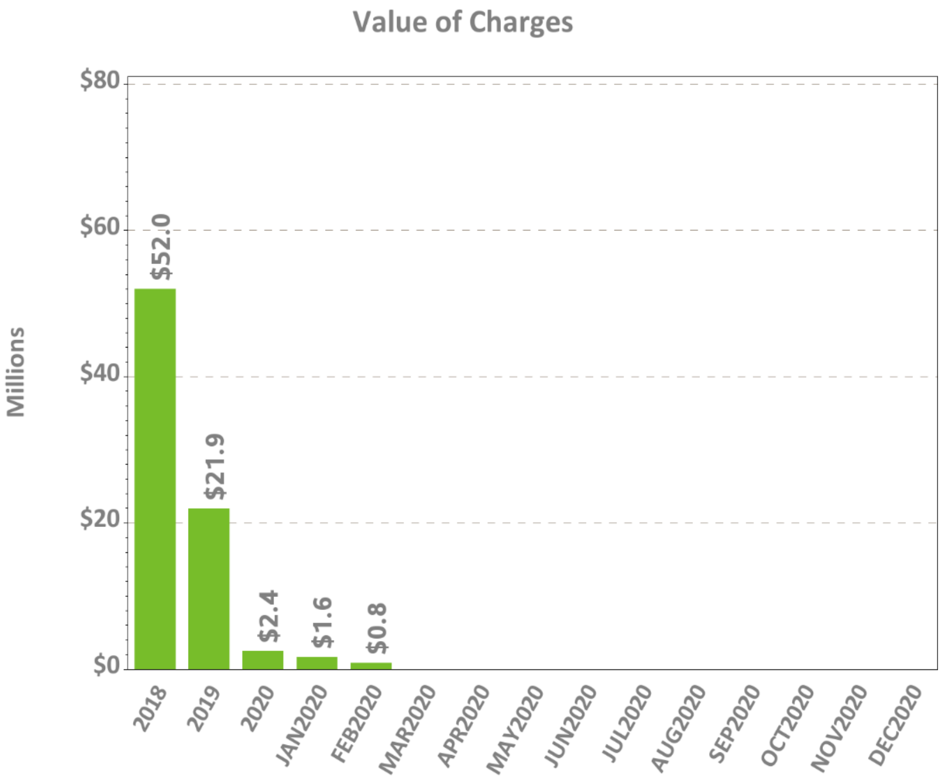
NCPC Charges by Type

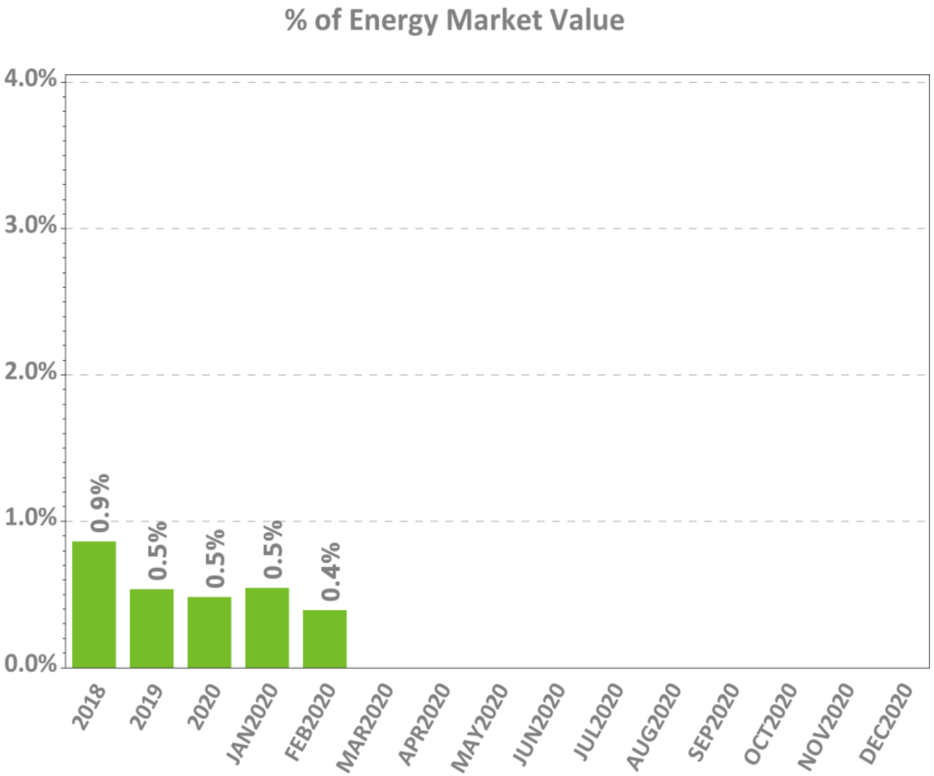


NCPC Charges as Percent of Energy Market



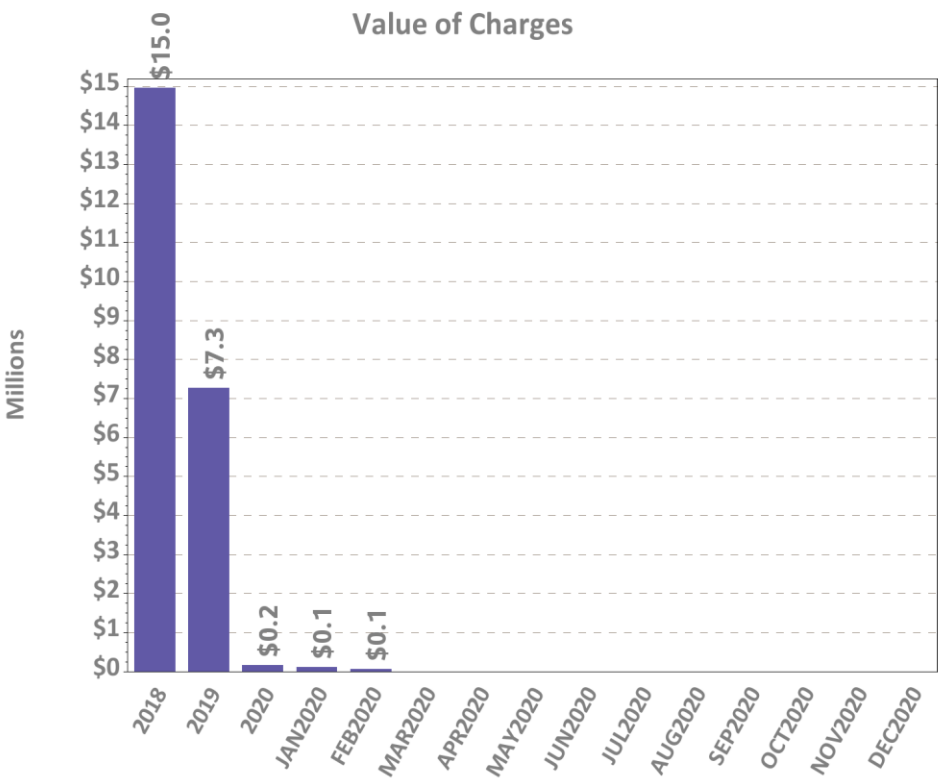
First Contingency NCPC Charges

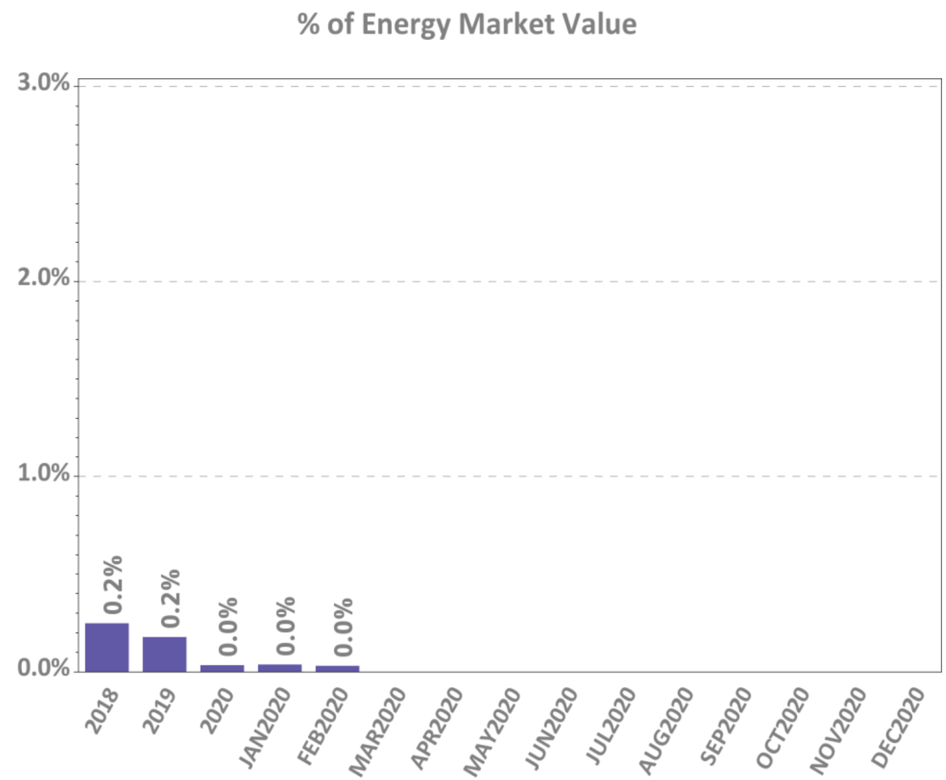




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

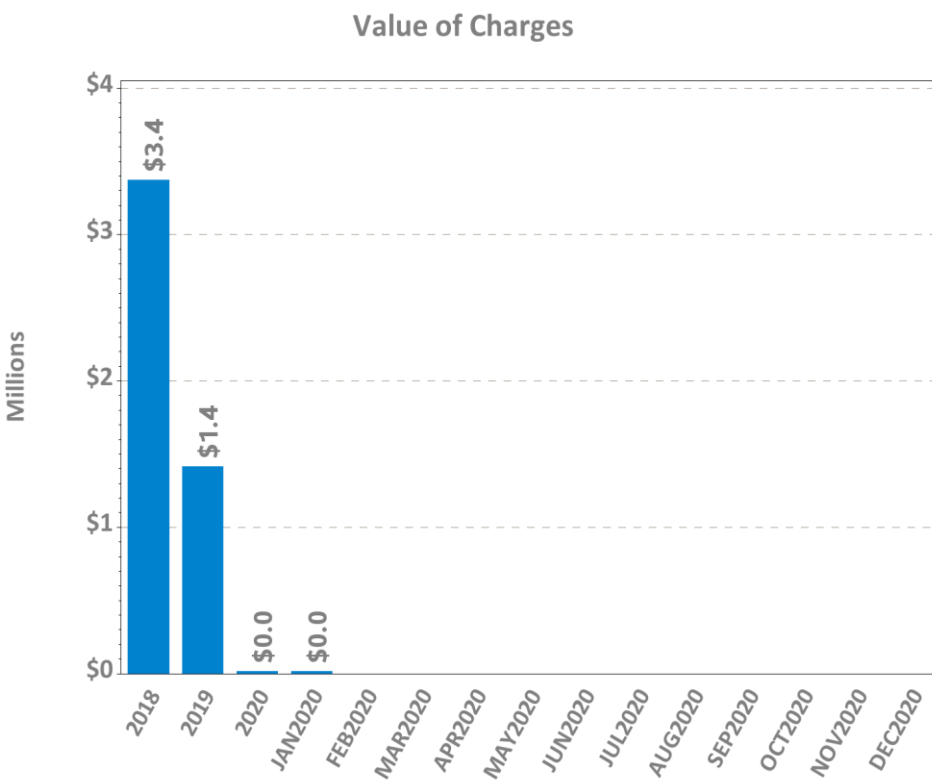
Second Contingency NCPC Charges

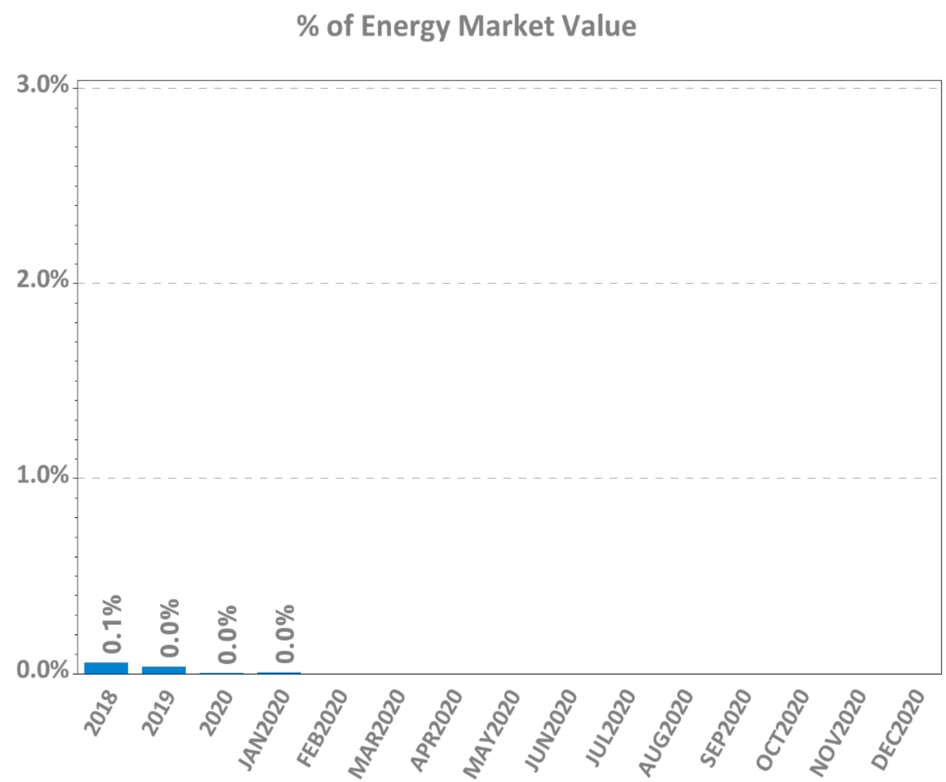




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

Voltage and Distribution NCPC Charges





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

DA vs. RT Pricing

The following slides outline:

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

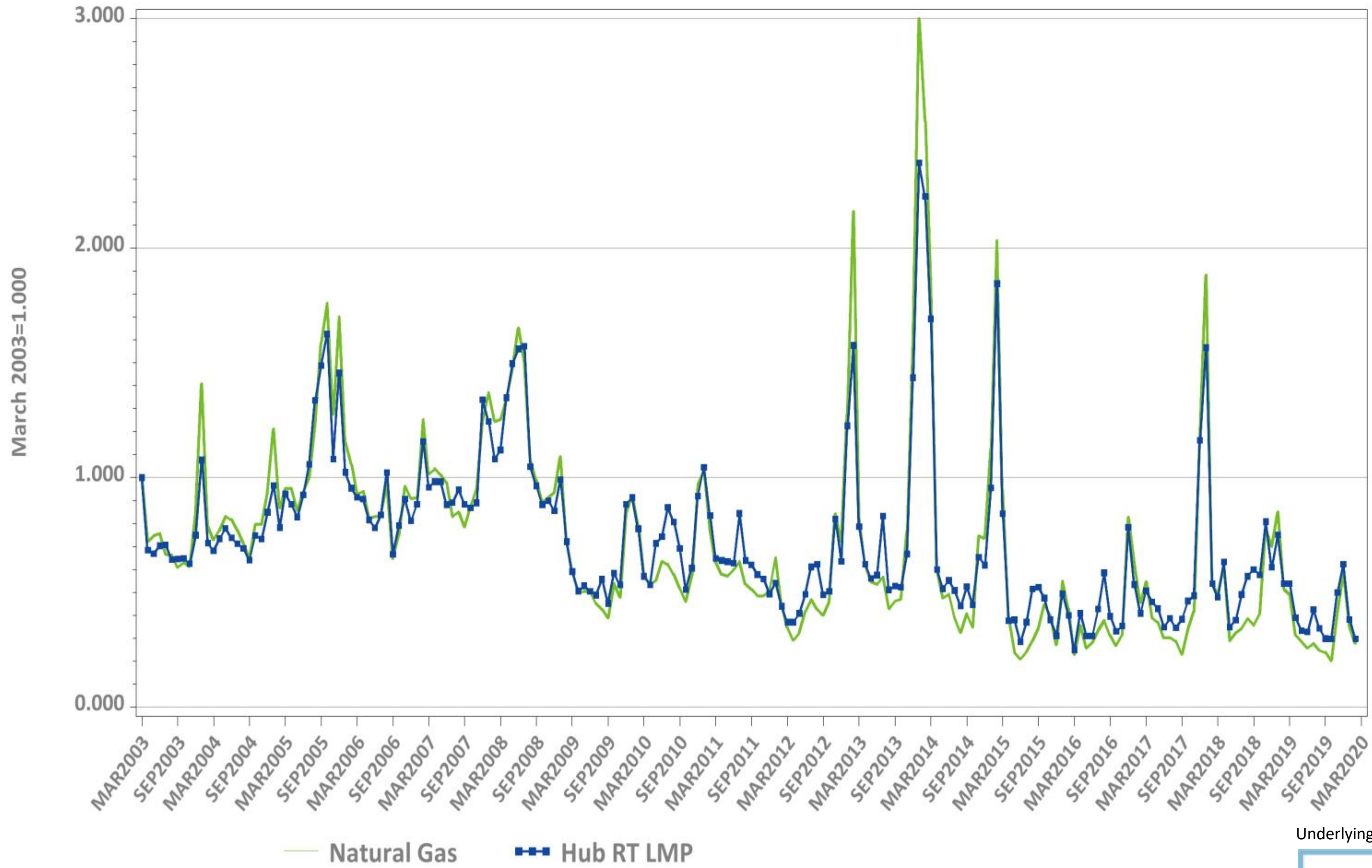
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 2018	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$44.45	$43.60	$42.63	$44.04	$43.71	$44.11	$44.62	$44.19	$44.13
Real-Time	$43.87	$43.13	$41.03	$43.17	$42.83	$43.37	$43.68	$43.58	$43.54
RT Delta %	-1.3%	-1.1%	-3.8%	-2.0%	-2.0%	-1.7%	-2.1%	-1.4%	-1.3%
Year 2019	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$31.54	$30.72	$30.76	$31.20	$30.67	$31.19	$31.51	$31.24	$31.22
Real-Time	$30.92	$30.26	$30.12	$30.70	$30.05	$30.61	$30.80	$30.68	$30.67
RT Delta %	-2.0%	-1.5%	-2.1%	-1.6%	-2.0%	-1.9%	-2.2%	-1.8%	-1.8%

February-19	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$35.90	$35.01	$35.01	$35.76	$35.06	$35.64	$35.66	$35.64	$35.62
Real-Time	$37.26	$36.37	$36.25	$37.08	$36.17	$36.97	$36.99	$36.91	$36.92
RT Delta %	3.8%	3.9%	3.6%	3.7%	3.2%	3.7%	3.8%	3.6%	3.7%
February-20	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$23.65	$22.66	$23.51	$23.62	$22.99	$23.34	$23.60	$23.38	$23.40
Real-Time	$20.73	$20.00	$20.57	$20.74	$20.21	$20.48	$20.69	$20.50	$20.52
RT Delta %	-12.4%	-11.8%	-12.5%	-12.2%	-12.1%	-12.2%	-12.3%	-12.3%	-12.3%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	-34.1%	-35.3%	-32.9%	-33.9%	-34.4%	-34.5%	-33.8%	-34.4%	-34.3%
Yr over Yr RT	-44.4%	-45.0%	-43.3%	-44.1%	-44.1%	-44.6%	-44.1%	-44.5%	-44.4%

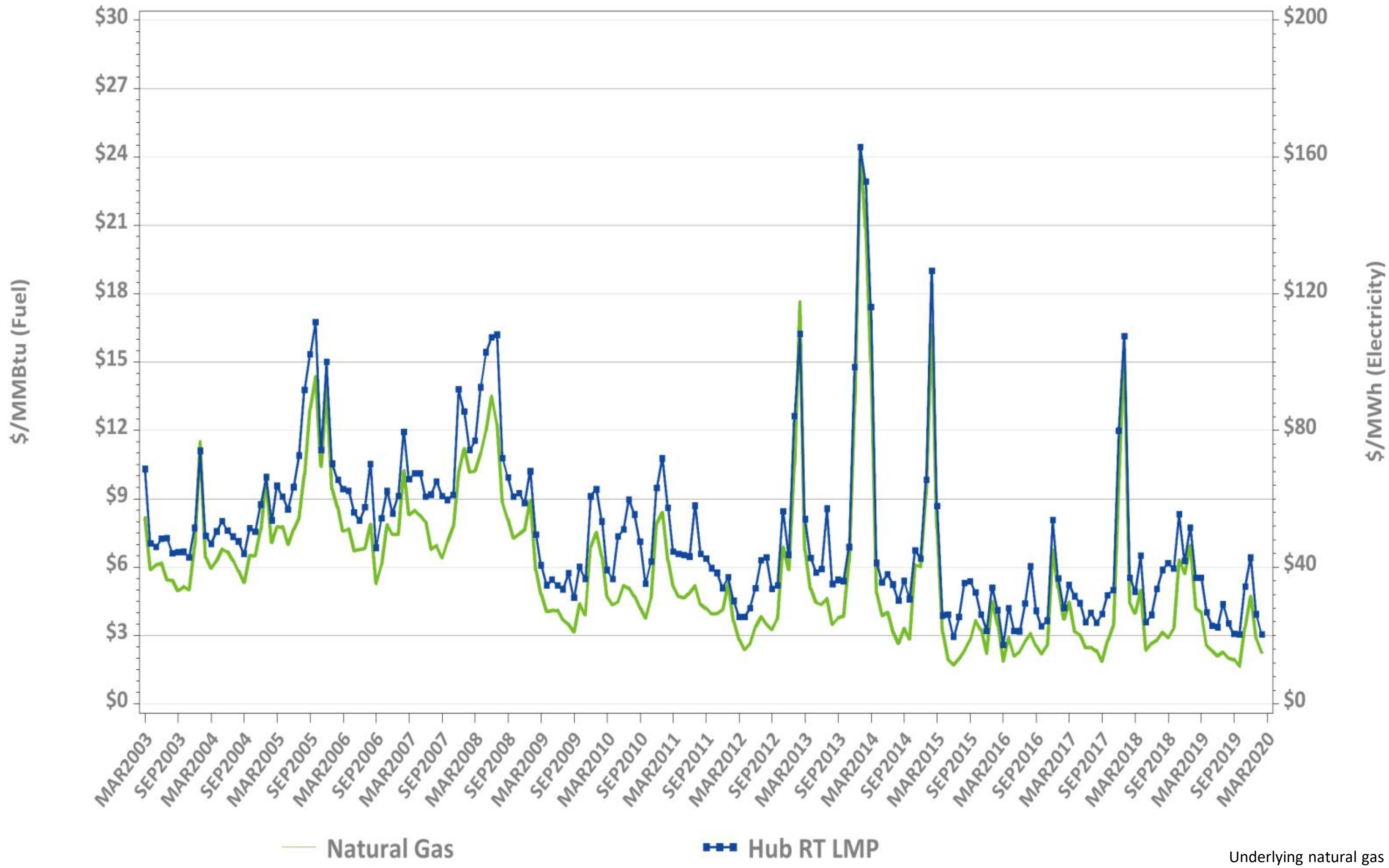
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ICE Global markets in clear view

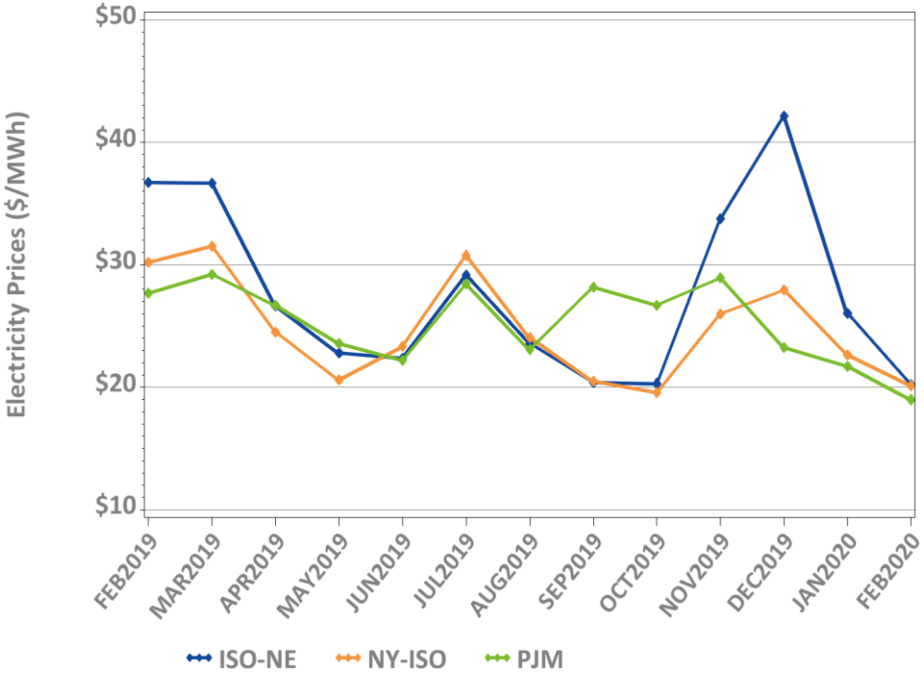
Monthly Average Fuel Price and RT Hub LMP



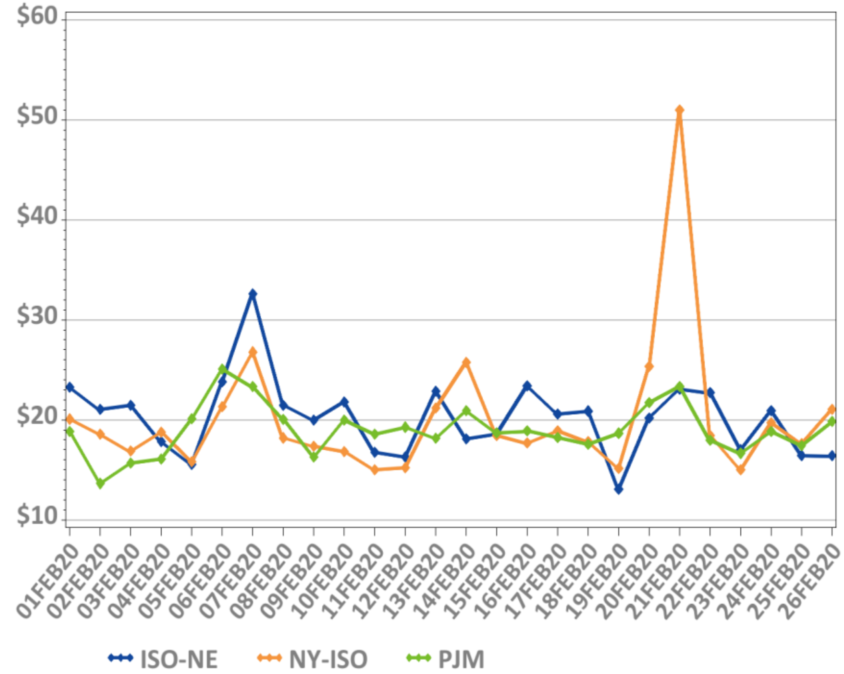
Underlying natural gas data furnished by:

ice Global markets in clear view

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

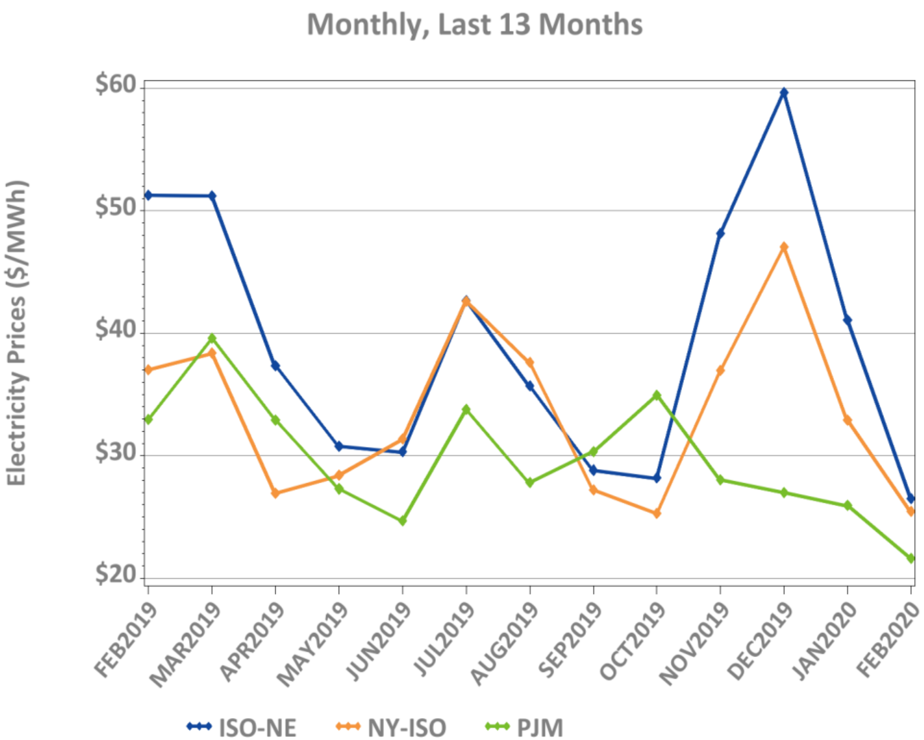


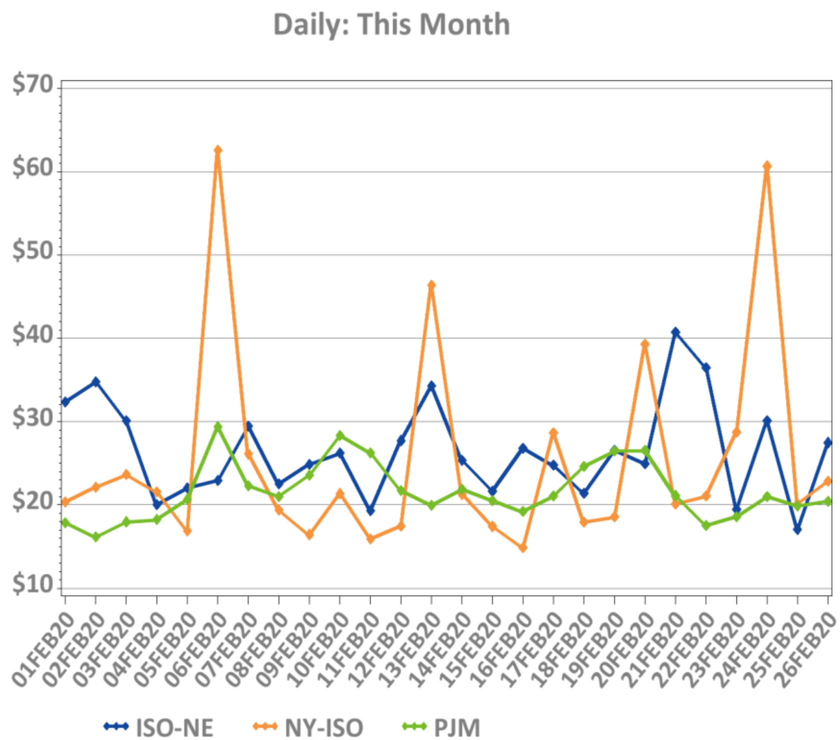
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





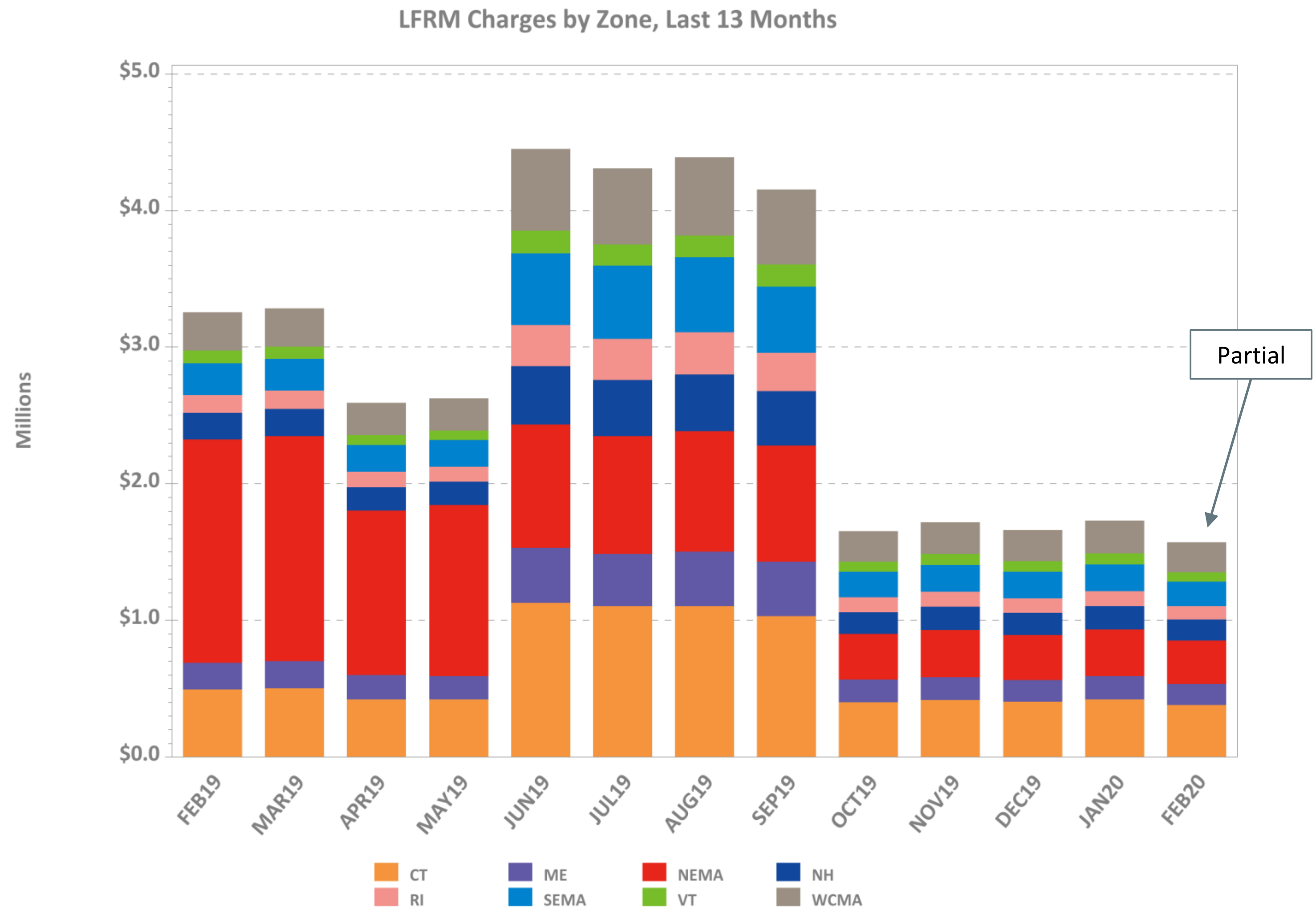
*Forecasted New England daily peak hours reflected

Reserve Market Results – February 2020

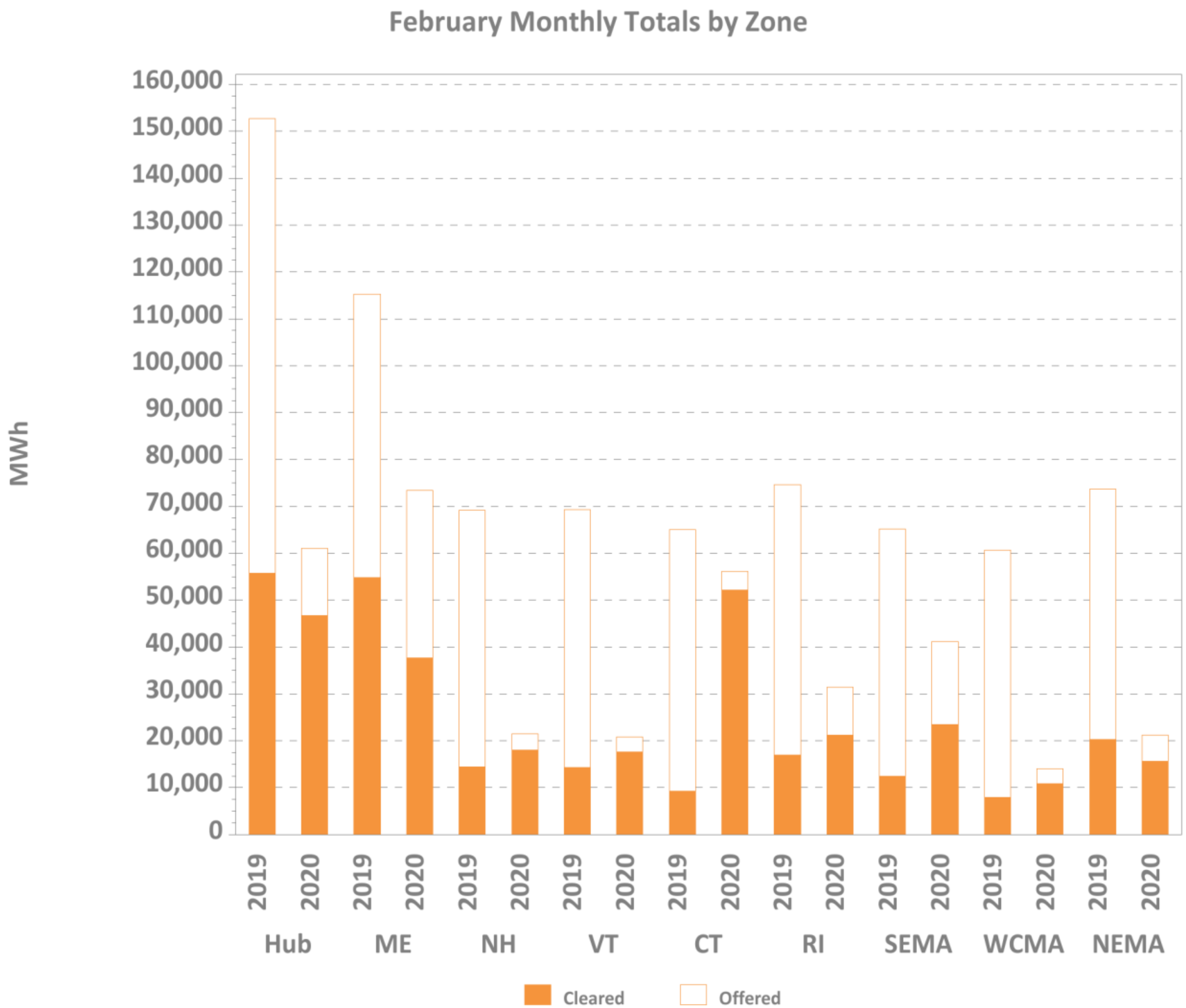
- Maximum potential Forward Reserve Market payments of $1.3M were reduced by credit reductions of $2K, failure-to-reserve penalties of $4K and no failure-to-activate penalties, resulting in a net payout of $1.3M or 100% of maximum
  - Rest of System: $0.99M/1M (99%)
  - Southwest Connecticut: $0.04M/0.04M (100%)
  - Connecticut: $0.27M/0.27M (100%)
- $282K total Real-Time credits were not reduced by any Forward Reserve Energy Obligation Charges for a net of $282K in Real-Time Reserve payments
  - Rest of System: 199 hours, $176K
  - Southwest Connecticut: 199 hours, $52K
  - Connecticut: 199 hours, $32K
  - NEMA: 199 hours, $23K

Note: "Failure to reserve" results in both credit reductions and penalties in the Locational Forward Reserve Market. While this summary reports performance by location, there were no locational requirements in effect for the current Forward Reserve auction period.

