David T. Doot
Secretary

March 25, 2021

VIA ELECTRONIC MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of April 1, 2021 NEPOOL Participants Committee Teleconference Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the April meeting of the Participants Committee will be held **via teleconference on *Thursday*, April 1, 2021, at 10:00 a.m.** for the purposes set forth on the attached agenda and posted with the meeting materials at nepool.com/meetings/. The dial-in number, to be used only by those who otherwise attend NEPOOL meetings and their approved guests, is **866-803-2146; Passcode: 7169224.** To join WebEx, click this link and enter the event password **nepool**.

For your information, the April 1 meeting will be recorded. 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 in the meeting are required to identify themselves and their affiliation during the meeting. Official records and minutes of meetings are posted publicly. No statements made in NEPOOL meetings are to be quoted or published publicly.

Respectfully yours,

/s/
David T. Doot, Secretary

FINAL AGENDA

1. To approve the draft minutes of the March 4, 2021 Participants Committee meeting. The draft preliminary minutes of that meeting, marked to show changes from the draft circulated with the initial notice, are included with this supplemental notice and posted with the meeting materials.

2. To adopt and approve the action recommended by the Reliability Committee 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. Summaries of ISO Board and Board Committee meetings that occurred since the March 4 Participants Committee meeting is included with this supplemental notice and posted with the meeting materials.

4. To receive an ISO Chief Operating Officer report. The April 1 COO report will be circulated and posted in advance of the meeting.

5. The receive a report, deferred from the March 4 meeting, of the February cold weather challenges outside of New England. Background materials addressing ERCOT's recent experience were posted with the materials for the March 4 meeting and are included for convenience with this supplemental notice.

6. To consider and take action, as appropriate, on an ISO proposal to remove Appendix B of Market Rule 1 (Imposition of Sanctions by the ISO). Background materials and a draft resolution are included with this supplemental notice and posted with the meeting materials.

7. To receive a report on current contested matters before the FERC and the Federal 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
   - Others
   - Transmission Committee
   - Budget & Finance Subcommittee
   - Joint Nominating Committee

9. Administrative matters.

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

PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held via teleconference beginning at 10:00 a.m. on Thursday, March 4, 2021. A quorum determined in accordance with the Second Restated NEPOOL Agreement was present and acting throughout the meeting. Attachment 1 identifies the members, alternates and temporary alternates who participated in the teleconference meeting.

Mr. David Cavanaugh, Chair, presided and Mr. David Doot, Secretary, recorded.

APPROVAL OF FEBRUARY 4, 2021 MEETING MINUTES

Mr. Cavanaugh referred the Committee to the preliminary minutes of the February 4, 2021 meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of the February 4, 2021 meeting were unanimously approved as circulated, with an abstention by Mr. Michael Kuser's alternate noted.

CONSENT AGENDA

Mr. Cavanaugh 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 as circulated, with an abstention on behalf of Mr. Kuser recorded.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), referred the Committee to the summaries of the ISO Board and Board Committee meetings that had occurred since the February 4, 2021 Participants Committee meeting, which had been circulated and posted in advance of the meeting. There were no questions or comments related to the report. Mr. van

Welie did note that Dr. Vamsi Chadalavada would address the happenings in Texas and planned to provide an operational overview of the events later in the meeting.

In response to a question about the process associated with addressing concerns with the FERC's orders concerning the minimum offer price rule, Mr. van Welie explained that FERC Chairman Glick has encouraged the ISO to address those concerns for New England, which the ISO hoped to accomplish in the future grid pathways process. He committed the ISO to re-evaluate various options to address these concerns if a solution was not identified through the future grid pathways process and to make a recommendation as appropriate.

ISO COO REPORT

Dr. Chadalavada, ISO Chief Operating Officer (COO), referred the Committee to his March report, which had been circulated and posted in advance of the meeting. He noted that the data in the report was through February 24 unless otherwise noted. The report highlighted: (i) Energy Market value for February 2021 was $716 million, up $228 million from an updated January 2021 value of $488 million and up $483 million from February 2020; (ii) February 2021 average natural gas prices were 92% higher than January average prices; (iii) the average Real-Time Hub Locational Marginal Prices (LMPs) for February ($77.42/MWh) were 77% higher than January averages; (iv) average February 2021 natural gas prices and Real-Time Hub LMPs over the period were up 320% and 281%, respectively, from February 2020 average prices; (v) the average Day-Ahead cleared physical energy during peak hours as percent of forecasted load was 99.2% during February (up from 98.4% in January), with the minimum value for the month (94.4%) on February 1. From a load profile standpoint, ~~the~~ midday and evening loads ~~are~~ largely ~~reflective of the~~reflected societal changes experienced as part of the pandemic ~~with~~(more work from home, remote learning and other resulting changes); and (vi) the Daily Net Commitment

Period Compensation (NCPC) payments for February totaled $2.3 million, which was down $1.2 million from January 2021 and up $1.3 million from February 2020. February NCPC payments, which were 0.3% of total Energy Market value, were comprised of (a) $1.9 million in first contingency payments (down $0.2 million from January); ~~and~~ (b) $0.1 million in second contingency payments (down $1.1 million from January)~~. Most of the second contingency costs were~~, mostly for eastern load zones, which, as previously noted, can on cold days require the out-of-merit dispatch of a generator or two to protect against constraints caused by increased flows from the west moving east~~. NCPC also included~~; and (c) $259,000 in distribution payments (up $134,000 from January).

Turning to operational highlights from February, Dr. Chadalavada noted that FCA15 was completed on February 8, and results were filed with the FERC on February 26. He said the ISO would report on that auction at the March 16 Reliability Committee meeting.

He then reported on a planned outage which started March 1 and would last through March 20 for a major transmission line--Line 393/312 (Alps-Berkshire/Berkshire-Northfield). He said this outage would reduce transfers between New York and New England, in both directions, by about 600-800 MW. In response to a question about planed outages on Line 3001 in combination with Line 385, Dr. Chadalavada noted those outages ~~have~~had been repositioned due to an outage in New Brunswick. He committed to share details on the rescheduled date.

In responding to a question on February loads ~~during February~~, Dr. Chadalavada noted that the ISO saw a 20 percent reduction in solar production in February due to increased snow coverage ~~in February~~, with some of that reduction behind the meter. As a result, the system experienced higher midday loads and evening peaks.

JOINT NOMINATING COMMITTEE

In support of the ongoing efforts to enhance the transparency of the Joint Nominating Committee (JNC) process, Mr. Cavanaugh introduced Ms. Jennifer Rockwood from Russell Reynolds Associates, who ~~provided~~gave a presentation on the search process for new Board nominees, which had been circulated and posted in advance of the meeting.

Ms. Rockwood, who had worked with the ISO for approximately eight years on the new Board member search process, explained that the ~~search process~~ cycle typically ~~commences~~begins in December and concludes the following September when new Board Members are seated. ~~Each~~She explained that each cycle begins with an onboarding process for JNC committee members~~, reviewing their~~ (a review of JNC member roles and responsibilities and ~~discussing~~discussion of the direction and range of profiles required to fill Board openings). Board composition, experiences, competencies and experiential gaps are analyzed and assessed by the ~~Boar~~Board at the beginning of the cycle. That analysis allows for the creation of a reference and marketing document to assist to in defining future needs for the Board and identifying suitable candidates. Out of that effort, candidates are identified for first and second round interviews. She reported that the current focus was in finding 28-30 potential candidates that could fill the perceived needs of the Board. Ms. Rockwood noted that referrals are part of the candidate recruitment process, though experience was that roughly 80 percent of referrals end up being conflicted out of consideration.

~~Once~~Continuing, she explained that, once a candidate pool is assembled, the candidate profiles are shared and reviewed in depth with the JNC. A short list of candidates are then defined and first round interviews begin. (First round interviews in 2021 were planned to take place late-April to mid-May.) Second round interviews with the finalist group then take place, followed by finalist candidate discussions with the JNC. During this stage, extensive background checks are conducted, and the JNC members share final candidate information with their constituents once finalized. Russell Reynolds Associates adheres to a proactive approach to stay ahead of Board recruitment needs, an "evergreen" process, which continuously evaluates Board composition and assists ongoing engagement with past, fully-vetted top candidates.

In response to a question about the need for confidentiality in the process, Ms. Rockwood explained that an open slate process leads to potential candidates self-selecting themselves for removal from consideration to avoid public disclosure of their candidacy. She provided a number of reasons explaining why a decision to remove confidentiality would limit the pool of suitable candidates. She noted in response to a question that the vetting process for new candidates is not currently applied to incumbent board members standing for re-election.

Referring to her presentation, Ms. Rockwood then spoke more specifically about the JNC's input for the 2021 slate of nominees. She further noted the JNC's consideration also of other parameters such as (i) board readiness; (ii) ~~the~~ core requirements for board composition as set forth in Participants Agreement Sections 9 and 13~~ in the Participants Agreement~~; (iii) expertise in light of gaps ~~as related to the current~~in the remaining composition of the Board; (iv) regional preferences; and (v) expertise ~~requirement~~ for ~~population of~~populating the six standing Board committees. She referred the Committee to the summary of the current Board composition and their areas of expertise. She noted the ISO's Code of Conduct, which includes (i) rules on permissible FERC interlocks; (ii) restrictions on securities ownership; and (iii) prohibition of any association with Market Participants or their Affiliates. She then discussed the ~~independent factor of the~~ age limitation ~~of~~imposed on board members ~~of~~(70 years old or less at the time of election or re-election), which she noted was a relatively young age limitation, particularly when looking at the length of term and the ability to serve multiple terms, although that limit could be waived by the JNC.

LITIGATION REPORT

Mr. Doot referred the Committee to the March 3 Litigation Report that had been circulated and posted in advance of the meeting. He then highlighted the following:

- ***FCM Dynamic De-List Bid Threshold (DDBT~~-~~) Changes*** that had been worked out in the stakeholder processes were approved by the FERC.

- ***FCA15 Results*** had been filed with the FERC, with comments on those results due on April 12.

- ***A Series of Technical Conferences*** announced or held by the FERC focused on (i) modernization of electricity market design, with a first technical conference to address resource adequacy scheduled for March 23; (ii) electrification and the grid of the future (to discuss the shift from non-electric to electric sources of energy at the point of final consumption and how to prepare for an increasingly electrified future) to be held April 16; and (iii) principles and best practices for credit risk management in ISO/RTOs held the week before.

- ***March 1 Deficiency Letter Issued in Response to Net Cone filing,*** directing the ISO to provide within 30 days additional information explaining positions the ISO had taken in its calculations of Cost of New Entry (CONE), Net ~~Cone~~CONE and the Performance Payment Rate (PPR). Mr. Mark Karl, ISO Vice President, Market Development & Settlements, noted that the ISO planned at that point to provide a response to the deficiency letter the following week, but in any case in advance of the March 31 deadline. The ISO response would request expedited action to avoid any further disruption in the planned timing for FCA16. He referenced and clarified the ISO's plans as set forth in a March 4 memorandum on that topic that had been circulated just before the meeting. In the interim, the ISO planned to proceed as if its filing of CONE, Net CONE and PPR had been approved by the FERC, which would allow compliance with current Tariff requirements. The gist of his explanation and clarification was that the ISO was intent on maintaining the schedule for FCA16, and would work to ensure that Market Participants would be permitted to adjust their upcoming submissions in the FCA16 process if such adjustments were caused by changes to relevant values for FCA16 that were different than the values filed by the ISO. The ISO clarified that, if it concluded that changes to CONE, Net CONE or PPR values were necessary, the ISO would not make such changes without first reviewing those changes with NEPOOL. The ISO recognized the possibility that changes might be required by FERC and was intent on doing what it could to effect any required changes without a delay to FCA16. The ISO was not planning, however, the present its response to the Deficiency Notice to NEPOOL ahead of filing it with FERC.

AMENDMENTS TO FCA16 ORTP VALUES

After a brief recess, Mr. Cavanaugh turned to Mr. Karl to discuss the ISO's changes to its Offer Review Trigger Price (ORTP~~-~~) proposal. He began by noting that the ISO had modified its proposal by adopting some, but not all, of the NEPOOL-supported ORTPs. The ISO continued to disagree, however, with NEPOOL's offshore wind ORTP and unit life amendments, so there would still be a need for a jump ball. Mr. Karl then proceeded to explain the ISO's desire to delay the vote on its own ORTP proposal. He explained that questions concerning the tax treatment for renewable resources, raised previously in the Participant Processes, needed still to be addressed and might potentially impact the ISO's proposed solar ORTP, increasing that value from the $0.000/kW-month currently in its proposal. He explained that, regardless of the tax treatment issue for offshore wind, ~~that resource's~~the offshore wind ORTP would remain above the FCA Starting Price. Mr. Karl confirmed that the delay in the vote on the ISO's ORTP proposal would be short and the intent was to file the ORTP values and associated Tariff revisions by the end of March.

In response to questions, the Chair and NEPOOL counsel noted that, should an ISO change in tax treatment under its model impact ORTPs, the NEPOOL Markets Committee would have the opportunity to consider whether to recommend further changes to previously-supported ORTP provisions. Thus, even if the Participants Committee were to vote at this meeting on the Markets Committee-recommended proposal, if the ISO were again to modify its ORTP proposal, NEPOOL might then need to consider further, corresponding amendments to its supported proposal. It was further clarified that the Markets Committee, if it desired, would be afforded a chance to consider any change to an ISO-proposed ORTP, although the ISO would not be ready to identify its proposal in time for the March 9 Markets Committee meeting. Mr. Cavanaugh reminded the Committee of the already scheduled March 18 Participants Committee working session and the possibility of voting this matter at that time.

Members sought further clarification from the ISO on the reason for thinking changes might be needed. The ISO referred that question to its consultant, who explained that the potential change related to the impact of the Investment Tax Credit (ITC), ~~the basis that the ITC is used for~~given the role ITC played in determining depreciation, and how the depreciation is handled over the life of a unit. Changes would be made to the discounted cash flow model to reflect that impact, and while such changes could affect all technologies, the expectation was that it would likely materially impact only the recommended solar ORTP. The consultant confirmed that the only potential change it had identified was to the solar ORTP. She acknowledged that other tax related concerns had also been raised at the Markets Committee but the consultants did not agree that those concerns warranted any change to the ISO proposal. The Committee agreed that any changes should be presented first to the Markets Committee and the ISO committed to work to provide information concerning proposed changes within 10 days in order to allow time for Markets Committee (at another meeting if needed) and Participants Committee consideration and vote before the end of the month.

The ISO was asked to provide a lessons-learned report once that filing was submitted. Further, the ISO was asked to review in a memorandum how its proposal differs from the proposal recommended by the Markets Committee. There was concern that the ISO continued to revisit some of the ~~many, many~~numerous variables that were inputs to its recommended ORTPs and the ISO was asked to explain in its update why it did not just declare its work complete for FCA16 and work to reflect these changes for FCA17 and FCA18.

In response to questions on process and the potential for bypassing Markets Committee reconsideration of the recommended ORTPs, NEPOOL referred members to its process memorandum that had been circulated in advance of the meeting, noting the potential that the Participants Committee could support changes to what it previously approved in December but then be unable to agree on an amended package of changes. NEPOOL counsel explained that, were that outcome to occur, NEPOOL would no longer have a competing proposal and there would be no jump ball. He reminded members that, regardless of what the Markets Committee ~~recommends~~recommended, it is the action of the Participants Committee only that defines NEPOOL's alternative.

Market Participants then reviewed with the ISO their concerns about how changes to the variables being discussed might impact FCA16 Retirement De-List Bids that needed to be submitted by March 12, 2021. The memorandum from the Internal Market Monitor (IMM), which was circulated to the Committee with the meeting materials, provided only partial guidance and there were many more potential outcomes that could impact De-List Bids that were not reflected in that memorandum. On behalf of the IMM, Dr. Jeffrey McDonald, ISO Vice President, Market Monitoring, acknowledged these concerns, noting his view that the impacts of the possible changes would likely be minimal. Members asked that the memorandum be clarified to address what changes might be permitted.