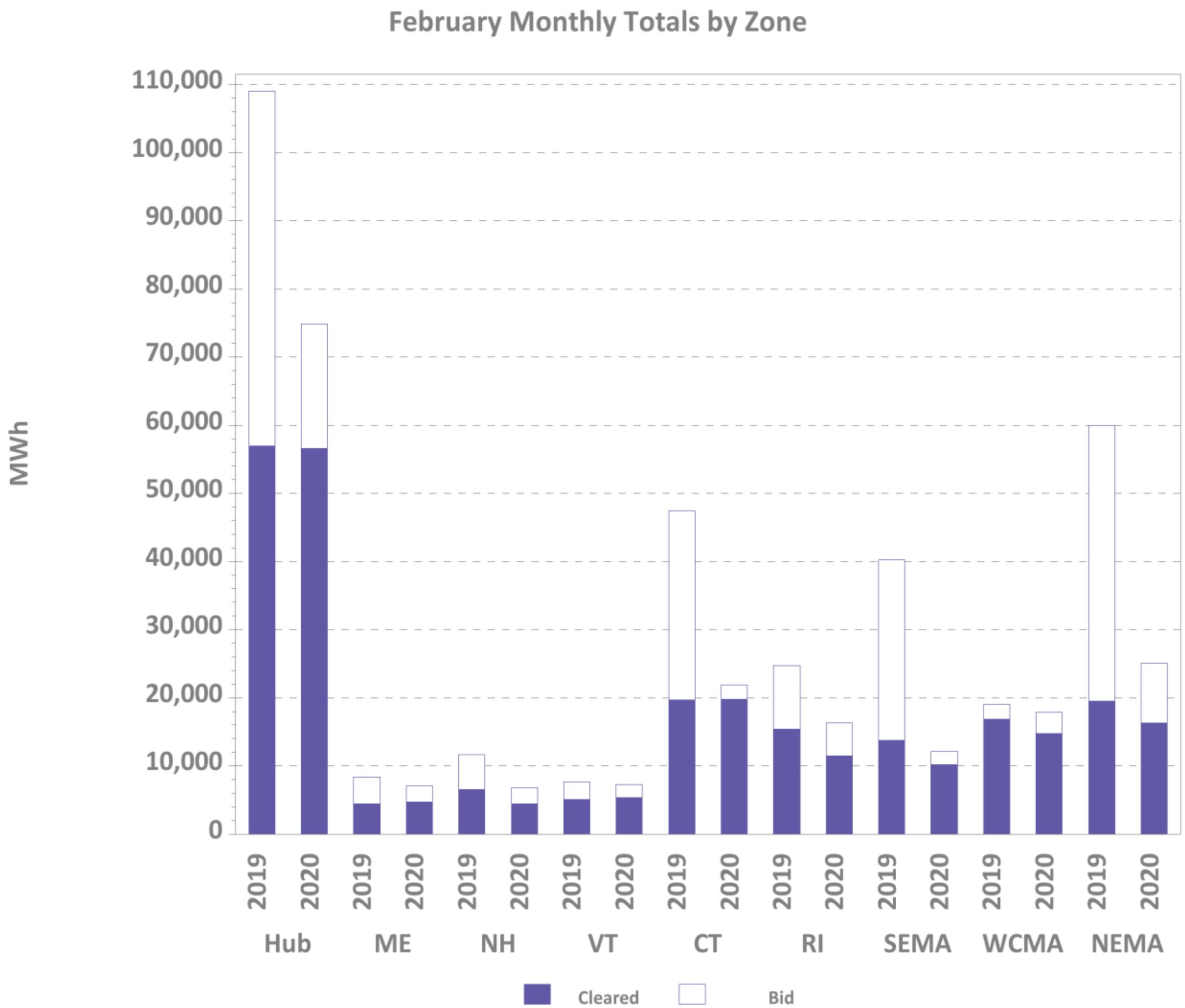
LFRM Charges to Load by Load Zone ($)



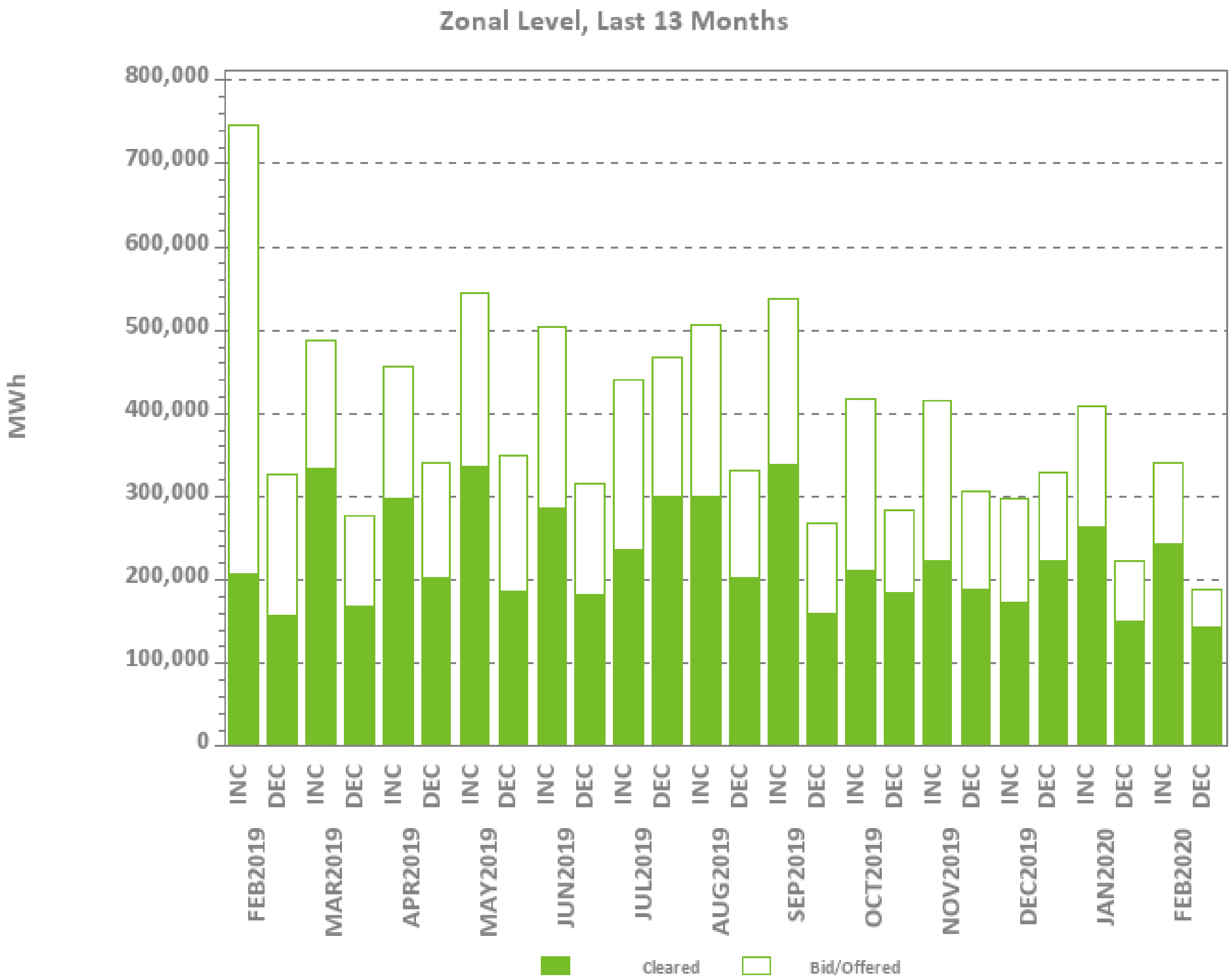
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

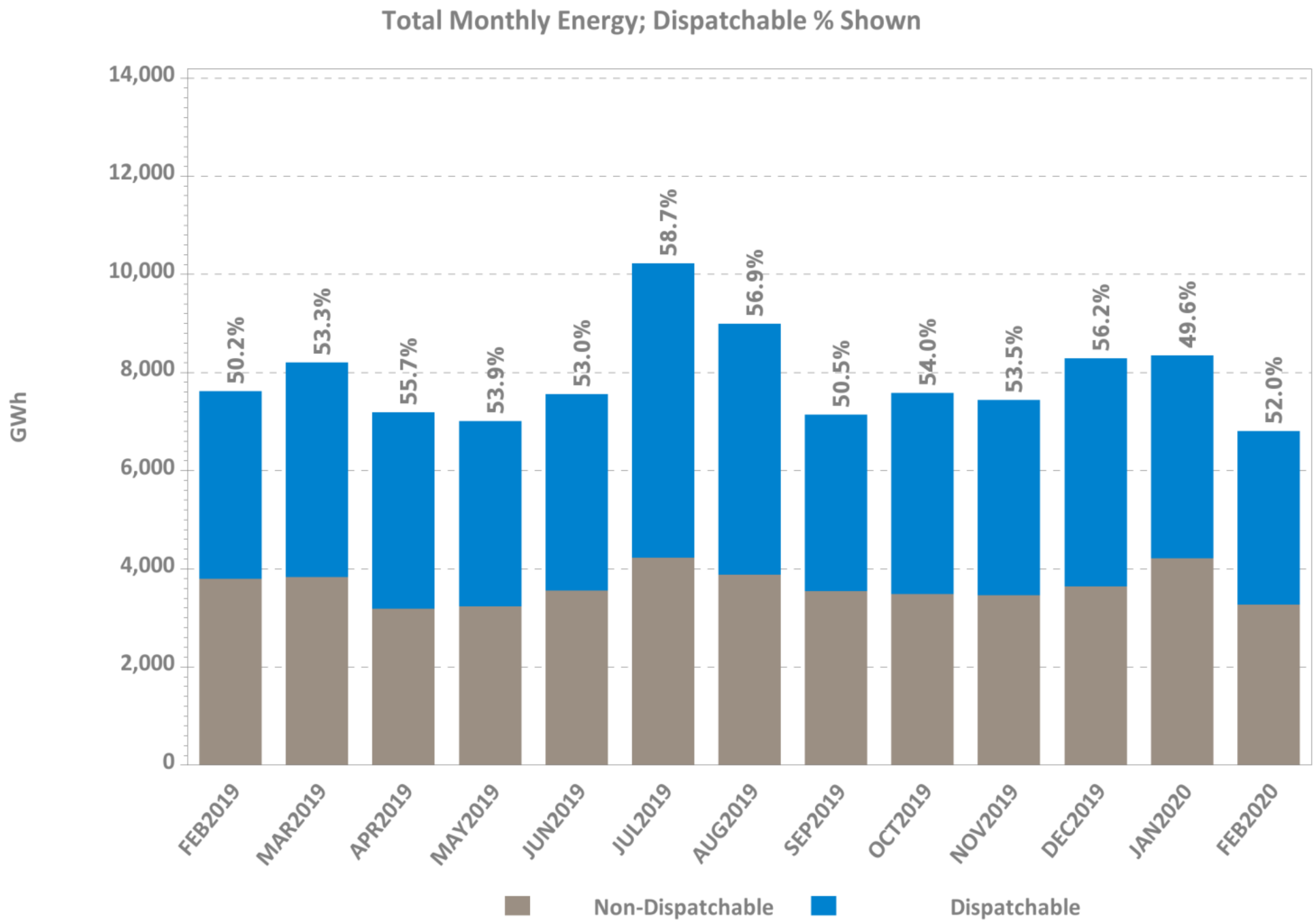


Total Increment Offers and Decrement Bids



Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



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

REGIONAL SYSTEM PLAN (RSP)

Future Regional System Plans

- Before developing the next Regional System Plan (RSP), the ISO would like input from stakeholders on how to enhance the report
- Goals
  - Increase usability of the RSP
  - Focus on content that stakeholders are interested in
  - Find new ways to keep the RSP forward looking
  - Streamline the development process
  - Increase visibility of the regional system planning process
- On February 13, the ISO received survey feedback regarding the content and format of the RSP
  - Results of this stakeholder survey will be discussed with PAC later this spring

Planning Advisory Committee (PAC)

- March 18 PAC Meeting Agenda Topics*
  - Update on New England Natural Gas Developments
  - Regional System Plan Transmission Projects and Asset Condition March 2020 Update
  - FCA 15 Zonal Boundary Determinations
  - Update on Draft 2020 CELT Load Forecast
  - 2019 Economic Study Requests Results - Anbaric
  - NESCOE Economic Study Request: Preliminary Transmission Study Results
  - Transmission Line Refurbishment Projects 340 and K41 Lines
  - SEMA/RI 2029 Needs Assessment Update

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

Economic Studies

- Economic study requests were submitted by Anbaric, NESCOE, and RENEW Northeast
  - Detailed assumptions for each study request were discussed at the August 8 PAC meeting
- Results for the NESCOE study (up to 8,000 MW of offshore wind additions) were presented at the December and February PAC meetings
  - The transmission portion of the study is anticipated to be presented to PAC in the March-April timeframe
- Preliminary results for the Anbaric and RENEW studies are anticipated to be discussed with PAC in the March-May timeframe
- The ISO plans to complete reports for all three requests by Q2 2020
- On February 14, the ISO sent a memo to stakeholders requesting the submission of 2020 economic study requests by April 1

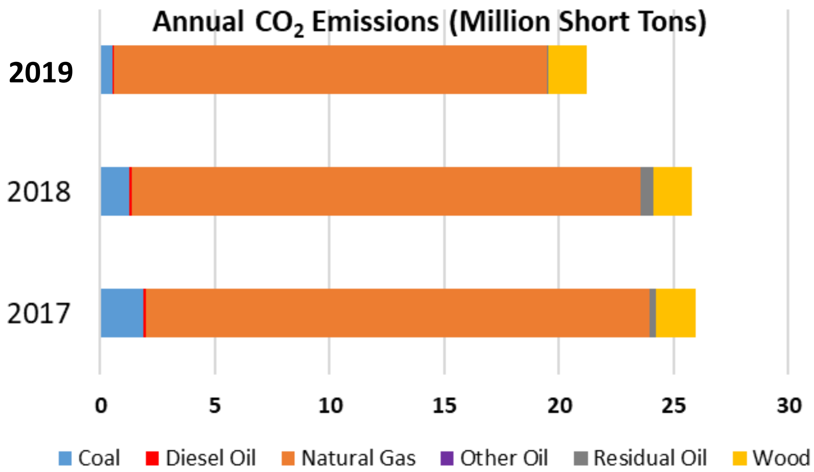
2018 Generator Emissions Report

- Preparation of the Annual Electric Generator Air Emissions Report is underway and expected to be completed in the April timeframe
- Preliminary results for the load-weighted and non-load-weighted marginal resource analyses were presented to the EAG in January and February
  - Similar to methodology that ISO-NE's market monitoring unit uses
- In response to stakeholder requests, the April EAG meeting will be devoted to discussing obstacles to reporting emissions from imports, and what actions could be taken to overcome the lack of publically available information

Environmental Matters – Annual Emissions

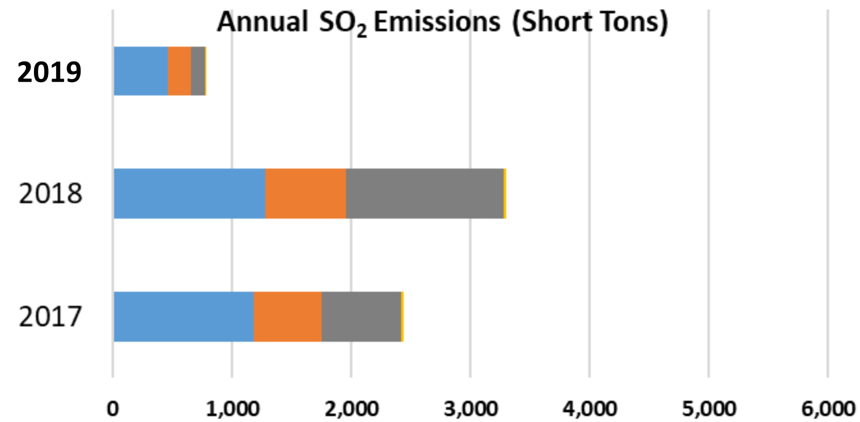
Reported to EPA by native emitting generators directly

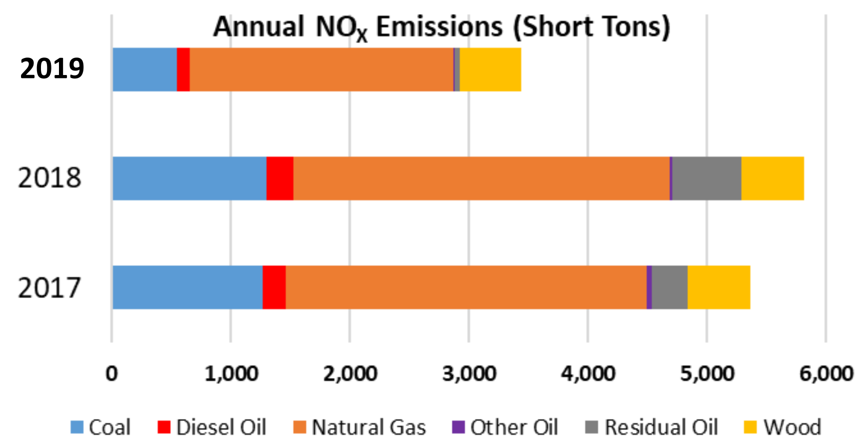
Regional 2019 CO_2 Emissions Trend Lower for All Fuel Types



- Compared to 2017 & 2018, a 4% decline in NEL during 2019 vs. 2018 caused all emissions to decline:
  - CO_2 emissions < 18%
  - SO_2 emissions < 73%
  - NO_x emissions < 39%

Lower Production by All Fuel Types Lowers Other System Emissions



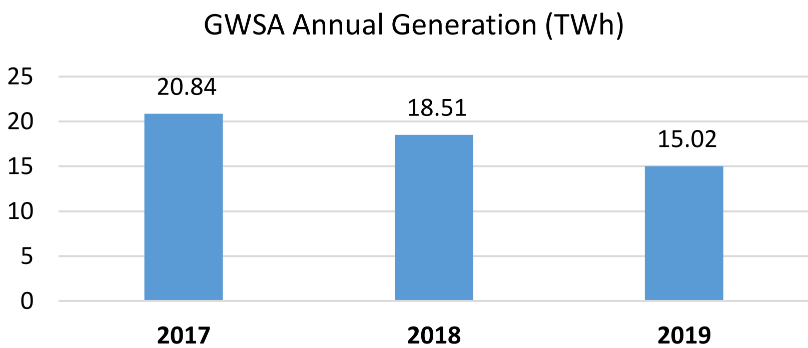


Environmental Matters – Massachusetts CO_2 Generator Emissions Cap

2019 Emissions Declined 23%, Generation Declined 19% vs. 2018

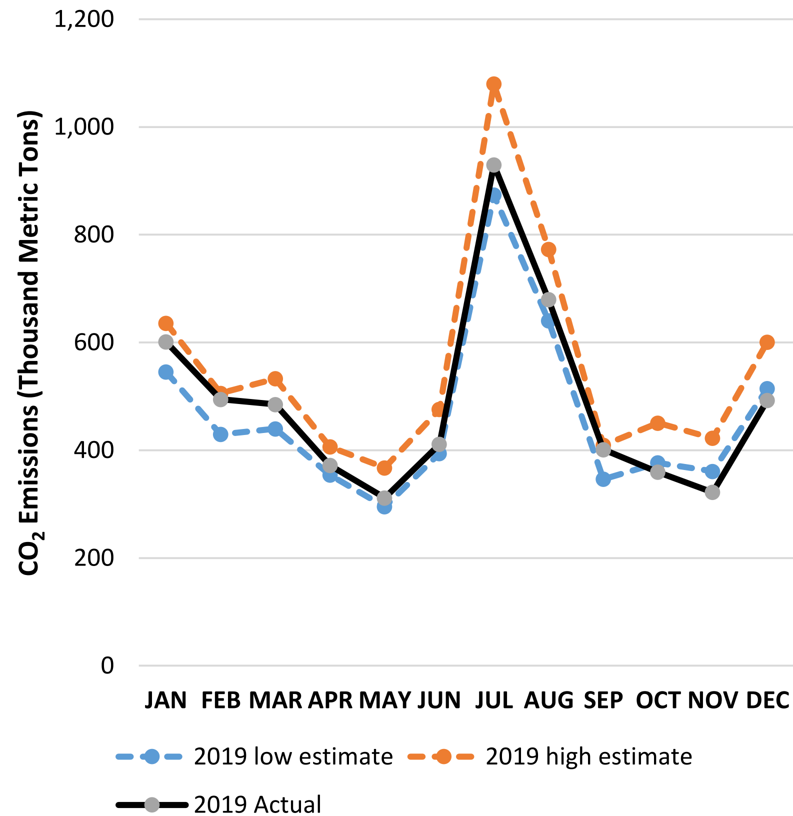
2019 CO_2 Emissions Well Below Cap

- 2019: **8.73** million metric ton (MMT) cap (25% auctioned, 75% allocated)
  - 2019 actual emissions **5.86** MMT
- 2020: **8.50** MMT cap (50% auctioned, 50% allocated)
- Generation from GWSA affected generators declined 19%, while NEL overall declined 4%



GWSA - Global Warming Solutions Act

2019 Estimated v. Actual GWSA CO_2 Cap Emissions



RSP Project Stage Descriptions

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

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

New Hampshire/Vermont 10-Year Upgrades

Status as of 2/21/20

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected/ Actual In-Service	Present Stage
Eagle Substation Add: 345/115 kV autotransformer	Dec-16	4
Littleton Substation Add: Second 230/115 kV autotransformer	Oct-14	4
New C-203 230 kV line tap to Littleton NH Substation	Nov-14	4
New 115 kV overhead line, Fitzwilliam-Monadnock	Feb-17	4
New 115 kV overhead line, Scobie Pond-Huse Road	Dec-15	4
New 115 kV overhead/submarine line, Madbury-Portsmouth	May-20	3
New 115 kV overhead line, Scobie Pond-Chester	Dec-15	4

New Hampshire/Vermont 10-Year Upgrades, cont.

Status as of 2/21/20

Project Benefit: Addresses Needs in New Hampshire and Vermont

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

New Hampshire/Vermont 10-Year Upgrades, cont.

Status as of 2/21/20

Project Benefit: Addresses Needs in New Hampshire and Vermont

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

Greater Hartford and Central Connecticut (GHCC) Projects*

Status as of 2/21/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Add a 2nd 345/115 kV autotransformer at Haddam substation and reconfigure the 3-terminal 345 kV 348 line into two 2-terminal lines	Apr-17	4
Terminal equipment upgrades on the 345 kV line between Haddam Neck and Beseck (362)	Feb-17	4
Redesign the Green Hill 115 kV substation from a straight bus to a ring bus and add two 115 kV 25.2 MVAR capacitor banks	Jun-18	4
Add a 37.8 MVAR capacitor bank at the Hopewell 115 kV substation	Dec-15	4
Separation of 115 kV double circuit towers corresponding to the Branford – Branford RR line (1537) and the Branford to North Haven (1655) line and adding a 115 kV breaker at Branford 115 kV substation	Mar-17	4
Increase the size of the existing 115 kV capacitor bank at Branford Substation from 37.8 to 50.4 MVAR	Jan-17	4
Separation of 115 kV double circuit towers corresponding to the Middletown – Pratt and Whitney line (1572) and the Middletown to Haddam (1620) line	Dec-16	4

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 2/21/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Terminal equipment upgrades on the 115 kV line from Middletown to Dooley (1050)	Jun-15	4
Terminal equipment upgrades on the 115 kV line from Middletown to Portland (1443)	Jun-15	4
Add a 3.7 mile 115 kV hybrid overhead/underground line from Newington to Southwest Hartford and associated terminal equipment including a 1.4% series reactor	Jun-20	3
Add a 115 kV 25.2 MVAR capacitor at Westside 115 kV substation	Jun-18	4
Loop the 1779 line between South Meadow and Bloomfield into the Rood Avenue substation and reconfigure the Rood Avenue substation	May-17	4
Reconfigure the Berlin 115 kV substation including two new 115 kV breakers and the relocation of a capacitor bank	Nov-17	4
Reconductor the 115 kV line between Newington and Newington Tap (1783)	Jun-20	3

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 2/21/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Separation of 115 kV DCT corresponding to the Bloomfield to South Meadow (1779) line and the Bloomfield to North Bloomfield (1777) line and add a breaker at Bloomfield 115 kV substation	Dec-17	4
Separation of 115 kV DCT corresponding to the Bloomfield to North Bloomfield (1777) line and the North Bloomfield – Rood Avenue – Northwest Hartford (1751) line and add a breaker at North Bloomfield 115 kV substation	Dec-17	4
Install a 115 kV 3% reactor on the 115 kV line between South Meadow and Southwest Hartford (1704)	Jun-20	3
Replace the existing 3% series reactors on the 115 kV lines between Southington and Todd (1910) and between Southington and Canal (1950) with a 5% series reactors	Dec-18	4
Replace the normally open 19T breaker at Southington 115 kV with a normally closed 3% series reactor	Jun-19	4
Add a 345 kV breaker in series with breaker 5T at Southington	May-17	4

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 2/21/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Add a new control house at Southington 115 kV substation	Dec-18	4
Add a new 115 kV line from Frost Bridge to Campville	Dec-17	4
Separation of 115 kV DCT corresponding to the Frost Bridge to Campville (1191) line and the Thomaston to Campville (1921) line and add a breaker at Campville 115 kV substation	Jun-18	4
Upgrade the 115 kV line between Southington and Lake Avenue Junction (1810-1)	Dec-16	4
Add a new 345/115 kV autotransformer at Barbour Hill substation	Dec-15	4
Add a 345 kV breaker in series with breaker 24T at the Manchester 345 kV substation	Dec-15	4
Reconductor the 115 kV line between Manchester and Barbour Hill (1763)	Apr-16	4

* Replaces the NEEWS Central Connecticut Reliability Project

Southwest Connecticut (SWCT) Projects

Status as of 2/21/20

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

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

Southwest Connecticut Projects, cont.

Status as of 2/21/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Add two 14.4 MVAR capacitor banks at the West Brookfield substation	Dec-17	4
Add a new 115 kV line from Plumtree to Brookfield Junction	Jun-18	4
Reconductor the 115 kV line between West Brookfield and Brookfield Junction (1887)	Dec-20	2
Reduce the existing 25.2 MVAR capacitor bank at the Rocky River substation to 14.4 MVAR	Apr-17	4
Reconfigure the 1887 line into a three-terminal line (Plumtree - W. Brookfield - Shepaug)	May-18	4
Reconfigure the 1770 line into 2 two-terminal lines (Plumtree - Stony Hill and Stony Hill - Bates Rock)	May-18	4
Install a synchronous condenser (+25/-12.5 MVAR) at Stony Hill	Jun-18	4
Relocate an existing 37.8 MVAR capacitor bank at Stony Hill to the 25.2 MVAR capacitor bank side	May-18	4

Southwest Connecticut Projects, cont.

Status as of 2/21/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Relocate the existing 37.8 MVAR capacitor bank from 115 kV B bus to 115 kV A bus at the Plumtree substation	Apr-17	4
Add a 115 kV circuit breaker in series with the existing 29T breaker at the Plumtree substation	May-16	4
Terminal equipment upgrade at the Newtown substation (1876)	Dec-15	4
Rebuild the 115 kV line from Wilton to Norwalk (1682) and upgrade Wilton substation terminal equipment	Jun-17	4
Reconductor the 115 kV line from Wilton to Ridgefield Junction (1470-1)	Dec-19	4
Reconductor the 115 kV line from Ridgefield Junction to Peaceable (1470-3)	Dec-19	4

Southwest Connecticut Projects, cont.

Status as of 2/21/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Add 2 x 20 MVAR capacitor banks at the Hawthorne substation	Mar-16	4
Upgrade the 115 kV bus at the Baird substation	Mar-18	4
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)	Dec-18	4
Rebuild the 115 kV lines from Housatonic River Crossing (HRX) to Barnum to Baird (88006A / 89006B)	Jun-21	2

Southwest Connecticut Projects, cont.

Status as of 2/21/20

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

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

Greater Boston Projects

Status as of 2/21/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Install new 345 kV line from Scobie to Tewksbury	Dec-17	4
Reconductor the Y-151 115 kV line from Dracut Junction to Power Street	Apr-17	4
Reconductor the M-139 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
Reconductor the N-140 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
Reconductor the F-158N 115 kV line from Wakefield Junction to Maplewood and associated work at Maplewood	Dec-15	4
Reconductor the F-158S 115 kV line from Maplewood to Everett	Jun-19	4
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-21	3*
Refurbish X-24 69 kV line from Millbury to Northboro Road	Dec-15	4
Reconductor W-23W 69 kV line from Woodside to Northboro Road	Jun-19	4

* Substation portion of the project is a Present Stage status 4

Greater Boston Projects, cont.

Status as of 2/21/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Separate X-24 and E-157W DCT	Dec-18	4
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	May-20	3
Install third 115 kV line from West Walpole to Holbrook	May-20	3
Install new 345 kV breaker in series with the 104 breaker at Stoughton	May-16	4
Install new 230/115 kV autotransformer at Sudbury and loop the 282-602 230 kV line in and out of the new 230 kV switchyard at Sudbury	Dec-17	4
Install a new 115 kV line from Sudbury to Hudson	Dec-23	2

Greater Boston Projects, cont.

Status as of 2/21/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Replace 345/115 kV autotransformer, 345 kV breakers, and 115 kV switchgear at Woburn	Dec-19	4
Install a 345 kV breaker in series with breaker 104 at Woburn	May-17	4
Reconfigure Waltham by relocating PARs, 282-507 line, and a breaker	Dec-17	4
Upgrade 533-508 115 kV line from Lexington to Hartwell and associated work at the stations	Aug-16	4
Install a new 115 kV 54 MVAR capacitor bank at Newton	Dec-16	4
Install a new 115 kV 36.7 MVAR capacitor bank at Sudbury	May-17	4
Install a second Mystic 345/115 kV autotransformer and reconfigure the bus	May-19	4
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	Jul-20	3
Split 110-522 and 240-510 DCT from Baker Street to Needham for a portion of the way and install a 115 kV cable for the rest of the way	Dec-20	3

Greater Boston Projects, cont.

Status as of 2/21/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Install a second 115 kV cable from Mystic to Woburn to create a bifurcated 211-514 line	Dec-21	3
Open lines 329-510/511 and 250-516/517 at Mystic and Chatham, respectively. Operate K Street as a normally closed station.	May-19	4
Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard	Mar-19	4
Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-16	4

Greater Boston Projects, cont.

Status as of 2/21/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Upgrade North Cambridge to mitigate 115 kV 5 and 10 stuck breaker contingencies	Dec-17	4
Install a 200 MVAR STATCOM at Coopers Mills	Nov-18	4
Install a 115 kV 36.7 MVAR capacitor bank at Hartwell	May-17	4
Install a 345 kV 160 MVAR shunt reactor at K Street	Dec-19	4
Install a 115 kV breaker in series with the 5 breaker at Framingham	Apr-17	4
Install a 115 kV breaker in series with the 29 breaker at K Street	Apr-17	4

Pittsfield/Greenfield Projects

Status as of 2/21/20

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

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

Pittsfield/Greenfield Projects, cont.

Status as of 2/21/20

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

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

Pittsfield/Greenfield Projects, cont.

Status as of 2/21/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Install a 115 kV 20.6 MVAR capacitor at the Doreen substation and operate the 115 kV 13T breaker N.O.	Oct-17	4
Install a 75-150 MVAR variable reactor at Northfield substation	Dec-17	4
Install a 75-150 MVAR variable reactor at Ludlow substation	Dec-17	4
Construct a 115 kV three-breaker ring bus at or adjacent to Pochassic 37R Substation, loop line 1512-1 into the new three-breaker ring bus, construct a new line connecting the new three-breaker ring bus to the Buck Pond 115 kV Substation on the vacant side of the double-circuit towers that carry line 1302-2, add a new breaker to the Buck Pond 115 kV straight bus and reconnect lines 1302-2, 1657-2 and transformer 2X into new positions	Jun-20	3

SEMA/RI Reliability Projects

Status as of 2/21/20

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

Project ID	Upgrade	Expected/ Actual In-Service	Present Stage
1714	Construct a new 115 kV GIS switching station (Grand Army) which includes remote terminal station work at Brayton Point and Somerset substations, and the looping in of the E-183E, F-184, X3, and W4 lines	May-20	3
1742	Conduct remote terminal station work at the Wampanoag and Pawtucket substations for the new Grand Army GIS switching station	Nov-20	3
1715	Install upgrades at Brayton Point substation which include a new 115 kV breaker, new 345/115 kV transformer, and upgrades to E183E, F184 station equipment	Jun-20	3
1716	Increase clearances on E-183E & F-184 lines between Brayton Point and Grand Army substations	Nov-19	4
1717	Separate the X3/W4 DCT and reconductor the X3 and W4 lines between Somerset and Grand Army substations; reconfigure Y2 and Z1 lines	Nov-19	4

SEMA/RI Reliability Projects, cont.

Status as of 2/21/20

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

Project ID	Upgrade	Expected/ Actual In-Service	Present Stage
1718	Add 115 kV circuit breaker at Robinson Ave substation and re-terminate the Q10 line	Dec-20	2
1719	Install 45.0 MVAR capacitor bank at Berry Street substation	Dec-20	2
1720	Separate the N12/M13 DCT and reconductor the N12 and M13 between Somerset and Bell Rock substations	Nov-21	2
1721	Reconfigure Bell Rock to breaker-and-a-half station, split the M13 line at Bell Rock substation, and terminate 114 line at Bell Rock; install a new breaker in series with N12/D21 tie breaker, upgrade D21 line switch, and install a 37.5 MVAR capacitor	Dec-21	2
1722	Extend the Line 114 from the Dartmouth town line (Eversource- NGRID border) to Bell Rock substation	Dec-21	2
1723	Reconductor L14 and M13 lines from Bell Rock substation to Bates Tap	Sep-21	2

SEMA/RI Reliability Projects, cont.

Status as of 2/21/20

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

Project ID	Upgrade	Expected/ Actual In-Service	Present Stage
1725	Build a new 115 kV line from Bourne to West Barnstable substations which includes associated terminal work	Dec-23	1
1726	Separate the 135/122 DCT from West Barnstable to Barnstable substations	Dec-21	1
1727	Retire the Barnstable SPS	Dec-21	1
1728	Build a new 115 kV line from Carver to Kingston substations and add a new Carver terminal	Dec-22	1
1729	Install a new bay position at Kingston substation to accommodate new 115 kV line	Dec-22	1
1730	Extend the 114 line from the Eversource/National Grid border to the Industrial Park Tap	Dec-21	1

SEMA/RI Reliability Projects, cont.

Status as of 2/21/20

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

Project ID	Upgrade	Expected/ Actual In-Service	Present Stage
1731	Install 35.3 MVAR capacitors at High Hill and Wing Lane substations	Dec-21	1
1732	Loop the 201-502 line into the Medway substation to form the 201-502N and 201-502S lines	Jan-23	1
1733	Separate the 325/344 DCT lines from West Medway to West Walpole substations	Dec-21	1
1734	Reconductor and upgrade the 112 Line from the Tremont substation to the Industrial Tap	Jun-18	4
1736	Reconductor the 108 line from Bourne substation to Horse Pond Tap*	Oct-18	4
1737	Replace disconnect switches on 323 line at West Medway substation and replace 8 line structures	Dec-20	3

* Does not include the reconductoring work over the Cape Cod canal

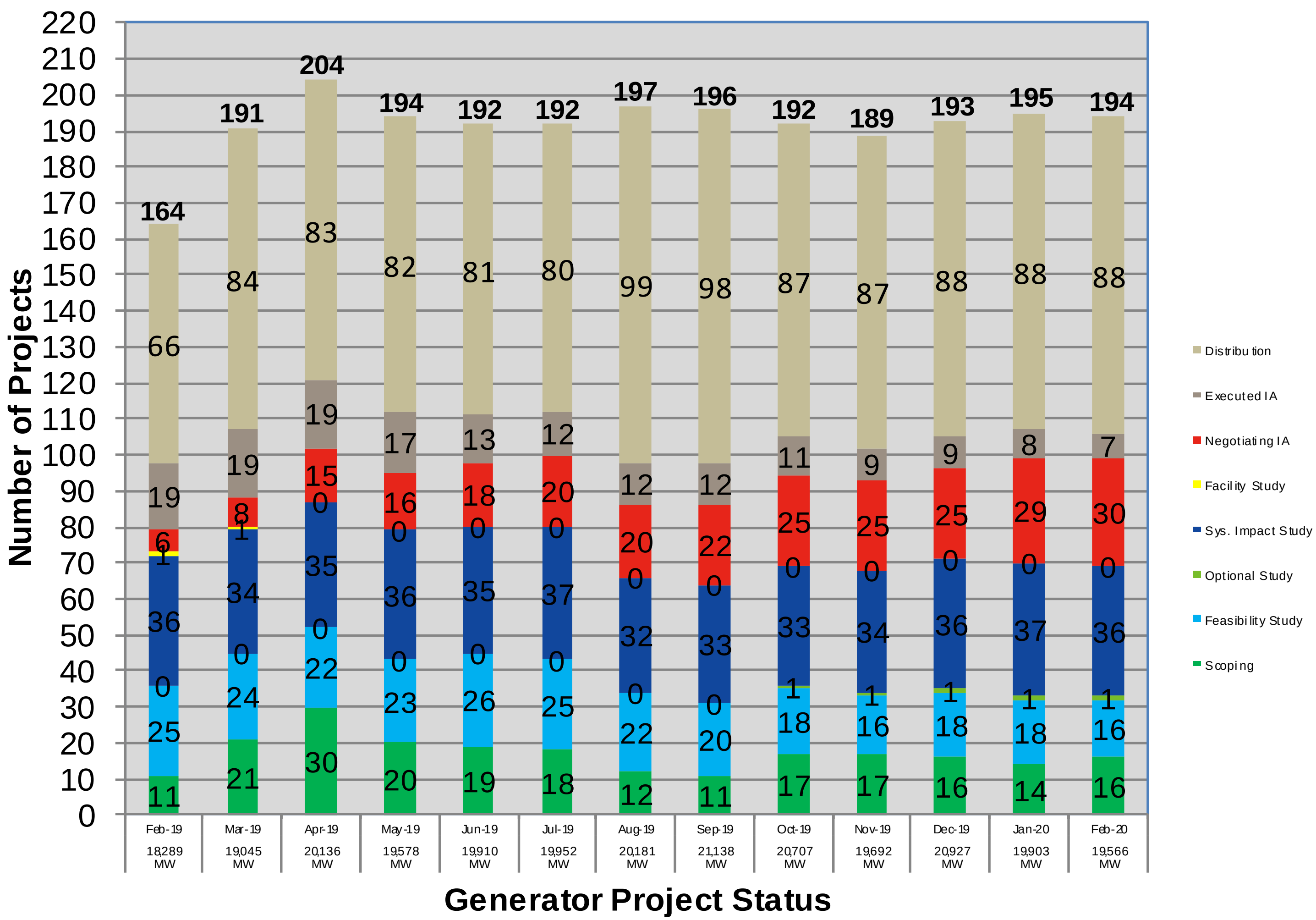
SEMA/RI Reliability Projects, cont.

Status as of 2/21/20

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

Project ID	Upgrade	Expected/ Actual In-Service	Present Stage
1741	Rebuild the Middleborough Gas and Electric portion of the E1 line from Bridgewater to Middleborough	Apr-19	4
1782	Reconductor the J16S line	Dec-20	2
1724	Replace the Kent County 345/115 kV transformer	Feb-21	2
1789	West Medway 345 kV circuit breaker upgrades	Dec-21	3
1790	Medway 115 kV circuit breaker replacements	Dec-21	3

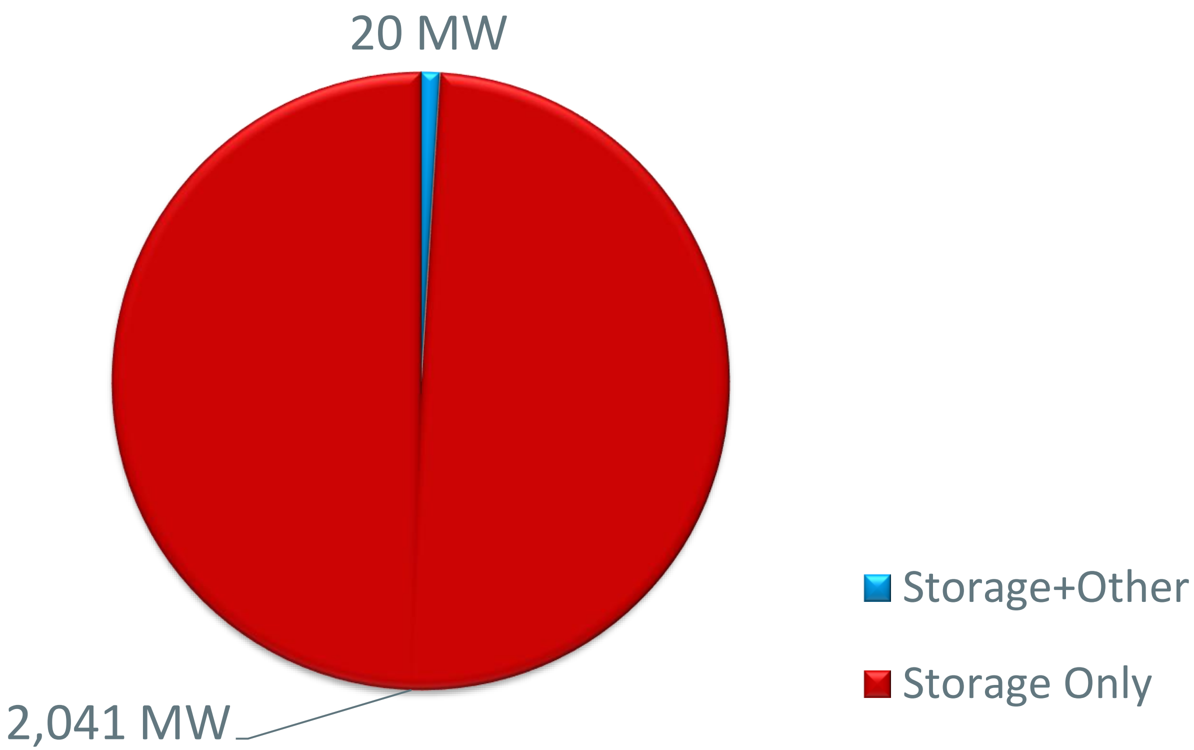
Status of Tariff Studies



Note: February 2020 based on partial data
As of February 2020, there are 4 ETU's in Scoping, 4 in FS, 4 in SIS, 0 in FAC, 0 Negotiating IA, and 1 with Executed IA
https://irtt.iso-ne.com/external.aspx

What is in the Queue (as of February 25, 2020)

Storage Projects are proposed as stand-alone storage or as co-located with wind or solar projects



OPERABLE CAPACITY ANALYSIS

Spring 2020 Analysis

Spring 2020 Operable Capacity Analysis

50/50 Load Forecast (Reference)	May - 2020[2] CSO (MW)	May - 2020[2] SCC (MW)
Operable Capacity MW [1]	31,344	33,795
Active Demand Capacity Resource (+) [5]	453	443
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	917	917
Non Commercial Capacity (+)	28	28
Non Gas-fired Planned Outage MW (-)	5,680	5,823
Gas Generator Outages MW (-)	1,697	1,867
Allowance for Unplanned Outages (-) [4]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	21,965	24,093
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	19,340	19,340
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	21,645	21,645
Operable Capacity Margin	320	2,448

[1]Operable Capacity is based on data as of **February 17, 2020** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **February 17, 2020.**

[2] Load forecast that is based on the 2019 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 9, 2020.**

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

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

[5] Active Demand Capacity Resources (ADCRs) can participate in the Forward Capacity Market (FCM), have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.

Spring 2020 Operable Capacity Analysis

90/10 **Load Forecast** (Extreme)	**May - 2020[2] CSO (MW)**	**May - 2020[2] SCC (MW)**
Operable Capacity MW [1]	31,344	33,795
Active Demand Capacity Resource (+) [5]	453	443
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	917	917
Non Commercial Capacity (+)	28	28
Non Gas-fired Planned Outage MW (-)	5,680	5,823
Gas Generator Outages MW (-)	1,697	1,867
Allowance for Unplanned Outages (-) [4]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	21,965	24,093
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,858	20,858
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,163	23,163
Operable Capacity Margin	-1,198	930

[1]Operable Capacity is based on data as of **February 17, 2020** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **February 17, 2020.**

[2] Load forecast that is based on the 2019 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 9, 2020.**

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

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

[5] Active Demand Capacity Resources (ADCRs) can participate in the Forward Capacity Market (FCM), have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.

Spring 2020 Operable Capacity Analysis
50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

March 1, 2020 - 50-50 FORECAST using CSO

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, August, and Mid September

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW [1]	Active Capacity Demand MW [2]	EXTERNAL NODE AVAIL CAPACITY MW [3]	NON COMMERCIAL CAPACITY MW [4]	NON-GAS PLANNED OUTAGES CSO MW [5]	GAS GENERATOR OUTAGES CSO MW [6]	ALLOWANCE FOR UNPLANNED OUTAGES MW [7]	GAS AT RISK MW [8]	NET OPCAP SUPPLY MW [9]	PEAK LOAD FORECAST MW [10]	OPER RESERVE REQUIREMENT MW [11]	NET LOAD OBLIGATION MW [12]	OPCAP MARGIN MW [13]
2/29/2020	31176	401	945	28	814	0	2200	1557	27979	18273	2305	20578	7401
3/7/2020	31176	401	945	28	771	0	2200	1246	28333	18069	2305	20374	7959
3/14/2020	31176	401	945	28	1159	647	2200	0	28544	17690	2305	19995	8549
3/21/2020	31176	401	945	28	1789	655	2200	0	27906	17102	2305	19407	8499
3/28/2020	31366	433	917	28	4218	1299	2700	0	24527	16344	2305	18649	5878
4/4/2020	31366	433	917	28	4331	1627	2700	0	24086	16082	2305	18387	5699
4/11/2020	31366	433	917	28	4425	1837	2700	0	23782	15552	2305	17857	5925
4/18/2020	31366	433	917	28	5621	2246	2700	0	22177	15277	2305	17582	4595
4/25/2020	31366	433	917	28	6152	1445	2700	0	22447	14472	2305	16777	5670
5/2/2020	31344	453	917	28	5553	2350	3400	0	21439	18318	2305	20623	816
5/9/2020	**31344**	**453**	**917**	**28**	**5680**	**1697**	**3400**	**0**	**21965**	**19340**	**2305**	**21645**	**320**
5/16/2020	31344	453	763	28	3421	1135	3400	0	24632	20290	2305	22595	2037
5/23/2020	31344	453	763	28	1913	0	3400	0	27275	21333	2305	23638	3637

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity Market (FCM). These resources will have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
4. New resources and generator improvements that have acquired a CSO but have not become commercial.
5. 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.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. 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.
8. 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.
9. Net OpCap Supply MW Available (1 + 2 + 3 + 4 - 5 - 6 - 7 - 8 = 9)
10. Peak Load Forecast as provided in the 2019 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 25,323 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV)
11. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
12. Total Net Load Obligation per the formula(10 + 11 = 12)
13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

Spring 2020 Operable Capacity Analysis
90/10 Forecast (Extreme)

ISO-NE OPERABLE CAPACITY ANALYSIS

March 1, 2020 - 90-10 FORECAST using CSO

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, August, and Mid September

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW [1]	Active Capacity Demand MW [2]	EXTERNAL NODE AVAIL CAPACITY MW [3]	NON COMMERCIAL CAPACITY MW [4]	NON-GAS PLANNED OUTAGES CSO MW [5]	GAS GENERATOR OUTAGES CSO MW [6]	ALLOWANCE FOR UNPLANNED OUTAGES MW [7]	GAS AT RISK MW [8]	NET OPCAP SUPPLY MW [9]	PEAK LOAD FORECAST MW [10]	OPER RESERVE REQUIREMENT MW [11]	NET LOAD OBLIGATION MW [12]	OPCAP MARGIN MW [13]
2/29/2020	31176	401	945	28	814	0	2200	2336	27200	18903	2305	21208	5992
3/7/2020	31176	401	945	28	771	0	2200	2180	27399	18693	2305	20998	6401
3/14/2020	31176	401	945	28	1159	647	2200	910	27634	18302	2305	20607	7027
3/21/2020	31176	401	945	28	1789	655	2200	435	27471	17697	2305	20002	7469
3/28/2020	31366	433	917	28	4218	1299	2700	0	24527	16923	2305	19228	5299
4/4/2020	31366	433	917	28	4331	1627	2700	0	24086	16654	2305	18959	5127
4/11/2020	31366	433	917	28	4425	1837	2700	0	23782	16108	2305	18413	5369
4/18/2020	31366	433	917	28	5621	2246	2700	0	22177	15824	2305	18129	4048
4/25/2020	31366	433	917	28	6152	1445	2700	0	22447	15018	2305	17323	5124
5/2/2020	31344	453	917	28	5553	2350	3400	0	21439	19768	2305	22073	-634
5/9/2020	**31344**	**453**	**917**	**28**	**5680**	**1697**	**3400**	**0**	**21965**	**20858**	**2305**	**23163**	**-1198**
5/16/2020	31344	453	763	28	3421	1135	3400	0	24632	21870	2305	24175	457
5/23/2020	31344	453	763	28	1913	0	3400	0	27275	22982	2305	25287	1988

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity Market (FCM). These resources will have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
4. New resources and generator improvements that have acquired a CSO but have not become commercial.
5. 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.
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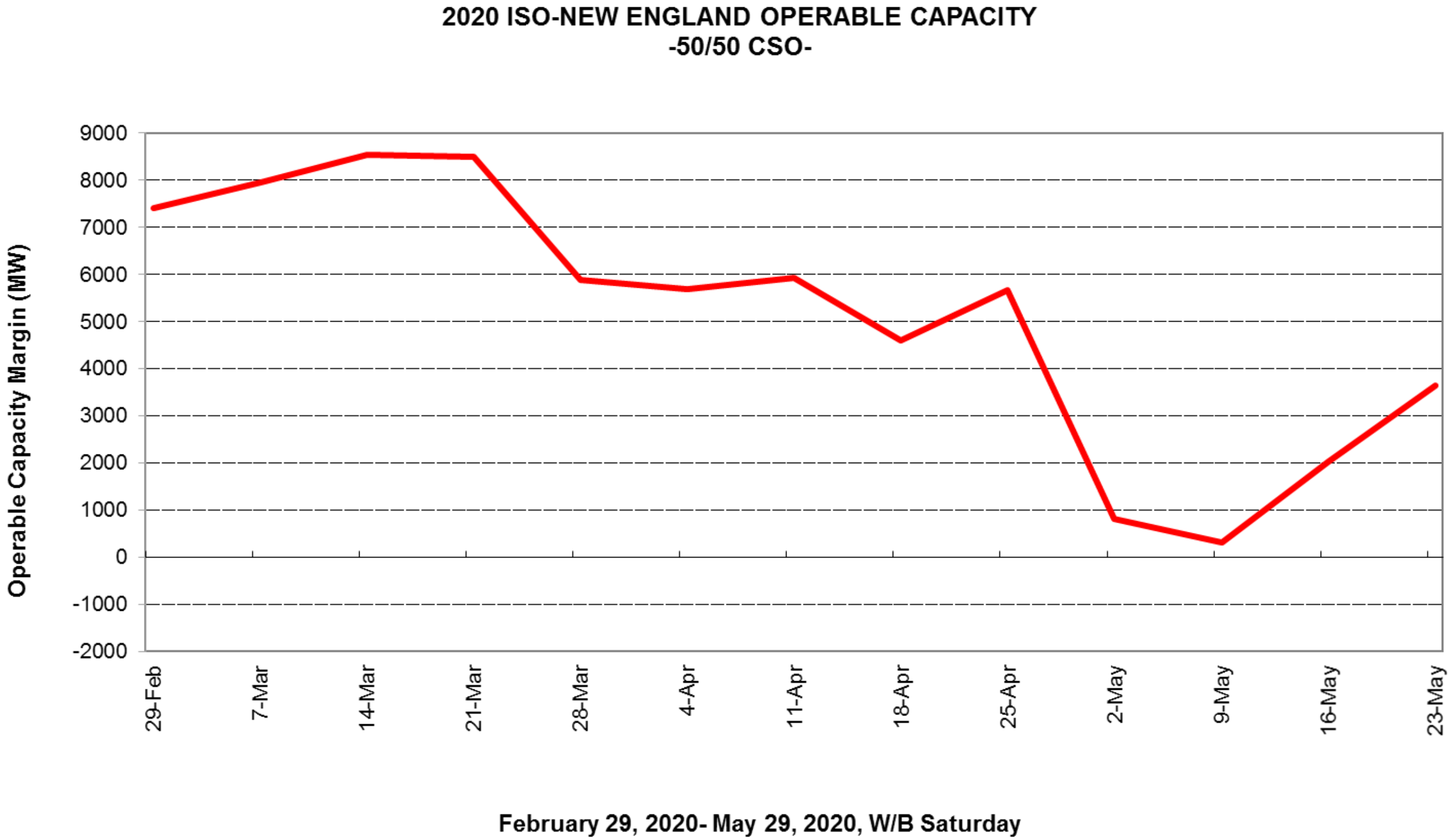
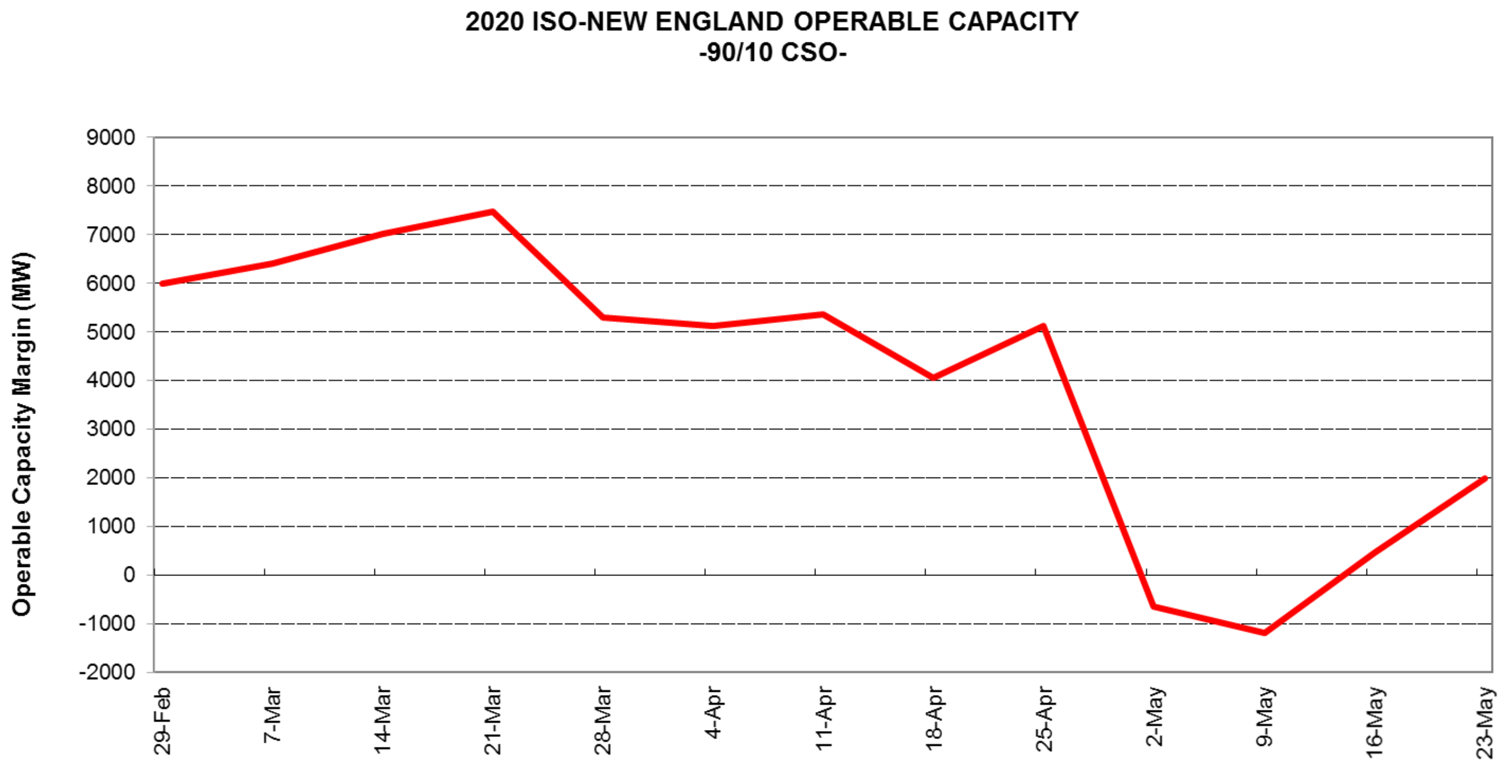
7. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. Net OpCap Supply MW Available (1 + 2 + 3 + 4 - 5 - 6 - 7 - 8 = 9)
10. Peak Load Forecast as provided in the 2019 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 27,212 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV)
11. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
12. Total Net Load Obligation per the formula(10 + 11 = 12)
13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

***Highlighted week is based on the week determined by the 50/50 Load Forecast Reference week**

Spring 2020 Operable Capacity Analysis
50/50 Forecast (Reference)



Spring 2020 Operable Capacity Analysis
90/10 Forecast (Extreme)



February 29, 2020- May 29, 2020, W/B Saturday

OPERABLE CAPACITY ANALYSIS

Preliminary Summer 2020 Analysis

Preliminary Summer 2020 Operable Capacity Analysis

50/50 Load Forecast (Reference)	May - 2020[2] CSO (MW)	May - 2020[2] SCC (MW)
Operable Capacity MW [1]	30,763	31,087
Active Demand Capacity Resource (+) [5]	524	443
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,455	1,455
Non Commercial Capacity (+)	28	28
Non Gas-fired Planned Outage MW (-)	156	157
Gas Generator Outages MW (-)	164	164
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	29,650	29,892
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	25,025	25,025
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	27,330	27,330
Operable Capacity Margin	2,320	2,562

[1]Operable Capacity is based on data as of **February 17, 2020** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **February 17, 2020.**

[2] Load forecast that is based on the 2019 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 30, 2020.**

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

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

[5] Active Demand Capacity Resources (ADCRs) can participate in the Forward Capacity Market (FCM), have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.

Preliminary Summer 2020 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	May - 2020[2] CSO (MW)	May - 2020[2] SCC (MW)
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Non Commercial Capacity (+)	28	28
Non Gas-fired Planned Outage MW (-)	156	157
Gas Generator Outages MW (-)	164	164
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	29,650	29,892
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	26,945	26,945
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	29,250	29,250
Operable Capacity Margin	400	642

[1] Operable Capacity is based on data as of **February 17, 2020** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **February 17, 2020.**

[2] Load forecast that is based on the 2019 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 30, 2020.**

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[5] Active Demand Capacity Resources (ADCRs) can participate in the Forward Capacity Market (FCM), have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.

Preliminary Summer 2020 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

March 1, 2020 - 50-50 FORECAST using CSO

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, August, and Mid September

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW [1]	Active Capacity Demand MW [2]	EXTERNAL NODE AVAIL CAPACITY MW [3]	NON COMMERCIAL CAPACITY MW [4]	NON-GAS PLANNED OUTAGES CSO MW [5]	GAS GENERATOR OUTAGES CSO MW [6]	ALLOWANCE FOR UNPLANNED OUTAGES MW [7]	GAS AT RISK MW [8]	NET OPCAP SUPPLY MW [9]	PEAK LOAD FORECAST MW [10]	OPER RESERVE REQUIREMENT MW [11]	NET LOAD OBLIGATION MW [12]	OPCAP MARGIN MW [13]
5/30/2020	**30763**	**524**	**1455**	**28**	**156**	**164**	**2800**	**0**	**29650**	**25025**	**2305**	**27330**	**2320**
6/6/2020	30763	524	1510	28	206	0	2800	0	29819	25025	2305	27330	2489
6/13/2020	30763	524	1510	28	156	0	2800	0	29869	25025	2305	27330	2539
6/20/2020	30763	524	1510	28	14	0	2800	0	30011	25025	2305	27330	2681
6/27/2020	30763	524	1510	28	1	0	2800	0	30024	25025	2305	27330	2694
7/4/2020	30763	524	1510	28	15	0	2100	0	30710	25025	2305	27330	3380
7/11/2020	30763	524	1510	28	61	0	2100	0	30664	25025	2305	27330	3334
7/18/2020	30763	524	1510	28	36	0	2100	0	30689	25025	2305	27330	3359
7/25/2020	30763	524	1510	28	71	0	2100	0	30654	25025	2305	27330	3324
8/1/2020	30763	524	1510	28	58	0	2100	0	30667	25025	2305	27330	3337
8/8/2020	30763	524	1510	28	57	0	2100	0	30668	25025	2305	27330	3338
8/15/2020	30763	524	1510	28	61	0	2100	0	30664	25025	2305	27330	3334
8/22/2020	30763	524	1510	28	61	0	2100	0	30664	25025	2305	27330	3334
8/29/2020	30763	524	1510	28	518	0	2100	0	30207	25025	2305	27330	2877
9/5/2020	30763	524	1510	28	462	0	2100	0	30263	25025	2305	27330	2933
9/12/2020	30763	524	1510	28	2062	0	2100	0	28663	20851	2305	23156	5507

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
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9. Net OpCap Supply MW Available (1 + 2 + 3 + 4 - 5 - 6 - 7 - 8 = 9)
10. Peak Load Forecast as provided in the 2019 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 25,323 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV)
11. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
12. Total Net Load Obligation per the formula(10 + 11 = 12)
13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

Preliminary Summer 2020 Operable Capacity Analysis
90/10 Forecast (Extreme)

ISO-NE OPERABLE CAPACITY ANALYSIS

March 1, 2020 - 90-10 FORECAST using CSO

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	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
5/30/2020	**30763**	**524**	**1455**	**28**	**156**	**164**	**2800**	**0**	**29650**	**26945**	**2305**	**29250**	**400**
6/6/2020	30763	524	1510	28	206	0	2800	0	29819	26945	2305	29250	569
6/13/2020	30763	524	1510	28	156	0	2800	0	29869	26945	2305	29250	619
6/20/2020	30763	524	1510	28	14	0	2800	0	30011	26945	2305	29250	761
6/27/2020	30763	524	1510	28	1	0	2800	0	30024	26945	2305	29250	774
7/4/2020	30763	524	1510	28	15	0	2100	0	30710	26945	2305	29250	1460
7/11/2020	30763	524	1510	28	61	0	2100	0	30664	26945	2305	29250	1414
7/18/2020	30763	524	1510	28	36	0	2100	0	30689	26945	2305	29250	1439
7/25/2020	30763	524	1510	28	71	0	2100	0	30654	26945	2305	29250	1404
8/1/2020	30763	524	1510	28	58	0	2100	0	30667	26945	2305	29250	1417
8/8/2020	30763	524	1510	28	57	0	2100	0	30668	26945	2305	29250	1418
8/15/2020	30763	524	1510	28	61	0	2100	0	30664	26945	2305	29250	1414
8/22/2020	30763	524	1510	28	61	0	2100	0	30664	26945	2305	29250	1414
8/29/2020	30763	524	1510	28	518	0	2100	0	30207	26945	2305	29250	957
9/5/2020	30763	524	1510	28	462	0	2100	0	30263	26945	2305	29250	1013
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13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

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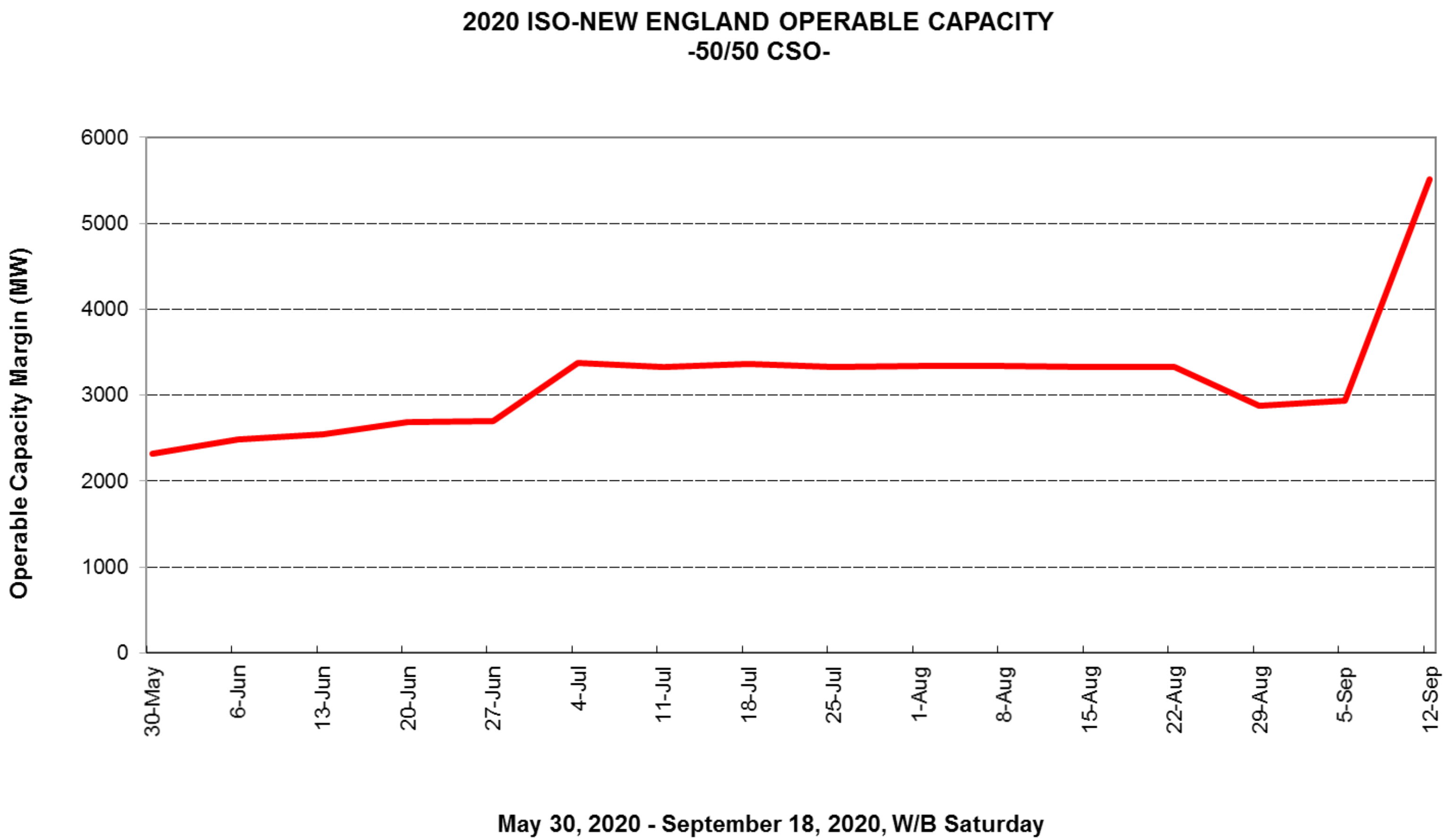
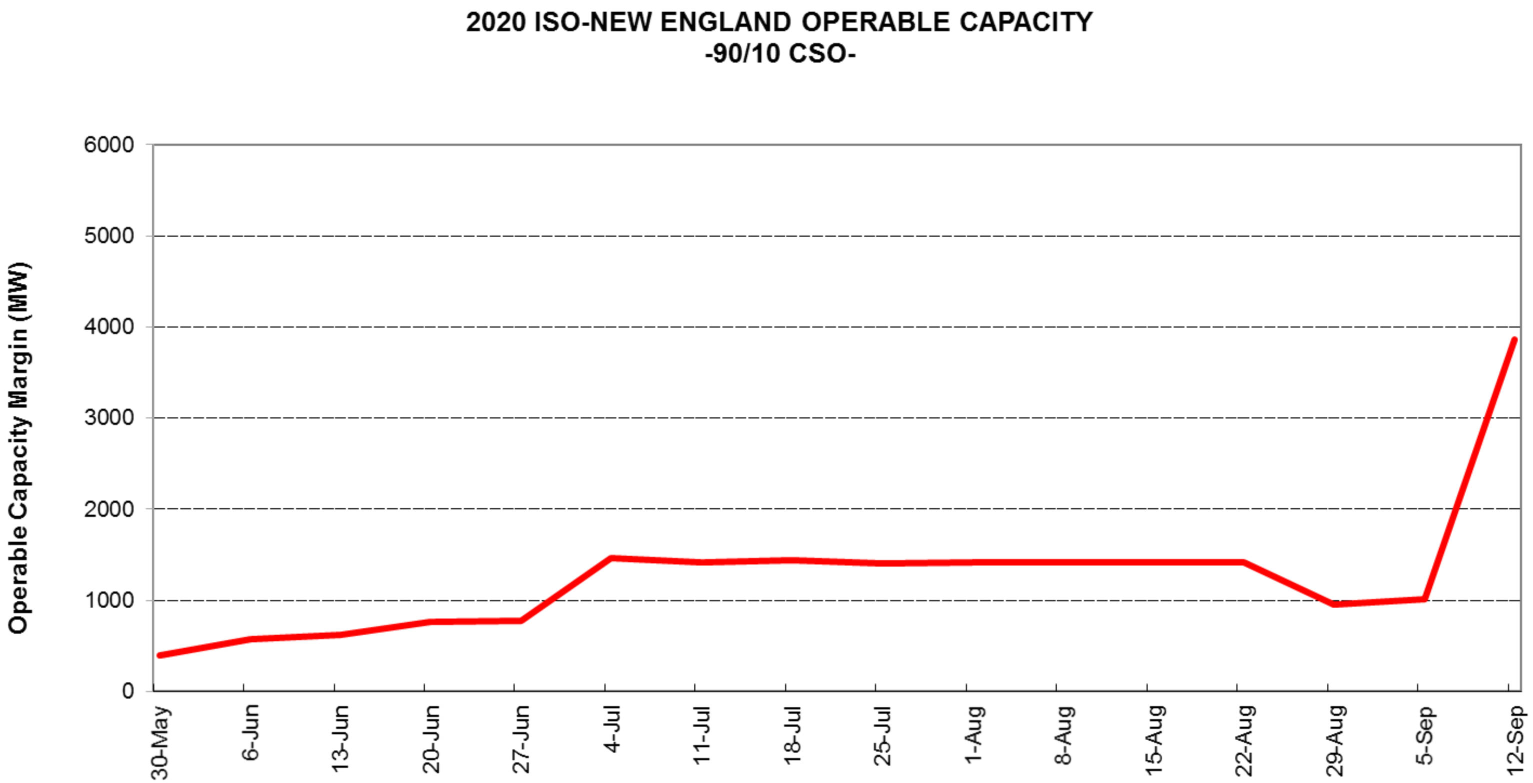
Preliminary Summer 2020 Operable Capacity Analysis 50/50 Forecast (Reference)



Preliminary Summer 2020 Operable Capacity Analysis
90/10 Forecast (Extreme)



May 30, 2020 - September 18, 2020, W/B Saturday

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 the depletion of 30-minute reserve.	0 [1] 600
2	Declare Energy Emergency Alert (EEA) Level 1[4]	0
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	125 [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 MW values are based on a 25,000 MW system load and verified by the most recent voltage reduction test.
4. EEA Levels are described in Attachment 1 to NERC Reliability Standard EOP-011 - Emergency Operations

Possible Relief Under OP4: Appendix A

OP 4 Action Number	Page 2 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
7	Request generating resources not subject to a Capacity Supply Obligation to voluntary provide energy for reliability purposes	0
8	5% Voltage Reduction requiring 10 minutes or less	250 [3]
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		**2,520**

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 MW values are based on a 25,000 MW system load and verified by the most recent voltage reduction test.
4. EEA Levels are described in Attachment 1 to NERC Reliability Standard EOP-011 - Emergency Operations

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Dave Doot and Sebastian Lombardi, NEPOOL Counsel

DATE: February 27, 2020

RE: NEPOOL Discussion of "Transition to Future Grid" Initiative

---

At the March 5, 2020 Participants Committee meeting, you will have an opportunity to provide input on proposed plans for future discussions on issues related to New England's transition to a future grid. Your elected leaders, working with appointed representatives of NESCOE and the ISO have proposed to inform future discussions with a study of the future state of New England's power system. Included with this memorandum as Attachment A is a high-level summary of a proposed study process.

Background

Last year, the ISO received multiple requests from NESCOE, NEPGA and other stakeholders for the region to dedicate time and resources to assess and explore market and reliability issues in light of evolving state energy and environmental policies. In response to those requests, the ISO committed to dedicate resources to support this effort. As reported at prior Participants Committee meetings, your elected Chair and Sector Vice-Chairs have been working with NESCOE and ISO representatives to propose a process for stakeholder input that would be used for the region to explore these issues together following completion of the Energy Security Improvements filing in April. This leadership group has met on multiple occasions to discuss and develop a proposed plan, we understand with preliminary thoughts and input from many of you through your elected NEPOOL leader.

Proposed Study Process

The leadership group concluded that any broader discussions would best be informed by a study and assessment of what the grid might look like at a set time in the future, presuming the goals of the states are achieved. Reflecting the general consensus of the group, Attachment A was developed as a straw to help frame, at a high-level, the objective(s) of this proposed study process. Your input at next Thursday's meeting on this proposed plan will be helpful to the leadership group as they work to flesh out additional detail about the contemplated study process, including the "when" and "where."

“TRANSITION TO FUTURE GRID” PROPOSED STUDY PROCESS

Objective

Assess and discuss future state of the regional power system in light of current state energy and environmental policies

Study Process to Define and Assess Future State of Regional Power System

1. Identify Resource Mix in [Year]
2. Identify Resource & Operational/Reliability Needs

**Assumptions, future scenarios, etc. to be developed within stakeholder process*

Gap Analysis

As part of study process, conduct a gap analysis to determine whether, in the future state envisioned, the markets (current design plus ESI) provide resources/ISO-NE what they need to continue to reliably operate the system? If not, what market deficits need to be addressed to assure reliability?

Discuss Potential Market Approach(es) to Address Gap(s)

Based on study results/gap analysis, explore potential market approaches to address any future gaps identified in the prior step, including evaluation of the pros/cons of different approaches and discussion of how any such market approach contemplates state energy and environmental laws

MEMORANDUM

TO: Participants Committee Members and Alternates

FROM: Pat Gerity, NEPOOL Counsel

DATE: February 27, 2020

RE: Fuels Industry Participant Determination and Approval of AEE Membership Application

---

The Participants Committee (NPC) will be asked at its March 5 meeting to consider the recommendation of the Membership Subcommittee (Subcommittee) that Advanced Energy Economy (AEE)[1] be determined by the NPC to be a Fuels Industry Participant and conditionally approved for membership as a NEPOOL Participant. This memorandum briefly reviews the background and substance of the Subcommittee's recommendations and includes forms of resolution for Participants Committee action.

AEE Membership Application

As explained at the December 6, 2019 NPC meeting, AEE has expressed a desire to participate directly in the NEPOOL stakeholder process. AEE seeks the opportunity for its representatives to attend NEPOOL meetings as Participants, to articulate AEE positions during discussion, to offer proposals if and as appropriate, and to otherwise enjoy the benefits and responsibilities of NEPOOL membership. AEE does not meet the eligibility criteria for membership in a Sector, however, and the Subcommittee sought at the December 6 meeting NPC guidance on the Sector or status for which AEE should be considered for membership. There was overwhelming support at that NPC meeting for identifying a basis for AEE membership and participation in the Pool, though some members were concerned with AEE membership in a Sector whose eligibility is determined based on ownership or control of New England-based resources, and the precedent that would be established if changes were made to permit membership in such a Sector without those resources. A number of members suggested that consideration be given to accepting AEE on the same basis as Fuels Industry Participants.

Subcommittee Recommendation

Following further consideration of the AEE application and the guidance provided by the NPC, those members participating in the December Subcommittee meeting concluded that AEE's participation would be facilitated by an NPC determination that AEE is, and AEE should be permitted to participate as, a Fuels Industry Participant.[2] Although there remained concerns that the term 'Fuels Industry Participant' on its face did not seem to aptly encompass AEE, there was agreement that, at least for now, and because the

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[1] AEE describes itself as "a national association of business leaders who are making the global energy system more secure, clean, and affordable. Advanced energy encompasses a broad range of products and services that constitute the best available technologies for meeting energy needs today and tomorrow. Among these are energy efficiency, demand response, energy storage, natural gas electric generation, solar, wind, hydro, nuclear, electric vehicles, biofuels and smart grid. It's all the innovations that make the energy we use more secure, clean, and affordable ... [AEE's] mission is transforming public policy to enable rapid growth of advanced energy companies." AEE counts among its members a number of Participants and Related Persons to Participants in the Generation, Transmission, Supplier, and AR Sectors. For a list of AEE members, *see* https://www.aee.net/members.