Members also questioned whether a commitment from the IMM to consider changes ~~is~~would be sufficient, since the Tariff as ~~the~~then worded did not seem to permit such changes. The ISO had previously concluded that Retirement Bids were irrevocable. The ISO and IMM opined, though, that allowing conditional or contingent bids based solely on regulatory outcome ~~seems~~seemed justified. There was concern that FERC might not agree and the ISO agreed to consider this matter further and perhaps propose new Tariff language to confirm that De-List Bid adjustments or withdrawals would be permitted under these circumstances.

The IMM was asked whether it would publish the Retirement De-List Bids a week before they are due given the various potential regulatory outcomes. Dr. McDonald committed to consider that request but was not able at that time to make that commitment.

The members returned to the topic of how expansive the re-visitation of prior positions of the ISO would be. Some expressed concern that the issue now being re-reviewed had been raised much earlier in the Participant Processes and the ISO needed to bring closure to the process. Further, if there were to be changes, NEPOOL needed a reasonable opportunity for informed input, preferably at the Markets Committee. There was some discussion of whether NEPOOL could or should finalize its proposal notwithstanding the ISO's potential changes. Recognizing that the ISO, and not NEPOOL, would be filing changes, and would dictate when that filing occurred, there was no advantage identified to voting the NEPOOL proposal weeks ahead of knowing or voting the ISO proposal.

Following this discussion, Mr. Cavanaugh asked the Committee whether anyone opposed deferring a vote on the Markets ~~Committee recommended~~Committee-recommended proposal until after the Markets Committee reviewed the ISO final proposal and decided whether to further change its recommendation to the Participants Committee. While frustration was expressed with the process, there was agreement that NEPOOL should be acting on the best information available under the circumstances and that process should not be used to prevent NEPOOL from considering new circumstances that arise that are reasonably concluded to be material changes in circumstances.

No member objected to deferral of the vote on the ISO proposal and the Markets Committee-recommended changes to NEPOOL's previously-approved proposal. The Chair noted that a meeting to consider and vote on this matter would be scheduled before the end of the month.

COMMITTEE REPORTS

Markets Committee (MC). Mr. William Fowler, the MC Vice-Chair, reported that a single-day MC meeting would be held on March 9, and that, as discussed earlier with the respect to the deferral of a vote on ORTPs, at least one other MC meeting would be scheduled later in March.

Transmission Committee (TC). Mr. José Rotger, the TC Vice-Chair, reported that the TC planned to meet on March 23, subject to potentially rescheduling if necessary to accommodate participation in the FERC's Resource Adequacy Technical Conference also scheduled for that day. The agenda for the next TC meeting would include further discussion on planning aspects of ISO compliance with Order 2222, the~~ ~~ Participating Transmission Owners' proposal to address reconstitution of behind-the-meter generation into the Regional Network Load calculation, operational and interconnection issues, and changes to the Market Participant Service Agreement (MPSA).

Reliability Committee (RC). Mr. Robert Stein, the RC Vice-Chair, reported that the RC was scheduled to meet on March 16 and the agenda would include, as previously noted, discussion of the FCA15 results.

Joint MC/RC (Future Grid - Reliability Study). Mr. Stein also reported that the next joint meeting of the MC and RC was scheduled for March 31 at which the Committees would review of the incremental changes to Phase One of the grid study framework document, which he explained would advance as a NEPOOL-requested economic study.

Budget & Finance Subcommittee. Mr. Thomas Kaslow, the Subcommittee Chair, announced that the next meeting of the Subcommittee was scheduled for March 25 and would include a presentation by the ISO on the changes to the Non-Commercial Capacity trading financial assurance provisions of the Financial Assurance Policy.

ADDITIONAL MATTERS

Mr. Cavanaugh referred the Committee to a memo circulated with the materials for the meeting, regarding the 2021 ISO audit results and audit plans. He noted the Budget & Finance Subcommittee would review the documents and determine if another audit ~~will~~would be required.

Mr. Cavanaugh then turned to Dr. Chadalavada for brief comments regarding agenda item number 4, but in light of the time requested that a more structured discussion take place at the April meeting. Dr. Chadalavada provided a few brief comments regarding the readiness of the ISO for handling weather events in New England as extreme as those seen in Texas, which he explained reflected drastic deviations (temperatures approximately 40 degrees colder than normal). He explained that such extreme weather events are difficult to include in the normal planning processes. The ISO intended to share how it might prepare for such extreme weather events and lessons that can be learned from the events in Texas.

Ms. Heather Hunt, NESCOE Executive Director, noted that the final technical session as part of the New England Energy Vision statement ~~will~~would take place on March 18, 6:30- 8pm and ~~will~~would be focused on environmental ~~justice related~~justice-related issues.

ADMINISTRATIVE MATTERS

Mr. Doot reminded the Committee of the upcoming Future Grid Pathways working session of the Participants Committee on March 18. He also noted another Participants Committee meeting would be scheduled to attend to the outstanding Market Rule issues addressed earlier in this meeting.

There being no further business, the meeting adjourned at 2:51 p.m.

Respectfully submitted,

David Doot, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN MARCH 4, 2021 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Acadia Center	End User			Bruce Ho
Actual Energy	Supplier		John Driscoll	
Advanced Energy Economy	Fuels Industry Participant	Caitlin Marquis		
American PowerNet Management	Supplier			Joyceline Chow
Anbaric Development Partners LLC				Francis Pullaro
AR Large Renewable Generation (RG) Group Member	AR-RG	Alex Worsley		
AR Small Load Response (LR) Group Member	AR-LR	Brad Swalwell		
AR Small RG Group Member	AR-RG	Erik Abend		
Ashburnham Municipal Light Plant	Publicly Owned Entity		Brian Thomson	
Associated Industries of Massachusetts (AIM)	End User			Roger Borghesani; Joyceline Chow
AVANGRID: CMP/UI	Transmission		Alan Trotta	
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
Borrego Solar Systems Inc.	AR-DG	Liz Delaney		
Boylston Municipal Light Department	Publicly Owned Entity		Brian Thomson	
BP Energy Company	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity			Dave Cavanaugh
Brookfield Renewable Trading and Marketing	Supplier	Aleks Mitreski		
Calpine Energy Services, LP	Supplier	Brett Kruse		Bill Fowler
Castleton Commodities Merchant Trading	Supplier			Bob Stein
Central Rivers Power	AR-RG		Dan Allegretti	Mike Booth; Bill Fowler
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
CLEAResult Consulting, Inc.	AR-DG	Tamera Oldfield		
Clearway Power Marketing LLC	Supplier			Pete Fuller
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw		
Connecticut Office of Consumer Counsel	End User		Dave Thompson	
Conservation Law Foundation (CLF)	End User	Phelps Turner		
Consolidated Edison Energy, Inc.	Supplier	Norman Mah		
CPV Towantic, LLC	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
DC Energy, LLC	Supplier	Bruce Bleiweis		
DTE Energy Trading, Inc.	Supplier			José Rotger
Dynegy Marketing and Trade, LLC	Supplier	Andy Weinstein		Bill Fowler
Emera Energy Services	Supplier			Bill Fowler
Enel X North America, Inc.	AR-LR	Michael Macrae		
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		Michael Macrae
Environmental Defense Fund	End User	Jolette Westbrook		
Eversource Energy	Transmission	James Daly	Dave Burnham	Vandan Divatia
Exelon Generation Company	Supplier	Steve Kirk	Bill Fowler	
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	José Rotger		
Generation Group Member	Generation	Dennis Duffy	Abby Krich	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Great River Hydro	AR-RG			Bill Fowler
Groton Electric Light Department	Publicly Owned Entity		Brian Thomson	
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQUS)	Supplier	Louis Guilbault	Bob Stein	
Harvard Dedicated Energy Limited	End User	Joyceline Chow		

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN MARCH 4, 2021 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned Entity	John Coyle	Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Holyoke Gas & Electric Department	Publicly Owned Entity		Brian Thomson	
Hull Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
IDT Energy, LLC	Supplier		Glen Biren	
Ipswich Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Jericho Power LLC (Jericho)	AR-RG	Mark Spencer	Nancy Chafetz	Herb Healy
Kleen Energy Systems, LLC	Generation			Tom Kaslow
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	
Littleton (NH) Water & Light Department	Publicly Owned Entity		Craig Kieny	
Long Island Power Authority (LIPA)	Supplier		Bill Killgoar	
Maine Power	Supplier	Jeff Jones		
Maine Public Advocate's Office	End User	Drew Landry		
Mansfield Municipal Electric Department	Publicly Owned Entity		Brian Thomson	
Maple Energy LLC	AR-LR		Luke Fishback	Doug Hurley
Marble River, LLC	Supplier			Abby Krich
Marblehead Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Marco DM Holdings	Generation			Tom Kaslow
Mass. Attorney General's Office (MA AG)	End User	Tina Belew	Ben Griffiths	
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Brian Thomson		
Mercuria Energy America, LLC	Supplier			José Rotger
Merrimac Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Michael Kuser	End User		Jason York	
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned Entity		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 Entity	Steve Kaminski		Brian. Forshaw; Dave Cavanaugh; Brian Thomson
New Hampshire Office of Consumer Advocate (NHOCA)	End User		Erin Camp	
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
NRG Power Marketing LLC	Generation		Pete Fuller	
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Paxton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Peabody Municipal Light Department	Publicly Owned Entity		Brian Thomson	
PowerOptions, Inc.	End User			Erin Camp
Princeton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
PSEG Energy Resources & Trade LLC	Supplier		Eric Stallings	
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Rodan Energy Solutions (USA) Inc.	Provisional Member	Aaron Breidenbaugh		
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity		Brian Thomson	
Shell Energy North America (US), L.P.	Supplier	Matt Picardi		
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Brian Thomson	
South Hadley Electric Light Department	Publicly Owned Entity		Brian Thomson	
Sterling Municipal Electric Light Department	Publicly Owned Entity		Brian Thomson	
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN MARCH 4, 2021 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Sunrun Inc.	AR-DG			Pete Fuller
Taunton Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
The Energy Consortium	End User	Roger Borghesani	Mary Smith	Joyceline Chow
Union of Concerned Scientists	End User		Francis Pullaro	
Vermont Electric Cooperative	Publicly Owned Entity	Craig Kieny		
Vermont Electric Power Co. (VELCO)	Transmission	Frank Ettori		
Vermont Energy Investment Corp (VEIC)	AR-LR		Doug Hurley	
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw
Versant Power	Transmission	Lisa Martin		
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Brian Thomson	
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler	Jim Ginnetti

CONSENT AGENDA

Reliability Committee (RC)

From the previously-circulated notice of actions of the RC's March 16, 2021 meeting, dated March 16, 2021.[1]

1. Changes to OP-22 Disturbance Monitoring Requirements

Support changes to ISO New England Operating Procedure (OP) No. 22 (Disturbance Monitoring Requirements), which add clarifying language for one-line diagrams, new installations and continuous Phasor Measurement Unit (PMU) streaming, as recommended by the RC at its March 16, 2021 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was approved unanimously.

[1] RC 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

April 1, 2021 Participants Committee Meeting

Since the last update, the Board of Directors met on March 17 and 18. In addition, the Audit and Finance Committee, the Information Technology and Cyber Security Committee, the Markets Committee, and the System Planning and Reliability Committee met on March 17, and the Nominating and Governance Committee met on March 18. All meetings were held virtually.

The Audit and Finance Committee received an update on current Internal Audit Department activities, including the risk assessment process and audit planning cycle. The Committee was also presented with the Internal Audit Department's audit plan for 2021. The Committee received updates on financial performance against the 2021 budget, including the strain on the budget related to several unplanned studies, and discussed the renewal of working capital lines. The Committee then reviewed fiduciary changes related to the oversight of employee benefit plans and proposed edits to the Committee's charter for that purpose and to move several responsibilities to the new Information Technology and Cyber Security Committee of the Board. The Committee recommended that the Board approve the revised charter at an upcoming meeting. Next, the Committee met with KPMG along with management, and reviewed the 2020 audited financial statements and discussed disclosure controls. The Committee voted to recommend the adoption of the audited financial statements by the Board of Directors. The Committee met further with KPMG and reviewed the work plan for the 2021 Service Organization Controls report. The Committee discussed the scope of the work, including objectives, audit team and methodology, and then held an executive session with KPMG.

The Information Technology and Cyber Security Committee held its first meeting. The Committee reviewed a draft committee charter and annual calendar, and agreed to recommend that the Board approve the charter at an upcoming Board meeting. The Committee received an update on the Company's cyber security plan and an overview of three-year work plan for cyber security projects currently underway. The Committee also discussed the rolling three-year infrastructure plan, which is part of the Company's overall information technology strategic plan.

The Markets Committee discussed initial observations related to the recent Texas extreme cold weather event, including continuing concerns about energy security and the future of the ESI proposal. Management stated that, before ESI can be reconsidered, the ISO needs to work with the states and stakeholders to re-evaluate energy security risks. The Committee also received an update on Offer-Review Trigger Prices and the net CONE deficiency order, including stakeholder positions on these topics. The Committee also received a report from management regarding progress on the pathways studies for the future grid process.

The System Planning and Reliability Committee was provided with a summary of the Forward Capacity Auction #15 results, received an update on economic studies, and reviewed winter operations for the 2020/2021 season. The Committee also discussed an overview of the future grid reliability study, the 2050 transmission study, and initial observations related to the recent Texas extreme cold weather event.

The Board of Directors prepared for the meeting with state regulators scheduled for the following day. Next, the Board reviewed the Company's annual communications plan and discussed the key themes and messages. The next day, following a meeting with state representatives, the Board continued its meeting and discussed strategic objectives for 2022. The Board then received reports from the standing committees. During the Audit and Finance Committee report, the Board approved the audited financial statements for 2020.

The Nominating and Governance Committee received an update on Joint Nominating Committee activities, and considered the format for the annual board and committee evaluation process. Next, the Committee was provided with an overview of the states' technical forum on governance that was part of the states' energy vision process. The Committee discussed comments regarding the need for improved Board transparency. The Committee also prepared for meetings at the upcoming Board IRC Conference in May, and considered the potential impacts on the communications plan related to the recent Texas extreme cold weather event.

NEPOOL Participants Committee Report

April 2021

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Regular Operations Report - Highlights

Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Update: February 2021 Energy Market value totaled $759M
  - March 2021 Energy market value over the period was $324M, down $435M from February 2021 and up $152M from March 2020
    - March natural gas prices over the period were 55% lower than February average values
    - Average RT Hub Locational Marginal Prices ($37.10/MWh) over the period were 48% lower than February averages
      - DA Hub: $38.83/MWh
    - Average March 2021 natural gas prices and RT Hub LMPs over the period were up 144% and 121%, respectively, from March 2020 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 99% during March, down from 99.1% during February*
    - The minimum value for the month was 94.3% on Saturday, March 6th

Data through March 24th.