[2] As a Fuels Industry Participant, AEE would have the right to appoint to each Principal Committee a non-voting member, and an alternate to that member, each of whom would have the rights of any other member of a Principal Committee except the right to vote or to serve as an officer. AEE would not be a member of a Sector. AEE would pay an Annual Fee of $5,000.

determination and membership as a Fuels Industry Participant would accommodate AEE's request, the Subcommittee recommend that NPC determination and AEE's membership as a Fuels Industry Participant.

Given the limited, delegated authority of the Subcommittee, action on this matter must be taken by the NPC. Accordingly, the following two forms of resolutions could be used to act on the Subcommittee's recommendations:

> RESOLVED, that, in accordance with Section 1.28A of the Second Restated NEPOOL Agreement, the Participants Committee determines Advanced Energy Economy (AEE) to be a Fuels Industry Participant.
>
> FURTHER RESOLVED, that the Participants Committee approves the membership Application of AEE subject to the following conditions: (i) that AEE sign and return the Standard Membership Conditions, Waivers and Reminders acceptance letter; (ii) that the ISO and NEPOOL counsel find the AEE Application complete; and (iii) that AEE execute an Indemnification Agreement should its requested membership effective date be less than 60 days from date of the membership filing that requests FERC acceptance of the addition of AEE to the list of NEPOOL Participants.

Should there be any questions or concerns ahead of the March 5 NPC meeting, please do not hesitate to contact me (pmgerity@daypitney.com; 860-275-0533).

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of March 3, 2020

The following activity, as more fully described in the attached litigation report, has occurred since the report dated February 4, 2020 was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

I. Complaints/Section 206 Proceedings

*	1	Liberty RBA Appeal – Failure to Correct Nov 2018 Meter Data Error/Load Assignment (EL20-27)	Feb 28	Liberty seeks an order directing Eversource to refund the Disputed Amount ($191,440 plus interest) to ISO-NE and ISO-NE to refund the Disputed Amount to Liberty; comment date Mar 19
	1	206 Investigation: ISO-NE Implementation of *Order 1000* Exemptions for Immediate Need Rel. Projects (EL19-90)	Feb 11 Feb 21	ISO-NE, Eversource/Avangrid, National Grid submit reply comments State Agencies answer National Grid comments

II. Rate, ICR, FCA, Cost Recovery Filings

*	7	FCA14 Results Filing (ER20-1025)	Feb 18 Feb 20-Mar 3	ISO-NE files FCA14 results; comment date Apr 3 Avangrid, Calpine, Dominion, Exelon, National Grid, NESCOE, Public Citizen intervene
	7	FCA14 Qualification Informational Filing (ER20-308)	Feb 21 Feb 25	FERC accepts FCA14 qualification filing MA DPU files an out-of-time doc-less motion to intervene

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

*	11	NCPC Audit Eligibility Clean Up (ER20-1094)	Feb 27	ISO-NE and NEPOOL file changes to NCPC eligibility rules, adding Real-Time Dispatch Lost Opportunity Cost NCPC Credits and Rapid Response Pricing Opportunity Cost NCPC Credits; comment date Mar 19
	12	ISO-NE eTariff Versioning True-Up (ER20-763)	Feb 25	FERC accepts changes, eff. Dec 18, 2019
	12	Fuel Security Retention Sunset (ER20-645)	Feb 14	FERC rejects Sunset
	13	Waiver Request: FCA14 Qual. (CPower) (ER20-458)	Feb 5	FERC denies requested Waivers
	15	*Order 841* Compliance Filings (Electric Storage in RTO/ISO Markets) (ER19-470)	Feb 10	ISO-NE and NEPOOL file Tariff revisions in response to *Order 841 Initial Compliance Filing Order*

IV. OATT Amendments / TOAs / Coordination Agreements

	20	CIP IROL Cost Recovery Rules (ER20-739)	Feb 11 Feb 26	ISO-NE, NESCOE, IROL-Critical Facility Owners submit answers FERC issues deficiency letter; ISO-NE answer(s) to that letter due on or before Mar 27

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes

*	22	Sched. 21-NEP: Deepwater Block Island Wind Indem. Agreement Cancellation (ER20-962)	Feb 6	Narragansett files notice of cancellation
	22	Schedule 21-ES: Berkshire Phase 2 LSA (ER20-585)	Feb 7	FERC accepts LSA, eff. Oct 1, 2019

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

*	24	Capital Projects Report - 2019 Q4 (ER20-973)	Feb 11 Feb 20, 25 Feb 28-Mar 2	ISO-NE files Q4 Report NEPOOL intervenes and files comments supporting Q4 Report Eversource, National Grid intervene
*	24	IMM Quarterly Markets Reports - 2019 Fall (ZZ19-4)	Feb 12	IMM files Fall 2019 Report; to be reviewed at Apr 6-7 Markets Committee meeting

IX. Membership Filings

*	24	March 2020 Membership Filing (ER20-1130)	Feb 28	***Membership***: SP Transmission; ***Termination***: QPH Capital; ***Name Change***: Pixelle Energy Services; comment date Mar 20
	24	January 2020 Membership Filing (ER20-710)	Feb 14	FERC accepts the memberships of Enel Trading North America, MP2 Energy, and Rodan Energy Solutions (USA)
*	25	Suspension Notice – Number Nine Wind Farm (not docketed)	Feb 26	ISO-NE files notice of suspension of Number Nine Wind Farm from the New England Markets
*	25	Suspension Notice – Empire Generating Co, LLC (not docketed)	Feb 24	ISO-NE files notice of suspension of Empire Generating from the New England Markets

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

*	25	Complaint re: CIP-014-2 (Physical Security) (EL20-21)	Jan 30 Feb 19 Feb 7-27 Feb 25-Mar 3 Mar 2	Private citizen files a formal complaint alleging CIP-014-2 is inadequate and asked for an order directing NERC to correct the deficiencies Complaint supplemented; comment date on Complaint Mar 10 LA PSC, Public Citizen, Dayton Power & Light intervene Private citizens comment on Complaint NERC urges FERC to dismiss Complaint
*	25	Revised Reliability Standards: FAC-002-3; IRO-010-3; MOD-031-3; MOD-033-2; NUC-001-4; PRC-006-4; TOP-003-4 (RD20-4)	Feb 21	NERC files revised standards for approval; comment date Mar 23
*	26	Revised Reliability Standard: TPL-007-4 (RD20-3)	Feb 7	NERC files revised standard for approval
*	26	CIP Standards Development: Virtualization and Cloud Computing Services Projects Informational Filings (RD20-2)	Feb 20	FERC directs NERC to submit, on or before Mar 23, 2020, an info. filing describing the activity of its virtualization and cloud computing services CIP standard drafting projects
	26	Revised Regional Rel. Standard: PRC-006-NPCC-2 (RD20-1)	Feb 18	NERC approves PRC-006-NPCC-2, to become eff. Apr 1, 2020

*	26	NOI: Virtualization and Cloud Computing Services in BES Operations (RM20-8)	Feb 20	FERC issues NOI seeking comments on (i) the potential benefits and risks associated with the use of virtualization and cloud computing services in BES operations; and (ii) whether CIP Rel. Standards impede the voluntary adoption of virtualization or cloud computing services; comment date Apr 27, 2020; reply comment date May 2, 2020
	28	5-Year ERO Performance Assessment Report (RR19-7)	Feb 21	NERC requests extension of time, to and including Aug 28, 2020, to submit its 180-day compliance filing
			Feb 28	FERC grants NERC's Feb 21 request

XI. Misc. - of Regional Interest

	29	203 Application: Verso/Pixelle (EC20-20)	Feb 12	Pixelle files notice that transaction was consummated on Feb 10, 2020
	29	PJM MOPR-Related Proceedings (EL18-178; EL16-49)	Feb 5	PJM IMM, Old Dominion Elec. Coop, Longroad Development file answers
			Feb 10	EEI moves for reconsideration
			Feb 18	PJM IMM files 2nd request for clarification; Nat'l Assoc. of State Energy Officials files letter with Commissioners; FERC issues tolling order affording it additional time to consider Requests for Rehearing
			Feb 25	Old Dominion Elec. Coop. answers EEI's motion for reconsideration ; MD PSC answers IMM's 2nd request for clarification
			Feb 28	NJ Rate Counsel appeals *Dec 2019 PJM MOPR Order* to DC Circuit and requests appeal be held in abeyance pending a decision in *Allegheny Defense Project v. FERC* (addressing FERC's tolling order process)
	32	NYISO MOPR Proceeding (IPNYY Complaint) (EL13-62)	Feb 20	FERC issue orders in four NYISO Capacity Market-related proceedings, including an order in this proceeding generally denying all requests for rehearing and/or clarification of the FERC's findings in the *Complaint Order*
*	34	IA / TSA Cancellations: Emera Maine/ReEnergy Fort Fairfield (ER20-1076/1077)	Feb 26	Emera Maine submits notices of cancellation of the IA and TSA with ReEnergy Fort Fairfield; comment date Mar 18
*	34	Northern Pass: TSA Cancellation / Cost Reimbursement (ER20-1030/1031)	Feb 18	Northern Pass files notice of TSA cancellation and for cost reimbursement; comment date Mar 10
*	34	Amended and Restated CONVEX Services Agreement: CL&P/MMWEC (ER20-996)	Feb 13	Eversource files amended and restated Agreement; comment date Mar 5
*	34	Facilities Use Agreement Cancellation: NGrid/Deepwater Block Island Wind (ER20-960)	Feb 6	New England Power files notice of cancellation
	34	Related Facilities Agreement Cancellations: Clear River Energy (ER20-729/730)	Feb 27	FERC accepts notice of cancellation, each eff. Nov 25, 2019

XII. Misc. - Administrative & Rulemaking Proceedings

	36	Credit Reforms in Organized Wholesale Markets (AD20-6)	Feb 10	ETI answers IRC comments FERC notices ETI request for tech. conf. and petition for rulemaking; comment date Mar 12, 2020

40	*Order 864*: Public Util. Trans. ADIT Rate Changes (RM19-5)	Feb 10	National Grid requests extension of time, to Jul 31, 2020, to submit its compliance filing
		Feb 18	FERC grants National Grid extension of time requested; Eversource requests similar extension to Jul 31 to submit its compliance filing
		Feb 20	UI, GMP request extension of time to Jul 31 for compliance filing
		Feb 24, 26	FERC grants Eversource, UI requests
		Feb 25	VETCO requests extension to Jul 31 for compliance filing
		Feb 26	NHT requests extension to Jul 31 for compliance filing
		Mar 2	FERC grants VETCO request
40	*Order 861/861-A*: Refinements to Horizontal Market Power Analysis Requirements (RM19-2)	Feb 20	FERC issues *Order 861-A* granting CAISO's requested clarification and denying PG&E's request for rehearing and alternative request for clarification of *Order 861*
41	*Order 860/860-A*: Data Collection for Analytics & Surveillance and MBR Purposes (RM16-17)	Feb 20	FERC issues order on reh'g and clarification (*Order 860-A*)
		Feb 27	FERC holds technical workshop

XIII. Natural Gas Proceedings

No Activity to Report

XIV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XV. Federal Courts

49	ISO-NE's Inventoried Energy Program (Chapter 2B) Proposal (19-1224) (consol.)***	Feb 11	RENEW moves to withdraw as a Petitioner
		Feb 24	Court grants RENEW's motion to withdraw
49	*Order 841* (19-1142, 19-1147) (consol.)	Feb 7	MA/DC/CA/MI/RI submit Amicus for Respondent; EDF/NRDC/Vote Solar and ESA/SEIA/AEE each submit joint intervenor for Respondent Brief; Engie Storage Services, Vivant Solar, Tesla and Sunrun submit join *amicus* for Respondent brief
		Feb 10	Engie et al. submit corrected *amicus* for Respondent brief
		Mar 2	AMP/APPA/EEI/NRECA and NARUC submit Petitioner Reply Briefs; TAPS submits intervenor for Petitioner Reply Brief
50	PG&E Bankruptcy (19-71615) (9th Cir.)	Feb 24	PG&E files unopposed motion to expedite case
50	First Energy Solutions Bankruptcy (18-3787) (6th Cir.)	Feb 26	FirstEnergy, the Official Committee of Unsecured Creditors, the Ad Hoc Noteholders Group, and Pass-Through Creditors answer and opposes the FERC's petition for an *en banc* rehearing of the Dec 12 decision

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: March 3, 2020

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

We have summarized below the status of key ongoing proceedings relating to NEPOOL matters before the Federal Energy Regulatory Commission ("FERC"),[1] state regulatory commissions, and the Federal Courts and legislatures through March 3, 2020. If you have questions, please contact us.

I. Complaints/Section 206 Proceedings

- **Liberty Complaint – Eversource/ISO-NE Failure to Correct Nov 2018 Meter Data Error/Load Assignment (EL20-27)**

On February 28, 2020, Liberty Power Holdings, LLC ("Liberty") filed a complaint against Eversource Energy Company ("Eversource") and ISO-NE related to a Meter Data Error for a November 2018 load in Metering Domain #685 ("Nov 2018 Load"). Liberty asserts (i) that Eversource incorrectly assigned the Nov 2018 Load to Liberty (as it did with a December 2018 load, which was subsequently corrected via Meter Data Error ("MDE") request #12/18/02MD); and (ii) ISO-NE has refused to correct the error for the Nov 2018 Load at Liberty's Request Billing Adjustment ("RBA") because the RBA was not received within three months of the date that the Invoice containing the Disputed Amount was issued. Liberty further asserts that the Tariff, in light of the facts and circumstances Liberty describes in the Complaint, provides a basis for the correction beyond the three-month period for RBA submissions.[2] The amount in dispute is $191,440 plus interest ("Disputed Amount"). Liberty seeks an order directing Eversource to refund the Disputed Amount to ISO-NE and directing ISO-NE to refund the Disputed Amount to Liberty. Responses to and comments on the Liberty Complaint are due on or before March 19, 2020. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **206 Investigation: ISO-NE Implementation of Order 1000 Exemptions for Immediate Need Reliability Projects (EL19-90)**

As previously reported, the FERC instituted a proceeding under FPA Section 206 on October 17, 2019 to consider whether ISO-NE may be implementing exemptions for immediate need reliability projects in a manner that is inconsistent with what the FERC directed pursuant to *Order 1000*, and therefore may be unjust and unreasonable, unduly preferential and discriminatory.[3] The FERC noted that, "based on its review of the annual informational filings and materials provided in stakeholder processes as posted on the Responding RTOs' websites, we are concerned that the Responding RTOs may be implementing the exemption in a

[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] *See* § 6.3.1 of the Tariff: A Disputing Party must submit its Requested Billing Adjustment within three months of the date that the Invoice or Remittance Advice containing the Disputed Amount was issued by the ISO unless the Disputing Party could not have reasonably known of the existence of the alleged error within such time.

[3] *ISO New England Inc. et al.*, 169 FERC ¶ 61,054 (Oct. 17, 2019) ("*October 17 Order*").

manner that is inconsistent with or more expansive than what the Commission directed."[4] The FERC directed ISO-NE to respond to questions in the *October 17 Order* to: (1) demonstrate how it is complying with the immediate need reliability project criteria; (2) demonstrate that the provisions in the Tariff, as implemented, containing certain exemptions to the requirements of *Order 1000* for immediate need reliability projects remain just and reasonable; and (3) consider additional conditions or restrictions on the use of the exemption for immediate need reliability projects to appropriately balance the need to promote competition for transmission development and avoid delays that could endanger reliability. ISO-NE's response was due and was filed on December 27, 2019. The FERC noted its expectation that it would issue a final order within six months of ISO-NE's response.[5] On October 18, the FERC issued a notice of the proceeding and of the refund effective date, which will be October 28, 2019 (the date the *October 17 Order* was published in the *Federal Register*).

Those interested in participating in this proceeding were required to intervene on or before November 27, 2019.[6] Interventions were filed by: NEPOOL, ISO-NE, Anbaric, Avangrid, Calpine, CT AG, CT, OCC, CT PURA, ENE, Eversource, IECG, LSPower, MA AG, MA DPU, MMWEC, MS PSC, NESCOE, NHEC, NextEra, NRDC, NRG, PSEG, AK PSC, ATC, Developers Advocating Transmission Advancements, East TX Cooperative, EEI, IECA, LA PSC, MD PSC, Mid-Kansas Electric Co., NJ PBU, NY TOs, NY Transco, Northeast TX Electric Cooperative, PA PUC, Public Citizen, Sunflower Electric Cooperative, and Xcel Energy Services. As noted above, ISO-NE submitted its responses on December 27, 2019.

Comments on ISO-NE's response are due on or before January 27, 2020 and were filed by: NEPOOL, Avangrid, Eversource, LSPower, MMEWC, National Grid, NESCOE, CT PURA, State Agencies,[7] Developers Advocating Transmission Advancements, and EEI. Reply comments were submitted by ISO-NE, Eversource and Avangrid and National Grid. On February 21, State Agencies answered National Grid's reply comments.

As noted above, a FERC order in this proceeding is expected by the end of June 2020. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Energy Security Improvements (Chapter 3) (EL18-182)**

As previously reported, the July 2, 2018 *Mystic Waiver Order*[8] (reported on in more detail in ER18-1509 in Section III below) in part instituted this Section 206 proceeding in light of the FERC's preliminarily finding that the ISO-NE Tariff may be unjust and unreasonable in that it fails to address specific regional fuel security concerns identified in the record in ER18-1509 that could result in reliability violations as soon as 2022. Accordingly, the *Mystic Waiver Order* directed ISO-NE, in part, to submit permanent Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns (the "Chapter 3 Proposal"). Following an ISO-NE request for an extension of time to file its Chapter 3 Proposal, the FERC issued a notice granting an extension of time, to and including October 15, 2019, a month earlier than requested, for the filing of that Proposal. The deadline has since been further extended – to ***April 15, 2020***.[9] Markets Committee consideration of ISO-NE's Energy Security Improvements ("ESI") project is on-going, with action by the Markets Committee scheduled for March 28 and by the Participants Committee on April 2, 2020. If you have any questions concerning this proceeding, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

[4] *Id.* at P 7.

[5] *Id.* at P 23.

[6] The *October 17 Order* was published in the *Fed. Reg.* on Oct. 29, 2019 (Vol. 84, No. 208) pp. 57,726-57,727.

[7] "State Agencies" are: the CT and MA Attorneys General, CT DEEP, CT OCC, and MOPA.

[8] *ISO New England Inc.*, 164 FERC ¶ 61,003 (July 2, 2018), *reh'g requested* ("*Mystic Waiver Order*").

[9] Notice of Extension of Time, *ISO New England Inc.*, Docket No. EL18-182 (Aug. 30, 2019).

- **206 Proceeding: RNS/LNS Rates and Rate Protocols (EL16-19-002)**

As described below, the procedural schedule in this proceeding is now suspended until April 22, 2020 to "allow the active participants to continue to work together to finalize the details of a formal offer of settlement and promote the efficient use of resources by avoiding litigation." In the absence of a settlement filing, the TOs will next file a status report with the Presiding Judge and Settlement Judge on March 9, 2020.

2018 Settlement (Rejected). Concluding that the contested 2018 Joint Offer of Settlement (the "Settlement"),[10] filed to resolve all issues in the Section 206 proceeding instituted by the FERC on December 28, 2015,[11] lacked sufficient detailed information to enable it to apply any of the approaches available to it to approve a contested settlement,[12] the FERC rejected the Settlement and remanded this proceeding (EL16-19) to Chief Judge Cintron to resume hearing procedures.[13]

As previously reported, the Settlement was supported by ***NESCOE*** but opposed by Municipal PTF Owners[14] and FERC Trial Staff. The ***Municipal PTF Owners*** ("Munis") asserted that the Settlement would worsen, rather than improve, the issues of "lack of transparency, clarity and specificity that led the Commission [to] find the existing Attachment F formula unjust and unreasonable", discriminate against load directly connected to PTF and exempted by Section II.12(c) of the ISO-NE Tariff from paying costs associated with service across non-PTF facilities, contravened numerous settled rate principles without explanation or justification,[15] and would have imposed an unacceptable moratorium and burden on parties inclined to challenge Attachment F. ***FERC Trial Staff*** asserted that the Settlement, as filed, was not fair and reasonable nor in the public interest "because it would result in unreasonable rates and contains fundamental defects",[16] and opposed the Settlement terms which would

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[10] As previously reported, the Settling Parties filed the Settlement on Aug. 17, 2018, in ER18-2235. The Settlement proposed changes to Section II.25, Schedules 8 and 9, Attachment F (including the addition of Interim Formula Rate Protocols ("Interim Protocols")), and the Schedule 21s to the ISO-NE OATT. Had they been approved, the changes to Attachment F would have become effective mid-June, 2019, with the remaining changes to be effective January 1, 2020. The Interim Protocols, as well as the changes to Section II.25 and Schedules 8 and 9, were supported by the Participants Committee at its July 24, 2018 meeting.

[11] *ISO New England Inc. Participating Transmission Owners Admin. Comm.*, 153 FERC ¶ 61,343 (Dec. 28, 2015), *reh'g denied,* 154 FERC ¶ 61,230 (Mar. 22, 2016) ("*RNS/LNS Rates and Rate Protocols Order*"). The *RNS/LNS Rates and Rate Protocols Order* found the ISO-NE Tariff 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"). 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". The FERC encouraged the parties to make every effort to settle this matter before hearing procedures are commenced. The FERC-established refund date is January 4, 2016.

[12] The FERC outlined in a seminal case the following four alternative approaches for approving contested settlements: (1) where the FERC can render a binding merits decision on each contested issue, (2) where the FERC can approve the settlement based on a finding that the overall settlement *as a package* is just and reasonable, (3) where the FERC can determine that the benefits of the settlement outweigh the nature of the objections and the interests of the contesting party are too attenuated, and (4) where the FERC can approve the settlement as uncontested for the consenting parties, and can sever the contesting parties to allow them to litigate the issues raised. *See Trailblazer Pipeline Co.*, 85 FERC ¶ 61,345, at 62,342-44 (1998).

[13] *ISO New England Inc. Participating Transmission Owners Admin. Comm., et al.*, 167 FERC ¶ 61,164 (May 22, 2019) ("*RNS Rate/Rate Protocol Settlement Order*").

[14] "Municipal PTF Owners" are: Braintree, Chicopee, Middleborough, Norwood, Reading, Taunton, and Wallingford.

[15] The elements of the Settlement that Municipal PTF Owners assert contravene settled rate principles include: provision for a fixed accrual for Post-Employment Benefits Other than Pension ("PBOPs"); continued TO use of net proceeds of debt, rather than gross proceeds of debt, in establishing capital structures under their proposed revenue requirement formula; inappropriate allocation of rental revenues from secondary uses of transmission facilities; the addition of miscellaneous intangible plant (Account 303), and depreciation and amortization of intangibles, to rate base; and the creation of a Regulatory Asset for an unspecified Massachusetts state tax rate change (without explanation).

[16] Included in the "fundamental defects" of the Settlement identified by FERC Trial Staff are that it: (1) enables the TOs to conduct extra-formulaic, ad hoc ratemaking for all externally-sourced inputs every year; (2) enables certain PTOs to over-recover certain plant costs; (3) enables certain PTOs to recover greater than 50% of Construction Work in Progress ("CWIP") in rate base (4) violates prior FERC orders

bind non-settling parties to the terms of the Settlement and establish a standard of review for changes to the Settlement. FERC Trial Staff suggested that these defects could be corrected in a comprehensive compliance filing. ***Reply comments*** were submitted by NEPOOL, NESCOE and the MA AG. In its limited comments, ***NEPOOL*** noted that it supported the Interim Protocols and that it had no objection to the Settlement. ***NESCOE*** reiterated its support for the Settlement in its reply comments, urging the FERC to reject any arguments that consumer-interested parties "were not familiar with the issues relating to the Settlement or that they reached a settlement for any reason other than their view that it is in the best interests of consumers."[17] ***MA AG*** urged the FERC to approve the Settlement as submitted, despite the objections of FERC Trial Staff and Municipal PTF Owners, because it complies with the *RNS/LNS Rates and Rate Protocols Order* and represents a carefully negotiated resolution to numerous complex ratemaking and transparency issues.[18]

Hearings. On May 23, 2019, Chief Judge Cintron designated Judge David H. Coffman as the Presiding Judge for the purpose of hearings and issuance of an initial decision within Track III procedural time standards.[19] A prehearing conference was held on June 6, 2019. Following that conference, orders establishing a procedural schedule and adopting rules of conduct for the hearing were issued. That schedule has since been extended three times by a total of 85 days and is currently suspended (*see* immediately below).

Procedural Schedule Suspended Until April 22, 2020. On January 22, 2020, the TOs requested the suspension of the procedural schedule for an additional 90 days. Chief Judge Cintron issued an order on January 24, 2020 holding the proceedings in abeyance until April 22, 2020. The TOs must file a status report with the Chief Judge and Presiding Judge by March 9, 2020. As previously noted, if the current suspension period concludes without a settlement filed, the Chief Judge and Presiding Judge will take action to re-establish a procedural schedule absent good cause provided for a further suspension.

If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Base ROE Complaints I-IV: (EL11-66, EL13-33; EL14-86; EL16-64)**

There are four proceedings pending before the FERC in which consumer representatives seek to reduce the TOs' return on equity ("Base ROE") for regional transmission service.

- ***Base ROE Complaint I (EL11-66)***. In the first Base ROE Complaint proceeding, the FERC concluded that the TOs' ROE had become unjust and unreasonable,[20] set the TOs' Base ROE at 10.57% (reduced from 11.14%), capped the TOs' total ROE (Base ROE *plus* transmission incentive adders) at 11.74%, and required implementation effective as of October 16, 2014 (the date of *Opinion 531-A*).[21] However, the FERC's orders were challenged, and in *Emera Maine,*[22] the DC Circuit Court

about which customer groups can be made to pay incentive returns; (5) fails to appropriately calculate federal and state income taxes and, in particular, fails to account for excess Accumulated Deferred Income Taxes ("ADIT") created by the Tax Cuts and Jobs Act; (6) does not contain a fixed and stated ROE; and (7) does not contain a fixed and stated PBOPs expense.

[17] Reply Comments of NESCOE, Docket Nos. ER18-2235 and EL16-19, at p. 2 (filed Sep. 28, 2018).

[18] Reply Comments of the Mass. Att'y General in Support of Settlement, Docket Nos. EL16-19 and ER18-2235 (filed Sep. 28, 2018).

[19] Track III time standards require a hearing be convened within 42 weeks and an initial decision issued within 63 weeks.

[20] The TOs' 11.14% pre-existing Base ROE was established in *Opinion 489*. *Bangor Hydro-Elec. Co.*, Opinion No. 489, 117 FERC ¶ 61,129 (2006), *order on reh'g*, 122 FERC ¶ 61,265 (2008), *order granting clarific.*, 124 FERC ¶ 61,136 (2008), *aff'd sub nom.*, Conn. Dep't of Pub. Util. Control v. FERC, 593 F.3d 30 (D.C. Cir. 2010) ("*Opinion 489*")).

[21] *Coakley Mass. Att'y Gen. v. Bangor Hydro-Elec. Co.*, 147 FERC ¶ 61,234 (2014) ("*Opinion 531*"), *order on paper hearing*, 149 FERC ¶ 61,032 (2014) ("*Opinion 531-A*"), *order on reh'g*, 150 FERC ¶ 61,165 (2015) ("*Opinion 531-B*").

[22] *Emera Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017) ("*Emera Maine*"). *Emera Maine* vacated the FERC's prior orders in the Base ROE Complaint I proceeding, and remanded the case for further proceedings consistent with its order. The Court agreed with both the TOs (that the FERC did not meet the Section 206 obligation to first find the existing rate unlawful before setting the new rate) and "Customers"

vacated the FERC's prior orders, and remanded the case for further proceedings consistent with its order. The FERC's determinations in *Opinion 531* are thus no longer precedential, though the FERC remains free to re-adopt those determinations on remand as long as it provides a reasoned basis for doing so.

- ***Base ROE Complaints II & III (EL13-33 and EL14-86) (consolidated)***. The second (EL13-33)[23] and third (EL14-86)[24] ROE complaint proceedings were consolidated for purposes of hearing and decision, though the parties were permitted to litigate a separate ROE for each refund period. After hearings were completed, ALJ Sterner issued a 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 *Initial Decision* also lowered the ROE ceilings. Parties to these proceedings filed briefs on exception to the FERC, which has not yet issued an opinion on the ALJ's *Initial Decision*.

- ***Base ROE Complaint IV (EL16-64)***. The fourth and final ROE proceeding[26] also went to hearing before an ALJ, Judge Glazer, who issued his initial decision on March 27, 2017.[27] The *Base ROE IV Initial Decision* concluded that the currently-filed base ROE of 10.57%, which may reach a maximum ROE of 11.74% with incentive adders, was ***not*** unjust and unreasonable for the Complaint IV period, and hence was not unlawful under section 206 of the FPA.[28] Parties in this proceeding filed briefs on exception to the FERC, which has not yet issued an opinion on the *Base ROE IV Initial Decision*.

October 16, 2018 Order Proposing Methodology for Addressing ROE Issues Remanded in Emera Maine and Directing Briefs. On October 16, 2018, the FERC, addressing the issues that were remanded in *Emera Maine,* proposed a new methodology for determining whether an existing ROE remains just and reasonable.[29] The FERC indicated its intention that the methodology be its policy going forward, including in

(that the 10.57% ROE was not based on reasoned decision-making, and was a departure from past precedent of setting the ROE at the midpoint of the zone of reasonableness).

[23] 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% ROE, and seeks a reduction of the Base ROE to 8.7%.

[24] 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.

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

[26] The 4th ROE Complaint asked the FERC to reduce the TOs' current 10.57% return on equity ("Base ROE") to 8.93% and to determine that the upper end of the zone of reasonableness (which sets the incentives cap) is no higher than 11.24%. The FERC established hearing and settlement judge procedures (and set a refund effective date of April 29, 2016) for the 4th ROE Complaint on September 20, 2016. Settlement procedures did not lead to a settlement, were terminated, and hearings were held subsequently held December 11-15, 2017. The September 26, 2016 order was challenged on rehearing, but rehearing of that order was denied on January 16, 2018. *Belmont Mun. Light Dept. v. Central Me. Power Co.*, 156 FERC ¶ 61,198 (Sep. 20, 2016) ("*Base ROE Complaint IV Order*"), *reh'g denied*, 162 FERC ¶ 61,035 (Jan. 18, 2018) (together, the "*Base ROE Complaint IV Orders"*). *The Base ROE Complaint IV Orders*, as described in Section XV below, have been appealed to, and are pending before, the DC Circuit.

[27] *Belmont Mun. Light Dept. v. Central Me. Power Co.*, 162 FERC ¶ 63,026 (Mar. 27, 2018) ("*Base ROE Complaint IV Initial Decision*").

[28] *Id.* at P 2.; Finding of Fact (B).

[29] *Coakley v. Bangor Hydro-Elec. Co.*, 165 FERC ¶ 61,030 (Oct. 18, 2018) ("*Order Directing Briefs"* or "*Coakley*").

the four currently pending New England proceedings. The FERC established a paper hearing on how its proposed methodology should apply to the four pending ROE proceedings.[30]

At highest level, the new methodology will determine whether (1) an existing ROE is unjust and unreasonable under the first prong of FPA section 206 and (2) if so, what the replacement ROE should be under the second prong of FPA section 206. In determining whether an existing ROE is unjust and under the first prong of Section 206, the FERC stated that it will determine a "composite" zone of reasonableness based on the results of three models: the Discounted Cash Flow ("DCF"), Capital Asset Pricing Model ("CAPM"), and Expected Earnings models. Within that composite zone, a smaller, "presumptively reasonable" zone will be established. Absent additional evidence to the contrary, if the utility's existing ROE falls within the presumptively reasonable zone, it is not unjust and unreasonable. Changes in capital market conditions since the existing ROE was established may be considered in assessing whether the ROE is unjust and unreasonable.

If the FERC finds an existing ROE unjust and unreasonable, it will then determine the new just and reasonable ROE using an averaging process. For a diverse group of average risk utilities, FERC will average four values: the midpoints of the DCF, CAPM and Expected Earnings models, and the results of the Risk Premium model. For a single utility of average risk, the FERC will average the medians rather than the midpoints. The FERC said that it would continue to use the same proxy group criteria it established in *Opinion 531* to run the ROE models, but it made a significant change to the manner in which it will apply the high-end outlier test.

The FERC provided preliminary analysis of how it would apply the proposed methodology in the Base ROE I Complaint, suggesting that it would affirm its holding that an 11.14% Base ROE is unjust and unreasonable. The FERC suggested that it would adopt a 10.41% Base ROE and cap any preexisting incentive-based total ROE at 13.08%.[31] The new ROE would be effective as of the date of *Opinion 531-A*, or October 16, 2014. Accordingly, the issue to be addressed in the Base ROE Complaint II proceeding is whether the ROE established on remand in the first complaint proceeding remained just and reasonable based on financial data for the six-month period September 2013 through February 2014 addressed by the evidence presented by the participants in the second proceeding. Similarly, briefing in the third and fourth complaints will have to address whether whatever ROE is in effect as a result of the immediately preceding complaint proceeding continues to be just and reasonable.

The FERC directed participants in the four proceedings to submit briefs regarding the proposed approaches to the FPA section 206 inquiry and how to apply them to the complaints (separate briefs for each proceeding). Additional financial data or evidence concerning economic conditions in any proceeding must relate to periods before the conclusion of the hearings in the relevant complaint proceeding. Following a FERC notice granting a request by the TOs and Customers[32] for an extension of time to submit briefs, the latest date for filing initial and reply briefs was extended to January 11 and March 8, 2019, respectively. On January 11, initial briefs were filed by EMCOS, Complainant-Aligned Parties, TOs, EEI, Louisiana PSC, Southern California Edison, and AEP. As part of their initial briefs, each of the Louisiana PSC, SEC and AEP also moved to intervene out-of-time. Those interventions were opposed by the TOs on January 24. The Louisiana PSC answered the TOs' January 24 motion on February 12. Reply briefs were due March 8, 2019 and were submitted by the TOs, Complainant-Aligned Parties, EMCOS, FERC Trial Staff.

[30] *Id.* at 19.

[31] *Id.* at P 59.

[32] For purposes of the motion seeking clarification, "Customers" are CT PURA, MA AG and EMCOS.

TOs Request to Re-Open Record and file Supplemental Paper Hearing Brief. On December 26, 2019, the TOs filed a Supplemental Brief that addresses the consequences of the November 21 *MISO ROE Order*[33] and requested that the FERC re-open the record to permit that additional testimony on the impacts of the *MISO ROE Order*'s changes. On January 21, EMCOS and CAPs opposed the TOs' request and brief.

These matters are pending before the FERC. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Joe Fagan (202-218-3901; jfagan@daypitney.com).

II.Rate, ICR, FCA, Cost Recovery Filings

- **FCA14 Results Filing (ER20-1025)**

On February 18, ISO-NE filed the results of the fourteenth FCA ("FCA14") held February 3, 2020. ISO-NE reported the following highlights:

- FCA14 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). NNE was modeled as an export-constrained Capacity Zone. The Maine Load Zone was modeled as a separate nested export-constrained Capacity Zone within NNE.
- FCA14 commenced with a starting price of $13.099/kW-mo. and concluded for all Capacity Zones after five rounds.
- All Resources will be paid the same Capacity Clearing Price -- $2.001/kW-mo. – including imports at the NY AC Ties (510.7 MW), Highgate (64 MW), Phase I/II HQ Excess external interface (412 MW), and New Brunswick (72 MW).
- There were no active demand bids for the substitution auction and, accordingly, the substitution auction was not conducted.
- 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.

ISO-NE asked the FERC to accept the FCA14 rates and results, effective June 17, 2020. Comments on this filing are due on or before April 3, 2020. Thus far, Avangrid, Calpine, Dominion, Exelon, National Grid, NESCOE, and Public Citizen have filed doc-less interventions. 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).

- **FCA14 Qualification Informational Filing (ER20-308)**

On February 21, 2020, a little more than two weeks after FCA14 was run,[34] the FERC issued an order accepting ISO-NE's November 5, 2019 informational filing (the "FCA14 Informational Filing") for qualification in

[33] *Ass'n of Buss. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569, 169 FERC ¶ 61,129 (2019) ("*MISO ROE Order*").

[34] FCA14 was run on Feb. 3, 2020 without an order on this filing. Pursuant to Section III.13.8.1(d) of the Tariff, when the FERC did not issue an order within 75 days after the date of the filing (i.e. Jan. 19, 2020) directing otherwise, ISO-NE was authorized to use, and did use, the determinations contained in the Informational Filing in conducting FCA14.

FCA14.[35] In a 2-1 decision, the FERC accepted the IMM's Offer Floor Prices ("OFPs") and the IMM's mitigation of certain energy storage resources ("ESRs"), a category of resources which were the center of contention in this proceeding. Although the FERC found that the IMM acted consistently with the Tariff, including with respect to ESRs, it acknowledged that the IMM has yet to develop, through the stakeholder process and a filing with the FERC, an Offer Review Trigger Price ("ORTP") model specific to ESRs, and encouraged that discussion take place.[36] Commissioner Glick concluded in his dissent that the ESRs should not have been subject to buyer-side market power mitigation, because they were not capacity buyers or shown to have market power,[37] and the better course of action would have been to "rely on energy storage market participants' own expertise and judgement about the revenue that their business model can earn in the market."[38]

As previously reported, comments and protests on the FCA14 Informational Filing were filed by: (i) ISO-NE's External Market Monitor ("EMM"), which identified methodological concerns with certain elements of the IMM's determinations for large-scale energy storage resources ("ESRs"), suggesting that, while it was appropriate for the IMM to adjust net revenues for Energy and Ancillary Services ("EAS") and mitigate the OFPs of such ESRs, the EAS revenue levels assumed by the IMM in mitigating the ESR OFPs were unreasonably low and should be revised for FCA14; (ii) RENEW Northeast, Inc. ("RENEW"), which supported the EMM's comments and called for the re-calculation of ESR OFPs and re-issuance of Qualification Determination Notifications ("QDNs") to all affected ESR developers; and (iii) Able Grid Infrastructure Holding, LLC ("Able Grid"), which challenged the IMM-determined OFPs for its projects and asked that hose projects be permitted to participate in FCA14 with its requested OFP, rather than the one determined by the IMM. The ***IMM*** answered the comments and protests, asserting that its determinations were "a just and reasonable exercise of buyer-side mitigation in the face of unreasonable, unsupported and/or overly optimistic assumptions underlying requested OCPs by Project Sponsors for ESRs, which otherwise could artificially suppress capacity prices if unchecked". Although the IMM agreed with RENEW "that there is no perfect revenue model" and "favors more open discussion with market participants in anticipation of future auctions", it asserted that its "estimates are reasonable based on a revenue model that was developed with the benefit of reviewing many submitted models , review for quality assurance, and applied in the mitigation process within the qualification period provided." ***Able Grid*** answered the IMM's Answer on December 20.

In accepting the filing, the FERC found the IMM's method for the calculation of OFPs reasonable because "its assumptions [were] based on a careful study of submitted models and associated assumptions, conducted in the proper time frame." The FERC made no finding as to whether the EMM's method was more or less accurate than the IMM's (though even if it had found the EMM's method more accurate, that would not have been sufficient to change the outcome). In addition, the FERC found that the IMM acted appropriately and reasonably when mitigating Able Grid projects' OFPs.[39] Since the *FCA14 Info Filing Order*, on February 25, 2020, the MA DPU filed a doc-less motion to intervene (out-of-time). If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Mystic 8/9 Cost of Service Agreement (ER18-1639)**

As previously reported, on December 20, 2018, in a 2-1 decision (Commissioner Glick dissenting; Commissioner McIntyre not voting; Commissioner McNamee not participating), which followed an evidentiary proceeding and two rounds of briefing, the FERC conditionally accepted the Cost-of-Service Agreement ("COS

[35] *ISO New England Inc.*, 170 FERC ¶ 61,132 (Feb. 21, 2020) ("*FCA14 Info Filing Order*").

[36] *Id.* at P 50.

[37] *Id.*, Glick, Comm'r, dissenting at P 1.

[38] *Id.* at P 3.

[39] *FCA14 Info Filing Order* at PP 49-54.

Agreement")[40] among Constellation Mystic Power ("Mystic"), Exelon Generation Company ("ExGen") and ISO-NE.[41] The COS Agreement will provide compensation for the continued operation of the Mystic 8 & 9 units from June 1, 2022 through May 31, 2024. The *Mystic Order* directed Mystic to submit a compliance filing (intended to modify aspects of the COS Agreement that FERC rejected or directed be changed) on or before February 18, 2019, and established a paper hearing to ascertain whether and how the ROE methodology that FERC proposed in *Coakley* should apply in the case. Initial briefs on the ROE issue are due on or before April 19, 2019, and reply briefs are due on or before July 18, 2019.[42] Requests for clarification and/or rehearing of the *Mystic Order* were filed by Constellation Mystic Power, CT Parties, EDF, ENECOS, MA AG, NESCOE, NextEra, and Repsol. On February 6, Constellation answered the other parties' requests for rehearing. CT Parties answered Constellation's request for rehearing on February 8. On February 14, NESCOE answered Constellation's February 6 answer. On February 15, 2019, the FERC issued a tolling order affording it additional time to consider the requests for clarification and/or rehearing, which remain pending.

Mystic's Compliance Filing. On March 1, 2019, Mystic submitted its required compliance filing. The compliance filing included the following modifications:

- Modification to Section 2.2 (Termination) which provides ISO-NE will be required to seek FERC authorization to extend the term of the COS Agreement beyond May 31, 2024; deletion of Section 2.2.1 in its entirety;
- Inclusion of a clawback provision;
- Modification to Section 4.4 related to settlement of over- and underperformance credits;
- A clarification that fuel opportunity costs will not be included as part of the Stipulated Variable Costs used to calculate the revenue credits;
- Modifications to information access provisions (§ 6.2) both to allow ISO-NE full access to information and to support verification of third-party sales;
- Modifications to Schedule 3 supporting multiple compensation-related directives (e.g. cost of capital/cost of service, fuel supply charge, settlement of over- and under-performance credits);
- Schedule 3A modifications related to Mystic's true-up process; and
- Non-substantive conforming changes.

In addition, Mystic's compliance filing included for informational purposes changes to the Fuel Supply and Terminal Services Agreements. Comments on Mystic's compliance filing were due on or before March 22, 2019. Protests and comments were filed by CT Parties, ENECOS, MA AG, National Grid, Public Systems (MMWEC/NHEC), and NESCOE. Mystic answered the March 22 protests on April 8. Also, on March 22, Concord, Reading and Wellesley moved for the release from Protective Order a documentary response regarding the net book value of Mystic 8 and 9 from the 2006 Mystic 8/9 RMR proceeding (ER06-427). Mystic's compliance filing and the pleadings related thereto remain pending before the FERC.

ROE Paper Hearing. The *Mystic Order* established a paper hearing to determine the just and reasonable ROE to be used in setting charges under Mystic's COS Agreement. On April 19, Mystic, Connecticut Parties, ENECOS, MA AG, and FERC Trial Staff filed initial briefs. On July 18, 2019, Constellation Mystic Power, CT Parties,

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[40] The COS Agreement, submitted on May 16, 2018, is between Mystic, Exelon Generation Company, LLC ("ExGen") and ISO-NE. The COS Agreement is to provide cost-of-service compensation to Mystic for continued operation of Mystic 8 & 9, which ISO-NE has requested be retained to ensure fuel security for the New England region, for the period of June 1, 2022 to May 31, 2024. The COS Agreement provides for recovery of Mystic's fixed and variable costs of operating Mystic 8 & 9 over the 2-year term of the Agreement, which is based on the pro forma cost-of-service agreement contained in Appendix I to Market Rule 1, modified and updated to address Mystic's unique circumstances, including the value placed on continued sourcing of fuel from the Distrigas liquefied natural gas ("LNG") facility, and on the continued provision of surplus LNG from Distrigas to third parties.

[41] *Constellation Mystic Power, LLC*, 165 FERC ¶ 61,267 (Dec. 20, 2018) ("*Mystic Order*").

[42] *Id.* at PP 31-34.

ENECOS, MA AG, National Grid, FERC Trial Staff filed reply briefs. The ROE Paper Hearing is now pending before the FERC.

July Mystic COS Agreement Order. Rehearing remains pending of the FERC's July order. As previously reported, the FERC issued an initial order regarding the COS Agreement, accepting the COS Agreement but suspending its effectiveness and setting it for accelerated hearings and settlement discussions.[43] The *Mystic COS Agreement Order* was approved by a 3-2 vote, with dissents by Commissioners Powelson and Glick. Challenges to the *July Mystic COS Agreement Order* were filed by NESCOE, ENECOS, MA AG, and the NH PUC. Constellation answered the NESCOE request for reconsideration on August 21. On September 10, 2018, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending.

If you have questions on this proceeding, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com); or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **MPD OATT 2019 Annual Informational Filing (ER15-1429-000)**

On May 1, 2019, as corrected by its filing on May 16, 2019, Emera Maine submitted its 2019 annual informational filing setting forth, for the June 1, 2019 to May 31, 2020 rate year, the charges for transmission service under the MPD OATT ("MPD Charges") and an updated transmission real power loss factor. Although this filing and the May 16 correction were not noticed for public comment, it will nevertheless be subject to the process established in the "Protocols for Implementing and Reviewing Charges Established by the MPD OATT Attachment J Rate Formulas" and may result in further proceedings (*see, e.g.*, ER15-1429-010 below). On June 11, Maine Customer Group ("MCG") moved to strike a portion of Emera Maine's May 1 filing. Specifically, MCG moved to strike the trueup to actuals portion of Emera's Annual Update filing to the extent that true-up proposes a change in the formula rate from a direct assignment of Maine Public District ("MPD") post- retirement benefits other than pensions ("PBOPs") to an allocation of company-wide PBOPs (which MCG argued would be a retroactive change to Emera Maine's formula rate, otherwise required to effect only prospectively). On June 26, Emera Maine answered MCG's June 11 motion to strike. This matter remains pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **MPD OATT 2018 Annual Informational Filing (ER15-1429-010)**

As previously reported, the FERC granted, in part, on April 30, 2019, the formal challenge filed on December 31, 2018 by the Maine Customer Group[44] (the "2018 Challenge") to Emera Maine's May 15, 2018 annual informational filing[45]and set the remaining issues for hearing and settlement judge procedures.[46] As previously reported, the 2018 Challenge sought certain cost reductions/ exclusions[47] to be effective June 1, 2018 following unsuccessful efforts to obtain the relief sought directly from Emera Maine MPD through

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[43] *Constellation Mystic Power,* 164 FERC ¶ 61,022 (July 13, 2018) ("*July Mystic COS Agreement Order*"), *reh'g requested*.

[44] For purposes of this proceeding, "Maine Customer Group" or "MCG" is the MPUC, MOPA, Houlton Water Co., and Van Buren Light & Power District, and Eastern Maine Electric Cooperative.

[45] The May 15 filing, submitted in accordance with the Protocols for Implementing and Reviewing Charges Established by the MPD OATT Attachment J Rate Formulas ("Protocols"), set forth for the June 1, 2018 to May 31, 2019 rate year, the charges for transmission service under the MPD OATT ("MPD Charges"). *See* May 31, 2018 Litigation Report.

[46] *Emera Maine*, 167 FERC ¶ 61,090 (Apr. 30, 2019) ("*2018 Challenge Order*").

[47] The formal challenge sought (i) exclusion of certain regulatory expenses allocated or directly assigned to the MPD transmission customers; (ii) exclusion of costs that would otherwise constitute a double-recovery for amortization of losses incurred as a result of a merger; (iii) correction of MPD-acknowledged errors in its Annual Update Filing; (iv) exclusion of certain costs for land associated with a project not in service; (v) exclusion from transmission rates certain costs for distribution equipment; (vi) exclude of costs improperly attributed to line 6901; and (vii) a flowback of excess ADIT resulting from the corporate tax reduction, and a requirement for Emera MPD to include a worksheet in its tariff to track excess/deficient ADIT.

informal resolution procedures in accordance with the Protocols. In granting in part the 2018 Challenge, the FERC found that Emera Maine's formula rate should be corrected for the current rate year and Emera Maine must submit a compliance filing on or before May 30 that revises its 2018-2019 formula rate charges to correct certain acknowledged errors, exclusion of certain costs for land associated with a project not in service, the exclusion of certain costs for distribution equipment from transmission rates, and the flowback of excess accumulated deferred income tax ("ADIT"). As to the remaining issues, addressing Administrative and General ("A&G") expenses, merger-related prior losses, exclusion of costs attributed to Line 6901, and exclusion of land rights cost, the FERC found that the 2018 Annual Update raises issues of material fact that cannot be resolved based on the record and set those issues for hearing and settlement judge procedures. Hearings will be held in abeyance to provide time for settlement judge procedures.

Settlement Judge Procedures. Chief Judge Cintron designated John P. Dring as the Settlement Judge for these proceedings. Judge Dring has held two settlement conferences, one on July 18, 2019 and the second on September 11, 2019. A third settlement conference occurred on October 7 and the parties reached an agreement in principle at that time. On January 23, 2020, Judge Dring issued a report advising that the "participants currently are in the process of finalizing an offer of settlement" and recommending the continuation of settlement judge procedures. There has been no published activity since that report.

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

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

Rehearing remains pending of the FERC's October 6, 2017 order rejecting the TOs' June 5, 2017 filing in this proceeding.[48] As previously reported, the June 5 filing was designed to reinstate TOs' transmission rates to those in place prior to the FERC's orders later vacated by the DC Circuit's *Emera Maine*[49] decision. In its *Order Rejecting Filing*, the FERC required the TOs to continue collecting their ROEs currently on file, subject to a future FERC order.[50] The FERC explained that it will "order such refunds or surcharges as necessary to replace the rates set in the now-vacated order with the rates that the Commission ultimately determines to be just and reasonable in its order on remand" so as to "put the parties in the position that they would have been in but for [its] error." For the time being, so as not to "significantly complicate the process of putting into effect whatever ROEs the Commission establishes on remand" or create "unnecessary and detrimental variability in rates," the FERC has temporarily left in place the ROEs set in *Opinion 531-A*, pending an order on remand.[51] On November 6, the TOs requested rehearing of the *Order Rejecting Filing*. On December 4, 2017, the FERC issued a tolling order providing it additional time to consider the TOs' request for rehearing of the *Order Rejecting Filing*, which remains pending. If you have any questions concerning this matter, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

- **NCPC Audit Eligibility Clean Up (ER20-1094)**

On February 27, ISO-NE and NEPOOL filed changes to the Net Commitment Period Compensation ("NCPC") eligibility rules, adding Real-Time Dispatch Lost Opportunity Cost NCPC Credits and Rapid Response Pricing Opportunity Cost NCPC Credits. A May 1, 2020 effective date was requested. The changes were supported by the Participants Committee at the February 5, 2020 meeting (Consent Agenda Item #6). Comments on this

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

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

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

[51] *Id.* at P 36.

filing are due on or before March 19, 2020. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **ISO-NE eTariff Versioning True-Up (ER20-763)**

On February 25, the FERC accepted revisions that remove from the version of Tariff § III.13.2 (accepted with the PRD Clean-Up Changes (ER20-140)) those changes submitted with still-pending Fuel Security Retention Limit Revisions (*see* ER20-89 below).[52] The revisions that back out those pending changes are effective as of December 18, 2019, as requested. Unless the February 25 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **ISO-NE Waiver Request: FCA15 De-List Bids Submission Deadline (ER20-759)**

On January 8, 2020, ISO-NE requested waiver of § III.13.1.10(b) of the Tariff to allow Market Participants to adjust or withdraw their FCA15 Retirement De-List Bids or Permanent De-List Bids should ISO-NE make a subsequent non-clerical change to certain ISO Tariff revisions after the current March 13, 2020 deadline for De-List Bids (which will not change) or in the lead-up to (or as part of) the Participants Committee vote on the Energy Security Improvements ("ESI")-related Market Rules (scheduled for April 2, 2020). Under such circumstances, Participants that have submitted an FCA15 Retirement De-List Bid or Permanent De-List Bid would have the option to either (i) update its De-List Bid to reflect the impact of the changes to the ESI design or (ii) withdraw the De-List Bid altogether, and to exercise that option within a week (seven calendar days) following the Participants Committee vote. Comments on ISO-NE's waiver request were due on or before January 29; none were filed. Doc-less interventions were filed by NEPOOL, Dominion, Eversource, Exelon, National Grid, NESCOE, NRG, and Calpine (out-of-time). This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **Fuel Security Retention Sunset (ER20-645)**

On February 14, 2020, the ***FERC rejected*** in a 2-1 decision (Glick dissenting)[53] the changes jointly filed by ISO-NE and NEPOOL to sunset one year early the mechanism in the Forward Capacity Market ("FCM") to retain a resource for fuel security reasons ("Fuel Security Retention Sunset").[54] In rejecting the Sunset, the FERC found that the filing would have "prematurely terminate[d] the Fuel Security Reliability Retention Mechanism prior to ISO-NE submitting its Permanent Market Solution … for review" and would have prevented the FERC from "ensur[ing] that the Permanent Market Solution will be implemented on or before the sunset date proposed".[55] Unless the *Order Rejecting Fuel Security Retention Sunset* is challenged, with any challenges due on or before March 16, 2020, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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52 *ISO New England Inc.*, Docket No. ER20-763 (Feb. 25, 2020 (unpublished letter order).

53 *ISO New England Inc. and New England Power Pool Participants Comm.*, 170 FERC ¶ 61,099 (Feb. 14, 2020) ("*Order Rejecting Fuel Security Retention Sunset*").

54 As previously reported, the fuel security retention mechanism would have been sunsetted for the third and final year for which it was to be in place in light of the market solution to be filed in April 2020 and implemented by June 2024 ("Permanent Market Solution") and so that it could have been in effect for the start of the March 2020 FCA15 qualification period, when the fuel security retention review is scheduled to be performed. The Participants Committee unanimously supported the Fuel Security Retention Sunset at its December 6 meeting. Exelon protested the filing, stating that "there is simply no reason to shorten the life of the Fuel Security Provisions now when doing so would unnecessarily limit ISO-NE's options for addressing fuel security needs when it is not clear that market reforms will be in place in time for FCA15".

55 *Order Rejecting Fuel Security Retention Sunset* at P 17.

- **Waiver Request: FCA14 Qualification (CPower) (ER20-458)**

On February 5, the FERC denied the Waivers[56] requested by Enerwise Global Technologies, Inc. d/b/a/ CPower ("CPower") that would have allowed its seven residential and commercial, summer-only solar Distributed Generation On-Peak Demand Resources (the "Resources") to participate in FCA14.[57] In denying the request, the FERC found that Genbright failed to demonstrate that the waiver request was limited in scope.[58] FCA14 was run without the Resources participating. Unless the *Order Denying CPower Waivers* is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Waiver Request: FCA14 Qualification (Genbright II) (ER20-366)**

On February 3, 2020, the FERC denied Genbright's request for a waiver of the FCM qualification rules for 14 distributed energy resource projects (the "DER Projects") disqualified from FCA14 based on an ISO-NE finding that the DER Projects' interconnection requests should have been filed with ISO-NE in accordance with Schedule 23 of the OATT prior to the close of the FCA14 Show-of-Interest ("SOI") submission window.[59] As previously reported, Genbright challenged that finding and the equity of the outcome even if the finding were correct (given Eversource's failure to timely and accurately inform each Project of the correct jurisdictional status of the distribution feeder into which the Project would interconnect, as Eversource was required to do). In denying the request, the FERC found that Genbright failed to demonstrate that the waiver request was limited in scope.[60] Unless the February 3 order is challenged, with any challenges due on or before March 4, 2020, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Fuel Security Retention Limit Revision (ER20-89)**

On October 11, 2019, ISO-NE and NEPOOL jointly filed a revision to Market Rule 1 Section III.13.2.5.2.5A(j) to make clear that a resource retained for fuel security reasons will not be retained for a longer period for some other reason beyond the two-year fuel-security retention period ("Fuel Security Retention Limit Revision"). The Fuel Security Retention Limit Revision was supported by the Participants Committee at its October 4 meeting (Consent Agenda Item #1). Comments on this filing were due on or before November 1, 2019. ***Exelon protested*** the Revision, asserting that the Revision (i) unduly discriminates against fuel security resources in general, and Mystic specifically; (ii) is premature and unreasonably ignores the likelihood that neither the transmission upgrades nor the comprehensive fuel security market mechanism will be completed or implemented prior to the proposed sunset; and (ii) has not been shown to be just and reasonable. ***NEPGA supported*** the Revision, asking that it be accepted without modification. On November 18, both NEPOOL and ISO-NE answered Exelon's protest. Exelon answered the NEPOOL and ISO-NE answers on November 27. Doc-less interventions were filed by

[56] CPower requested waivers necessary to participate in FCA14 and the substitution auction (i) with only summer-only Qualified Capacity, which it was unable to do because it could not use composite offers for FCA14 participation due to the interplay between RTR proration and substitution auction rules ("Primary Waiver Request"); or alternatively, (ii) withdraw its RTR election and allow the Resources to form a composite offer (if winter capacity remains available) ("Alternative Waiver Request", and together with the Primary Waiver Request, the "Waivers").

[57] *Enerwise Global Technologies, Inc.*, 170 FERC ¶ 61,084 (Feb. 5, 2020) ("*Order Denying CPower Waivers*").

[58] *Id.* at PP 19-21 (finding that CPower did not demonstrate why ISO-NE should treat its Resources differently from other Demand Capacity Resources seeking to participate in FCA14 or other resources that ISO-NE prorated under the FCA14 RTR exemption).

[59] *Genbright LLC*, 170 FERC ¶ 61,079 (Feb. 3, 2020).

[60] Id. at PP 29-30 (distinguishing the Genbright request from others previously granted because it sought the waiver of several Tariff provisions, including some that might have allowed the DER Projects to avoid system impact study and other aspects of ISO-NE's "complex interconnection study process").

Brookfield, Calpine, Dominion, Eversource, Exelon, LS Power Companies, MMWEC, National Grid, NESCOE, NRG, Verso, and Vistra.[61]

Deficiency Letter. On December 6, 2019, the FERC issued a deficiency letter, directing ISO-NE to provide the following additional information: (i) how the Fuel Security Retention Limit Revisions impacts the planning and consideration of outcomes of the Boston Area Needs Assessment and to describe, absent the Revisions, how resources retained for fuel security reasons currently impact the planning of the Boston Area Needs Assessment; and (ii) to explain the actions that ISO-NE would take to mitigate any violations of local reliability criteria if a competitively developed transmission solution cannot be developed or made available in time to alleviate the reliability need that could otherwise be resolved by a resource previously retained for fuel security. The additional information was due and was filed by ISO-NE on January 6, 2020. The submission of the additional information re-set the deadline for FERC action (which is now required on or before March 6, 2020).

Comments on the deficiency letter responses were due January 27, 2020. ***Exelon*** filed the lone set of comments, asserting that ISO-NE's deficiency letter response "does nothing to ameliorate the concerns raised by Exelon and fails to provide additional support to demonstrate that the proposal is just and reasonable and not unduly discriminatory" and renewing its request that the FERC "reject the Fuel Security Retention [Limit] Revision in its entirety."

This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **Waiver Request: Vineyard Wind FCA13 Participation (ER19-570)**

Still pending is Vineyard Wind's December 14, 2018 petition for a waiver of the ISO-NE Tariff provisions necessary to allow Vineyard Wind to participate in FCA13 as an RTR. As previously reported, Vineyard Wind's request for RTR designation was earlier rejected by ISO-NE on the basis that the resource is to be located in federal waters. Under the CASPR Conforming Changes, Vineyard Wind would not have been precluded from utilizing the RTR exemption. Consistent with the discussion in the CASPR Conforming Changes filing, Vineyard Wind asked that the proration requirement that would be triggered by Vineyard Wind's participation in FCA13 as an RTR be limited for FCA13 to it and any other similarly-situated entities (i.e. new offshore wind resources located in federal waters seeking RTR treatment); Vineyard Wind claimed that there would have been no impact on resources qualified to use the RTR exemption in FCA13. ISO-NE filed comments not opposing the Waiver Request, but requested FERC action by January 29, 2019 if the waiver was to be effective for FCA13. NEPGA protested the Waiver Request. Answers to NEPGA's protest were filed by Vineyard Wind and NESCOE. On January 15, the Massachusetts Department of Energy Resources ("MA DOER") intervened out-of-time and submitted comments supporting the Waiver Request. Doc-less interventions were filed by NEPOOL, Avangrid, Dominion, ENE, National Grid, and NextEra. Despite several last minute requests to do so, including a Vineyard Wind emergency motion for immediate stay of FCA13 or, in the alternative, a requirement that FCA13 be re-run following FERC action, the FERC took no action ahead of FCA13 and FCA13 was run without Vineyard Wind receiving RTR treatment. As noted, this matter remains pending before the FERC, with no activity since the last Report. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

[61] For purposes of this Report, "Vistra" includes each of Vistra's Related Persons that are NEPOOL Participants: Dynegy Marketing and Trade, LLC; Ambit Northeast LLC; Connecticut Gas & Electric, Inc.; Energy Rewards, LLC; Everyday Energy, LLC; Massachusetts Gas and Electric, Inc.; Public Power, LLC; and Viridian Energy, LLC.

- ***Order 841* Compliance Filings (Electric Storage in RTO/ISO Markets) (ER19-470)**

As previously reported, the FERC conditionally accepted on November 22, 2019, subject to an additional compliance filing, New England's *Order 841*[62] compliance filing.[63] For the majority of the revisions, the effective date was December 3, 2019; the effective date for the revisions to Section II.21, Schedule 9 (Regional Network Service), and Schedule 21 (Local Service) of the OATT was December 1, 2019; the effective date for the remainder of the changes will be January 1, 2024.[64]

ISO-NE Request for Rehearing (ER19-470-003). On December 23, 2019,[65] ISO-NE requested rehearing of the FERC's finding that the initial compliance filing did not comply with *Order 841*'s requirement to allow electric storage resources to account for their state of charge and duration in the Day-Ahead Energy Market. ISO-NE asserted that the finding "ignore[d] substantial record evidence and would require ISO-NE to implement a needlessly problematic solution. On January 21, 2020, the FERC issued a tolling order affording it additional time to consider ISO-NE's request for rehearing, which remains pending before the FERC.

Order 841 Compliance Filing II (ER19-470-004). On February 10, 2020, ISO-NE and NEPOOL jointly filed Tariff revisions in response to the *Order 841 Initial Compliance Filing Order*. The revisions included: (i) a provision that addresses the state of charge and duration characteristics of an energy storage facility in the Day-Ahead Energy Market;[66] (ii) metering and accounting practices for electric storage resources, including direct metering requirements and certainty that electric storage resources will not pay twice for the same charging energy; and (ii) a provision which provides that an electric storage facility will "not be precluded from providing retail services so long as it is able to fulfill its wholesale Energy Market and [FCM] obligations". The filing explained why no additional Tariff language was needed to apply transmission charges to an electric storage resource when it is charging for later resale in the wholesale markets and not providing a service. The Tariff Revisions were unanimously supported by the Participants Committee at its February 6 meeting (Agenda Item #5). Comments on this filing were due on or before March 2, 2020; none were filed. This filing is now pending before the FERC.

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

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

[63] *ISO New England Inc.*, 169 FEC ¶ 61,140 (Nov. 22, 2019) ("*Order 841 Initial Compliance Filing Order*").

[64] The Order 841 revisions that became effective on Dec. 3, 2019 were filed in ER19-470-000; the revisions to § II.21, Schedule 9 and Schedule 21 became effective on Dec. 1, 2019 as requested in ER19-470-002; the remainder of the changes will become effective on Jan. 1, 2024 as requested in ER19-470-001.

[65] The Request for Rehearing was assigned a Dec. 26 filing date in FERC's eLibrary as filing was successfully completed shortly after the 5pm deadline for official receipt as of the 23rd in the FERC's eFiling system. On December 26, ISO-NE filed a motion explaining the technical difficulties experienced and asked that its request for rehearing be deemed timely filed.

[66] *See* proposed § III.1.10.6(d) -- "In clearing the Day-Ahead Energy Market, the ISO will account for maximum run time, maximum charge time, state of charge, maximum state of charge, and minimum state of charge through bidding parameters or other means, as required by the Commission in Order No. 841." This language reflects ISO-NE's pending challenge to the *Order 841 Initial Compliance Filing Order* on this point and will be subject to additional revision following disposition of that challenge.

- **Fuel Security Retention Proposal (ER18-2364)**

Requests for rehearing and/or clarification of the *Fuel Security Retention Proposal Order*[67] remain pending before the FERC. As previously reported, the *Fuel Security Retention Proposal Order* accepted ISO-NE's Proposal[68] in all respects, despite the various protests and alternative proposals filed. There was a concurring decision from Commissioner Glick, and a partial dissent from Chairman Chatterjee on the FCA price treatment issue. Challenges to the *Fuel Security Retention Proposal Order* were filed by NEPGA, NRG, Verso, Vistra/Dynegy Marketing & Trade, MPUC, and PIOs.[69] On February 1, 2019, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending. If you have further questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Economic Life Determination Revisions (ER18-1770)**

Rehearing of the FERC's November 9, 2018 order,[70] accepting the revised Tariff language that changed the determination of economic life under Section III.13.1.2.3.2.1.2.C of the Tariff, remains pending before the FERC. As previously reported, the Economic Life Revisions provide that the economic life of an Existing Capacity Resource is calculated as the evaluation period in which the net present value of the resource's expected future profit is maximized. The Economic Life Revisions were accepted effective as of August 10, 2018, as requested. In accepting the revisions, the FERC found that "it is just and reasonable to consider as part of the Economic Life calculation that a rational resource, in exercising competitive bidding behavior, would seek to exit the market, or retire, before it starts incurring consecutive losses."[71] The FERC found, contrary to NEPGA's assertions, that the "Economic Life Revisions do not represent a violation of the filed rate doctrine or constitute retroactive ratemaking."[72] Further, while the FERC was "mindful of the importance of not disrupting settled expectations based on existing market rules," the FERC concluded "that under these specific facts, the benefits of the proposed Economic Life Revisions outweigh potential disruptions to market participants' settled expectations and harm

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[67] *ISO New England Inc.*, 165 FERC ¶ 61,202 (Dec. 3, 2018), *reh'g requested* ("*Fuel Security Retention Proposal Order*"). In accepting the ISO-NE Proposal, the FERC, among other things: (i) found ISO-NE's trigger and assumptions for the fuel security reliability review for retention of resources be reasonable, but required ISO-NE at the end of each winter to "to submit an informational filing comparing the study assumptions and triggers from the modeling analysis to actual conditions experienced in the winter of 2018/19; (ii) found cost allocation on a regional basis to Real-Time Load Obligation just and reasonable and consistent with precedent regarding the past Winter Reliability Programs; (iii) found that entering retained resources into the FCAs as price takers would be just and reasonable to ensure that they clear and are counted towards resource adequacy so that customers do not pay twice for the resource; and (Iv) found that it was appropriate to include FCAs 13, 14 and 15 in the term. The FERC agreed that it is necessary to implement a longer-term market solution as soon as possible, and required ISO-NE to file its longer-term market solution no later than June 1, 2019. The FERC declined to provide guidance on what the long-term solution(s) should be.

[68] As previously reported, ISO-NE filed, in response to the *Mystic Waiver Order*, "interim Tariff revisions that provide for the filing of a short-term, cost-of-service agreement to address demonstrated fuel security concerns". ISO-NE proposed three sets of provisions to expand its authority on a short-term basis to enter into out-of-market arrangements in order to provide greater assurance of fuel security during winter months in New England (collectively, the "Fuel Security Retention Proposal"). ISO-NE stated that the interim provisions would sunset after FCA15, with a longer-term market solution to be filed by July 1, 2019, as directed in the *Mystic Waiver Order*. In addition, the ISO-NE transmittal letter described (i) the generally-applicable fuel security reliability review standard that will be used to determine whether a retiring generating resource is needed for fuel security reliability reasons; (ii) the proposed cost allocation methodology (Real-Time Load Obligation, though ISO-NE indicated an ability to implement NEPOOL's alternative allocation methodology if determined appropriate by the FERC); and (iii) the proposed treatment in the FCA of a retiring generator needed for fuel security reasons that elects to remain in service. The ISO-NE Fuel Security Changes were considered but not supported by the Participants Committee at its August 24, 2018 meeting. There was, however, super-majority support for (1) the Appendix L Proposal with some important adjustments to make that proposal more responsive to the FERC's guidance in the Mystic Waiver Order and other FERC precedent, and (2) the PP-10 Revisions, also with important adjustments (together, the "NEPOOL Alternative").

[69] "PIOs" for purposes of this proceeding are Sierra Club, NRDC, Sustainable FERC Project, and Acadia Center.

[70] *ISO New England Inc. and New England Power Pool Participants Comm.*, 165 FERC ¶ 61,088 (Nov. 9, 2018) ("*Economic Life Determination Revisions Order*").

[71] *Economic Life Determination Revisions Order* at P 23.

[72] *Id.* at P 24.

caused by reliance on the existing FCM rules."[73] On December 10, 2018, NEPGA requested rehearing of the *Economic Life Determination Revisions Order*. On January 8, 2019, the FERC issued a tolling order affording it additional time to consider NEPGA's request for rehearing, which remains pending. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **ISO-NE Waiver Filing: Mystic 8 & 9 (ER18-1509; EL18-182)**

On July 2, 2018, the FERC issued an order[74] that (i) denied ISO-NE's request for waiver of certain Tariff provisions that would have permitted ISO-NE to retain Mystic 8 & 9 for fuel security purposes (ER18-1509); and (ii) instituted an FPA Section 206 proceeding (EL18-182) (having preliminarily found that the ISO-NE Tariff may be unjust and unreasonable in that it fails to address specific regional fuel security concerns identified in the record that could result in reliability violations as soon as year 2022). The *Mystic Waiver Order* required ISO-NE, on or before August 31, 2018 to either: (a) submit interim Tariff revisions that provide for the filing of a short-term, cost-of-service agreement (COS Agreement) to address demonstrated fuel security concerns (and to submit by July 1, 2019 permanent Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns "Chapter 3 Proposal"); or (b) show cause as to why the Tariff remains just and reasonable in the short- and long-term such that one or both of Tariff revisions filings is not necessary.

Addressing the waiver element, the FERC found the waiver request "an inappropriate vehicle for allowing Mystic 8 and 9 to submit a [COS Agreement] in response to the identified fuel security need" and further that the request "would not only suspend tariff provisions but also alter the existing conditions upon which a market participant could enter into a [COS Agreement] (for a transmission constraint that impacts reliability) and allow for an entirely new basis (for fuel security concerns that impact reliability) to enter into such an agreement." The FERC concluded that "[s]uch new processes may not be effectuated by a waiver of the ISO-NE Tariff; they must be filed as proposed tariff provisions under FPA section 205(d)."[75] Even if it were inclined to apply its waiver criteria, the FERC stated that it would still have denied the waiver request as "not sufficiently limited in scope."[76]

Although it denied the waiver request, the FERC was persuaded that the record supported "the conclusion that, due largely to fuel security concerns, the retirement of Mystic 8 and 9 may cause ISO-NE to violate NERC reliability criteria." Finding ISO-NE's methodology and assumptions in the Operational Fuel-Security Analysis ("OFSA") and Mystic Retirement Studies reasonable, the FERC directed the filing of both interim and permanent Tariff revisions to address fuel security concerns (or a filing showing why such revisions are not necessary).[77] The FERC directed ISO-NE to consider the possibility that a resource owner may need to decide, prior to receiving approval of a COS Agreement, whether to unconditionally retire, and provided examples of how to address that possibility.[78] The FERC also directed ISO-NE include with any proposed Tariff revisions a mechanism that addresses how cost-of-service-retained resources would be treated in the FCM[79] and an *ex ante* cost allocation proposal that appropriately identifies beneficiaries and adheres to FERC cost causation precedent.[80]

Requests for Rehearing and/or Clarification. The following requests for rehearing and or clarification of the *Mystic Waiver Order* remain pending before the FERC:

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[73] *Id.* at P 27.

[74] *ISO New England Inc.*, 164 FERC ¶ 61,003 (July 2, 2018), *reh'g requested* ("*Mystic Waiver Order*").

[75] *Id.* at P 47.

[76] *Id.* at P 48.

[77] *Id.* at P 55.

[78] *Id.* at PP 56-57.

[79] *Id.* at P 57.

[80] *Id.* at P 58.

- ***NEPGA*** (requesting that the FERC grant clarification that it directed, or on rehearing direct, ISO-NE to adopt a mechanism that prohibits the re-pricing of Fuel Security Resources in the FCA at $0/kW-mo. or at any other uncompetitive offer price);
- ***Connecticut Parties***[81] (requesting that the FERC clarify that (i) the discussion in the *Mystic Waiver Order* of pricing treatment in the FCM for fuel security reliability resources is not a final determination nor is it intended to establish FERC policy; (ii) the FERC did not intend to prejudge whether entering those resources in the FCM as price takers would be just and reasonable; and (iii) that ISO-NE may confirm its submitted position that price taking treatment for these resources would, in fact, be a just and reasonable outcome. Failing such clarification, Connecticut Parties request rehearing, asserting that the record fails to support a determination that resources retained for reliability to address fuel security concerns must be entered into the FCM at a price greater than zero);
- ***ENECOS*** (asserting that the *Mystic Waiver Order* (i) misplaces reliance on ISO-NE "assertions concerning 'fuel security,' which do not in fact establish a basis in evidence or logic for initiating" a Section 206(a) proceeding; (ii) impermissibly relies on extra-record material that the FERC did not actually review and that intervenors were afforded no meaningful opportunity to challenge; and (iii) speculation concerning potential future modifications to the FCM bidding rules as to retiring generation retained for fuel security misunderstands the problem it seeks to address, and prejudices the already truncated opportunities for stakeholder input in this proceeding), ENECOS suggest that the FERC should grant rehearing, vacate its show cause directive, strike its dictum concerning potential treatment of FCM bidding for retiring generation retained for "fuel security," and direct ISO-NE to proceed either in accordance with its Tariff or under FPA Section 205 to address, with appropriate evidentiary support, whatever concerns it believes to exist concerning "fuel security");
- ***MA AG*** (asserting that the decision to institute a Section 206 proceeding was insufficiently supported by sole reliance on highly contested OFSA and Mystic Retirement Studies; and the FERC should reconsider the timeline for the permanent tariff solution and set the deadline for implementation no later than February 2020);
- ***MPUC*** (challenging the Order's (i) adoption of ISO-NE's methodology and assumptions in the OFSA and Mystic Retirement Studies without undertaking any independent analysis; (ii) failure to address arguments and analysis challenging assumptions in the OFSA and Mystic Retirement Studies; (iii) failure to address the MPUC argument that the Mystic Retirement Studies adopted a completely new standard for determining a reliability problem three years in advance; (iv) unreasonably discounting of the ability of Pay-for-Performance to provide sufficient incentives to Market Participants to ensure their performance under stressed system conditions; and (v) failure to direct ISO-NE to undertake a Transmission Security Analysis consistent with the provisions in the Tariff);
- ***New England EDCs***[82] (requesting clarification that (i) the central purpose of ISO-NE's July 1, 2019 filing is to assure that New England adds needed new infrastructure to address the fuel supply shortfalls and associated threats to electric reliability that ISO-NE identified in its OFSA and (ii) that, in developing the July 1, 2019 filing, ISO-NE is to evaluate Tariff revisions (such as those the EDCs described in their request), through which ISO-NE customers would pay for the costs of natural gas pipeline capacity additions via rates under the ISO-NE Tariff);
- ***PIOs***[83] (asserting that (i) the FERC failed to respond to or provide a reasoned explanation for rejecting the arguments submitted by numerous parties that key assumptions underlying and the results of the ISO-NE analyses were flawed; and (ii) the FERC's determination that ISO-NE's analyses were reasonable is not supported by substantial evidence in the record); and

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81 "Connecticut Parties" are the Conn. Pub. Utils. Regulatory Authority ("CT PURA") and the Conn. Dept. of Energy and Environ. Protection ("CT DEEP").

82 The "EDCs" are the National Grid companies (Mass. Elec. Co., Nantucket Elec. Co., and Narragansett Elec. Co.) and Eversource Energy Service Co. (on behalf of its electric distribution companies – CL&P, NSTAR and PSNH).

83 "PIOs" are the Sierra Club, Natural Resources Defense Council ("NRDC"), and Sustainable FERC Project.

- ***AWEA/NGSA*** (asserting that the FERC erred (i) in finding that ISO-NE's OFSA and subsequent impact analysis of fuel security was reasonable without further examination and (ii) in its preliminary finding that a short-term out-of-market solution to keep Mystic 8 & 9 in operation is needed to address fuel security issues).

On August 13, 2018, CT Parties opposed the NEPGA motion for clarification. On August 14, NEPOOL filed a limited response to Indicated New England EDCs, requesting that the FERC "reject the relief sought in [their motion] to the extent that relief would bypass or predetermine the outcome of the stakeholder process, without prejudice to [them] refiling their proposal, if appropriate, following its full consideration in the stakeholder process." Answers to the Indicated New England EDCs were also filed by the MA AG, NEPGA, NextEra, and CLF/NRDC/Sierra Club/Sustainable FERC Project. On August 29, the Indicated New England EDCs answered the August 14/16 answers. On August 27, 2018, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending.