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

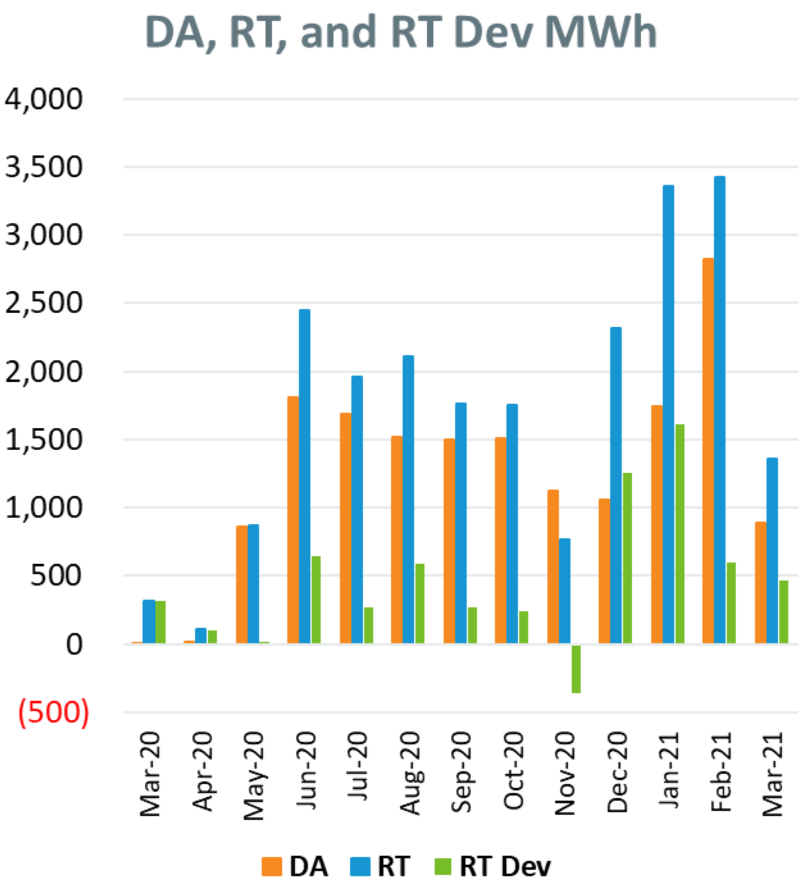
***DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market**

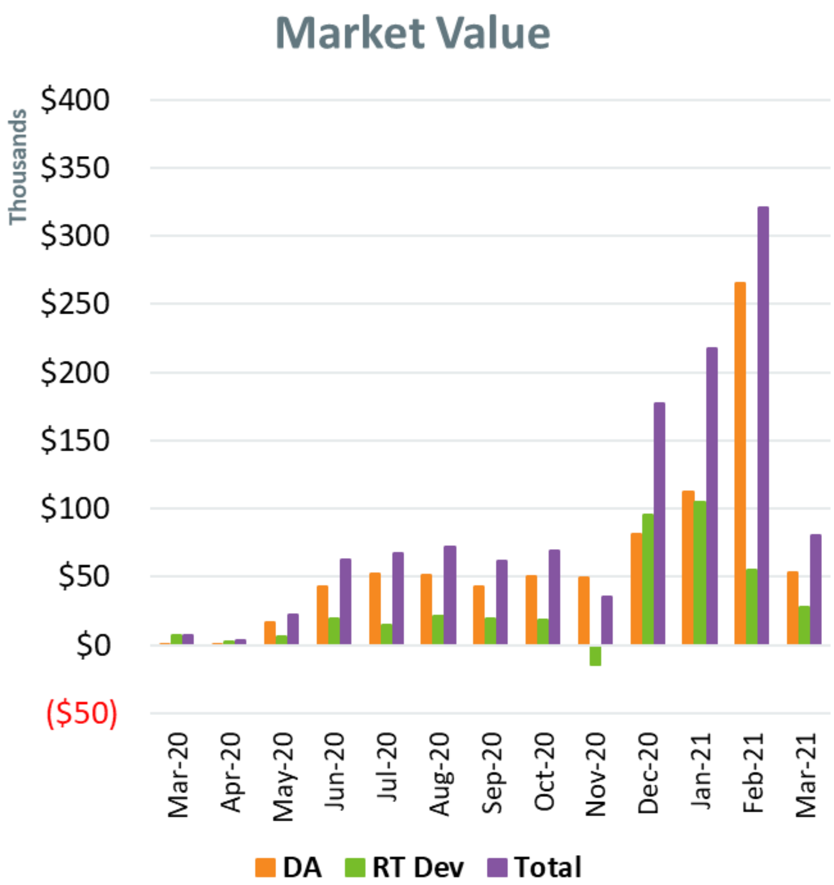
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - March 2021 NCPC payments over the period totaled $1.8M, down $0.8M from February 2021 and up $0.1M from March 2020
    - First Contingency payments totaled $1.7M, down $0.6M from February
      - $1.6M paid to internal resources, down $0.6M from February
        - » $722K charged to DALO, $496K to RT Deviations, $424K to RTLO*
      - $28K paid to resources at external locations, up $13K from February
        - » $6K charged to DALO at external locations, $23K to RT Deviations
    - Second Contingency payments totaled $131K, down $12K from February
    - Distribution and Voltage payments were both zero
  - NCPC payments over the period as percent of Energy Market value were 0.6%

* NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $228K; Rapid Response Pricing (RRP) Opportunity Cost - $189K; Posturing - $0K; Generator Performance Auditing (GPA) - $6K;

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.

Forward Capacity Market (FCM) Highlights

- CCP 12 (2021-2022)
  - Third and final annual reconfiguration auction (ARA3) was held on March 1-3, and results will be posted no later than March 31
- CCP 13 (2022-2023)
  - Second annual reconfiguration auction (ARA2) will be held on August 2-4, and results will be posted no later than September 1
- CCP 14 (2023-2024)
  - First annual reconfiguration auction (ARA1) will be held on June 1-3, and results will be posted no later than July 1
- CCP 15 (2024-2025)
  - Auction results were filed with FERC on February 26, and the filing is pending at FERC

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP 16 (2025-2026)
  - The qualification process has started, and training has been provided
  - Topology certifications were shared at the January 20 RC meeting
  - FCA 16 will evaluate the same zones as evaluated in FCA 15
    - Potential export-constrained zones: Northern New England and Maine nested inside Northern New England
    - Potential import-constrained zones: Southeast New England and Connecticut
  - Existing capacity values were posted on March 5
  - Retirement and permanent delist bids summary was posted on March 17

FCM Highlights, cont.

- CCP 16 (2025-2026), cont.
  - FCA 16 CONE, Net CONE, and Capacity Performance Payment Rate values are currently pending FERC approval
    - The final calculations for capacity zones and the final retirement and permanent delist bids summary are dependent on receiving a final order from FERC on the FCA 16 values
  - FCA 16 dynamic delist bid threshold price has been posted to the ISO-NE website as part of the FCM parameters page
    - https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/#2025-2026
  - First PSPC meeting to discuss ICR and Related Value assumptions will be held on May 20

Load Forecast

- Efforts continue to enhance load forecast models and tools to improve day-ahead and long-term load forecast performance
- Continuing to evaluate the impacts of COVID-19 to the load forecast
- The 2021 load forecast development process is almost complete
  - Changes to reconstitution used in the gross load forecast have required fundamental changes to be developed and implemented into the 2021 energy-efficiency forecast
    - Gross load forecast is estimated to decrease approximately 1,500 MW for summer 2025 from the 2020 CELT
    - Final draft forecast will be discussed at the April PAC meeting
  - Publication of the final ten-year forecast will be in the 2021 CELT report, which will be posted on April 30

FERC Order 1000

- Qualified Transmission Project Sponsor (QTPS)
  - 25 companies have achieved QTPS status

Competitive Solution Process: Order 1000/Boston 2028 Request for Proposal Lessons Learned

- The ISO began one-on-one discussions with each QTPS that participated in the Boston 2028 RFP where QTPS specific questions regarding their proposals and/or the process can be discussed
- The lessons-learned process, with respect to competitive transmission solutions, was discussed at the October PAC meeting
- Stakeholder feedback was discussed at the 12/16/20 PAC meeting, and initial ISO responses were discussed at the 2/17/21 PAC meeting
- Further discussion is expected at the 4/14/21 PAC meeting

Highlights

- The lowest 50/50 and 90/10 Spring Operable Capacity Margins are projected for week beginning May 8, 2021.

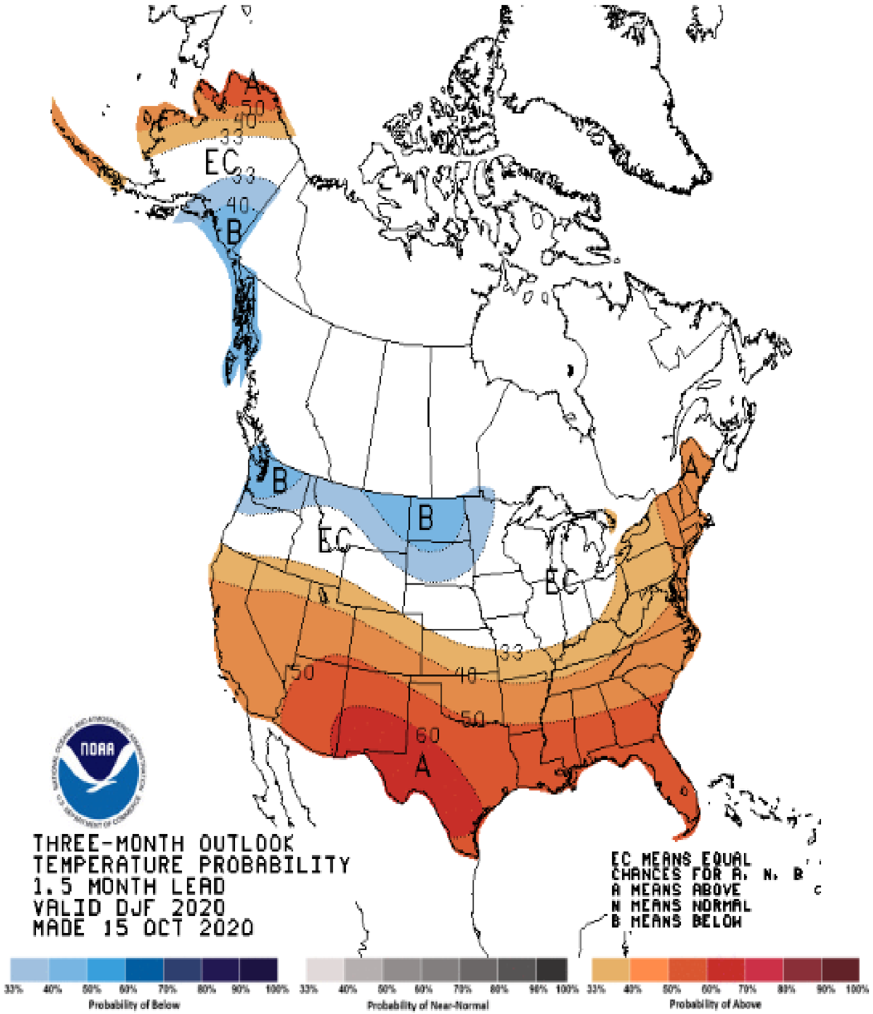
- The lowest 50/50 and 90/10 Preliminary Summer Operable Capacity Margins are projected for week beginning September 11, 2021.

ISO New England 2020-2021 Winter Operations

Highlights

- The New England average winter temperature departure from normal of +1.8°F was consistent with NOAA's seasonal outlook of above-normal temperatures
- COVID-19 appears to have had an impact on the load curve and the overall energy demand in New England
- No significant reductions in natural-gas availability were experienced
- 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

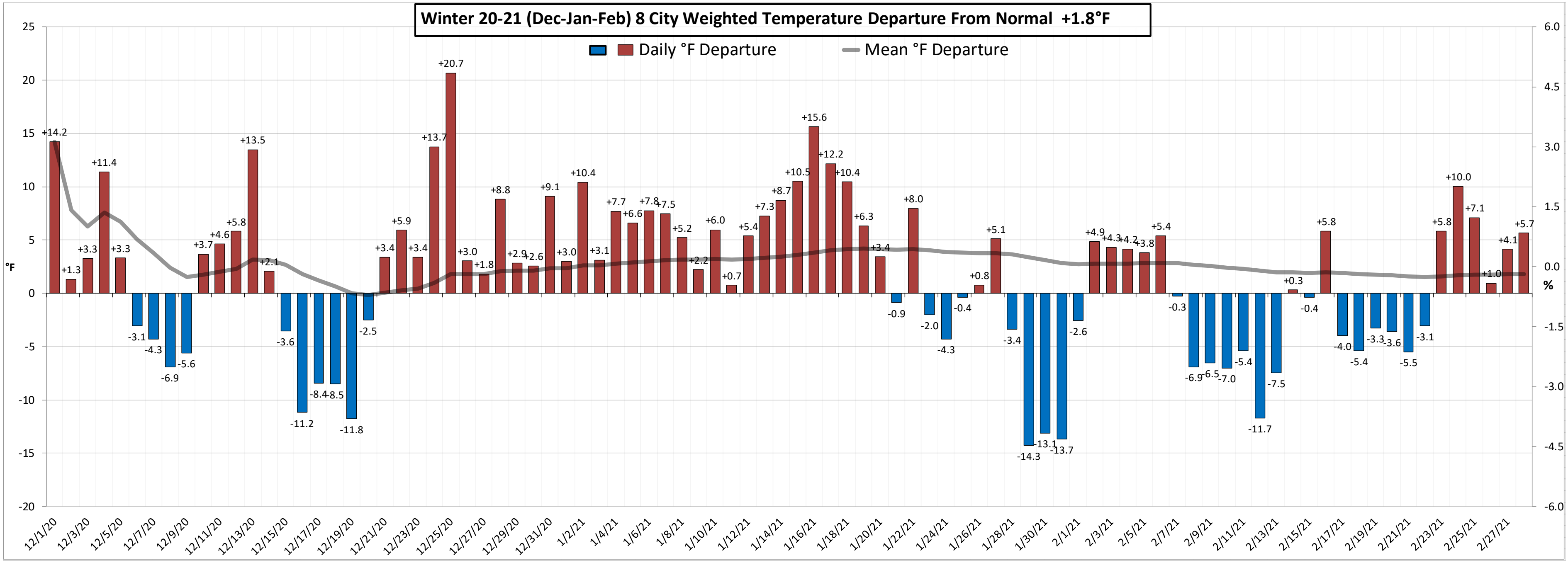
Observed Winter Temperatures



- There were a few periods of consecutive days with below-normal temperatures, but no sustained significant cold was observed
- New England was affected by three moderate cold snaps
  - December 15 - 20
  - January 28 - February 1
  - February 7 - February 13
- 31 consecutive days from December 21 – January 20 had above-normal temperatures

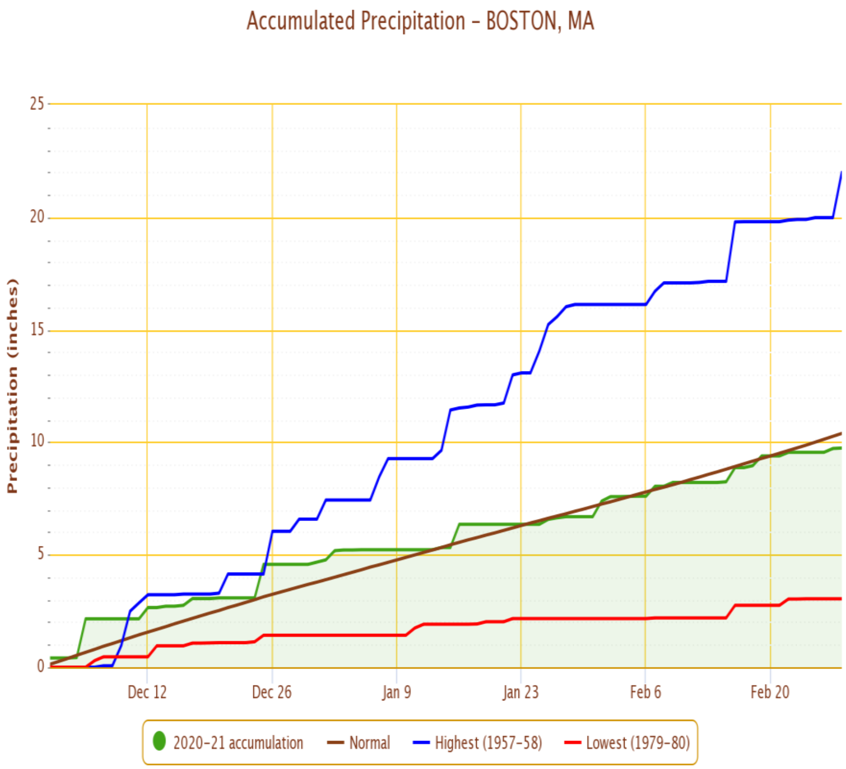
Observed Winter Temperatures, cont.