If you have any questions concerning this proceeding, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **CASPR (ER18-619)**

Rehearing of the FERC's order accepting ISO-NE's Competitive Auctions with Sponsored Policy Resources ("CASPR") revisions,[84] summarized in more detail in prior Reports, remains pending. Those requests were filed by (i) ***NextEra/NRG*** *(which* challenged the RTR Exemption Phase Out); (ii) ***ENECOS***[85] (challenging the FERC's findings with respect to the definition of Sponsored Policy Resource and the allocation of CASPR side payment costs to municipal utilities); (iii) ***Clean Energy Advocates***[86] (which challenged the CASPR construct in its entirety, asserting that state-sponsored resources should not be subject to the MOPR); and (iv) ***Public Citizen*** (which also challenged the CASPR construct in its entirety and the *CASPR Order*'s failure to define "investor confidence"). On April 24, ISO-NE answered Clean Energy Advocates' answer. On May 7, 2018, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending. If you have any questions concerning this proceeding, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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

Still pending before the FERC is ISO-NE's compliance filing in response to the FERC's August 8, 2016 remand order.[87] In the *2013/14 Winter Reliability Program Remand Order*, the FERC directed ISO-NE to request from Program participants the basis for their bids, including the process used to formulate the bids, and to file with the FERC a compilation of that information, an IMM analysis of that information, and ISO-NE's recommendation as to the reasonableness of the bids, so that the FERC can further consider the question of

[84] *ISO New England Inc.*, 162 FERC ¶ 61,205 (Mar. 9, 2018) ("*CASPR Order*"), *reh'g requested*.

[85] The Eastern New England Consumer-Owned Systems ("ENECOS") are: Braintree Electric Light Department, Georgetown Municipal Light Department, Groveland Electric Light Department, Littleton Electric Light & Water Department, Middleton Electric Light Department, Middleborough Gas & Electric Department, Norwood Light & Broadband Department, Pascoag (Rhode Island) Utility District, Rowley Municipal Lighting Plant, Taunton Municipal Lighting Plant, and Wallingford (Connecticut) Department of Public Utilities. Wellesley Municipal Light Plant, which intervened in this proceeding as one of the ENECOS, did not join in the ENECOS' request for rehearing.

[86] For purposes of this proceeding, "Clean Energy Advocates" are, collectively, the NRDC, Sierra Club, Sustainable FERC Project, CLF, and RENEW Northeast, Inc.

[87] *ISO New England Inc.*, 156 FERC ¶ 61,097 (Aug. 8, 2016) ("*2013/14 Winter Reliability Program Remand Order*"). As previously reported, the DC Circuit remanded the FERC's decision in ER13-2266, agreeing with TransCanada that the record upon which the FERC relied is devoid of any evidence regarding how much of the 2013/14 Winter Reliability Program cost was attributable to profit and risk mark-up (without which the FERC could not properly assess whether the Program's rates were just and reasonable), and directing the FERC to either offer a reasoned justification for the order in ER13-2266 or revise its disposition to ensure that the Program rates are just and reasonable. *TransCanada Power Mktg. Ltd. v. FERC,* 2015 U.S. App. LEXIS 22304 (D.C. Cir. 2015).

whether the Bid Results were just and reasonable.[88] ISO-NE submitted its compliance filing on January 23, 2017, reporting the IMM's conclusion that "the auction was not structurally competitive and a 'small proportion' of the total cost of the program may be the result of the exercise of market power" but that the "vast majority of supply was offered at prices that appear reasonable and that, for a number of reasons, it is difficult to assess the impact of market power on cost." Based on the IMM and additional analysis, ISO-NE recommended that "there is insufficient demonstration of market power to warrant modification of program." In February 13 comments, both TransCanada and the MA AG protested ISO-NE's conclusion and recommendation that modification of the program was unwarranted. TransCanada requested that FERC establish a settlement proceeding where Market Participants could "exchange confidential information to determine what the rates should be" and refunds and "such other relief as may be warranted" provided. On February 28, ISO-NE answered the TransCanada and MA AG protests. On March 10, 2017, TransCanada answered ISO-NE's February 28 answer. This matter remains 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

- **CIP IROL Cost Recovery Rules (ER20-739)**

On January 6, 2020, ISO-NE filed revisions to incorporate into the Tariff as a new Schedule 17 a mechanism to facilitate the recovery of critical infrastructure protection ("CIP") costs by facilities that ISO-NE identifies as critical to the derivation of Interconnection Reliability Operating Limits ("IROL") (the "CIP IROL Cost Recovery Rules"). ISO-NE requested a March 6, 2020 effective date for the CIP IROL Cost Recovery Rules. The CIP IROL Cost Recovery Rules were considered but not supported by the Participants Committee at its November 1, 2019 meeting (Agenda Item #8). Comments on this filing were due on or before January 27, 2020. On January 22, NEPOOL filed comments to provide the FERC with further information explaining NEPOOL's consideration of the Rules and reasons provided by members for supporting or not supporting the Rules. Calpine, Cross-Sound Cable, and the IROL-Critical Facility Owners[89] filed comments supporting the Rules. NESCOE conditionally supported the Rules, subject to the FERC providing its requested guidance and clarifications.[90] Doc-less interventions only were filed by: Brookfield, Dominion, Eversource, Exelon, MA AG, National Grid, NextEra (out-of-time), PSEG, UI, MA DPU, MPUC, Public Citizen, and RESA. On February 11, ISO-NE and NESCOE answered the IROL-Critical Facility Owners' comments and the IROL-Critical Facility Owners answered NESCOE's comments.

Deficiency Letter. On February 26, 2020, the FERC issued a deficiency letter directing ISO-NE (a) to explain if it intends to allow the recovery of costs incurred prior to the March 6, 2020 requested effective date and if so (b) to explain how that cost recovery would be consistent with the filed rate doctrine and the rule against retroactive ratemaking. ISO-NE's answer(s), which are due on or before March 27, 2020, will constitute an amendment to the CIP IROL Cost Recovery Rules filing, will be noticed for public comment, and will extend the date by which the FERC must act on the filing to the date that is 60 days from the date of the answer(s).

If you have any questions concerning this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

[88] *2013/14 Winter Reliability Program Remand Order* at P 17.

[89] The "IROL-Critical Facility Owners" are: Cogentrix, CSC, FirstLight, NextEra, NRG, and Vistra.

[90] NESCOE requested that the FERC (i) clarify that any order approving Schedule 17 is limited in scope and does not set broad precedent, (ii) confirm that under no circumstances may IROL-critical facilities recover costs subject to recovery under another provision of the Tariff or under any other mechanism; (iii) clarify that costs eligible for recovery under Schedule 17 must be solely and directly related to ISO-NE's designation; and (iv) clarify that only going-forward costs are eligible for recovery under Schedule 17.

- **Interconnection Studies Scope and Reasonable Efforts Timelines Changes (ER19-1952)**

Still pending before the FERC are changes to Schedule 22 of the OATT, filed May 22, 2019 by ISO-NE, NEPOOL and the PTO AC, to: (i) reduce the scope of the Interconnection Feasibility Study ("Feasibility Study") and increase the Reasonable Efforts timeframe for completing that study; and (ii) increase the Reasonable Efforts timeframe for completing the Interconnection System Impact Study ("SIS"). The Filing Parties asked that these changes become effective on the same date that the *Order 845* Changes (*see* ER19-1951 below) become effective. The *Order 845* compliance changes were supported by the Participants Committee at its May 3, 2019 meeting (Consent Agenda Item #4).

On May 31, AWEA requested a 21-day extension of time to submit comments in this proceeding (and the ISO-NE Order 845 Compliance Filing proceeding (ER19-1951 just below)). The FERC granted AWEA's request, in part, on June 7. Comments in these proceedings were due June 26, 2019. Doc-less interventions were filed by Avangrid, Calpine, Dominion, EDP, National Grid, and NRG. A joint protest was filed by EDF Renewables, E.ON Climate & Renewables North America ("E.ON") and Enel Green Power North America ("Enel"), who asked the FERC to reject the changes for four reasons: (i) ISO-NE is incapable of meeting the study deadline changes proposed; (ii) the proposed study deadlines do not improve ISO-NE's ability to exercise Reasonable Efforts to meet queue study deadlines; (iii) the extensions proposed will delay and perhaps limit the extent of the informational reports to be required under *Order 845*; and (iv) the changes will not promote the transparency or improve the processing of ISO-NE's interconnection queue. On July 11, ISO-NE answered the joint protest. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **ISO-NE *Order 845* Compliance Filing (ER19-1951)**

Similarly, the proposed revisions to the Large Generator Interconnection Procedures ("LGIP") and Agreement ("LGIA") in Schedule 22 of the ISO-NE OATT jointly filed on May 22, 2019 by ISO-NE and the PTO AC ("Filing Parties") in response to the requirements of *Order 845* ("ISO-NE/TO Proposal") remain pending. The Filing Parties asserted that the ISO-NE/TO Proposal "fully compl[ies] with the requirements in Order Nos. 845 and 845-A, and request that the Commission accept them as proposed herein, without modifications or conditions, effective upon issuance of its order accepting this filing." The ISO-NE/TO Proposal did not include the RENEW Amendment's revisions to the Surplus Interconnection Service provisions supported by the Participants Committee at its May 3 meeting ("NEPOOL Proposal"). The Participants Committee considered but did not support the ISO-NE/TO Proposal (without the RENEW Amendment) at its May 3 meeting.

Comments in these proceedings were due June 26, 2019. Doc-less interventions were filed by Avangrid, Calpine, Dominion, EDP, Eversource, MA AG, National Grid, NRG, and ESA. Comments and protests were filed by the following:

- ♦ ***NEPOOL***, which in its protest urged the FERC to accept the ISO-NE/TO Proposal to the extent it is consistent with the NEPOOL Proposal, and reject those provisions for Surplus Interconnection Service that deviate both from the requirements of *Orders 845/845-A* and the NEPOOL Proposal. To the extent necessary or desirable, NEPOOL urged the FERC to direct ISO-NE to engage the NEPOOL stakeholder process to address any implementation concerns regarding Surplus Interconnection Service. NEPOOL went on to suggest that any additional provisions developed regarding such service that are properly considered rates, terms and conditions of service should be filed with the FERC and included in the ISO-NE Tariff. NEPOOL also urged the FERC to reject the PTOs' proposal for recovery of actual costs in the absence of a demonstration that their proposed deviation is consistent with or superior to the *Order 845* requirement for a negotiated and stated amount.
- ♦ ***MA AG*** (which urged the FERC to (i) reject the ISO-NE provisions for Surplus Interconnection Service that deviate from the NEPOOL Proposal and the requirements of *Order Nos. 845/845-A* and order ISO-NE to make changes to the ISO Tariff in accordance with the NEPOOL Proposal and (ii) reject the PTO AC amendment that seeks unlimited cost recovery for PTO oversight of the option to build rather than a fixed, negotiated amount as provided in the FERC's *pro forma*).

- ***AWEA/RENEW/Solar Council*** (supporting some of ISO-NE's revisions, but protesting ISO-NE's "unreasonably narrow definition of Surplus Interconnection Service" and ISO-NE's failure to establish an outside-the-queue process for reviewing Surplus Interconnection Service requests").
- ***ESA*** (objecting to ISO-NE's Surplus Interconnection Service proposal).

On July 11, ISO-NE and the PTO AC answered the comments and protests. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

V.Financial Assurance/Billing Policy Amendments

No Activity to Report

VI.Schedule 20/21/22/23 Changes

- **Schedule 21-NEP: Deepwater Block Island Wind Indemnification Agreement Cancellation (ER20-962)**

On February 6, 2020, Narragansett filed a notice of cancellation of its Indemnification Agreement with the Deepwater Companies. The Indemnification Agreement, which went into effect May 10, 2016, provided for the Deepwater Companies to indemnify Narragansett for costs directly incurred in connection with the delivery of switchgear at certain Rhode Island substations related to the Deepwater Companies' construction of the Block Island Wind Farm. The Indemnification Agreement is being cancelled because the Block Island Wind Farm is completed and in commercial operation and the Agreement is no longer needed. The cancellation is to become effective April 7, 2020. Comments on the notice were due on or before February 28; none were filed. This matter is pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-ES: Berkshire Phase 2 LSA (ER20-585)**

On February 7, 2020, the FERC accepted the Local Service Agreement ("LSA") among NSTAR, Berkshire Wind Power Cooperative Corporation ("Berkshire")[91] and ISO-NE.[92] The LSA provides for Firm and Non-Firm Local Point-To-Point Transmission Service for Berkshire's use of NSTAR (West)'s local facilities for "wheeling-out" power associated with Phase 2 to the regional transmission system.[93] The LSA was accepted effective as of October 1, 2019, as requested. Unless the February 7 order is challenged, this proceeding will be concluded. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-EM: Recovery of Bangor Hydro/Maine Public Service Merger-Related Costs (ER15-1434-001 *et al.*)**

The MPS Merger Cost Recovery Settlement, filed by Emera Maine on May 8, 2018 to resolve all issues pending before the FERC in the consolidated proceedings set for hearing in the *MPS Merger-Related Costs*

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[91] Berkshire is a non-profit entity created by 14 Mass. municipal utilities and MMWEC that owns and operates the 15 MW Berkshire Wind Power Project ("Berkshire Wind") located in Lanesboro, MA.

[92] *ISO New England Inc. and NSTAR Elec. Co.*, Docket No. ER20-585 (Feb. 7, 2020).

[93] A LSA for Phase 1 was filed and accepted in Docket No. ER19-309. See *ISO New England Inc. and NSTAR Elec. Co.*, Docket No. ER19-309 (Jan 2, 2019) (unpublished letter order).

Order,[94]and certified by Settlement Judge Dring[95] to the Commission,[96] remains pending before the FERC. As previously reported, under the Settlement, permitted cost recovery over a period from June 1, 2018 to May 31, 2021 will be $390,000 under Attachment P-EM of the BHD OATT and $260,000 under the MPD OATT. If you have any questions concerning these matters, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII.Regional Reports

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

FG&E's June 29, 2015 refund report for its customers taking local service during *Opinion 531-A's* refund period remains pending. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

The TOs' November 2, 2015 refund report documenting resettlements of regional transmission charges by ISO-NE in compliance with *Opinions No. 531-A*[97] *and 531-B*[98] 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
- VTransco

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

[94] *Emera Maine and BHE Holdings*, 155 FERC ¶ 61,230 (June 2, 2016) ("*MPS Merger-Related Costs Order*"). In the *MPS Merger-Related Costs Order*, the FERC accepted, but established hearing and settlement judge procedures for, filings by Emera Maine seeking 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"). 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 an 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. The *MPS Merger-Related Costs Order* set resolution of the issues of material fact for hearing and settlement judge procedures, consolidating the separate compliance filing dockets.

[95] ALJ John Dring was the settlement judge for these proceedings. There were five settlement conferences -- three in 2016 and two in 2017. With the Settlement pending before the FERC, settlement judge procedures, for now, have not been terminated.

[96] *Emera Maine and BHE Holdings*, 163 FERC ¶ 63,018 (June 11, 2018).

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

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

- **Capital Projects Report - 2019 Q4 (ER20-973)**

  On February 11, 2020, ISO-NE filed its Capital Projects Report and Unamortized Cost Schedule covering the fourth quarter ("Q4") of calendar year 2019 (the "Report"). ISO-NE is required to file the Report under Section 205 of the FPA pursuant to Section IV.B.6.2 of the Tariff. Report highlights include the following new projects: (i) nGEM software development part I ($3.2 million); (ii) markets database refresh ($1.7 million); (iii) enterprise application integration replacement ($1.4 million); (iv) application server upgrade ($894,100); (v) 2020 issue resolution project phase I ($680,000); (vi) streamline asset registration user interface enhancements ($631,300); and (vii) e-mail infrastructure upgrade ($84,500). Projects with a significant changes were (i) change request system replacement ($687,600 budget increase); (ii) energy market offer caps (*Order 831*) (2019 and overall budget decrease of $543,100); and (iii) energy storage device phase II ($141,300 budget increase). Comments on this filing were due on or before March 3. NEPOOL filed comments on February 25 supporting the Q4 Report. Eversource and National Grid filed doc-less interventions only. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **Transmission Projects Annual Informational Filing (ER13-193)**

  On January 30, 2020, ISO-NE filed, as required under Section 4.1(j)(iii) of the OATT, its annual informational filing of projects on the RSP project list that had a year of need three years or less from the completion of the Needs Assessment. The list of prior year designations is maintained on the ISO-NE website at https://www.iso-ne.com/static-assets/documents/2020/01/2019-prior-year-projects-section-4-j-iii-final.pdf. This filing will not be noticed for public comment by the FERC.

- **IMM Quarterly Markets Reports – Fall 2019 (ZZ19-4)**

  On February 12, 2020, the IMM filed with the FERC its Fall 2019 report of "market data regularly collected by [the IMM] in the course of carrying out its functions under … Appendix A and analysis of such market data," as required pursuant to Section 12.2.2 of Appendix A to Market Rule 1. These filings are not noticed for public comment by the FERC. The Fall 2019 Report will be discussed with the Markets Committee at the April 6-7, 2020 Markets Committee meeting. Participants with questions on the Report have been asked to forward them to the Markets Committee Chair by March 25, 2020.

IX.Membership Filings

- **March 2020 Membership Filing (ER20-1130)**

  On February 28, 2020 NEPOOL requested that the FERC accept (i) the membership of SP Transmission, LLC (Provisional Member); (ii) the termination of the Participant status of QPH Capital, LLC (Supplier Sector); and (iii) the name change of Pixelle Energy Services LLC (f/k/a Verso Energy Services LLC). Comments on this filing are due on or before March 20.

- **February 2020 Membership Filing (ER20-923)**

  On January 31, 2020 NEPOOL requested that the FERC accept (i) the memberships of Avangrid Networks, Inc. [Provisional Member, Related Person to Avangrid Companies (Transmission Sector)]; TrueLight Commodities, LLC (Supplier Sector); and Weaver Wind, LLC (AR Sector, RG Sub-Sector, Large RG Group Member); (ii) the termination of the Participant status of: BBPC LLC d/b/a Great Eastern Energy (Supplier Sector); Precept Power LLC (Supplier Sector); and the TransCanada Companies (TransCanada Power Marketing Ltd, TCPL Power Ltd.; and TransCanada Energy Ltd.) (Supplier Sector); and (iii) the name change of Mercuria Energy America, LLC (f/k/a Mercuria Energy America, Inc.). Comments on this filing were due on or before February 21; none were filed. This matter is pending before the FERC.

- **January 2020 Membership Filing (ER20-710)**

  On February 14, the FERC accepted the memberships of Enel Trading North America, LLC ([Related Person to Enel X Companies (AR Sector, LR Sub-Sector)]); MP2 Energy LLC ([Related Person to Shell and MP2 Energy New

England (Supplier Sector)]); and Rodan Energy Solutions (USA) Inc. (Provisional Member Group Seat).[99] Unless the February 14 order is challenged, this proceeding will be concluded.

- **Suspension Notices (not docketed)**

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

Date of Suspension/ FERC Notice	***Participant Name***	***Default Type***	***Date Reinstated***
Feb 24/26	Number Nine Wind Farm LLC	Payment	Feb 27
Feb 20/24	Empire Generating Co, LLC	Financial Assurance	--

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

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

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

- **Complaint re: CIP-014-2 (Physical Security) (EL20-21)**

On January 30, 2020, Michael Mabee, a private citizen ("Complainant"), filed a formal complaint alleging that Critical Infrastructure Protection ("CIP") Reliability Standard (CIP-014-2) (Physical Security) is inadequate and asked the FERC to issue an order directing NERC to correct the deficiencies. Specifically, Complainant alleges that (1) CIP-014-2 is inadequate in that there is no requirement that an entity's risk assessment or physical security plan be reviewed by anyone with any physical security expertise and no regulator determination as to the effectiveness of any entity's physical security plan and (2) enforcement of CIP-014-2 seems nonexistent (asserting that in the past seven years, there's only been four citations (for administrative violations) for violations of CIP-014-2. Complainant supplement his complaint on February 19 with further background and detail on the allegations and further recommendations. Responses and comments to this complaint, as supplemented, are due on or before March 10, 2020, and have thus far been filed by NERC (requesting that the FERC dismiss the Complaint), and by individuals supporting the Complaint, including R. James Woolsey, an honorary co-chairman of the Secure the Grid Coalition (a project of the Center for Security Policy) (encouraging the FERC to "deeply analyze the effectiveness and the enforcement of the physical security standard you previously approved against the current threat environment and the reality that our modern civilization depends entirely upon the bulk power system"). LA PSC, Public Citizen and Dayton Power & Light have thus far intervened doc-lessly.

- **Revised Reliability Standards: FAC-002-3; IRO-010-3; MOD-031-3; MOD-033-2; NUC-001-4; PRC-006-4; TOP-003-4 (RD20-4)**

On February 21, 2020, NERC filed for approval proposed changes to the following Reliability Standards: FAC-002-3 (Facility Interconnection Studies); IRO-010-3 (Reliability Coordinator Data Specification and Collection); MOD-031-3 (Demand and Energy Data); MOD-033-2 (Steady-State and Dynamic System Model Validation); NUC-001-4 (Nuclear Plant Interface Coordination); PRC-006-4 (Automatic Underfrequency Load Shedding); and TOP-003-4 (Operational Reliability Data) ("Revised Standards"). The changes remove references to Load Serving Entity (which is no longer an applicable entity), add Underfrequency Load Shedding ("UFLS")-Only Distribution Provider to PRC-006-3 as an applicable entity, and make consistent across the Standards the use of the term "Planning Coordinator". NERC asked that revised Reliability Standards become effective (and the currently effective

[99] *New England Power Pool Participants Comm.,* Docket No. ER20-710 (Feb. 14, 2020) (unpublished letter order).

versions be retired) on the first day of the first calendar quarter that is three months following FERC approval. Comments on the Revised Standards are due on or before March 23, 2020.

- **Revised Reliability Standard: TPL-007-4 (RD20-3)**

On February 7, 2020, NERC filed for approval proposed changes to proposed Reliability Standard TPL-007 (Transmission System Planned Performance for Geomagnetic Disturbance ("GMD") Events), the associated implementation plan, Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs"), and the retirement of the current version of the reliability standard (-003) (together, the "TPL-007 Changes"). The purpose of changes to TPL-007-4 is to enhance requirements related to Corrective Action Plans as directed in *Order 851*.[100] Specifically, the TPL-007 Changes require an applicable entity to develop a Corrective Action Plan if system performance issues are identified through the supplemental GMD Vulnerability Assessment; and to seek approval for any requests to extend Corrective Action Plan implementation deadlines, requests that NERC and the Regional Entities would then consider on a case-by-case basis. NERC asked that TPL-007-4 become effective (and TPL-007-3 be retired) on the first day of the first calendar quarter that is six months following FERC approval. Comments on the TPL-007 Changes were due on or before February 28, 2020; none were filed. This matter is pending before the FERC.

- **CIP Standards Development: Informational Filings on Virtualization and Cloud Computing Services Projects (RD20-2)**

On February 20, 2020, the FERC directed NERC to submit, on or before March 23, 2020, an informational filing describing the activity of two NERC CIP standard drafting projects pertaining to virtualization and cloud computing services.[101] Specifically, NERC was directed to submit a schedule for Project 2016-02 (Modifications to CIP Standards) and Project 2019-02 (BES Cyber System Information Access Management) (collectively, the "NERC Projects"), that would include the current status of the project, interim target dates, and the anticipated filing date for new or modified Reliability Standards. In addition, the FERC directed NERC to file on an information basis quarterly status updates, until such time as new or modified Reliability Standards are filed with the FERC.

- **Revised Regional Reliability Standard: PRC-006-NPCC-2 (RD20-1)**

On February 18, 2020 the FERC approved changes to Regional Reliability Standard PRC-006-NPCC2 (Automatic Underfrequency Load Shedding ("UFLS")), the associated implementation plan, Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs"), and the retirement of the current version of the regional reliability standard.[102] As previously reported, the purpose of PRC-006-NPCC-2 is to establish more stringent and specific NPCC UFLS program requirements than the NERC continent-wide PRC-006 standard, such that declining frequency is arrested and recovered in accordance with established NPCC performance requirements. NPCC states that it has revised the currently effective PRC-006-NPCC-1 to remove redundancies with PRC-006-3, clarify obligations for registered entities, improve communication of island boundaries to affected registered entities, and provide entities with the flexibility to calculate net load shed for UFLS in certain situations. PRC-006-NPCC-2 will become effective on April 1, 2020, with the exception of R.3, which will become effective April 1, 2021. Unless the February 18 order is challenged, this proceeding will be concluded.

- **NOI: Virtualization and Cloud Computing Services in BES Operations (RM20-8)**

On February 20, 2020, the FERC issued a notice of inquiry seeking comments on (i) the potential benefits and risks associated with the use of virtualization and cloud computing services in association with bulk electric system ("BES") operations; and (ii) whether the CIP Reliability Standards impede the voluntary adoption of

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[100] *Geomagnetic Disturbance Reliability Standard; Reliability Standard for Transmission Planned Performance for Geomagnetic Disturbance Events*, Order No. 851, 165 FERC 61,124 (Nov. 15, 2018) ("*Order 851*") at PP 29 and 39.

[101] *N. Am. Elec. Rel. Corp.*, 170 FERC ¶ 61,109 (Feb. 20, 2020).

[102] *N. Am. Elec. Rel. Corp.*, Docket No. RD20-1 (Feb. 18, 2020) (unpublished letter order).

virtualization or cloud computing services ("NOI").[103] Initial comments on the NOI are due April 27, 2020; reply comments, May 27, 2020.[104]

- **NOPR - Retirement of Reliability Standard Requirements (Standards Efficiency Review) (RM19-17; RM19-16)**

On January 23, 2020, the FERC issued a NOPR[105] proposing to approve the retirement of 74 of the 77 Reliability Standard requirements requested to be retired by NERC in these two dockets[106] in connection with the first phase of work under NERC's Standards Efficiency Review[107] ("*Retirements NOPR*"). The FERC explained in the *Retirements NOPR* that the requirements to be retired "(1) provide little or no reliability benefit; (2) are administrative in nature or relate expressly to commercial or business practices; or (3) are redundant with other Reliability Standards."[108] The FERC also proposes to approve the associated VRFs, VSLs, implementation plan, and effective dates proposed by NERC. With respect to the remaining three requirements that NERC seeks to retire, the FERC seeks more information on two -- the retirement of FCA-008-3, Requirements R7 and R8 (with the FERC's final determination to be based on the comments received) – and proposes to remand one – VAR-001-6 – in order to retain R2, which it found neither redundant nor unnecessary for reliability. Comments on the *Retirements NOPR* are due on or before April 6, 2020.[109]

- ***Order 867*** **- Revised Reliability Standard: TPL-001-5 (RM19-10)**

On January 23, 2020, the FERC approved revised Reliability Standard -- TPL-001-5 (Transmission System Planning Performance Requirements), and its associated implementation plan, VRFs and VSLs (together, the "TPL-001 Changes").[110] As previously reported, the TPL-001 Changes are to improve upon the currently effective standard by enhancing Requirements for the study of Protection System single points of failure. Additionally, the TLP-001 Changes address two FERC directives from *Order 786*: (1) the TPL-001 Changes provide for a more complete consideration of factors for selecting which known outages will be included in Near-Term Transmission Planning Horizon studies, addressing the FERC's concern that the exclusion of known outages of less than six months in TPL-001-4 could result in outages of significant facilities not being studied; and (2) the TPL-001 Changes modify Requirements for Stability analysis to require an entity to assess the impact of the possible unavailability of long lead time equipment, consistent with the entity's spare equipment strategy. The FERC determined *not* to direct NERC, as proposed in the *TPL-001-5 NOPR,*[111] to modify the Reliability Standards to require corrective action

[103] *Virtualization and Cloud Computing Services*, 170 FERC ¶ 61,110 (Feb. 20, 2020).

[104] The *NOI* was published in the *Fed. Reg.* on Feb. 27, 2020 (Vol. 85, No. 39) pp. 11,363-11,366.

[105] *Electric Reliability Organization Proposal to Retire Requirements in Rel. Standards Under the NERC Standards Efficiency Review*, 170 FERC ¶ 61,032 (Jan. 23, 2020).

[106] As previously reported, NERC filed in ***RM19-17*** for approval (i) the retirement of individual requirements in the following four Reliability Standards: FAC-008-4 (Facility Ratings); INT-006-5 (Evaluation of Interchange Transactions); INT-009-3 (Implementation of Interchange); and PRC-004-6 (Protection System Misoperation Identification and Correction); and (ii) the retirement, in their entirety, of the following 10 Reliability Standards: FAC-013-2 (Assessment of Transfer Capability for the Near-term Transmission Planning Horizon); INT-004-3.1 (Dynamic Transfers); INT-010-2.1 (Interchange Initiation and Modification for Reliability); MOD-001-1a (Available Transmission System Capability); MOD-004-1 (Capacity Benefit Margin); MOD-008-1 (Transmission Readability Margin Calculation Methodology); MOD-020-0 (Providing Interruptible Demands and Direct Control Load Management Data to System Operators and Reliability Coordinators); MOD-028-2 (Area Interchange Methodology); MOD-029-2a (Rated System Path Methodology); and MOD-030-3 (Flowgate Methodology). NERC filed in ***RM19-16*** for approval of the retirement of individual requirements in the following three Reliability Standards: IRO-002-7 (Reliability Coordination – Monitoring and Analysis); TOP-001-5 (Transmission Operations); and VAR-001-6 (Voltage and Reactive Control).

[107] The Standards Efficiency Review initiative, which began in 2017, reviewed the body of NERC Reliability Standards to identify those Reliability Standards and requirements that were administrative in nature, duplicative to other standards, or provided no benefit to reliability.

[108] *Id.* at P 1.

[109] The *Retirements NOPR* was published in the *Fed. Reg.* on Feb. 6, 2020 (Vol. 85, No. 25) pp. 6,831-6,838.

[110] *Transmission Planning Rel. Standard TPL-001-5*, Order No. 867, 170 FERC ¶ 61,030 (Jan. 23, 2020) ("*Order 867*").

[111] *Transmission Planning Rel. Standard TPL-001-5*, 167 FERC ¶ 61,249 (June 20, 2019) ("*TPL-001-5 NOPR*").

plans for protection system single points of failure in combination with a three-phase fault if planning studies indicate potential cascading. *Order 867* will become effective April 13, 2020.[112] *Order 867* was not challenged and is final and unappealable. Reporting on this proceeding is now concluded.

- ***Order 866* - New Reliability Standard: CIP-012-1 (RM18-20)**

On January 23, 2020, the FERC approved new Reliability Standard -- CIP-012-1 (Cyber Security – Communications between Control Centers),[113] and associated Glossary definitions, implementation plan, VRFs and VSLs (together, the "Control Center Cyber Security Communication Changes").[114] *Order 866* also directed NERC to develop certain modifications to CIP-012-1 to require protections regarding the availability of communication links and data communicated between bulk electric system control centers. In light of the comments received in response to the *CIP-012-1 NOPR*,[115] *Order 866* does not require NERC to clarify the types of data that must be protected.[116] *Order 866* will become effective April 7, 2020.[117] *Order 866* was not challenged and is final and unappealable. Reporting on this proceeding is now concluded.

- **5-Year ERO Performance Assessment Report (RR19-7)**

As previously reported, the FERC accepted, on January 23, 2020, NERC's most recent 5-year Performance Assessment,[118] finding (i) that NERC "continues to satisfy the statutory and regulatory criteria for certification as the ERO"; (ii) that the Regional Entities continue to satisfy applicable statutory and regulatory criteria; and (iii) that NERC should take several actions to continue improving its performance as the ERO. Specifically, the FERC directed NERC to submit a 90-day compliance filing providing additional information and a second, 180-day compliance filing revising NERC's Rules of Procedure to address specific matters as discussed in the *2020 Five Year Order*.[119] On February 28, 2020, the FERC granted NERC's February 21, 2020 request for an extension of time, to and including August 28, 2020, to submit the 180-day compliance filing.

XI. Misc. - of Regional Interest

- **203 Application: CMP/NECEC (EC20-24)**

On December 10, 2019, CMP requested authorization to transfer to NECEC Transmission LLC 7 TSAs, executed on June 13, 2018, that provide the rates, terms, and conditions under which transmission service will be provided over the New England Clean Energy Connect ("NECEC") Transmission Line to the participants that are

[112] *Order 867* was published in the *Fed. Reg.* on Feb. 13, 2020 (Vol. 85, No. 30) pp. 8,155-8,161.

[113] When it filed CIP-012-1, NERC stated that the changes modify the Critical Infrastructure Protection ("CIP") Reliability Standards to require Responsible Entities to implement controls to protect communication links and sensitive Bulk Electric System ("BES") data communicated between BES Control Centers. CIP-012-1 requires Responsible Entities to develop a plan to mitigate the risks posed by unauthorized modification (integrity) and unauthorized disclosure (confidentiality) of Real-time Assessment and Real-time monitoring data. The plan must include the following three components: (1) identification of security protection used to meet the security objective; (2) identification of where the Responsible Entity applied the security protection; and (3) identification of the responsibilities of each Responsible Entity for applying the security protection.

[114] *Critical Infrastructure Protection Rel. Standard CIP-012-1 – Cyber Security – Communications between Control Centers*, Order No. 866, 170 FERC ¶ 61,031 (Jan. 23, 2020) ("*Order 866*").

[115] *Critical Infrastructure Protection Rel. Standard CIP-012-1 – Cyber Security – Communications between Control Centers*, 167 FERC ¶ 61,055 (Apr. 18, 2019) ("*CIP-012-1 NOPR*").

[116] *Id.* at P 42.

[117] *Order 866* was published in the *Fed. Reg.* on Feb. 7, 2020 (Vol. 85, No. 26) pp. 7,197-7,204.

[118] *N. Amer. Elec. Rel. Corp.*, 170 FERC ¶ 61,029 (Jan. 23, 2020) ("*2020 Five Year Order*"). NERC's performance assessment report, filed July 22, 2019, (i) identified how NERC and its Regional Entities' activities and achievements during the Assessment Period (2014-2018) build upon the certification criteria of 18 C.F.R. § 39.3(b); (ii) evaluated the effectiveness of each Regional Entity in carrying out its Delegated Authority; and (iii) addressed stakeholder comments on NERC's performance (specific comments attached as directed by the FERC in *N. Amer. Elec. Rel. Corp.*, 149 FERC ¶ 61,141, at P 70 (2014) ("*2014 Five Year Order*")).

[119] *Id.* at P 2.

funding construction of the Line. Comments on the 203 application were due on or before December 31, 2019; none were filed. Doc-less interventions were filed by Eversource, HQUS and National Grid. On January 8, 2020, CMP supplemented the application to correct an error in the accounting entries attached as Exhibit N to the original application. This matter remains pending before the FERC.

- **203 Application: Verso/Pixelle (EC20-20)**

On February 12, Pixelle informed the FERC that the authorized sale[120] of 100% of the indirect membership interests in Verso Energy Services and Verso Androscoggin to Pixelle Specialty Solutions LLC ("Pixelle") occurred on February 10, 2020. Verso Energy Services is now known as Pixelle Energy Services and will remain a member of the Generation Sector. Reporting on this proceeding has now concluded.

- **203 Application: Emera Maine/ENMAX (EC19-80)**

On June 25, the FERC authorized a transaction pursuant to which Emera Maine (though not the Emera Energy Service Companies) will become a wholly-owned, indirect subsidiary of ENMAX Corporation, an Alberta corporation wholly-owned by the City of Calgary, Alberta, Canada ("ENMAX"), rather than Emera Inc.[121] Pursuant to the June 25 order, notice must be filed within 10 days of consummation of the transaction, which as of the date of this Report has not yet occurred.

- **PJM MOPR-Related Proceedings (EL18-178; EL16-49)**

On December 19, 2019, in a long-awaited order (approved 2-1),[122] the FERC ***found*** that "any resource, new *or existing*, that receives, or is entitled to receive, a State Subsidy, and does not qualify for [an exemption], should be subject to the [Minimum Offer Price Rule ("MOPR")]"[123] and ***directed*** PJM to submit a replacement rate that "extends the MOPR to include both new and existing resources, internal and external, that receive, or are entitled to receive, certain out-of-market payments, with certain exemptions."[124] The FERC directed PJM to include five exemptions: (1) a Self-Supply Exemption [PP 12; 202-204]; (2) a Demand Response, Energy Efficiency, and Capacity Storage Resources Exemption [PP 13; 208-209]; (3) a RPS Exemption [PP 14; 173-174]; (4) a Competitive Exemption [PP 15; 161]; and (5) a Unit-Specific Exemption [PP 16; 214-216].[125] The FERC established the replacement rate under section 206 of the FPA, but declined to order refunds (which it otherwise had the discretion to do).[126] The FERC directed PJM to submit a compliance filing consistent with its guidance on or before March 18, 2020 (90 days from the date of the *Dec 2019 PJM MOPR Order*). In the compliance filing, PJM was directed to also provide revised dates and timelines for the 2019

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[120] *Verso Androscoggin LLC and Verso Energy Services LLC*, 170 FERC ¶ 62,037 (Jan. 17, 2020).

[121] *Emera Maine*, 167 FERC ¶ 62,194 (June 25, 2019).

[122] *PJM Interconnection, L.L.C.* and *Calpine Corp. et al.*, 169 FERC ¶ 61,239 (Dec. 19, 2019) ("*Dec 2019 PJM MOPR Order*").

[123] *Id.* at P 9 (emphasis added).

[124] *Id.* at P 2 ("[g]oing forward, the default offer price floor for applicable new resources will be the Net Cost of New Entry ("Net CONE") for their resource class; the default offer price floor for applicable existing resources will be the Net Avoidable Cost Rate ("Net ACR") for their resource class").

[125] *Id.* ("The replacement rate will include three categorical exemptions to reflect reliance on prior Commission decisions: (1) existing self-supply resources, (2) existing demand response, energy efficiency, and storage resources, and (3) existing renewable resources participating in RPS programs. The replacement rate will also include a fourth exemption, the Competitive Exemption, for new and existing resources that are not subsidized and thus do not generally require review to protect 'the integrity and effectiveness of the capacity market.' To preserve flexibility, PJM will also permit new and existing suppliers that do not qualify for a categorical exemption to justify a competitive offer below the applicable default offer price floor through a Unit-Specific Exemption.")

[126] *Id.* at P 3. The FERC had previously established a refund effective date of March 21, 2016, the date of the original Calpine Complaint in EL16-49.

Base Residual Auction ("BRA") and related incremental auctions, along with revised dates and timelines for the May 2020 BRA and related incremental auctions.[127]

The *Dec 2019 PJM MOPR Order* is the latest milestone in the FERC's consideration of out-of-market support affecting the PJM capacity market.[128] As previously reported, the FERC found in a *June 2018 PJM MOPR Order*[129] that "the integrity and effectiveness of the capacity market administered by [PJM] have become untenably threatened by out-of-market payments provided or required by certain states for the purpose of supporting the entry or continued operation of preferred generation resources," determined that the PJM Tariff was unjust and unreasonable, rejected the PJM MOPR Filing, granted in part Calpine's Complaint, and *sua sponte* initiated a new FPA section 206 proceeding (EL18-178) in which it conducted a paper hearing to resolve proposed alternatives, whether put forth in the *June 2018 PJM MOPR Order* or otherwise,[130] addressing "price-suppressive" effects of out-of-market support for certain resources.

The *Dec 2019 PJM MOPR Order* affirms the FERC's prior finding that "[a]n expanded MOPR with few or no exceptions, should protect PJM's capacity market from the price-suppressive effects of resources receiving out-of-market support by ensuring that such resources are not able to offer below a competitive price."[131] The expanded MOPR[132] only applies to "State-Subsidized Resources" (Resources that receive, or are entitled to receive, State Subsidies).[133] The FERC considers a "State Subsidy" to be:

> a direct or indirect payment, concession, rebate, subsidy, non-bypassable consumer charge, or other financial benefit that is (1) a result of any action, mandated process, or sponsored process of a state government, a political subdivision or agency of a state, or an electric cooperative formed pursuant to state law, and that (2) is derived from or connected to the procurement of (a) electricity or electric generation capacity sold at wholesale in interstate commerce, or (b) an

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[127] *Id.* at P 4. As previously reported, the FERC directed PJM not to run the BRA in August 2019 as it had proposed to do (*see Calpine et al. v. PJM*, 168 FERC ¶ 61,051 (July 25, 2019)).

[128] The *PJM 2019 MOPR Order* addressed a paper hearing that arose from two separate, but related proceedings. The first, EL16-49, was initiated by a complaint originally filed by Calpine, joined by additional generation entities ("Calpine Complaint") on March 21, 2016, and later amended on January 9, 2017. The Calpine Complaint argued that PJM's MOPR was unjust and unreasonable because it did not address the impact of existing resources receiving out-of-market payments on the capacity market, and proposed interim tariff revisions that would extend the MOPR to a limited set of existing resources. The Calpine Complaint also requested the FERC to direct PJM to conduct a stakeholder process to develop and submit a long-term solution. The second proceeding was PJM's filing of its proposed revisions to its Tariff, pursuant to section 205 of the FPA in ER18-1314 ("PJM MOPR Filing"). The PJM MOPR Filing consisted of two alternate proposals designed to address the price impacts of state out-of-market support for certain resources. The first approach, preferred by PJM but not supported by its stakeholders, consisted of a two-stage annual auction, with capacity commitments first determined in stage one of the auction and the clearing price set separately in stage two ("Capacity Repricing"). The second alternative approach, proposed in the event that the FERC determined that Capacity Repricing was unjust and unreasonable, would have revised PJM's MOPR to mitigate capacity offers from both new and existing resources, subject to certain proposed exemptions ("MOPR-Ex"). A summary of the development and FERC consideration of PJM's capacity market is set out in the Order.

[129] *Calpine Corp. et al.*, 163 FERC ¶ 61,236 (June 29, 2018) ("*June 2018 PJM MOPR Order*"), *clarif. and/or reh'g requested*.

[130] The proposed alternative approach would have (i) modified PJM's MOPR such that it would apply to new and existing resources that receive out-of-market payments, regardless of resource type, but would include few to no exemptions; and (ii) in order to accommodate state policy decisions and allow resources that receive out-of-market support to remain online, established an option in PJM's Tariff that would allow, on a resource-specific basis, resources receiving out-of-market support to choose to be removed from the PJM capacity market, along with a commensurate amount of load, for some period of time. That option, which is similar in concept to the Fixed Resource Requirement ("FRR") that currently exists in PJM's Tariff, is referred to as the "FRR Alternative." Unlike the existing FRR construct, the FRR Alternative would apply only to resources receiving out-of-market support.

[131] *Dec 2019 PJM MOPR Order* at P 5.

[132] The FERC adopted an expanded MOPR rather than PJM's Resource Carve-Out ("RCO") and Extended RCO proposals. The FERC determined that those proposals would unacceptably distort the markets, inhibiting incentives for competitive investment in the PJM market over the long term. PJM's longstanding FRR Alternative remains unchanged in the PJM tariff. *See Id.* at P 6.

[133] Resources with federal subsidies will not be subject to the MOPR. *See Id.* at P 10.

attribute of the generation process for electricity or electric generation capacity sold at wholesale in interstate commerce, or (3) will support the construction, development, or operation of a new or existing capacity resource, or (4) could have the effect of allowing a resource to clear in any PJM capacity auction.[134]

The FERC declined to adopt a materiality threshold for the level of State Subsidies or the size of State-Subsidized Resources. State-Subsidized Resources "that intend to offer below the default offer price floor for a given resource type, and do not qualify for [one of the four] categorical exemption[s], must support their offers through a Unit-Specific Exemption."[135] While the FERC acknowledged that the extension of the MOPR may prevent certain existing resources that states have recently chosen to subsidize from clearing PJM's capacity auctions, it noted that states may continue to support their preferred resource types in pursuit of state policy goals and make decisions about preferred generation resources, with "resources that states choose to support, and whose offers may fail to clear the capacity market under the revised MOPR directed in this order, … still … permitted to sell energy and ancillary services in the relevant PJM markets."[136] The *Order*, the FERC highlighted, "addresses the growing impact of State-Subsidized Resources because those subsidies reject the premise of the capacity market and circumvent competitive outcomes."[137]

The *Dec 2019 PJM MOPR Order* was accompanied by a 28-page dissent of Commissioner Glick ("Glick Dissent"), who explained why he believes the Order to be "illegal, illogical, and truly bad public policy."[138] Commissioner Glick further suggested that it "may well be that a mandatory capacity market is no longer a sensible approach to resource adequacy at a time when states are increasingly exercising their authority under the FPA to shape the generation mix. Indeed, the conclusion that I draw from the record in front of us is not that there is an urgent need to mitigate the effects of state public policies, but rather that we should be taking a hard look at whether a mandatory capacity market remains a just and reasonable resource adequacy construct in today's rapidly evolving electricity sector."[139]

Requests for Rehearing. Requests for rehearing and/or clarification ("Requests") of the *Dec 2019 PJM MOPR Order* were filed by over 50 parties, including: PJM IMM, AEP/Duke, AES, Buckeye Power, Calpine, Clean Energy Advocates,[140] CPower, Dominion, EDF Renewables, Exelon, FirstEnergy Utility Companies, First Energy Solutions, Hershey Co., J-POWER, Longroad Development, PSEG, Vistra, Allegheny Electric Coop., East Kentucky Power Coop. ("EKPC"), IL Municipal Electric Agency, North Carolina Electric Membership Corp., Old Dominion Elec. Coop., the S. MD Elec. Coop, the Organization of PJM States ("OPSI"), DC PSC, IL ICC, MD PSC, NJ BPU, OH PUC, PA PUC, VA State Corporation Commission, WV PSC, DE Public Advocate, DC AG, IL AG, MD AG, NJ Div. of Rate Counsel/People's Counsel for DC/MD People's Counsel, OH Consumers' Counsel, PJM Consumer Representatives,[141] Advanced Energy Buyers Group, Advanced Energy Economy ("AEE"),

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[134] *Id.* at P 9. Renewable Energy Credits (RECs) procured as part of a state-mandated or state-sponsored procurement process are State Subsidies. *Id.* at P 176. Demand response, energy efficiency, and capacity storage resources that participate in the PJM capacity market are considered to be capacity resources for purposes of this definition. *Id.* at P 9.

[135] *Id.* ("A threshold based on resource size will not prevent a collection of smaller resources from having a significant cumulative impact on competitive outcomes. In addition, if a State Subsidy is small enough for a capacity resource to perform economically without it, then the State-Subsidized Resource should be able to secure a Unit-Specific Exemption.")

[136] *Id.* at P 7.

[137] *Id.* at P 17.

[138] Glick Dissent at P 1.

[139] Id. at P 62.

[140] "Clean Energy Advocates" are, for the purposes of this proceeding, Environmental Defense Fund ("EDF"), Natural Resources Defense Council ("NRDC), Sierra Club, Sustainable FERC Project, and Union of Concerned Scientists ("UCS").

[141] PJM Consumer Representatives are: PJM Industrial Customer Coalition ("PJMICC"), Illinois Industrial Energy Consumers ("IIEC"), the Electricity Consumers Resource Council, ("ELCON"), Industrial Energy Consumers of America ("IECA"), the Pennsylvania Energy

APPA/AMP/Public Power Assoc. of NJ, AWEA, ELCON, EPSA and the PJM Power Providers Group, NEI, NRECA/EKPC, and Public Citizen. An answer to PJM IMM's request for clarification was filed by the Talen PJM Companies. Answers were also filed by the PJM IMM, Longroad Development and Old Dominion Electric Cooperative. EEI filed a motion for reconsideration. On February 18, 2020, the PJM IMM filed a second request for clarification and The National Association of State Energy Officials filed a letter to the Commissioners. On February 25, Old Dominion answered EEI's request for reconsideration. On February 28, the MD PSC answered the IMM's second request for clarification. The FERC issued a tolling order on February 18, 2020 affording it additional time to consider the Requests, which remain pending before the FERC.

Also, the New Jersey Division of Rate Counsel ("NJ Rate Counsel"), out of an abundance of caution, appealed the *Dec 2019 PJM MOPR Order*. NJ Rate Counsel explained that it sought judicial review now in case the DC Circuit's action in *Allegheny Defense Project v. FERC*[142] work to advance the time period for those wishing to seek judicial review of the *Dec 2019 PJM MOPR Order.* Until a decision on *Allegheny Defense Project v. FERC* is issued and its import known, NJ Rate Counsel asked the DC Circuit to hold its appeal in abeyance. For further information on these proceedings, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **PJM Clean MOPR Complaint (EL18-169)**

This proceeding, which could impact potentially impact New England's markets, remains pending. As previously reported, CPV Power Holdings, L.P. ("CPV"), Calpine Corporation ("Calpine"), and Eastern Generation, LLC ("Eastern Generation") (collectively, "PJM MOPR Complainants") filed a complaint on May 31, 2018 requesting that the FERC protect PJM's Reliability Pricing Model ("RPM") market from below-cost offers for resources receiving out-of-market subsidies by requiring PJM to adopt a "Clean MOPR" (i.e. a MOPR applicable to all subsidized resources and without categorical exemptions like those in PJM's MOPR-Ex proposal). PJM MOPR Complainants state that the Complaint offers the FERC a procedural vehicle to require adoption of the "Clean MOPR" that Complainants opine is not otherwise available in EL16-49 and EL18-178 (the PJM MOPR-Related Proceedings). They assert that the "Clean MOPR" is required to effectively address the impacts of state subsidy programs, and is consistent with the FERC's MOPR principles identified in the *CASPR Order*. Comments on the PJM Clean MOPR Complaint were due on or before June 20, 2019. PJM's answer, as well as comments and protests from over 25 parties were filed. Given its potential to impact New England, NEPOOL filed a doc-less motion to intervene. More than 30 other parties also intervened. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **NYISO MOPR Proceeding (IPNYY Complaint) (EL13-62)**

On February 20, 2020, the FERC issued orders in four NYISO Capacity Market-related proceedings, including an order in this proceeding.[143]

The *IPPNY Complaint Rehearing Order* in this proceeding denied all requests for rehearing and/or clarification of the FERC's findings in the *Complaint Order*[144] (other than a request that its findings regarding

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Consumer Alliance ("PECA"), the Industrial Energy Consumers of Pennsylvania ("IECPA"), and the American Forest and Paper Association ("AF&PA").

[142] *Allegheny Def. Project v. FERC*, Case No. 17-1098 (D.C. Cir. Dec. 5, 2019).

[143] *Indep. Power Producers of NY, Inc. v. NYISO*, 170 FERC ¶ 61,118 (Feb. 20, 2020) ("*IPPNY Complaint Rehearing Order*").

[144] *Indep. Power Producers of NY, Inc. v. NYISO*, 150 FERC ¶ 61,214, at P 1 (2015) ("*Complaint Order*"). IPPNY's Complaint argued, unsuccessfully, that NYISO's Services Tariff was unjust and unreasonable because, by allowing for *de minimis* offers from existing capacity resources that would have exited the market but for the determination that those resources are needed for reliability, NYISO was allowing artificial price suppression in its ICAP markets. The FERC found that IPPNY failed to demonstrate conduct that was inconsistent with competitive bidding behavior or harm to the market that justified excluding the identified resources, and agreed with the NYISO MMU that "the units were economic from the perspective of satisfying . . . NYISO's reliability requirements."

the two Reliability Support Services Agreements in its *Complaint Order* did not prejudge the issues raised (and since addressed) in a NYISO RMR proceeding in Docket No. ER16-120). The *Complaint Order* denied IPPNY's request that certain capacity resources be prevented from being offered into the ICAP market at a *de minimis* price, thereby artificially suppressing prices. Of note, the *IPPNY Complaint Rehearing Order* was limited to the facts and circumstances presented in this proceeding and, consistent with NEPOOL's comments filed more than three years ago, does not limit New England's latitude to address through the NEPOOL stakeholder process its markets given its specific facts here in New England.

SCR Order. The FERC issued contemporaneously three additional orders related to NYISO's capacity market buyer-side market power mitigation rules. In the first, an order on rehearing issued in EL16-92-001 and ER17-996, the FERC addressed the application of NYISO's buyer-side market power mitigation rules to the participation of Special Case Resources ("SCRs") in NYISO's ICAP market.[145] The FERC found that SCRs should continue to be subject to NYISO's buyer-side market power mitigation rules when bidding into NYISO's ICAP markets, but SCRs' offer floors should include only the incremental costs of providing wholesale-level capacity services, and should not include payments from retail-level demand response programs ("Retail DR Programs") designed to address distribution-level reliability needs. Because it found the information related to those Retail DR Programs limited and stale, the FERC reopened the record for a paper hearing to give parties an additional opportunity to submit evidence as to which specific Retail DR Programs addressed in the complaint are designed to and do address distribution-level reliability needs. The FERC clarified that the relief directed s prospective and it would not re-run any mitigation exemption tests. The FERC rejected as moot NYISO's compliance filing in ER17-996, which in response to the Complaint order, would have exempted all new SCRs from buyer-side market power mitigation rules.

Storage Order. In the second additional order, in EL19-86,[146] the FERC denied a complaint by the New York Public Service Commission ("NY PSC") and the New York State Energy Research and Development Authority ("NYSERDA") regarding the application of NYISO's buyer-side market power mitigation rules to electric storage resources' entry and participation in NYISO's capacity market. The FERC disagreed with arguments that subjecting electric storage resources to buyer-side market power mitigation limits those resources' entry and participation in NYISO's capacity market, or that such mitigation was somehow inconsistent with *Order 841*.

Renewable Resource and Self-Supply Exemptions Order. In the third and final additional order, in ER16-1404,[147] the FERC addressed NYISO's April 13, 2016 compliance filing, which proposed renewable resource and self-supply exemptions to NYISO's buyer-side market power mitigation rules in response to the FERC's October 9, 2015 order granting in part, and denying in part, a complaint by the NY PSC, NYSERDA and NYPA. The order accepted, subject to conditions, including a 30-day compliance filing, NYISO's renewable resource and self-supply exemptions. The Order acknowledged that it "addresses buyer-side market power mitigation for renewable resources and self-supply resources in a different way than the Commission recently addressed such resources in [PJM]" explaining that "regional markets are not required to have the same rules. Our determination about what rules may be just and reasonable for a particular market depends on the relevant facts."

Reporting on these proceedings in these monthly Reports has now concluded. If you have any questions concerning this proceeding, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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145 *NY PSC et al v. NYISO,* 170 FERC ¶ 61,120 (Feb. 20, 2020) ("*SCR Order*").

146 *NY PSC and NYSERDA v. NYISO*, 170 FERC ¶ 61,119 (Feb. 20, 2020) ("*Storage Order*").

147 *NYISO*, 170 FERC ¶ 61,121 (Feb. 20, 2020) ("*Renewable Resource and Self-Supply Exemptions Order*").

- **IA / TSA Cancellations: Emera Maine/ReEnergy Fort Fairfield (ER20-1076/1077)**

On February 26, 2020, Emera Maine filed notices of cancellation of both the Interconnection Agreement ("IA") (ER20-1076) and Transmission Service Agreement ("TSA") (ER20-1077) between itself and ReEnergy Fort Fairfield LLC ("Fort Fairfield"). The Agreements have been cancelled in light of the termination of operations at the 37 MW Fort Fairfield biomass facility. A February 24, 2020 effective date for each of the notices of cancellation was requested. Comments on these filings are due on or before March 18, 2020. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Northern Pass: TSA Cancellation / Cost Reimbursement (ER20-1030/1031)**

On February 18, Northern Pass Transmission LLC ("Northern Pass") submitted (i) a notice of termination of its bilateral, cost-based Transmission Service Agreement ("TSA") with Hydro Renewable Energy Inc. ("HRE") for transmission service over the Northern Pass Transmission Project; and (ii) a December 16, 2019 agreement between Northern Pass and Hydro-Québec Production ("HQP") under which HQP has agreed to reimburse Northern Pass for certain Project costs. Northern Pass is no longer moving forward with the Project as a result of the New Hampshire Site Evaluation Committee's decision to deny a Certificate of Site and Facility for the Project, a decision that was affirmed by the New Hampshire Supreme Court on July 19, 2019. Northern Pass requested a September 6, 2019 effective date for the TSA termination and April 19, 2020 for the Letter Agreement. Comments on these filings are due on or before March 10, 2020. If there are questions on these proceedings, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Amended and Restated CONVEX Services Agreement: CL&P/MMWEC (ER20-996)**

On February 13, Eversource filed an Amended and Restated Agreement for CONVEX Services between CL&P and MMWEC. Under the Agreement, CL&P provides certain scheduling and dispatching services to MMWEC through the Connecticut Valley Exchange ("CONVEX") dispatch center. The amendments reflect the fact that MMWEC has elected not to take certain services previously provided by CONVEX (services related to switching and tagging, and training and coordination on switching and tagging plans). Eversource asked that the amended and restated Agreement become effective February 14, 2020. Comments on this filing are due on or before March 5, 2020. If there are questions on this proceeding, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Facilities Use Agreement Cancellation: NGrid/Deepwater Block Island Wind (ER20-960)**

On February 6, New England Power ("NEP") filed a notice of cancellation of its Facilities Use Agreement with Deepwater Block Island Wind. The Facilities Use Agreement allowed for the use of certain interconnection facilities constructed and owned by Narragansett and operated and maintained by NEP, in order to facilitate the construction and commercial operation of the Block Island Wind Farm. The Facilities Use Agreement went into effect on July 28, 2016. Because the Block Island Wind Farm has been completed and is in commercial operation, the parties agreed to cancel that agreement and requested an April 7, 2020 effective date. Comments on the notice were due on or before February 27, 2020; none were filed. This proceeding is pending before the FERC. If there are questions on this proceeding, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Related Facilities Agreement Cancellations: Clear River Energy (ER20-729/730)**

On February 27, 2020, the FERC accepted both CL&P's (ER20-729)[148] and NSTAR's (ER20-730)[149] notice of cancellation of their Related Facilities Agreements ("RFA") with Clear River. The RFAs provided the terms and conditions governing activities and cost responsibility associated with required upgrades in connection with Clear River's LGIA with ISO-NE and National Grid. In light of the cancellation of that LGIA (*see* ER20-586 in

[148] *Conn. Light and Power Co.*, Docket No. ER20-729 (Feb. 27, 2020) (unpublished letter order).

[149] *NSTAR Elec. Co.*, Docket No. ER20-730 (Feb. 27, 2020) (unpublished letter order).

Section VI above), Clear River provided a written notice of cancellation of each of the RFAs on November 25, 2019. Each of the cancellation notices were accepted effective as of November 25, 2019, as requested. Unless the February 27 order are challenged, these proceedings will be concluded. If there are questions on these proceedings, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Emera Maine *Order 845* Compliance Filing (ER19-1887)**

On May 17, 2019, in response to the requirements of *Order 845*, Emera Maine submitted changes to the LGIP and LGIA in its Open Access Transmission Tariff for the Maine Public District (the "MPD OATT"). Emera Maine request a May 20, 2019 effective for the changes. Though no comments were filed, the FERC issued a letter in a number of utility filing proceedings, including this one, requesting additional information related to the provisions for surplus interconnection service be filed within 30 days (or July 15). Emera Maine filed a response to the FERC's letter on July 15. Comments on that filing were due on or before August 5; none were filed. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **FERC Enforcement Action: ExGen Start-Up Fuel Reporting to ISO-NE (IN20-3)**

On January 10, the FERC approved a Stipulation and Consent Agreement with Exelon Generation Company, LLC ("ExGen")[150] that resolved the investigation by FERC's Office of Enforcement ("OE") into erroneous data transmitted to ISO-NE by ExGen regarding the type and quantity of fuel used to start up Mystic 7. OE determined and ExGen admitted that, from December 2014 through August 2016, as a result of an internal spreadsheet error, Mystic 7's supply offers indicated that it exclusively used No. 6 fuel oil (rather than natural gas) to start up, which caused ExGen to be overcompensated by ISO-NE when Mystic 7 was dispatched out-of-merit. OE did not conclude that ExGen purposefully submitted false data to ISO-NE and accepted the ExGen's representation that the errors were inadvertent. Under the Stipulation and Consent Agreement, ExGen must ***disgorge $101,756*** (plus interest) to ISO-NE, to be allocated by ISO-NE in its discretion for the benefit of ISO-NE customers and upon approval by OE of ISO-NE's plan for doing so, and ***pay a $32,500 civil penalty*** to the United States Treasury. The funds disgorged were allocated to Market Participants on the February Monthly Invoices/Statements. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **FERC Enforcement Action: Emera ISO-NE Tariff Violations (IN20-2)**

Also on January 10, the FERC approved a Stipulation and Consent Agreement with Emera Energy ("Emera")[151] that resolved OE's investigation into Emera's violations of the ISO-NE Tariff requirement that Fuel Price Adjustment ("FPA") Requests ("FPA Requests") use fuel costs that reflect an arm's length fuel purchase transaction. OE determined that, on 16 occasions, Emera's FPA Requests for Rumford used information from postings by Emera Energy's gas desk (made specifically to provide the necessary documentation to support an FPA request) rather than information from an arm's length transaction. The reporting resulted in NCPC overpayments of $14,120 when Emera Energy increased its ISO-NE reference level by requesting an above-market fuel price adjustment. Under the Stipulation and Consent Agreement, Emera agreed to ***disgorge $14,120*** (*plus* ***$2,002.19*** in interest) to ISO-NE, to be allocated by ISO-NE in its discretion for the benefit of ISO-NE customers, and ***pay a $5,000 civil penalty*** to the United States Treasury. The funds disgorged were allocated to Market Participants on the February Monthly Invoices/Statements. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

MISO Zone 4 Planning Resource Auction Offers. On October 1, 2015, the FERC issued an order authorizing OE to conduct a non-public, formal investigation, with subpoena authority, regarding violations of

150 *Exelon Generation Co., LLC*, 170 FERC ¶ 61,008 (Jan. 10, 2020).

151 *Exelon Generation Co., LLC*, 170 FERC ¶ 61,008 (Jan. 10, 2020).

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. There has been no public update provided since that order.

- **FERC Enforcement Action: Order Assessing Civil Penalties – Vitol & F. Corteggiano (IN14-4)**

On October 25, 2019, the FERC issued an order[152] finding Vitol Inc. ("Vitol") and its co-head of FTR trading operations, Frederico Corteggiano, violated from October 28-November 1, 2013, the FERC's Anti-Manipulation Rule by selling physical power at a loss in CAISO's market in order to eliminate congestion that they expected to cause losses on Vitol's congestion revenue rights ("CRRs").[153] The FERC assessed civil penalties of $1,515,738 against Vitol and $1 million against Corteggiano. In addition, the FERC directed Vitol to disgorge unjust profits, plus applicable interest of $1,227,143.

Because Respondents' previously elected the FPA's *de novo* review procedures, which permits a reviewing federal court "to review *de novo* the law and the facts involved" and "jurisdiction to enter a judgment . . . modifying . . . or setting aside [the assessment] in whole or in Part", the *Vitol Penalties Order* was not subject to rehearing. On January 6, 2020, the FERC instituted an action in federal district court (Eastern District of California) for an order affirming the penalties assessed against Respondents and ordering Vitol to disgorge its unjust profits, plus interest.[154] Reporting on this case will be continued in future Reports, when and as appropriate, in Section XV.

XII. Misc. - Administrative & Rulemaking Proceedings

- **Credit Reforms in Organized Wholesale Markets (AD20-6)**

On December 16, 2019, the Energy Trading Institute[155] requested that the FERC hold a technical conference and conduct a rulemaking to update the requirements adopted in *Order 741*[156] and Section 35.47 of the FERC's regulations addressing credit and risk management in the markets operated by RTO/ISOs. ETI, citing a

[152] *Vitol Inc. and Federico Corteggiano*, 169 FERC ¶ 61,070 (Oct. 25, 2019) ("*Vitol Penalties Order*").

[153] Enforcement Staff alleges that Vitol and Corteggiano ("Respondents") sold physical power at a loss at the Cragview node in CAISO's day-ahead market from Oct. 28 through Nov. 1, 2013, in order to eliminate congestion costs that they expected would negatively affect Vitol's CRRs. On Vitol's behalf, Corteggiano purchased CRRs sourcing at Cragview in CAISO's annual CRR auction for 2013. In mid-October 2013, CAISO derated the Cascade intertie to "0" in only the export direction, while still allowing imports. During the derate, an unusually high LMP appeared at Cragview due to congestion costs. The congestion costs caused Respondents' CRRs to lose money. CAISO announced that identical derates would occur during the week of October 28 through November 1 and on additional dates later in November and in December. Respondents were able to protect against losses on their CRR positions for November and December by buying counter-flow CRRs in the CRR auctions for those months (i.e., "flattening" the CRR position). However, because the monthly CRR auction for October had closed, it was too late for Respondents to flatten their CRR position for the last week of October. Facing over $1.2 million in potential losses on their CRRs during that week's scheduled partial derate, Respondents imported physical power in the day-ahead market at an offering price of $1/MWh, which prevented a recurrence of the congestion costs that Respondents had observed during the October 18-19 derate. Staff alleges Respondents undertook the import transactions in disregard of market fundamentals and were indifferent to whether they made a profit on them. In fact, Respondents lost money on the imports, but avoided a far larger loss on their CRRs. *Id.* at P 3.

[154] FERC v. Vitol Inc. and Federico Corteggiano, Case No. 2:20-cv-00040-KJM-AC (E. D. CA) (filed Jan. 6, 2020).

[155] In its request, The Energy Trading Institute ("ETI") describes itself generally as "represent[ing] a diverse group of energy market participants, all with substantial interests in wholesale electricity transactions in Commission-jurisdictional markets. ETI members provide important services to a wide variety of wholesale energy market participants. They act as intermediaries between producers and consumers of electric energy that have mismatched quantity, timing, and contract type needs. In addition, they provide liquidity by engaging in energy related commercial transactions with a variety of market entities including, but not limited to, generation owners, project developers, load-serving entities, and investors. ETI members advocate for markets that are open, transparent, competitive and fair - all necessary attributes for markets ultimately to benefit electricity consumers."

[156] *Credit Reforms in Organized Wholesale Elec. Mkts.*, 75 Fed. Reg. 65942 (2010), FERC Stats. & Regs. ¶ 31,317 (2010) ("*Order 741*"); *order on reh'g*, 76 Fed. Reg. 10492 (2011), FERC Stats. & Regs. ¶ 31,320 (2011) ("*Order 741-A*"); *order on reh'g*, 135 FERC ¶ 61,242 (2011) (*"Order 741-B*"); 18 C.F.R. § 35.47.

recent filing by NYISO (which it protested),[157] and stating that several expedited initiatives related to RTO/ISO credit policies are underway, suggested that it would be helpful for the FERC to consolidate any "filings with this proceeding and hold the technical conference ETI is requesting by March 30, 2020 so the ISOs, RTOs and their stakeholders consider those discussions in any initiatives they have underway." ETI suggested in its request that RTO/ISO credit support requirements be standardized, and that the requested technical conference and rulemaking explore various ways to identify and mitigate counterparty risk (including know-you-customer ("KYC") tools and participant suspensions or bans) and enhance risk management infrastructure/processes within the organized markets. Doc-less interventions have been filed by, among others, PJM, the PJM IMM, SPP, CAISO, Tenaska, Avangrid, and Roscommon Analytics. On January 24, the ISO/RTO Council ("IRC"), including ISO-NE, submitted comments and proposed, as an alternative approach to the one suggested by ETI, that the FERC not commence a rulemaking or schedule a technical conference at this time and instead allow individual RTO/ISOs to address their respective credit and risk management issues, permit sufficient time for experience with the evolving rules to be gained, and then consider the best path forward to facilitate a dialogue on best practices and potential points of alignment among the RTO/ISO. ETI responded to those comments on February 10, 2020. On February 11, the FERC issued a notice of ETI's request for technical conference and petition for rulemaking, setting a March 12, 2020 deadline for comments thereon.

- **Joint Staff White Paper on Notices of Penalty for Violations of CIP Standards (AD19-18)**

On August 27, 2019, the FERC published for public comment a White Paper prepared jointly with NERC staff setting out a proposed new format for NERC Notices of Penalty ("NOP") involving violations of CIP Reliability Standards. The FERC explained that the revised format is intended to improve the balance between security and transparency in the filing of NOPs. Specifically, NERC CIP NOP submissions would consist of a proposed public cover letter that discloses the name of the violator, the Reliability Standard(s) violated (but not the Requirement), and the penalty amount. NERC would submit the remainder of the CIP NOP filing containing details on the nature of the violation, mitigation activity, and potential vulnerabilities to cyber systems as a nonpublic attachment, along with a request for the designation of such information as CEII.

Public comment on the proposal was sought with respect to the following: (i) the potential security benefits from the new proposed format; (ii) potential security concerns that could arise from the new format; (iii) any other implementation difficulties or concerns that should be considered; and (iv) whether the proposed format provides sufficient transparency to the public. Other suggested approaches to CIP NOP submissions were welcomed. No changes to the CIP NOP filing format will be made prior to consideration of public comment on the White Paper. Comments were filed by over 80 parties. This matter is pending before the FERC.

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

On January 8, 2018, the FERC initiated a Grid Resilience in RTO/ISOs proceeding (AD18-7)[158] and terminated the DOE NOPR rulemaking proceeding (RM18-1).[159] In terminating the DOE NOPR proceeding, the FERC concluded that the Proposed Rule and comments received did not support FERC action under Section 206 of

[157] *See* Proposed Tariff Amendments to Enhance Credit Reporting Requirements and Remedies, *New York Indep. Sys. Operator*, Inc., Docket No. ER20-483 (filed Nov. 26, 2019).

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

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

the FPA, but did suggest the need for further examination by the FERC and market participants of the risks that the bulk power system faces and possible ways to address those risks in the changing electric markets. On February 7, Foundation for Resilient Societies ("FRS") requested rehearing of the January 8 order terminating the DOE NOPR proceeding. The FERC issued a tolling order on March 8, 2018 affording it additional time to consider the FRS request for rehearing, which remains pending.

Grid Resilience Administrative Proceeding (AD18-7). AD18-7 was initiated to evaluate the resilience of the bulk power system in RTO/ISO regions. The FERC directed each RTO/ISO to submit information on certain resilience issues and concerns, and committed to use the information submitted to evaluate whether additional FERC action regarding resilience is appropriate. RTO submissions were due on or before March 9, 2018.

ISO-NE Response. In its response, ISO-NE identified fuel security[160] as the most significant resilience challenge facing the New England region. ISO-NE reported that it has established a process to discuss market-based solutions to address this risk, and indicated that it believed it will need through the second quarter of 2019 to develop a solution and test its robustness through the stakeholder process. In the meantime, ISO-NE indicated that it would continue to independently assess the level of fuel-security risk to reliable system operation and, if circumstances dictate, would take, with FERC approval when required, actions it determines to be necessary to address near-term reliability risks. ISO-NE's response was broken into three parts: (i) an introduction to fuel-security risk; (ii) background on how ISO-NE's work in transmission planning, markets, and operations support the New England bulk power system's resilience; and (iii) answers to the specific questions posed in the January 8 order.

Industry Comments. Following a 30-day extension issued on March 20, 2018, reply comments were due on or before May 9, 2018. NEPOOL's comments, which were approved at the May 4 meeting, were filed May 7, and were among over 100 sets of initial comments filed. A summary of the comments that seemed most relevant to New England and NEPOOL was circulated to the Participants Committee on May 15 and is posted on the NEPOOL website. On May 23, NEPOOL submitted a limited response to four sets of comments, opposing the suggestions made in those pleadings to the extent that the suggestions would not permit full use of the Participant Processes. Supplemental comments and answers were also filed by FirstEnergy, MISO South Regulators, NEI, and EDF. Exelon and American Petroleum Institute filed reply comments. FirstEnergy included in this proceeding its motion for emergency action also filed in ER18-1509 (ISO-NE Waiver Filing: Mystic 8 & 9), which Eversource answered (in both proceedings). Reply comments were filed by APPA and AMP and the Nuclear Energy Institute ("NEI") moved to lodge presentations by the National Infrastructure Advisory Council. On December 6, the Harvard Electricity Law Initiative filed a comment suggesting that, as a matter of law, "Commission McNamee cannot be an impartial adjudicator in these proceedings" and "any proceeding about rates for 'fuel-secure' generators" and should recuse himself. Similarly, on December 18, "Clean Energy Advocates"[161] requested Commissioner McNamee recuse himself from these proceedings. These matters remain pending before the FERC.

FirstEnergy DOE Application for Section 202(c) Order. In a related but separate matter, FirstEnergy Solutions ("FirstEnergy") asked the Department of Energy ("DOE") in late March to issue an emergency order to provide cost recovery to coal and nuclear plants in PJM, saying market conditions there are a "threat to energy security and reliability". FirstEnergy made the appeal under Section 202(c) of the FPA, which allows the DOE to issue emergency orders to keep plants operating, but has previously been exercised only in response to natural disasters. Action on that 2018 request is pending.

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[160] ISO-NE defined fuel security as "the assurance that power plants will have or be able to obtain the fuel they need to run, particularly in winter – especially against the backdrop of coal, oil, and nuclear unit retirements, constrained fuel infrastructure, and the difficulty in permitting and operating dual-fuel generating capability."

[161] For purposes of these proceedings, "Clean Energy Advocates" are NRDC, Sierra Club and UCS.

- **NOPR: QF Rates and Requirements; Implementation Issues under PURPA (RM19-15)**

In an action that could have significant impacts on the development and financing of renewable resources, the FERC, on September 19, 2019, proposed rules to reform its long-standing regulations implementing sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA").[162] Those regulations address the obligation of electric utilities to purchase power produced by "qualifying facilities" or "QFs" at rates that must be "just and reasonable to the electric consumers of the electric utility and in the public interest, and not discriminate against" those QFs.[163]

The *QF NOPR* seeks public comment on draft rule changes "to rebalance the benefits and obligations of the [FERC's] PURPA Regulations in light of the changes in circumstances since the PURPA Regulations were promulgated."[164] The *QF NOPR* proposes the following changes that would revise how and when prices for QF power may be established and would reduce the circumstances under which a utility's mandatory purchase obligation would be triggered:

- Provide states the flexibility to establish QF energy rates at the purchasing utility's avoided costs at the time of energy *delivery*, rather than allowing the QFs to elect to *fix* the energy rate for an extended term at the time the utility becomes compelled to purchase the QF's energy.
- Specify that an avoided cost rate for QF energy can be based on *market factors* (including locational market prices, indices, trading hubs, or competitive solicitation processes) or, at the state's discretion, can continue to be set as they are under current PURPA Regulations.
- Reduce in states with a retail choice program an electric utility's obligation to purchase from QFs to the extent that the utility's provider of last resort ("POLR") supply obligation has been reduced by the state's program. If POLR supplies are obtained through solicitations having a specific contract term, the term of any PURPA purchase contract should match the term of the POLR supply contract.
- Decrease from 20 MW to 1 MW the maximum size of QFs that would be entitled to require utilities located in areas with demonstrably competitive markets (RTO/ISOs) to purchase their power. If QF facilities qualify as cogeneration, the 20 MW cap would not change.
- Replace the "one-mile rule" for determining whether generation facilities under common ownership should be considered to be part of a single facility (to be eligible for favorable QF treatment, a small power production facility must be 80 MW or less). Some have argued that the current one-mile rule has been gamed to permit QF certification of projects that if combined would otherwise exceed the 80 MW cap. The impact of this change, if made, would primarily affect projects in non-RTO/ISO markets (e.g., the bilateral markets of the southern and western United States).
- Clarify that a utility's mandatory purchase obligation under PURPA does not arise until the QF can demonstrate commercial viability and financial commitment pursuant to objective and reasonable state-defined criteria.
- Allow for interested stakeholders to protest the self-certification of a QF.

Comments on the proposed rule changes were due on or before December 3, 2019.[165] More than 130 sets of comments were submitted, including comments from Bloom Energy, Borrego Solar, ConEd, Covanta, CT PURA, MA AG, MA DPU, and AEE. Since the last Report, several Congressman have sent comments supporting comments submitted by others. Chairman Chatterjee acknowledged each of the comments received from Congressmen.

[162] 16 U.S.C. § 2601 et seq. (2018). PURPA was enacted to help lessen the dependence on fossil fuels and promote the development of power generation from non-utility power producers.

[163] 16 U.S.C. § 824a–3; PURPA, Sec. 210(a)-(b).

[164] *Qualifying Facility Rates and Requirements; Implementation Issues Under the Public Utility Regulatory Policies Act of 1978*, Notice of Proposed Rulemaking, 168 FERC ¶ 61,184 (2019) ("*QF NOPR*").

[165] The *QF NOPR* was published in the *Fed. Reg.* on Oct. 4, 2019 (Vol. 84, No. 193) pp. 53,246-53,275.

Late filed comments were submitted by the American Dams, California PUC, TerraForm and the Arizona Corporation Commission. This matter remains pending before the FERC.

- ***Order 864*: Public Util. Trans. ADIT Rate Changes (RM19-5)**

On November 21, 2019, the FERC issued its final rule a NOPR ("*Order 864*")[166] requiring all public utility transmission providers with transmission rates under an OATT, a transmission owner tariff, or a rate schedule to revise those rates to account for changes caused by the 2017 Tax Cuts and Jobs Act ("2017 Tax Law"). Specifically, for transmission formula rates, *Order 864* requires public utilities (i) to deduct excess ADIT from or add deficient ADIT to their rate bases and adjust their income tax allowances by amortized excess or deficient ADIT; and (ii) to incorporate a new permanent worksheet into their transmission formula rates that will annually track ADIT information. The FERC did not adopt its proposals in the ADIT NOPR[167] that were applicable to public utilities with stated rates. *Order 864* will become effective January 27, 2020. Requests for rehearing were filed by APPA and Exelon. On January 21, 2020, the FERC issued a tolling order affording it additional time to consider the APPA and Exelon requests.