- Daily Winter Temperature Departures from Normal

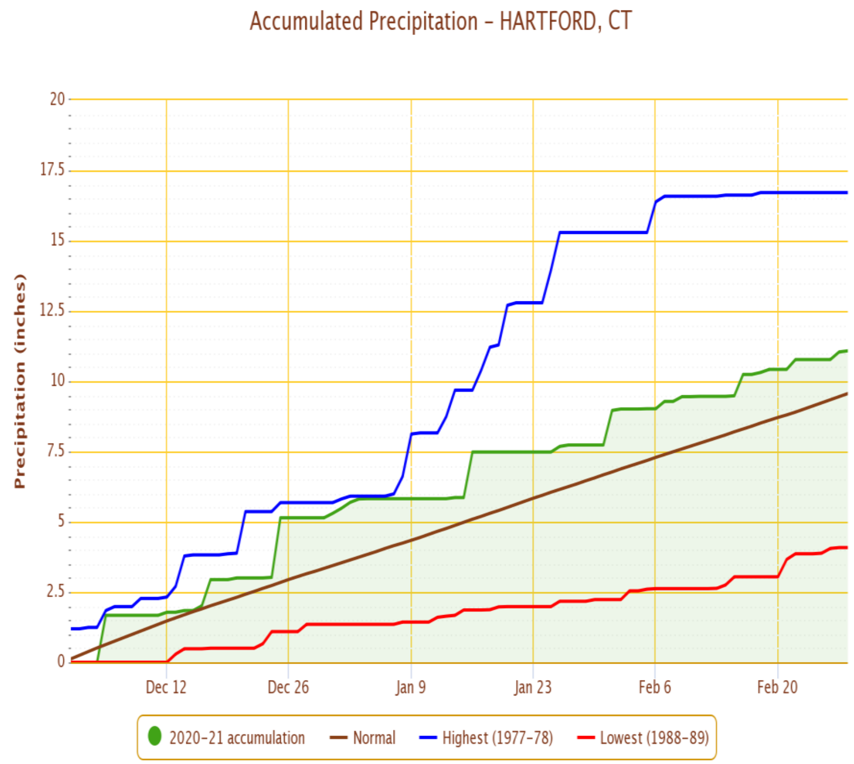


Observed Winter Precipitation

- Boston
  - 34.1” of snowfall which was 1.3” above normal
  - Total precipitation was 0.4 inches below normal



- Hartford
  - 39.1” of snowfall which was 8.4” above normal
  - Total precipitation was 1.5 inches above normal

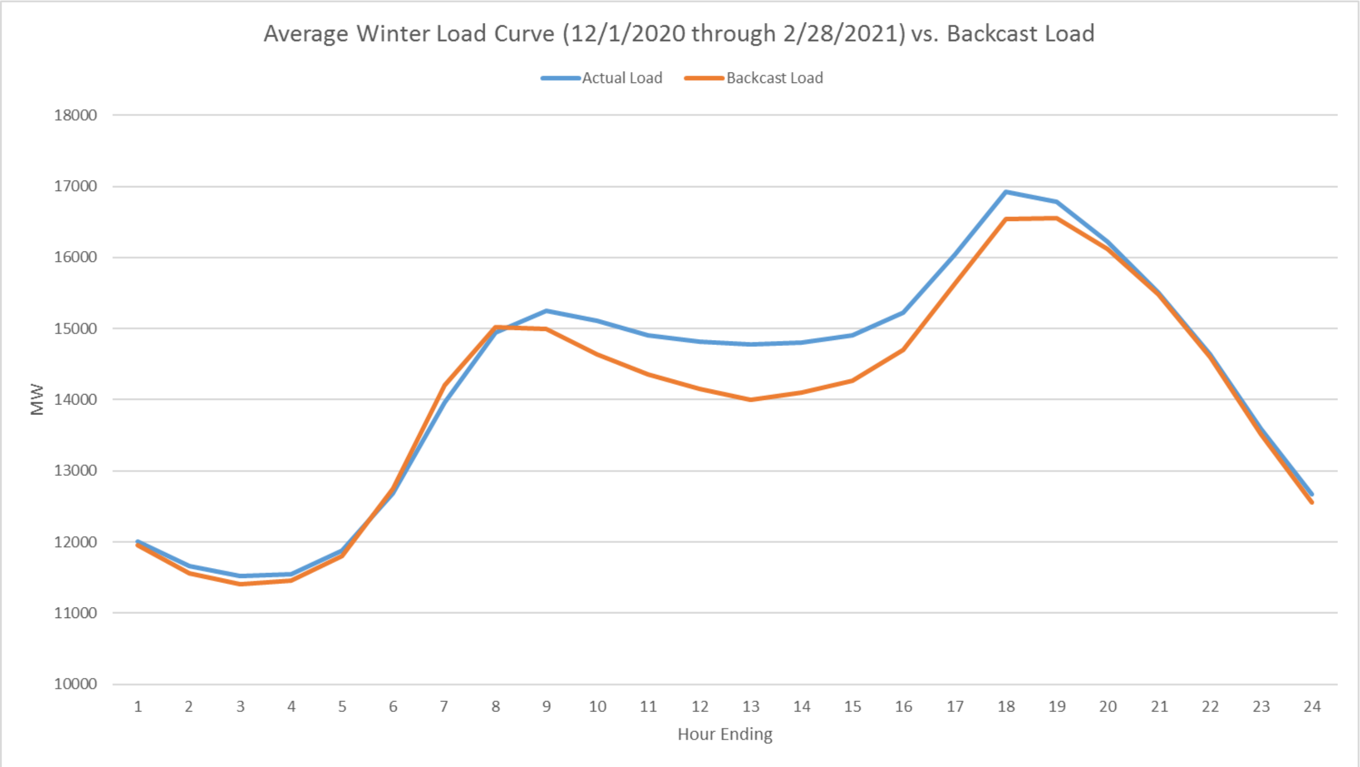


Winter Observations

- Winter Demand
  - COVID-19 appears to have had a noticeable impact on the load curve and the overall energy demand in New England (see next two slides)
  - Actual winter peak demand was 18,703 MW on January 29, 2021
- Transmission System & Transfer Capability
  - New England transmission system performed well
  - Transfer capability on the New York Northern AC ties was increased from 1,400 to 1,500 MW for the winter period

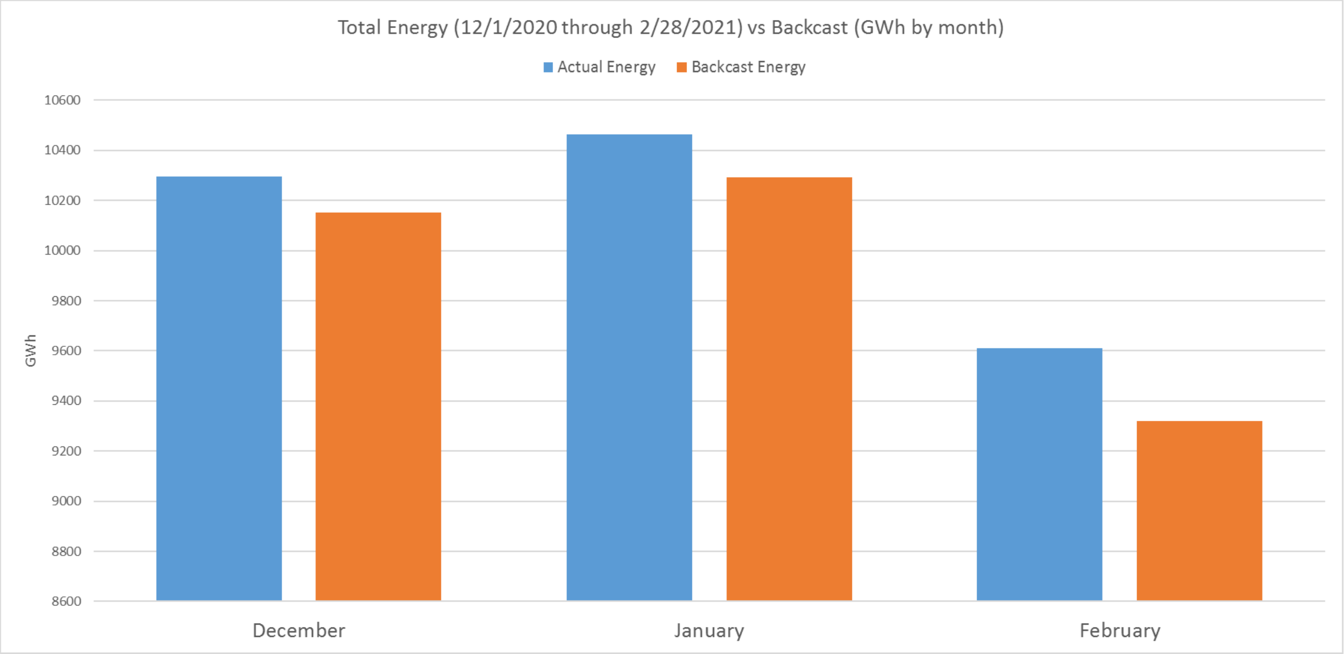
Winter Load Curve

- Higher loads overall can be attributed to work-from-home and remote-learning policies
  - Higher average evening peak and higher mid-day loads than backcast
  - Deviations observed primarily during “normal working hours”



Winter Energy Demand

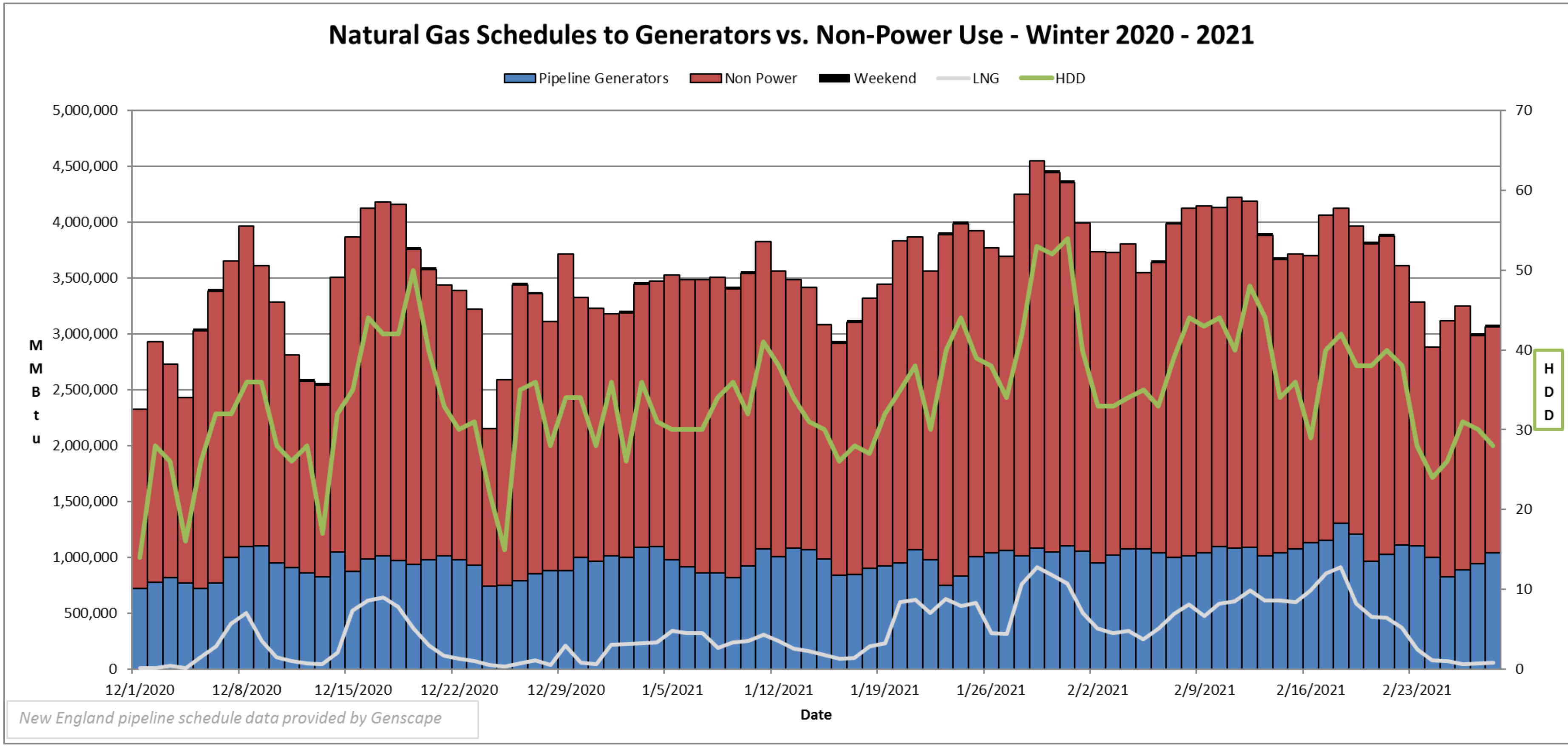
- Actual energy was greater than backcast energy in each month of this winter
- Snowfall resulted in lower PV output, which contributed to ~22% of the higher energy demand; the remaining additional energy can generally be attributed to the changed societal posture



Winter Observations, cont.

- Natural-Gas Deliverability
  - Overall natural-gas demand was higher than previous years
  - Scheduled liquefied natural gas injections were slightly above average
- 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 2020-2021 at approximately 58% full and are currently at approximately 56% full
- Winter Capacity
  - Generation fleet performed well overall throughout the winter

Winter Natural Gas Schedules



HDD – Heating Degree Days
LNG – Liquefied Natural Gas

BRIEF SUMMARY OF THE EXTREME WEATHER EVENT IN TEXAS

Summary of the Texas Extreme Cold Weather Event

- During the week beginning on Sunday February 14, the ERCOT Interconnection experienced severe weather and extreme low temperatures that led to supply and demand imbalance
- ERCOT system operators ordered firm customer load shedding beginning in the early morning hours of Monday February 15 to prevent an ERCOT wide blackout
- Resources of every technology type had difficulty with startup and operations; Resource losses were caused by multiple reasons including fuel supply disruption, fuel quality, infrastructure freeze ups, icing, snow cover, and other issues
  - 52,277 MW out of 107,514 MW total installed capacity was forced out or unavailable
- Continued load shedding was required for multiple days in order to maintain a supply and demand balance; The magnitude of the load that had to be disconnected made it difficult to rotate feeders
  - At its peak, ~20,000 MW of load was shed

Summary of the Texas Extreme Cold Weather Event

- ERCOT's presentation to its Board was circulated to stakeholders as part of last month's Participants Committee meeting
- SPP and MISO also experienced emergency conditions during this time frame which required firm customer load shedding but these events were not as extreme as those experienced in ERCOT
  - SPP directed the interruption of service twice: once for approximately 50 minutes on the morning of Feb. 15, and again for a little more than three hours on the morning of Feb. 16.
  - MISO also shed load during the event but exact dates and quantities are not available
- Several investigations are under way including a joint FERC/NERC inquiry and the State of Texas inquiries
- Subsequent to the event, Potomac Economics said that high prices (~$9000) lasted 32 hours longer than appropriate and recommended the PUC direct ERCOT to correct that pricing, to avoid "the inappropriate pricing intervention that occurred" in order to prevent "substantial adverse economic effects.“
  - This recommendation was rejected by the Texas PUC

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (3.3°F) Max: 74°F, Min: 13°F Precipitation: 1.69" – Below Normal Normal: 3.91" Snow: 0.10"	Hartford	Temperature: Above Normal (3.0°F) Max: 77°F, Min: 13°F Precipitation: 2.25" - Below Normal Normal: 3.26" Snow: 0.10"