New England TO Compliance Filings - Extensions of Time to File. Since the last Report, National Grid (Feb 10), Eversource (Feb 18), UI (Feb 20), VT Electric Transmission Co. ("VETCO") (Feb 25), and New Hampshire Transmission ("NHT") (Feb 26) each requested that their deadline for submitting a compliance filing be extended until July 31, 2020—the date of the TOs' next annual informational filing for regional formula rates. The National Grid, Eversource, UI, and VETCO requests were granted on February 18, 24, 26, and March 2, respectively. The NHT request is still pending. As previously reported, the deadline for submitting *Order 864* compliance filings has already been extended to July 31, 2020 for VTransco.[168] New England Electric Transmission Corporation (ER20-1089), New England Hydro Transmission Electric Company (ER20-1088), and New England Hydro Transmission Corporation (ER20-1087) each submitted their compliance filings on February 26, 2020, with comments, if any, on those filings due on or before March 18, 2020.

- ***Order 861/861-A*: Refinements to Horizontal Market Power Analysis Requirements (RM19-2)**

On February 20, 2020, in *Order 861-A*,[169] the FERC granted CAISO's requested clarification and denied PG&E's request for rehearing and alternative request for clarification of *Order 861*.[170] As previously reported, *Order 861* relieves market-based rate ("MBR") sellers of the obligation, when seeking to obtain or retain MBR authority in any RTO/ISO market with RTO/ISO-administered energy, ancillary services, and capacity markets subject to FERC-approved RTO/ISO monitoring and mitigation, to submit indicative screens. In RTOs and ISOs that lack an RTO/ISO-administered capacity market, MBR sellers are relieved of the requirement to submit indicative screens if their MBR authority is limited to sales of energy and/or ancillary services. FERC regulations will continue to require RTO/ISO sellers to submit indicative screens for authorization to make capacity sales in any RTO/ISO markets that lack an RTO/ISO-administered capacity market subject to FERC-approved RTO/ISO monitoring and mitigation. *Order 861* also eliminates the rebuttable presumption that FERC-approved RTO/ISO market monitoring and mitigation is sufficient to address any horizontal market power concerns regarding sales of capacity in RTOs/ISOs that do not have an RTO/ISO-administered capacity market. For those RTOs/ISOs that do not have an RTO/ISO-administered capacity market (like CAISO), FERC-approved RTO/ISO monitoring and

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166 *Public Util. Trans. Rate Changes to Address Accumulated Deferred Income Taxes*, Order No. 869, 169 FERC ¶ 61,139 (Nov. 21, 2019), *reh'g requested*.

167 *Public Util. Trans. Rate Changes to Address Accumulated Deferred Income Taxes*, 165 FERC ¶ 61,117 (Nov. 15, 2018) ("*ADIT NOPR*").

168 Notice of Extension of Time, *Vermont Transco LLC*, Docket No. RM19-5 (Feb. 3, 2020).

169 *Refinements to Horizontal Market Power Analysis for Sellers in Certain Regional Trans. Org. and Indep. Sys. Op. Mkts.*, Order No. 861-A, 170 FERC ¶ 61,106 (Feb. 20, 2020) ("*Order 861-A*").

170 *Refinements to Horizontal Market Power Analysis for Sellers in Certain Regional Trans. Org. and Indep. Sys. Op. Mkts.*, Order No. 861, 168 FERC ¶ 61,040 (July 18, 2019) ("*Order 861*"), *order on reh'g and clarif.*, 170 FERC ¶ 61,106 (Feb. 20, 2020).

mitigation is no longer presumed sufficient to address any horizontal market power concerns for capacity sales where there are indicative screen failures. *Order 861* became effective September 24, 2019.[171] CAISO requested clarification and PG&E requested rehearing or in the alternative clarification of *Order 861*. In response to the CAISO and PG&E requests, the FERC clarified that "the CAISO Capacity Procurement Mechanism soft offer cap represents an estimate of going-forward costs plus a 20 percent adder, as opposed to an estimate of the cost of entry."[172] The FERC denied PG&E's request for rehearing and will continue to require that capacity Sellers in CAISO submit indicative screens for capacity sales and will not permit capacity Sellers in CAISO to rely on a rebuttable presumption that the Capacity Procurement Mechanism adequately mitigates Sellers' horizontal market power. The FERC also denied PG&E's request to require that the Capacity Procurement Mechanism be modified so that it provides adequate mitigation of capacity market power comparable to other RTOs/ISOs (a request the FERC found outside of the scope of the rulemaking).

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

In *Order 841*[173] (*see* RM16-23 below), the FERC initiated a new proceeding in order to continue to explore the proposed distributed energy resource ("DER") aggregation reforms it was considering in the *Storage NOPR*.[174] All comments filed in response to the *Storage NOPR* will be incorporated by reference into Docket No. RM18-9 and further comments regarding the proposed distributed energy resource aggregation reforms, including comments regarding the April 10-11 technical conference in AD18-10,[175] were also to be filed in RM18-9. On June 26, 2018, over 50 parties submitted post-technical conference comments in this proceeding, including comments from ISO-NE, Calpine, Direct, Eversource, Icetec, NRG, Utility Services, EEI, EPRI, EPSA, NARUC, NRECA, and SEI. On February 11, 2019, a group of 18 US Senators submitted a letter urging the FERC to adopt a final rule that enable all DERs the opportunity to participate in the RTO/ISO markets and requesting an update no later than March 1, 2019. Reply comments and answers were submitted by the Arkansas PUC, AEE, AEMA, and the Missouri PUC. APPA/NRECA submitted supplemental comments.

On September 5, the FERC requested that each of the RTO/ISOs provide responses to data requests seeking information on their policies and procedures that affect DER interconnections. The RTO/ISO responses were due and were filed on October 7, 2019. Comments on the responses were filed by 8 parties, including comments addressing ISO-NE's responses by MA DPU, MA DOER and MA AG (collectively, "Massachusetts"), MMWEC, AEE, EEI and NRECA. This matter is pending before the FERC.

- ***Order 860/860-A*: Data Collection for Analytics & Surveillance and MBR Purposes (RM16-17)**

On July 18, 2019, the FERC issued *Order 860*.[176] *Order 860*, issued three years after the FERC's *Data Collection NOPR,*[177] (i) revises the FERC's MBR regulations by establishing a relational database of ownership

[171] *Order 861* was published *Fed. Reg.* on July 26, 2019 (Vol. 84, No. 144) pp. 36,374-36,387.

[172] *Order 861-A* at P 6.

[173] *Elec. Storage Participation in Mkts. Operated by Regional Trans. Orgs. and Indep. Sys. Operators*, Order No. 841, 162 FERC ¶ 61,127 (Feb. 15, 2018), reh'g and/or *clarif. requested* ("*Order 841*").

[174] *Elec. Storage Participation in Mkts. Operated by Regional Trans. Orgs. and Indep. Sys. Operators*, 157 FERC ¶ 61,121 (Nov. 17, 2016) ("*Storage NOPR*").

[175] On April 10-11, 2018, the FERC held a technical conference to gather additional information to help the FERC determine what action to take on DER aggregation reforms proposed in the *Storage NOPR* and to explore issues related to the potential effects of DERs on the bulk power system. Technical conference materials are posted on the FERC's eLibrary. Interested persons were invited to file post-technical conference comments on the topics concerning the Commission's DER aggregation proposal discussed during the technical conference, including on follow-up questions from FERC Staff related to the panels. Comments related to DER aggregation were to be filed in RM18-9; comments on the potential effects of DERs on the bulk power system, in AD18-10.

[176] *Data Collection for Analytics and Surveillance and Market-Based Rate Purposes*, 168 FERC ¶ 61,039 (July 18, 2019) ("*Order 860*"), *order on reh'g and clarif.*, 170 FERC ¶ 61,129 (Feb. 20, 2020).

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

and affiliate information for MBR Sellers (which, among other uses, will be used to create asset appendices and indicative screens), (ii) reduces the scope of information that must be provided in MBR filings, modifies the information required in, and format of, a MBR Seller's asset appendix, (iii) changes the process and timing of the requirements to advise the FERC of changes in status and affiliate information, and (iv) eliminates the requirement adopted in *Order 816* that MBR Sellers submit corporate organization charts. In addition, the FERC stated that it will *not* adopt the *Data Collection NOPR* proposal to collect Connected Entity data from MBR Sellers and entities trading virtuals or holding FTRs. The FERC will post on its website high-level instructions that describe the mechanics of the relational database submission process and how to prepare filings that incorporate information that is submitted to the relational database. While *Order 860* will become effective October 1, 2020, submitters will have until close of business on February 1, 2021 to make their initial baseline submissions. In the fall of 2020, submitters will be required to obtain FERC generated IDs for reportable entities that do not have CIDs or LEIs, as well as Asset IDs for reportable generation assets without an EIA code so that every ultimate upstream affiliate or other reportable entity has a FERC-assigned company identifiers ("CID"), Legal Entity Identifier,[178] or FERC-generated ID and that all reportable generation assets have an code from the Energy Information Agency ("EIA") Form EIA-860 database or a FERC-assigned Asset ID. Requests for rehearing and/or clarification of *Order 860* were submitted by EEI, Fund Management Parties ("FMP"), Joint Consumer Advocates, NRG/Vistra, Starwood Energy Group, and TAPS.

Order 860-A. On February 20, 2020, the FERC denied rehearing of *Order 860*.[179] The FERC denied all the requests for clarification of *Order 860*, other than TAPS' request that the FERC clarify that the public will be able to access the relational database. On that point, the FERC clarified "that we will make available services through which the public will be able to access organizational charts, asset appendices, and other reports, as well as have access to the same historical data as Sellers, including all market-based rate information submitted into the database. We also clarify that the database will retain information submitted by Sellers and that historical data can be accessed by the public."

MBR Database. On January 10, 2020, the FERC issued a notice that updated versions of the XML, XSD, and MBR Data Dictionary are available on the FERC's website and that the test environment for the MBR Database is now available and can be accessed on the MBR Database webpage.

Feb 27, 2020 Technical Conference. On February 27, 2020, FERC staff held a technical workshop on the relational database being built in accordance with *Order 860* ("MBR Database").

- ***Order 676-I*: NAESB WEQ Standards v. 003.2 - Incorporation by Reference into FERC Regs (RM05-5-027)**

On February 4, 2020, the FERC issued Order *676-I*,[180] which incorporates by reference into its regulations, with certain enumerated exceptions, the latest version (Version 003.2) of certain Standards for Business Practices and Communication Protocols for Public Utilities adopted by the Wholesale Electric Quadrant ("WEQ") of the North American Energy Standards Board ("NAESB").[181] The Version 003.2 Standards included NAESB's Version 003.1 revisions, which were the subject of an earlier NOPR.[182] The FERC declined to

[178] An LEI is a unique 20-digit alpha-numeric code assigned to a single entity. They are issued by the Local Operating Units of the Global LEI System.

[179] *Data Collection for Analytics and Surveillance and Market-Based Rate Purposes*, Order No. 860-A, 170 FERC ¶ 61,129 (Feb. 20, 2020) ("*Order 860-A*").

[180] *Standards for Business Practices and Communication Protocols for Public Utilities*, Order No. 676-I, 170 FERC ¶ 61,062 (Feb. 4, 2020) ("*Order 676-I*").

[181] *Standards for Business Practices and Communication Protocols for Public Utilities*, 167 FERC ¶ 61,127 (May 16, 2019) ("*NAESB WEQ v. 003.2 Standards NOPR*").

[182] *Standards for Business Practices and Communication Protocols for Public Utilities*, 156 FERC ¶ 61,055 (July 21, 2016), ("*WEQ v. 003.1 NOPR*").

adopt the proposal to remove the incorporation by reference of the WEQ-006 Manual Time Error Correction Business Practice Standards as adopted by NAESB. *Order 676-I* will become effective April 27, 2020.[183]

Compliance dates: Public utilities must make a compliance filing to comply with the requirements of *Order 676-I* through eTariff no later than May 26, 2020. The FERC will set an effective date for the proposed tariff changes in the order(s) on the compliance filings, but no earlier than July 27, 2020.

- **NOI: FERC's ROE Policy (PL19-4)**

On March 21, 2019, the FERC issued a notice of inquiry seeking information and views to help the Commission explore whether, and if so how, it should modify its policies concerning the determination of the return on equity ("ROE") to be used in designing jurisdictional rates charged by public utilities.[184] The Commission also seeks comment on whether any changes to its policies concerning public utility ROEs should be applied to interstate natural gas and oil pipelines. This NOI follows *Emera Maine*, which reversed *Opinion 531*, and seeks to engage interests beyond those represented in the *Emera Maine* proceeding (see EL11-66 *et al.* in Section I above). Initial comments were due June 26, 2019; reply comments, July 26, 2019.[185] Initial comments were been submitted by more than 60 organizations; nearly 15,000 initial comments were received from individuals. Reply comments were received from nearly 30 organizations. Further reply comments (also submitted in PL19-3, were submitted by a large group of state public utility commissions, public power utilities, electric cooperatives, consumer advocates, industrial users of electricity, and associations, TEC-RI and the RI Manufacturers Association. Since the last Report, SPP transmission owners submitted comments in light of *Opinion 569*[186] and statements made by the FERC concurrent with the issuance of *Opinion 569*. This matter, and its voluminous record, are pending before the FERC.

- **NOI: Electric Transmission Incentives Policy (PL19-3)**

Also on March 21, 2019, the FERC issued a notice of inquiry seeking comment on the scope and implementation of its electric transmission incentives regulations and policy pursuant to section 1241 of the Energy Policy Act of 2005 ("EPAct 2005"), codified in FPA Section 219, which directed the FERC to use transmission incentives to help ensure reliability and reduce the cost of delivered power by reducing transmission congestion.[187] Given the passage of time since *Order 679* and the FERC's 2012 Incentives Policy Statement and the "significant developments in how transmission is planned, developed, operated, and maintained," the FERC stated that "it is appropriate to seek comment … on the scope and implementation of the Commission's transmission incentives policy and on how the Commission should evaluate future requests for transmission incentives in a manner consistent with Congress's direction in section 219" and solicited comment on a variety of transmission incentives-related issues. Initial comments were due June 26, 2019[188] and were filed by more than 70 parties, including by Avangrid, Eversource, Exelon, Invenergy, MMWEC/NHEC, National Grid, NextEra, UCS, NESCOE, Potomac Economics, Southern New England State Agencies, AEE, AWEA, EEI, ESA, NRECA, PIOs, R Street Institute, and TAPS.

[183] *Order 676-I* was published *Fed. Reg.* on Feb. 25, 2020 (Vol. 85, No. 37) pp. 10,571-10,586.

[184] *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 166 FERC ¶ 61,207 (Mar. 21, 2019) ("*ROE Policy NOI*").

[185] The *ROE Policy NOI* was published in the *Fed. Reg.* on Mar. 28, 2019 (Vol. 84, No. 61) pp. 11,769-11,777.

[186] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569, 169 FERC ¶ 61,129 (2019) ("*Opinion 569*").

[187] *Inquiry Regarding the Commission's Elec. Trans. Incentives Policy*, 166 FERC ¶ 61,208 (Mar. 21, 2019) ("*Electric Transmission Incentives Policy NOI*").

[188] The *Electric Transmission Incentives Policy NOI* was published in the *Fed. Reg.* on Mar. 28, 2019 (Vol. 84, No. 60) pp. 11,759-11,768.

On May 10, 2019, APPA, EEI and NRECA, in a motion covering both this and the FERC's ROE Policy proceeding, requested an extension of time to file reply comments. With respect to this proceeding, and unlike the ROE Policy proceeding, the FERC granted the motion to extend the reply period. Reply comments were due on or before Aug 26, 2019, and nearly 50 sets of reply comments were submitted, including from the entities identified in PL19-4 and from Avangrid, EMCOS, Eversource, Exelon, LS Power, National Grid, and NESCOE. Since the last Report, a group of organizations, led by the CT PURA,[189] submitted comments on October 9, 2019 highlighting areas of agreement among them, and urging the FERC "to give these positional agreements consideration in assessing whether—and, if so, how—to modify current transmission incentive policies." This matter is pending before the FERC.

- **NOI: Certification of New Interstate Natural Gas Facilities (PL18-1)**

On April 19, 2018, the FERC announced its intention to revisit its approach under its 1999 Certificate Policy Statement to determine whether a proposed jurisdictional natural gas project is or will be required by the present or future public convenience and necessity, as that standard is established in NGA Section 7. Specifically, the NOI[190] seeks comments from interested parties on four broad issue categories: (1) project need, including whether precedent agreements are still the best demonstration of need; (2) exercise of eminent domain; (3) environmental impact evaluation (including climate change and upstream and downstream greenhouse gas emissions); and (4) the efficiency and effectiveness of the FERC certificate process. Pursuant to a May 23 order extending the comment deadline by 30 days,[191] comments were due on or before July 25, 2018. Literally thousands of individual and mass-mailed comments were filed. This matter remains pending before 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).

- **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*[192] 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 NGA Section 4A.[193] 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."[194] Accordingly, the FERC assessed a ***$20.16 million civil penalty*** and

[189] The group of organizations included CT PURA, DT CEEP, NH PUC, VT DPS, MN PUC, DC PUC, PA PUC, MA AG, CT AG, CT OCC, MMWEC, NHEC, TAPS, and APPA.

[190] The NOI was published in the *Fed. Reg.* on Apr. 26, 2018 (Vol. 83, No. 80) pp. 18,020-18,032.

[191] *Certification of New Interstate Natural Gas Facilities*, 163 FERC ¶ 61,138 (May 23, 2018).

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

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

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

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.[195] BP was directed to pay the civil penalty and disgorgement amount within 60 days of the *BP Penalties Order*. On August 10, 2016 BP requested rehearing of the *BP Penalties Order*. On September 8, 2018the FERC issued a tolling order, affording it additional time to consider BP's request for rehearing of the *BP Penalties Order*, which remains pending.

On September 7, 2016, BP submitted a motion for modification of the *BP Penalties Order's* disgorgement directive because it cannot comply with the disgorgement directive as ordered. BP explained that the entity to which disgorgement was to be directed, the Texas Low Income Home Energy Assistance Program ("LIHEAP"), is not set up to receive or disburse amounts received from any person other than the Texas Legislature. In response, on September 12, 2016, 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.[196]

BP moved, on December 11, 2017, to lodge, to reopen the proceeding, and to dismiss, or in the alternative, for reconsideration based on changes in the law it asserted are dispositive and that have occurred since BP filed its request for rehearing of the *BP Penalties Order*. FERC Staff asked for, and was granted, additional time, to January 25, 2018, to file its Answer to BP's December 11 motion. FERC Staff filed its answer on January 25, 2018, and revised that answer on January 31. On February 9, BP replied to FERC Staff's revised answer. This matter remains pending before the FERC.

Total Gas & Power North America, Inc. et al. (IN12-17). On April 28, 2016, the FERC issued a show cause order[197] in which it directed Total Gas & Power North America, Inc. ("TGPNA") and its West Desk traders and supervisors, Therese Tran f/k/a Nguyen ("Tran") and Aaron Hall (collectively, "Respondents") to show cause why Respondents should not be found to have violated NGA Section 4A and the FERC's Anti-Manipulation Rule through a scheme to manipulate the price of natural gas at four locations in the southwest United States between June 2009 and June 2012.[198]

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

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

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

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

198 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.

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

- **New England Pipeline Proceedings**
  The following New England pipeline projects are currently under construction or before the FERC:
  - ***Constitution Pipeline (CP13-499) and Wright Interconnection Project (CP13-502)***
    - Constitution Pipeline Company and Iroquois Gas Transmission (Wright Interconnection) concurrently filed for Section 7(c) certificates on June 13, 2013.
    - 650,000 Dth/d of firm capacity from Susquehanna County, PA (Marcellus Shale) through NY to Iroquois/Tennessee interconnection (Wright Interconnection).
    - New 122-mile interstate pipeline.
    - Two firm shippers: Cabot Oil & Gas and Southwestern Energy Services.
    - Final EIS completed on Oct 24, 2014.
    - Certificates of public convenience and necessity granted Dec 2, 2014.
      - By letter order issued July 26, 2016, the Director of the Division of Pipeline Certificates (Director) granted Constitution's requested two-year extension of time to construct the project.
      - Construction was expected to begin Spring 2016 (after final Federal Authorizations), but has been plagued by delays (see below).
    - On April 22, 2016, New York State Department of Environmental Conservation (NY DEC) denied Constitution's application for a Section 401 permit under the Clean Water Act.
      - On August 18, 2017, the 2nd Circuit denied Constitution's petition for review of the NY DEC decision, concluding that (1) the court lacked jurisdiction over the Constitution's claims to the extent that they challenged the timeliness of the decision; and (2) the NY DEC acted within its statutory authority in denying the certification, and its denial was not arbitrary or capricious.
      - Constitution filed a petition for a writ of certiorari of the 2nd Circuit's decision at the United States Supreme Court in January 2018 alleging, among other things, that the State's denial of the Clean Water Act permit exceeded the state's authority, and interfered with FERC's exclusive jurisdiction. On April 30, 2018, the Supreme Court denied Constitution's petition, thereby letting stand the 2nd Circuit's ruling.
    - On October 11, 2017, Constitution filed with the FERC a petition for declaratory order ("Petition") requesting that the FERC find that NY DEC waived its authority under section 401 of the Clean Water Act by failing to act within a "reasonable period of time." (CP18-5)
      - On January 11, 2018, the FERC denied Constitution's Petition.[199] Although noting that states and project sponsors that engage in repeated withdrawal and refiling of applications for water quality certifications are acting, in many cases, contrary to the public interest and to the spirit of the Clean Water Act by failing to provide reasonably expeditious state decisions, the FERC did not conclude that the practice violates the letter of the statute, found factually that Constitution gave the NY DEC new deadlines, and found that the record did not show that the NY DEC in any instance failed to act on Constitution's application for more than the outer time limit of one year.[200]

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

[200] *Id.* at P 23.

- On February 12, 2018, Constitution Pipeline requested rehearing of the January 11, 2018 order. FERC denied Constitution's request for rehearing of the January 2018 order.[201] On September 14, 2018, Constitution filed a petition for review in the U.S. Court of Appeals for the D.C. Circuit.[202]

- On May 16, 2016, the New York Attorney General filed a complaint against Constitution at the FERC (CP13-499) seeking a stay of the December 2014 order granting the original certificates, as well as alleging violations of the order, the Natural Gas Act, and the Commission's own regulations due to acts and omissions associated with clear-cutting and other construction-related activities on the pipeline right of way in New York.
    - In July 2016, the FERC rejected the NY AG's filing as procedurally deficient, and declined to stay of the Certificate Order. The NY AG sought rehearing, and the Commission denied rehearing on November 22, 2016, noting again that the NY AG's complaint was still procedurally deficient.
- Tree felling and site preparation continues, but the long-term status of the pipeline is currently unknown.
- On June 25, 2018, Constitution requested a further 2-year extension of the deadline to complete construction of its project, given the delays caused by the on-going fight over the water quality certification from the NYSDEC. Iroquois made a similar request on August 1, 2018. Constitution's request was opposed by several parties and Constitution answered some of the opposition pleadings. The FERC granted the requested two-year extension of time on November 5, 2018.[203]
- Rehearing of the November 5, 2018 order was requested by Halleran Landowners and a group of intervenors comprised of Catskill Mountainkeeper; Clean Air Council; Delaware-Otsego Audubon Society; Delaware Riverkeeper Network; Riverkeeper, Inc.; and Sierra Club ("Intervenors"). On November 8, 2019, the FERC dismissed or denied the requests for rehearing.[204]

- **Non-New England Pipeline Proceedings**
  The following pipeline projects could affect ongoing pipeline proceedings in New England and elsewhere:
    - **Northern Access Project (CP15-115)**
        - The New York State Department of Environmental Conservation ("NY DEC") and the Sierra Club requested rehearing of the *Northern Access Certificate Rehearing Order* on August 14 and September 5, 2018, respectively. On August 29, National Fuel Gas Supply Corporation and Empire Pipeline ("Applicants") answered the NY DEC's August 14 rehearing request and request for stay. On April 2, 2019, the FERC denied the NY DEC and Sierra Club requests for rehearing.[205] Those orders have been challenged on appeal to the US Court of Appeals for the Second Circuit (19-1610).
        - As previously reported, the August 6, 2018 *Northern Access Certificate Rehearing Order* dismissed or denied the requests for rehearing of the *Northern Access Certificate Order*.[206] Further, in an interesting twist, the FERC found that a December 5, 2017 "Renewed

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[201] *Constitution Pipeline Co., LLC*, 164 FERC ¶ 61,029 (2018) (September 2018 Waiver Rehearing Order).

[202] *Constitution*, Petition for Review in U.S. Court of Appeals for the D.C. Circuit, Docket No. CP18-5-000 (filed Sep. 14, 2018).

[203] *Constitution Pipeline Co.*, 165 FERC ¶ 61,081 (Nov. 5, 2018), *reh'g denied*, 169 FERC ¶ 61,102 (Nov. 8, 2019).

[204] *Constitution Pipeline Co.*, 169 FERC ¶ 61,102 (Nov. 8, 2019) (order on rehearing).

[205] *Nat'l Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 167 FERC ¶ 61,007 (Apr. 2, 2019).

[206] *Nat'l Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 164 FERC ¶ 61,084 (Aug. 6, 2018) ("*Northern Access Rehearing & Waiver Determination Order*"), *reh'g denied*, 167 FERC ¶ 61,007 (Apr. 2, 2019).

Motion for Expedited Action" filed by National Fuel Gas Supply Corporation and Empire Pipeline, Inc. (the "Companies"), in which the Companies asserted a separate basis for their claim that the NY DEC waived its authority under section 401 of the Clean Water Act ("CWA") to issue or deny a water quality certification for the Northern Access Project, served as a motion requesting a waiver determination by the FERC,[207] and proceeded to find that the NY DEC was obligated to act on the application within one year, failed to do so, and so waived its authority under section 401 of the CWA.

- The FERC authorized the Companies to construct and operate pipeline, compression, and ancillary facilities in McKean County, Pennsylvania, and Allegany, Cattaraugus, Erie, and Niagara Counties, New York ("Northern Access Project") in an order issued February 3, 2017.[208] The Allegheny Defense Project and Sierra Club (collectively, "Allegheny") requested rehearing of the *Northern Access Certificate Order*.
- Despite the FERC's *Northern Access Certificate Order*, the project remained halted pending the outcome of National Fuel's fight with the NY DEC's April denial of a Clean Water Act permit. NY DEC found National Fuel's application for a water quality certification under Section 401 of the Clean Water Act, as well as for stream and wetlands disturbance permits, failed to comply with water regulations aimed at protecting wetlands and wildlife and that the pipeline failed to explore construction alternatives. National Fuel appealed the NY DEC's decision to the 2nd Circuit on the grounds that the denial was improper.[209] On February 2, 2019, the 2nd Circuit vacated the decision of the NY DEC and remanded the case with instructions for the NY DEC to more clearly articulate its basis for the denial and how that basis is connected to information in the existing administrative record. The matter is again before the NY DEC.
- On November 26, 2018, the Applicants filed a request at FERC for a 3-year extension of time, until February 3, 2022, to complete construction and to place the certificated facilities into service. The Applicants cited the fact that they "do not anticipate commencement of Project construction until early 2021 due to New York's continued legal actions and to time lines required for procurement of necessary pipe and compressor facility materials." The extension request was granted on January 31, 2019.
- On August 8, 2019, the NY DEC again denied Applicants request for a Water Quality Certification, and as directed by the Second Circuit,[210] provided a "more clearly articulate[d] basis for denial."
- On August 27, Applicants requested an additional order finding on additional grounds that the NY DEC waived its authority over the Northern Access 2016 Project under Section 401 of the CWA, even if the NY DEC and Sierra Club prevail in their currently pending court petitions challenging the basis for the Commission's Waiver Order.[211]

[207] The DC Circuit has indicated that project applicants who believe that a state certifying agency has waived its authority under CWA section 401 to act on an application for a water quality certification must present evidence of waiver to the FERC. *Millennium Pipeline Co., L.L.C. v. Seggos*, 860 F.3d 696, 701 (D.C. Cir. 2017).

[208] *Nat'l Fuel Gas Supply Corp.*, 158 FERC ¶ 61,145 (2017) ("*Northern Access Certificate Order*"), *reh'g denied*, 164 FERC ¶ 61,084 (Aug 6, 2018) ("*Northern Access Certificate Rehearing Order*").

[209] *Nat'l Fuel Gas Supply Corp. v. NYSDEC et al*. (2d Cir., Case No. 17-1164).

[210] Summary Order, *Nat'l Fuel Gas Supply Corp. v. N.Y. State Dep't of Envtl. Conservation*, Case 17-1164 (2d Cir, issued Feb. 5, 2019).

[211] *See Sierra Club v. FERC*, No. 19-01618 (2d Cir. filed May 30, 2019); *NYSDEC v. FERC*, No. 19-1610 (2d. Cir. filed May 28, 2019) (consolidated).

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).

- **ISO-NE's Inventoried Energy Program (Chapter 2B) Proposal (19-1224***; 19-1247; 19-1252; 19-1253)(consolidated)**
  Underlying FERC Proceeding: ER19-1428[212]
  Petitioners: ENECOS (Belmont et al.) (19-1224); MA AG (19-1247); NH PUC/NH OCA (19-1252)

On October 24, 2019, ENECOS[213] petitioned the DC Circuit Court of Appeals for review of the FERC's August 6, 2019 Chapter 2B Notice that ISO-NE's Chapter 2B Proposal took effect by operation of law. MA AG (November 25), the NH PUC and NH OCA (December 3), and RENEW Northeast (December 3) similarly filed separate appeals. All of the cases were ultimately consolidated on December 30, 2019 (with 19-1224 as the lead docket). Petitioners' initial submissions, procedural and dispositive motions were filed on January 6, 2020. On January 6, 2020, the FERC submitted a motion asking for 60 days between the filing of Petitioners' opening brief and the FERC's brief in response, and filed the Certified Index to the Record. On January 21, the Court granted the motions to intervene of NEPOOL, ISO-NE, NEPGA, Calpine, and the MPUC. Since the last Report, RENEW moved and the court granted RENEW's motion to withdraw its appeal in 19-1253, previously consolidated with the lead docket (19-1224). Parties must submit by March 6, 2020 proposed formats for the briefing of these cases.

- ***Order 841* (19-1142, 19-1147) (consol.)**
  Underlying FERC Proceeding: RM16-23; AD16-[214]
  Petitioners: NARUC, APPA et al.

NARUC and APPA et al.[215] petitioned the DC Circuit Court of Appeals for review of *Orders 841* and *841-A* (Electric Storage Participation in RTO/ISO Markets). The cases have been consolidated, with 19-1142 as the lead docket. Docketing statements, statement of issues and interventions,[216] Petitioners' and Intervenors for Petitioners' briefs, and FERC's Respondent Brief, Joint Briefs of Environmental and Industry Intervenors for Respondent; and Petitioners' and Intervenor for Petitioners Reply Briefs have been filed. Future deadlines include: a Deferred Joint Appendix (Mar. 9, 2020); and Final Briefs (Mar. 16, 2020).

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[212] 162 FERC ¶ 61,127 (Feb. 15, 2018) ("*Order 841*"); 167 FERC ¶ 61,154 (May 16, 2019) ("*Order 841-A*").

[213] "ENECOS" are Belmont; Block Island Utility District; Braintree; Energy New England ("ENE"); Georgetown Municipal Light Department; Groveland; Hingham; Littleton; Merrimac; Middleborough; Middleton; North Attleborough; Norwood; Pascoag; Reading; Rowley; Stowe; Taunton; and Wellesley.

[214] 162 FERC ¶ 61,127 (Feb. 15, 2018) ("*Order 841*"); 167 FERC ¶ 61,154 (May 16, 2019) ("*Order 841-A*").

[215] "APPA et al." are the American Public Power Assoc. ("APPA"), National Rural Elec. Coop. Assoc. ("NRECA"), Edison Electric Institute ("EEI"), and American Municipal Power, Inc. ("AMP").

[216] Interventions were filed and granted for Southern California Edison, Energy Storage Association ("ESA"), Transmission Access Policy Study Group ("TAPS"), Solar Energy Industries Association ("SEIA"), AEE, NRDC, EDF, Vote Solar, MISO, and NextEra Energy Resources.

- **FCM Pricing Rules Complaints (15-1071**, 16-1042) (consol.)**
  Underlying FERC Proceeding: EL14-7,[217] EL15-23[218]
  Petitioners: NEPGA, Exelon

On February 2, 2018, DC Circuit granted NEPGA's and Exelon's petitions for review of orders accepting the FCM's 7-year price lock-in (EL14-7) and capacity-carry-forward rules (EL15-23).[219] Finding that "the FERC failed to adequately explain why its rationale [for rejecting price lock-in and capacity carry forward rules] in PJM – which seems to foreclose signing off on a Tariff scheme like ISO-NE's – does not apply even more forcefully to the scheme it accepted in the Orders [appealed from]," the DC Circuit granted the Petitions and remanded the case to the FERC for further proceedings in which the FERC, in order to accept the changes filed, must provide some analysis and explanation why it changed course. The remand is now pending before the FERC.

Other Federal Court Activity of Interest

- **PG&E Bankruptcy (19-71615) (9th Cir.)**
  Underlying FERC Proceeding: EL19-35, EL19-36[220]
  Petitioner: PG&E

On June 26, PG&E appealed the FERC's orders finding that it has concurrent jurisdiction with the bankruptcy courts to review and address the disposition of wholesale power contracts sought to be rejected through its bankruptcy. On July 11, PG&E moved to suspend the briefing schedule pending the Court's decision on whether to authorize direct appeal of a decision by the Bankruptcy Court in the Northern District of California. In a declaratory judgment, the Bankruptcy Court came to a completely different conclusion than the FERC and held that it has "original and exclusive jurisdiction over . . . [PG&E's] rights to assume or reject executory contracts under 11 U.S.C. § 365" and that the FERC "does not have concurrent jurisdiction, or any jurisdiction, over the determination of whether any rejections of power purchase contracts by [PG&E] should be authorized."[221] Because of the opposite conclusions, PG&E suggested that, should the Ninth Circuit allow the direct appeal of the Bankruptcy Court decision, the two appeals should proceed together. The PG&E motion was granted on August 1. Since the last Report, PG&E submitted a motion to further expedite oral argument in this case. This matter remains before the Ninth Circuit.

- **First Energy Solutions Bankruptcy (18-3787) (6th Cir.)**
  Petitioner: FERC

In this proceeding, the FERC appealed an Ohio bankruptcy court's August 2018 ruling that blocked the FERC from taking *any* action on FirstEnergy Solutions Corp.'s agreement with Ohio Valley Electric Corp. (a power purchase agreement that FES seeks to reject as part of its bankruptcy proceedings). The FERC asked the Sixth Circuit to vacate the bankruptcy court order, claiming that the ruling usurps its FPA authority over wholesale electricity contracts. Oral argument was held on June 26, 2019. This matter was decided. 2-1, on December 12, 2019.[222]

The Sixth Circuit concluded that the bankruptcy court has jurisdiction to decide whether FES may reject the contracts, but that its injunction of FERC in this case was overly broad (beyond its jurisdiction), and its standard for deciding rejection was too limited. Therefore, the Sixth Circuit affirmed in part, reversed in part, and remanded the matter to the bankruptcy court for further consideration. In reaching its decision, the Sixth Circuit

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[217] 150 FERC ¶ 61,064 (Jan. 30, 2015); 146 FERC ¶ 61,039 (Jan. 24, 2014).

[218] 154 FERC ¶ 61,005 (Jan. 7, 2016); 150 FERC ¶ 61,067 (Jan. 30, 2015).

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

[220] *NextEra Energy, Inc. v. PG&E*, 166 FERC ¶ 61,049 (Jan. 25, 2019); *Exelon Corp. v. PG&E*, 166 FERC ¶ 61,053 (Jan. 28, 2019); *Order Denying Rehearing*, 167 FERC ¶ 61,096 (May 1, 2019).

[221] Declaratory Judgment at 1-2, *PG&E v. FERC*, (Bankr. N.D. Cal. June 7, 2019).

[222] *In re: FirstEnergy Solution Corp., et al.*, No. 18-3767, ___ F.3d ___; 2019 WL 6767004 (6th Cir. Dec. 12, 2019).

held that "the public necessity of available and functional bankruptcy relief is generally superior to the necessity of FERC's having complete or exclusive authority to regulate energy contracts and markets ... the bankruptcy court has jurisdiction to decide whether FES, as a Chapter 11 debtor-in-possession, may reject the [ ] contracts, meaning that FES can reject the contracts subject to proper bankruptcy court approval and FERC cannot independently prevent it." The Sixth Circuit went on to hold, however, that "when a Chapter 11 debtor moves the bankruptcy court for permission to reject a filed energy contract that is otherwise governed by FERC, via the FPA, the bankruptcy court must consider the ***public interest*** and ensure that the equities balance in favor of rejecting the contract, and it must invite FERC to participate and provide an opinion in accordance with the ordinary FPA approach (e.g., under the Mobile–Sierra doctrine), within a reasonable time." The Court noted that a "reasonable delay in this remand may be much longer that it would be in an ordinary case" given the bankruptcy court's earlier "improper and absolute injunction preventing FERC from conducting its assessment."

On January 27, the FERC petitioned for *en banc* rehearing of the December 12 decision. An answer to the that petition and opposing FERC's request was filed on February 26, 2020 by counsel to FirstEnergy, the Official Committee of Unsecured Creditors, the Ad Hoc Noteholders Group, and Pass-Through Creditors. FERC's petition is pending remains before the 6th Circuit.

- **PennEast Project (18-1128)**
  Underlying FERC Proceeding: CP15-558[223]
  Petitioners: NJ DEP, DE and Raritan Canal Commission, NJ Div. of Rate Counsel

Pending before the DC Circuit is an appeal of the FERC's orders granting certificates of public convenience and necessity to PennEast Pipeline Company, LLC ("PennEast")[224] for the construction and operation of a new 116-mile natural gas pipeline from Luzerne County, Pennsylvania, to Mercer County, New Jersey, along with three laterals extending off the mainline, a compression station, and appurtenant above ground facilities ("PennEast Project"). All briefing is complete and oral argument was scheduled for October 4, 2019. However, on October 1, the court removed the cases from the oral argument calendar and will hold the cases in abeyance "pending final disposition of any post-dispositional proceedings in the Third Circuit or proceedings before the United States Supreme Court resulting from the Third Circuit's decision in No. 19-1191 (In re: PennEast Pipeline Company, LLC (3rd Cir. Sep. 10, 2019)), or other action that resolves the obstacle PennEast poses". That decision held that the Eleventh Amendment barred condemnation cases brought by PennEast in federal district court in New Jersey to gain access to property owned by the State or its agencies, thus calling into question the viability of PennEast's proposed project route, and the certificates issued in the underlying case. Until the Third Circuit case is resolved, the DC Circuit will not take up this case.

[223] *PennEa*st *Pipeline Co., LLC*, 162 FERC ¶ 61,053 (Jan. 19, 2018), *reh'g denied*, 163 FERC ¶ 61,159 (May 30, 2018).

[224] PennEast is a joint venture owned by Red Oak Enterprise Holdings, Inc., a subsidiary of AGL Resources Inc.; NJR Pipeline Company, a subsidiary of New Jersey Resources; SJI Midstream, LLC, a subsidiary of South Jersey Industries; UGI PennEast, LLC, a subsidiary of UGI Energy Services, LLC; and Spectra Energy Partners, LP.

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