Peak Load:	17,647 MW	March 02, 2021	19:00 (ending)

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

Procedure	Declared	Cancelled	Note
None for March, 2021			

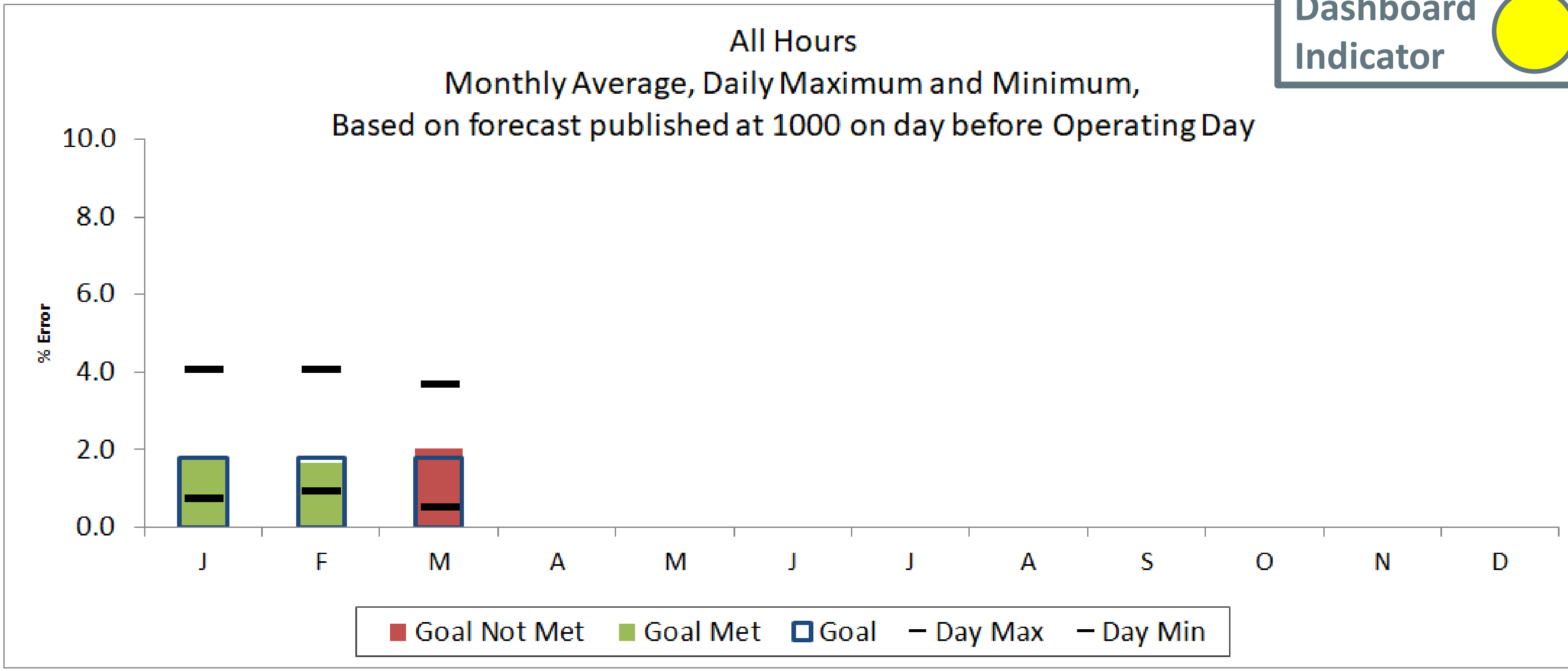
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
3/28	IESO	800

2021 System Operations - Load Forecast Accuracy

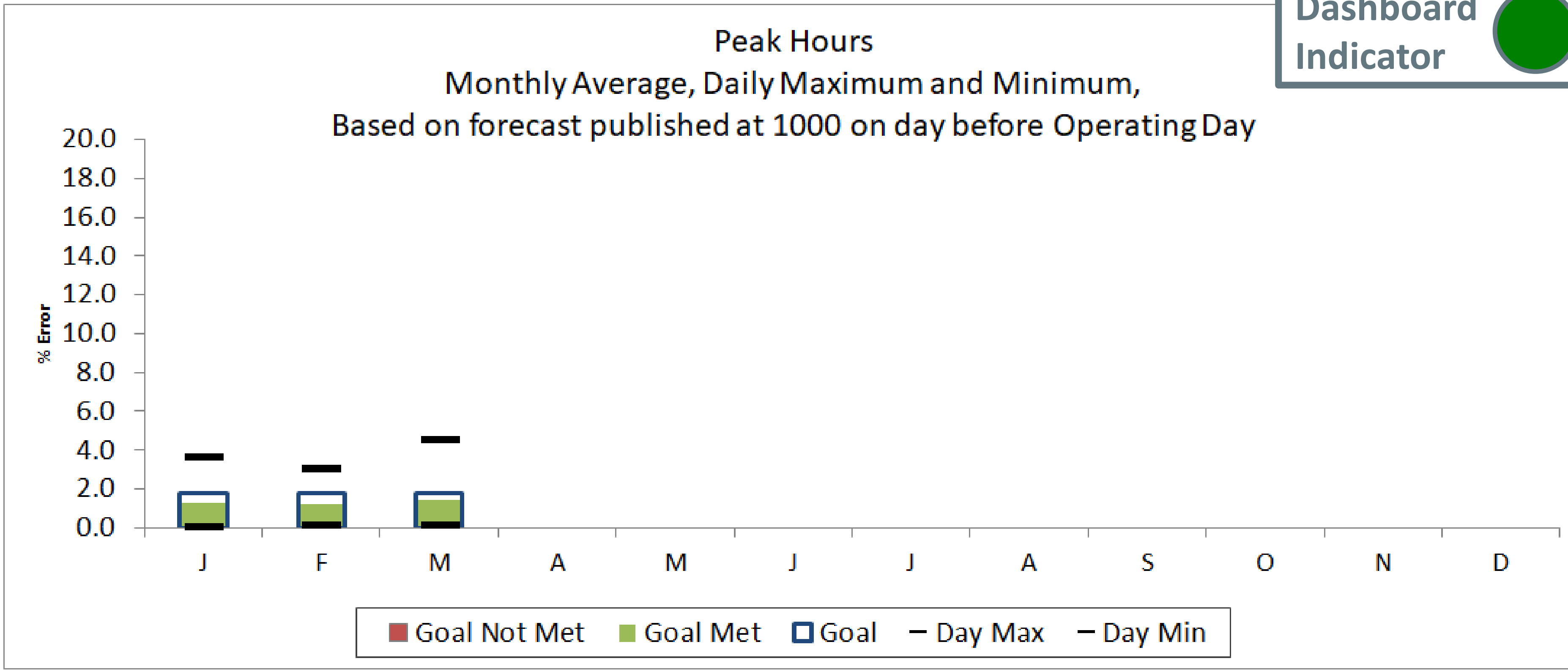
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.04	4.03	3.67										4.04
Day Min	0.70	0.92	0.49										0.49
MAPE	1.72	1.66	2.02										1.80
Goal	1.80	1.80	1.80										

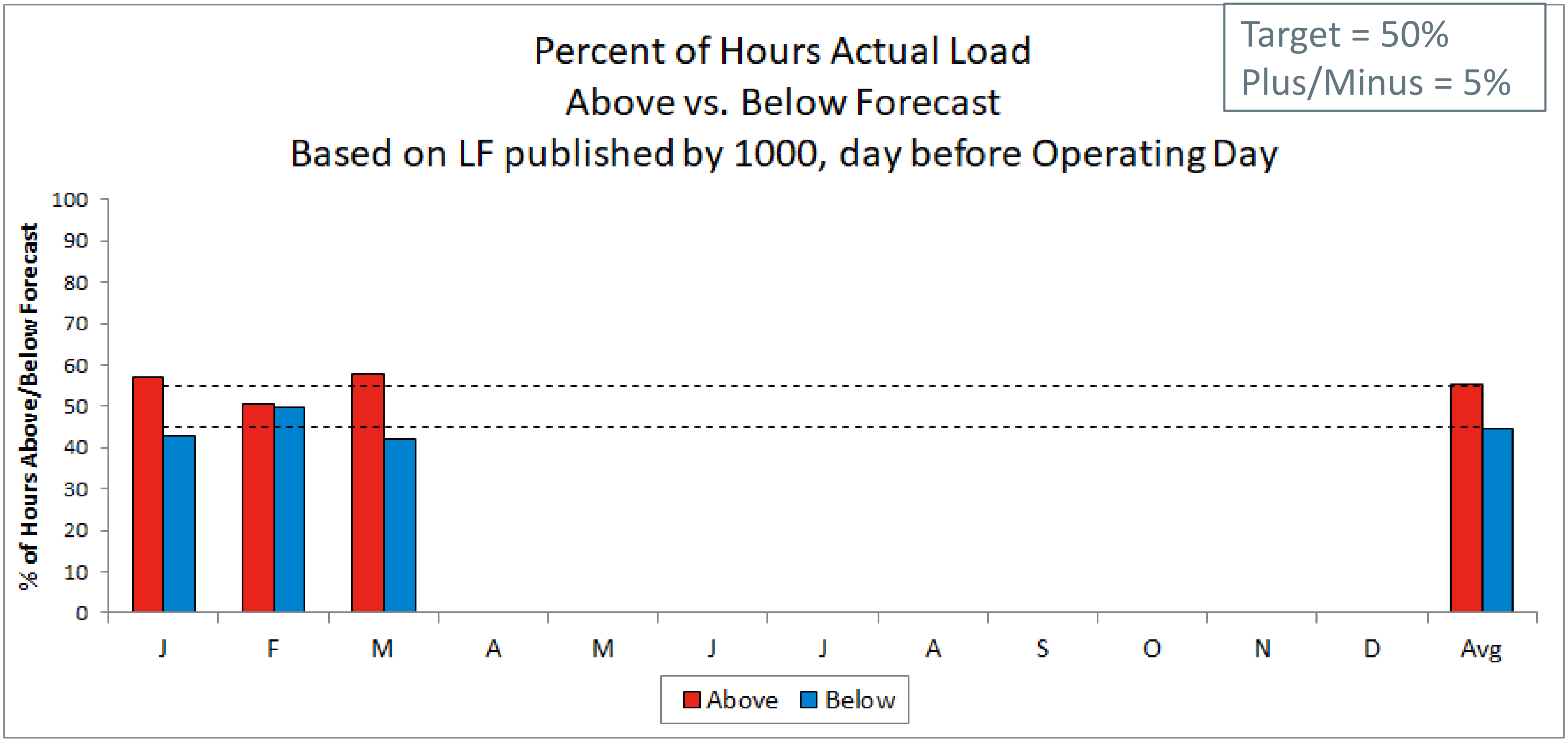
2021 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



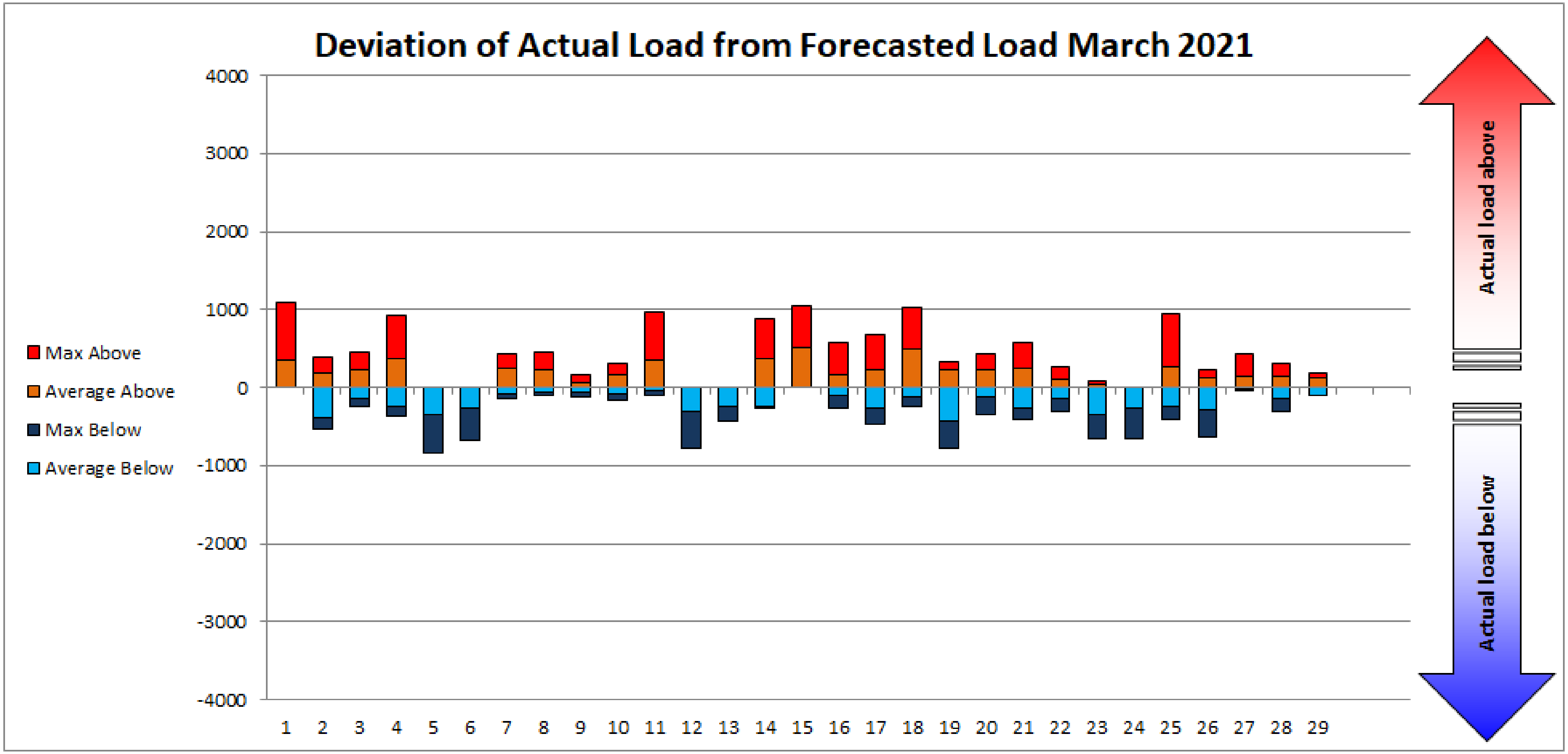
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	3.61	3.03	4.47										4.47
Day Min	0.02	0.06	0.08										0.02
MAPE	1.26	1.18	1.46										1.30
Goal	1.80	1.80	1.80										

2021 System Operations - Load Forecast Accuracy cont.



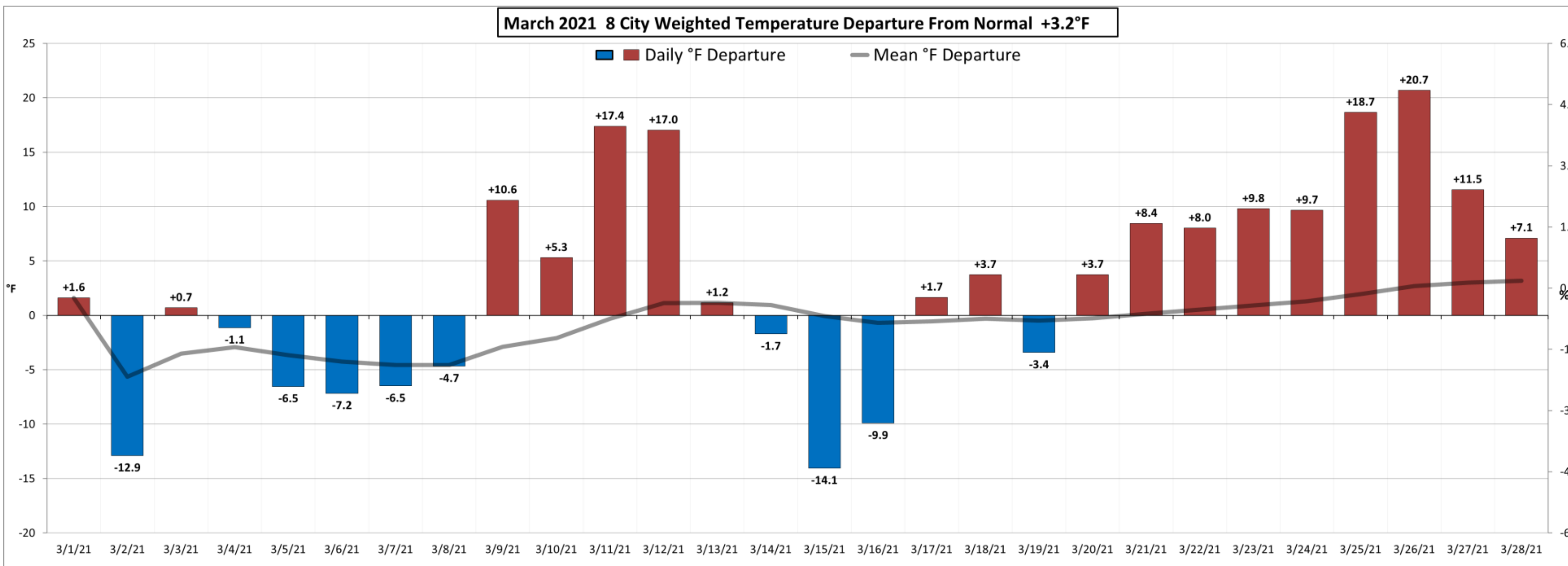
	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	57.1	50.4	57.8										55
Below %	42.9	49.6	42.2										45
Avg Above	209.5	166.7	180.8										210
Avg Below	-147.6	-216.4	-174.5										-216
Avg All	60	-25	43										28

2021 System Operations - Load Forecast Accuracy cont.

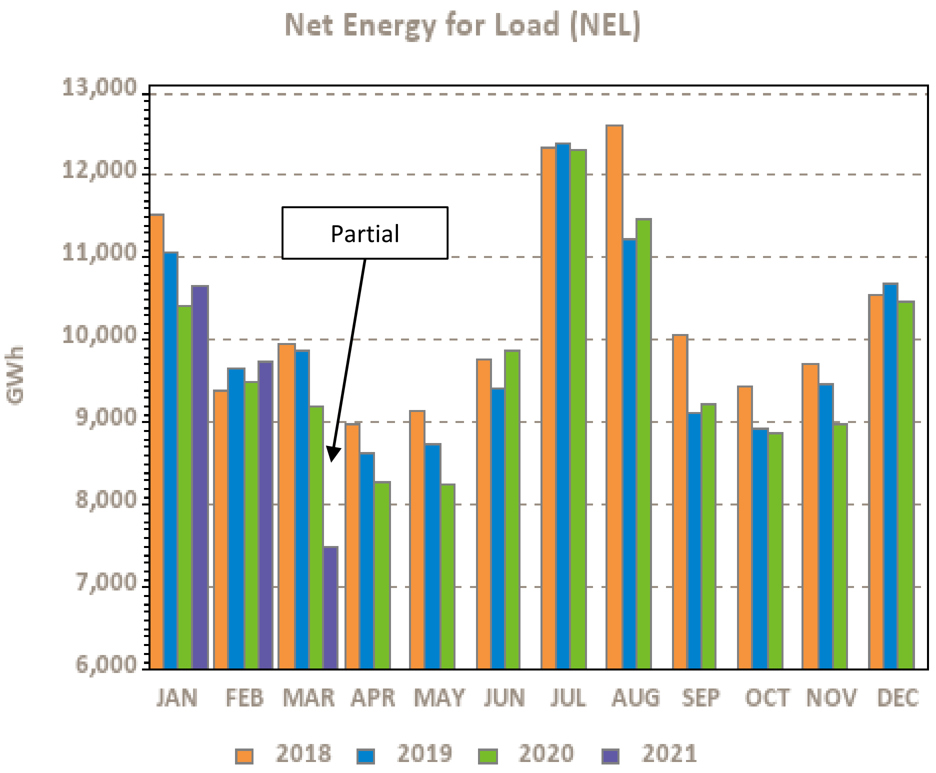


Temperature variability in reference to Normal

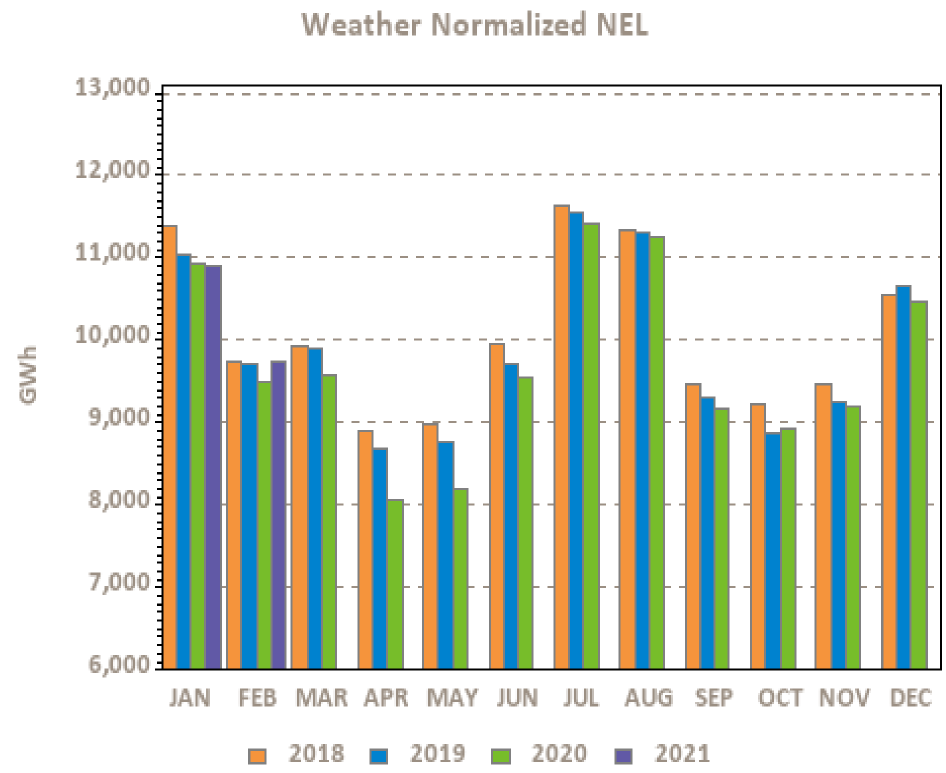
- Significant temperature variability contributed to reduced forecast accuracy



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



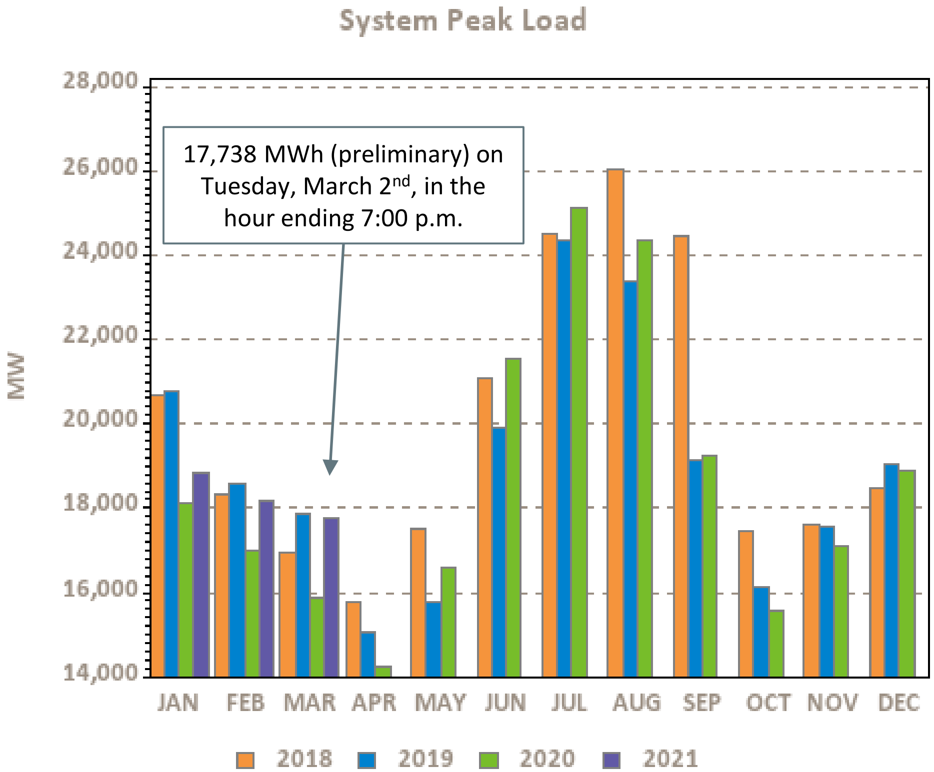
Ann Tot (TWh): 123.5 119.2 116.9 27.9



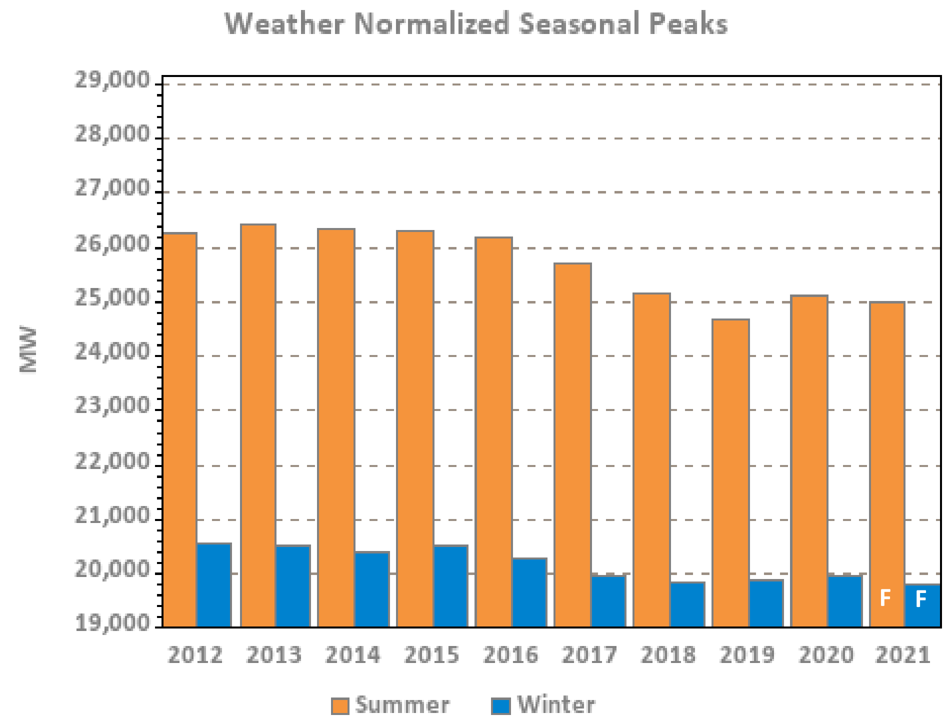
Ann Tot (TWh): 120.6 118.8 116.3 20.6

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

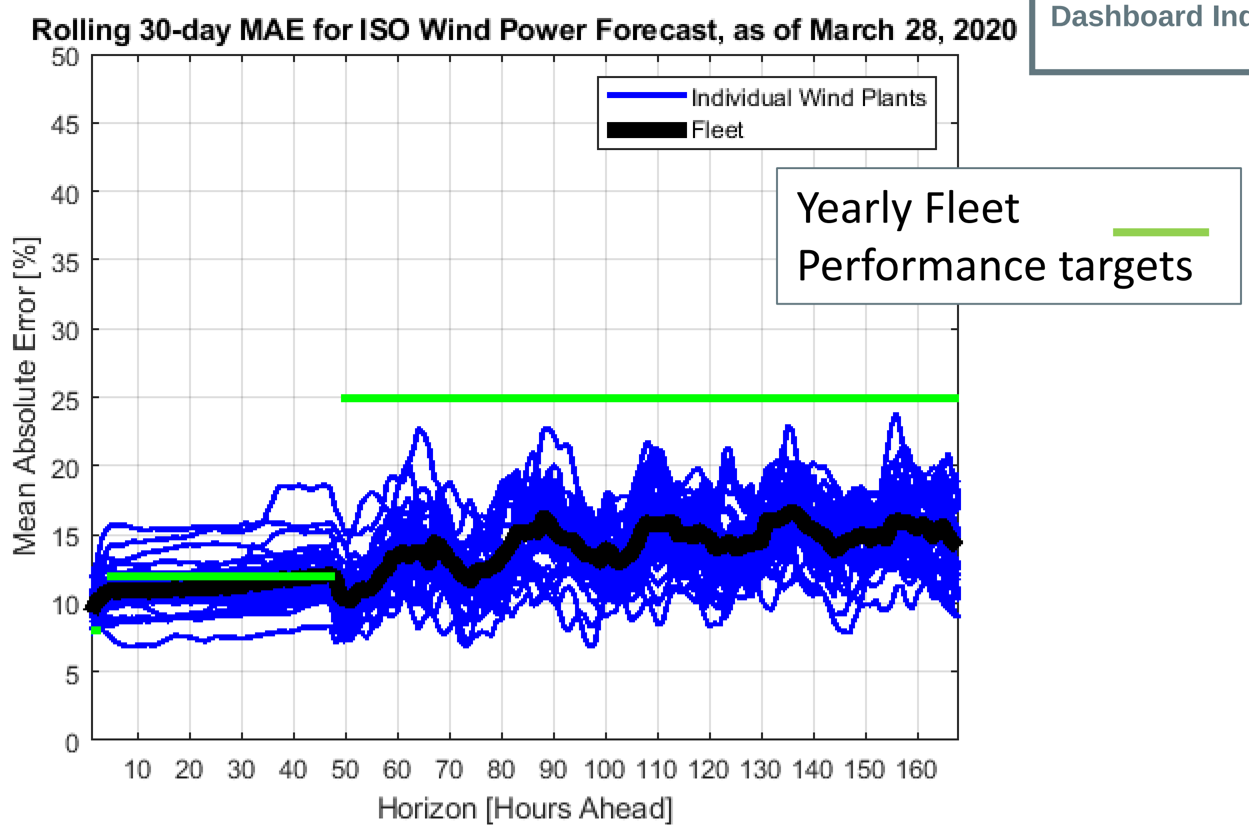


Winter beginning in year displayed

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

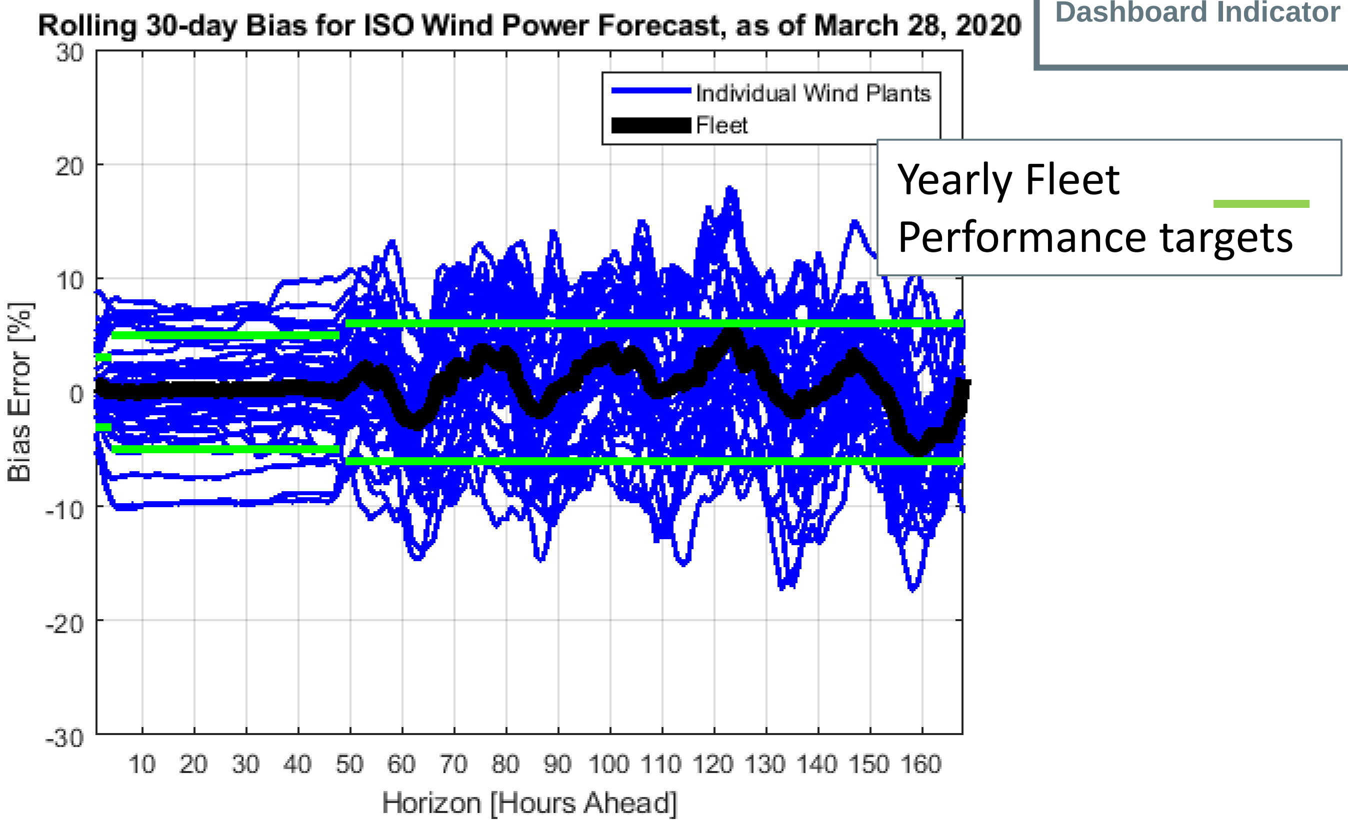
Dashboard Indicator



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

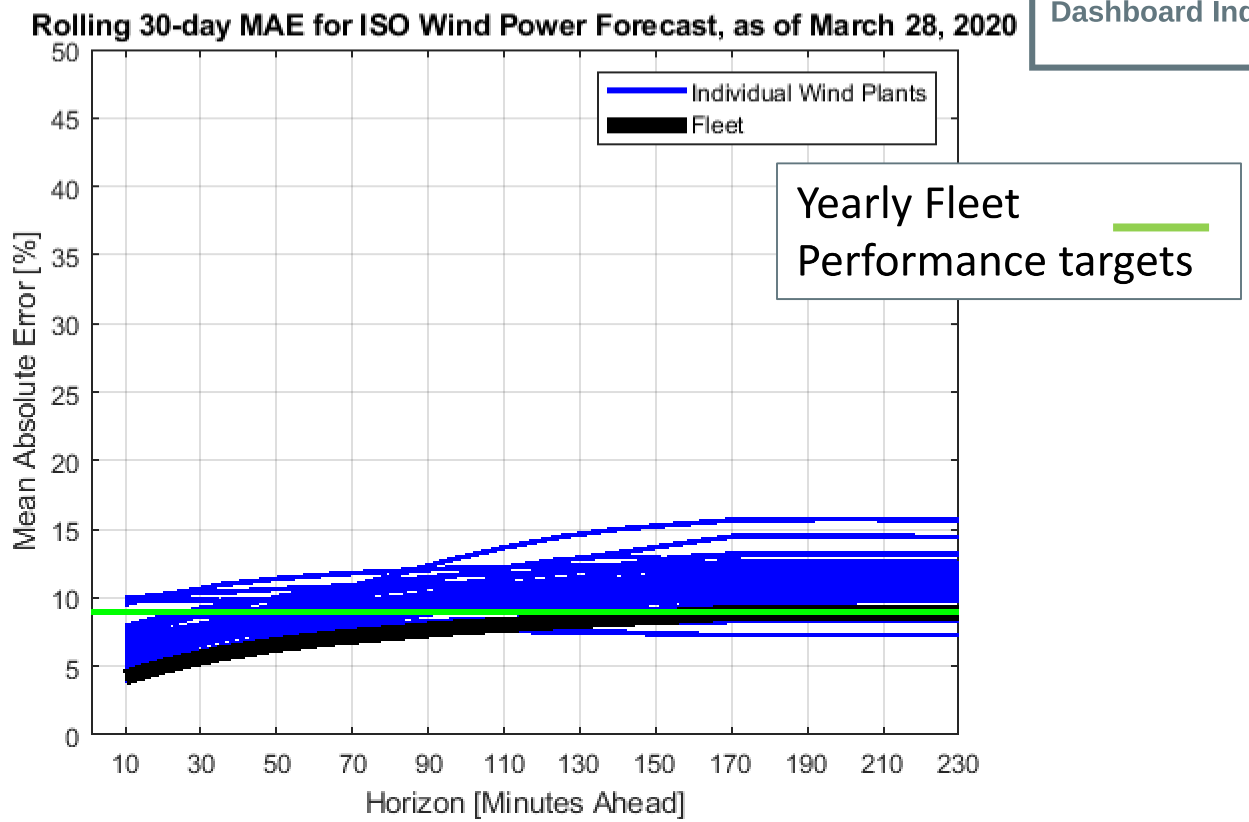
Dashboard Indicator



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 within yearly performance targets.

Wind Power Forecast Error Statistics: Short Term Forecast MAE

Dashboard Indicator



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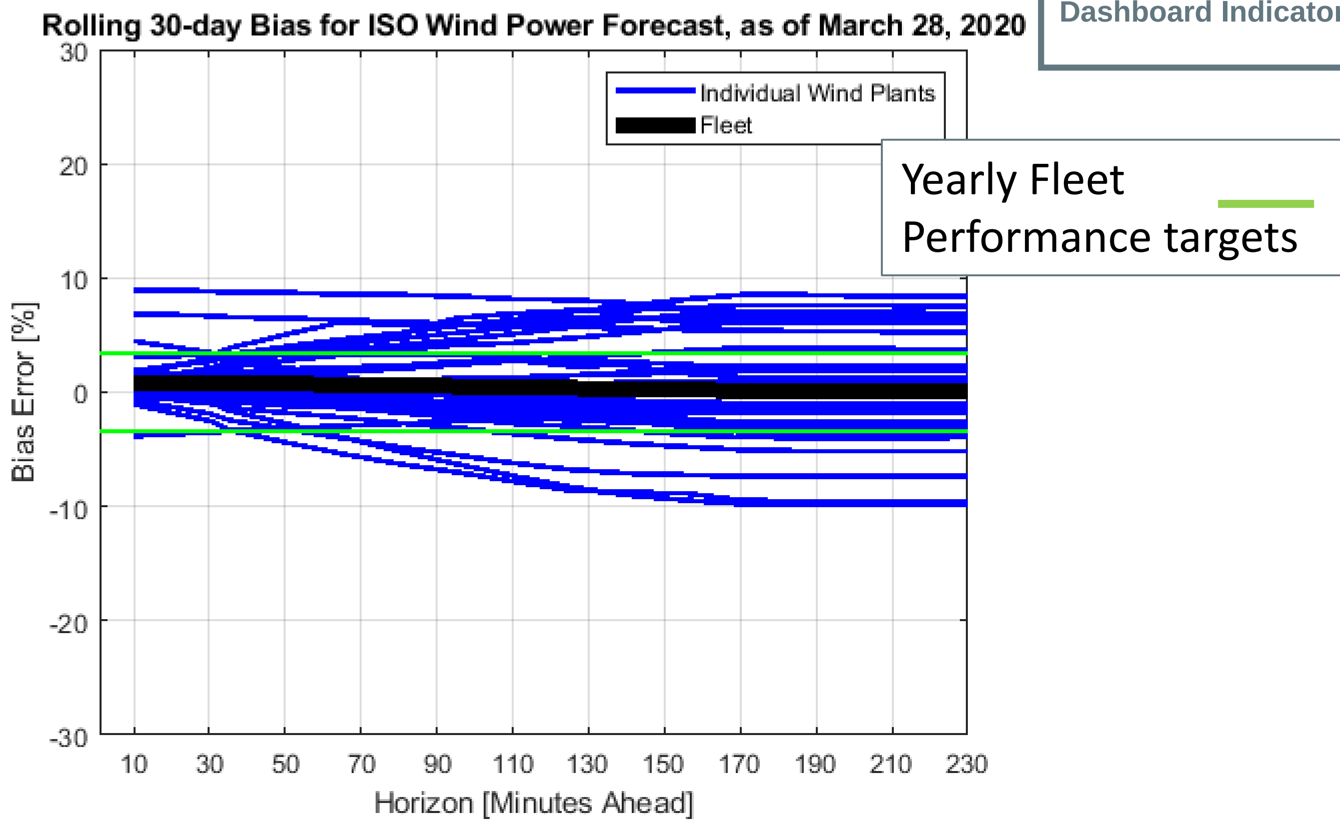
Wind Power Forecast Error Statistics: Short Term Forecast Bias

Dashboard Indicator



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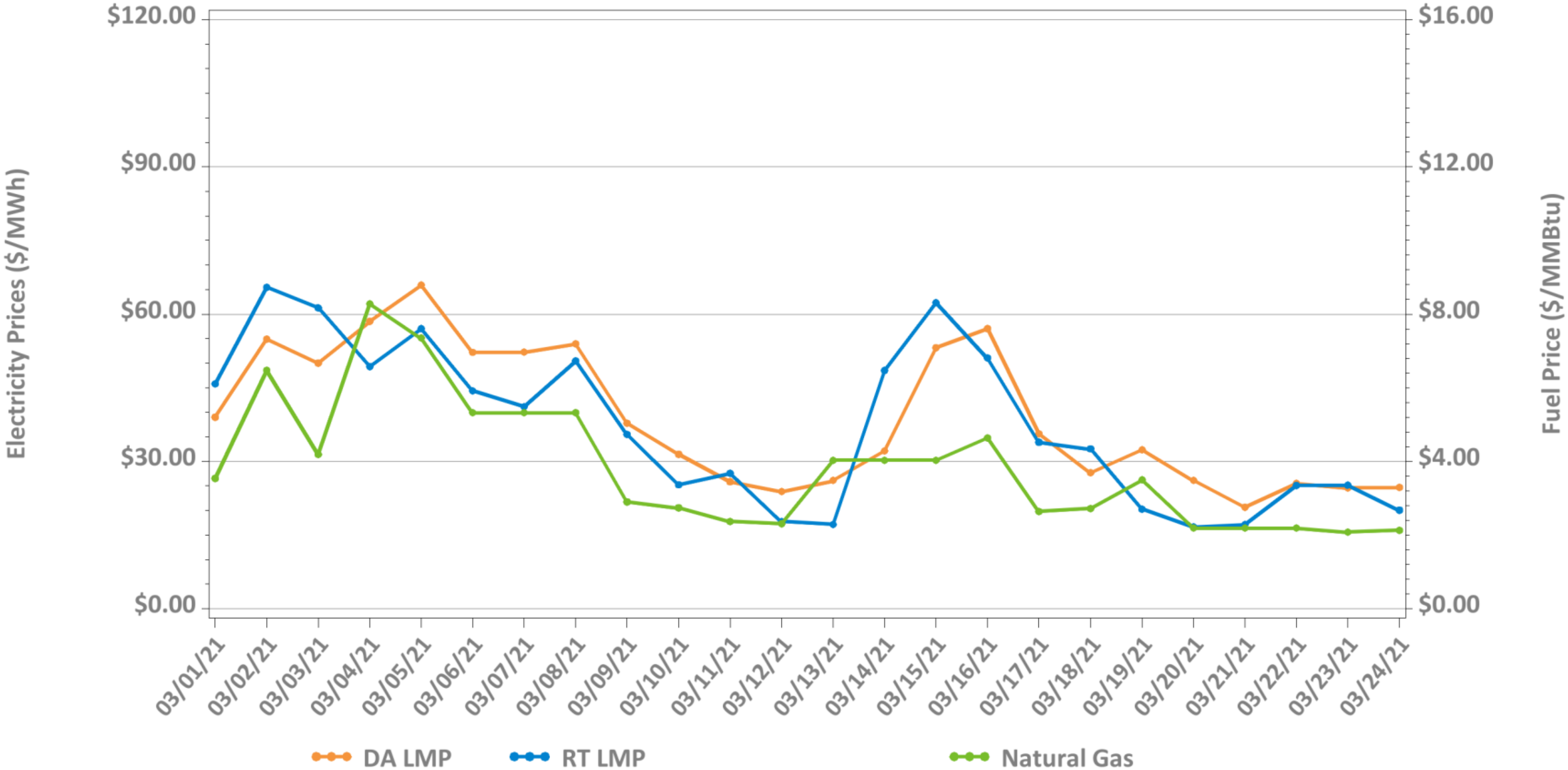
MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: March 1-24, 2021

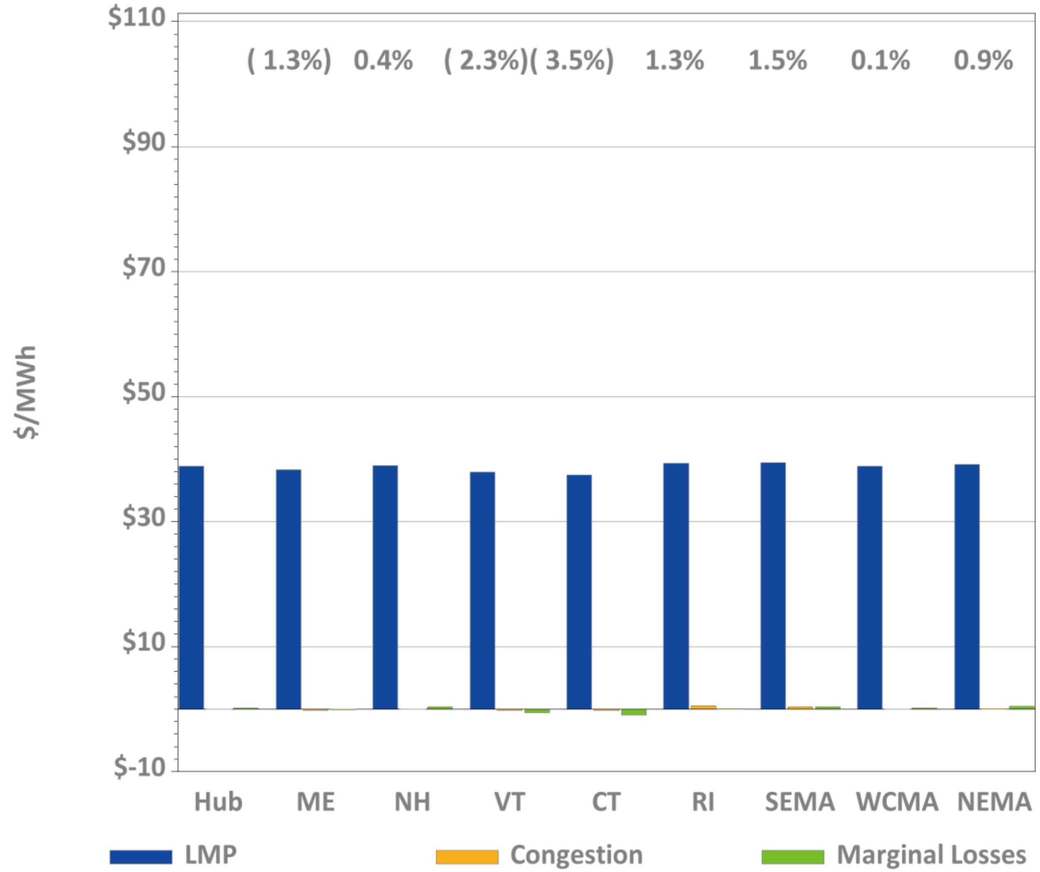


Underlying natural gas data furnished by:

ICE Global markets in clear view

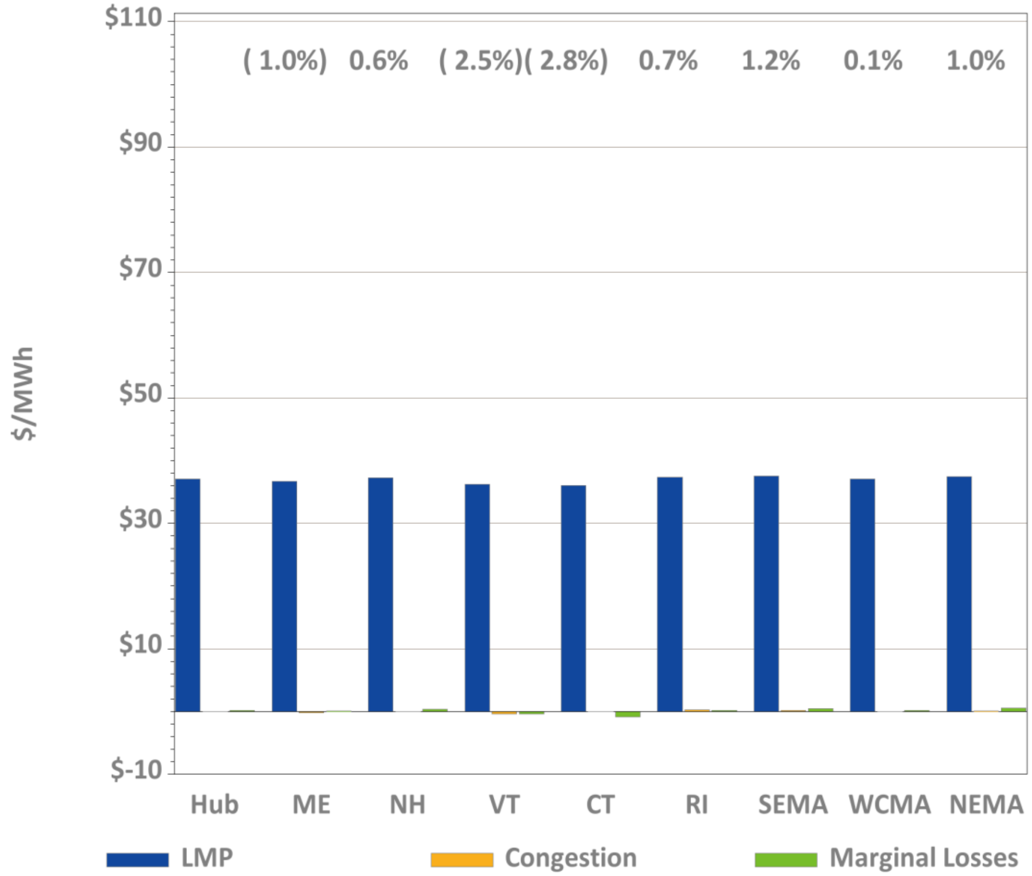
Average price difference over this period (DA-RT): $1.69
Average price difference over this period ABS(DA-RT): $6.80
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 18%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, March 2021



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

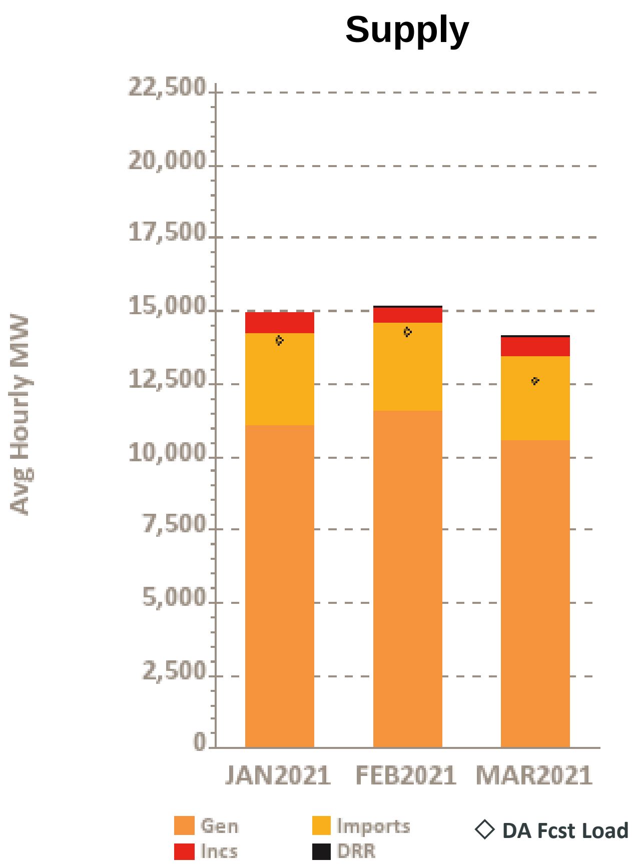
RT LMPs Average by Zone & Hub, March 2021

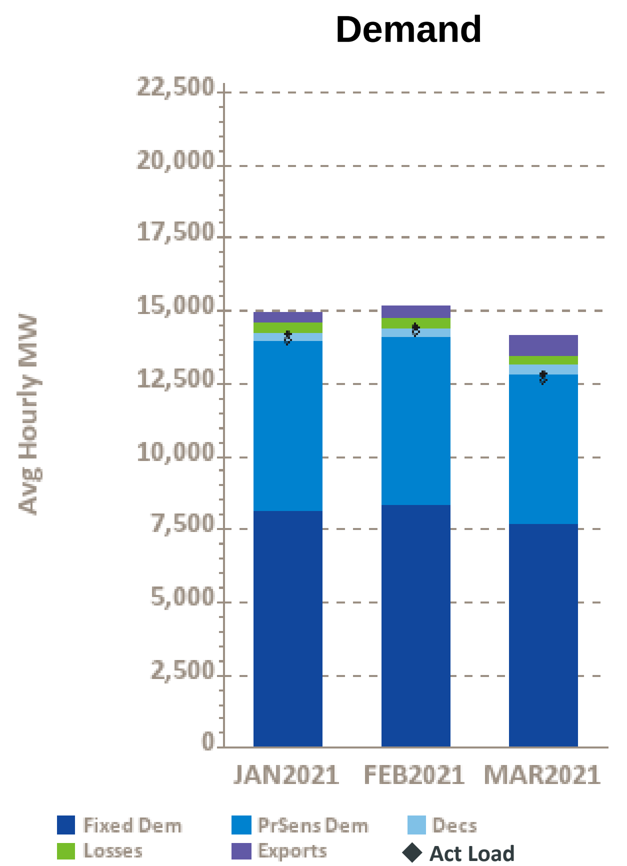


Definitions

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

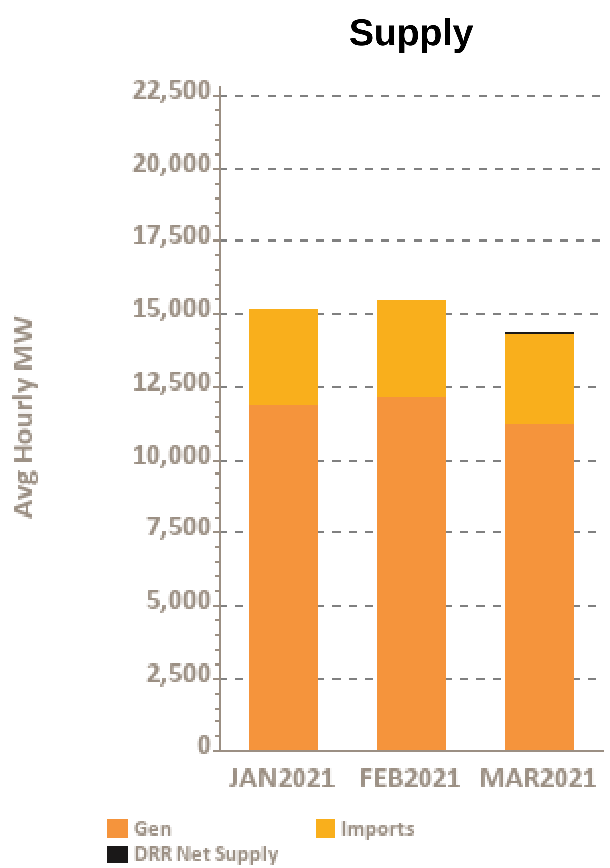


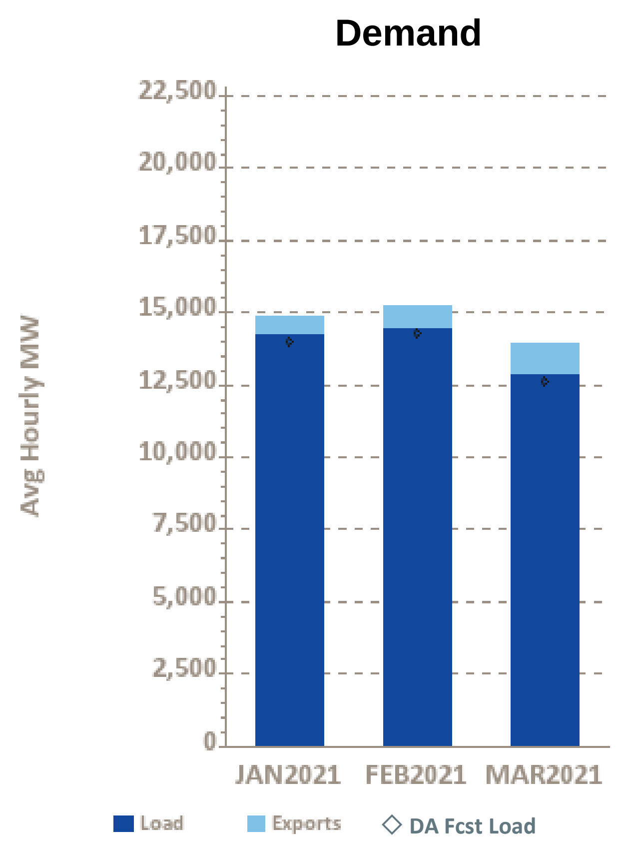


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load
DRR – Demand Response Resource

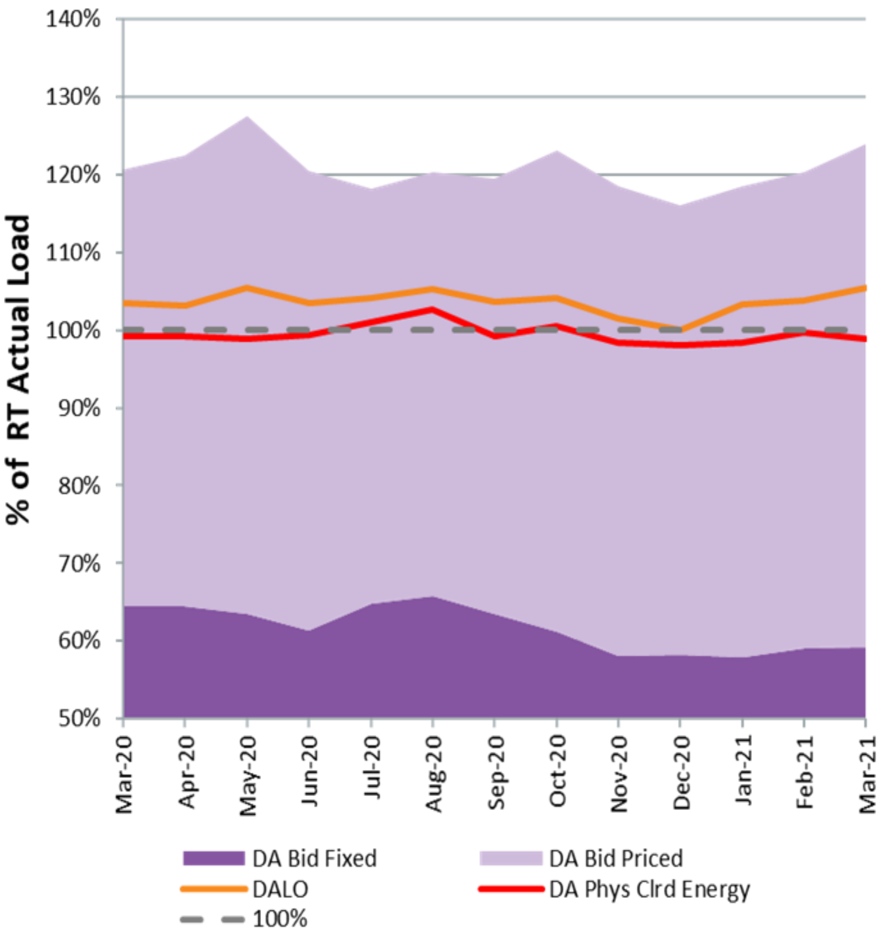
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

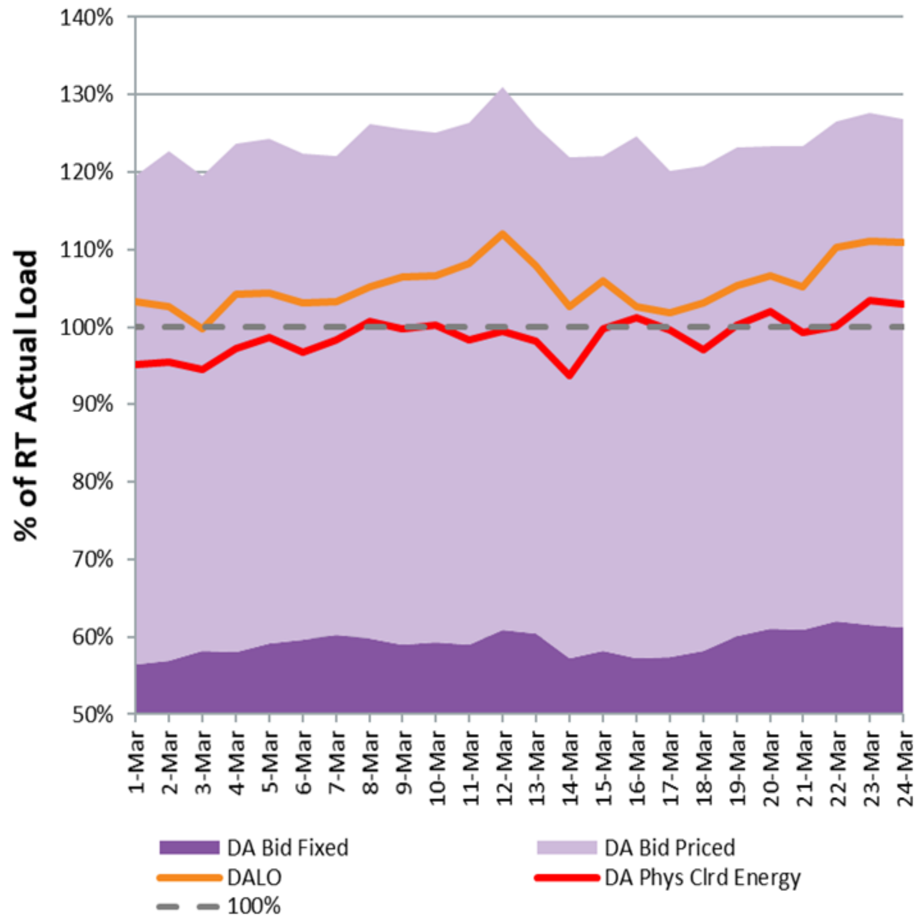
Components of RT Supply and Demand – Last Three Months





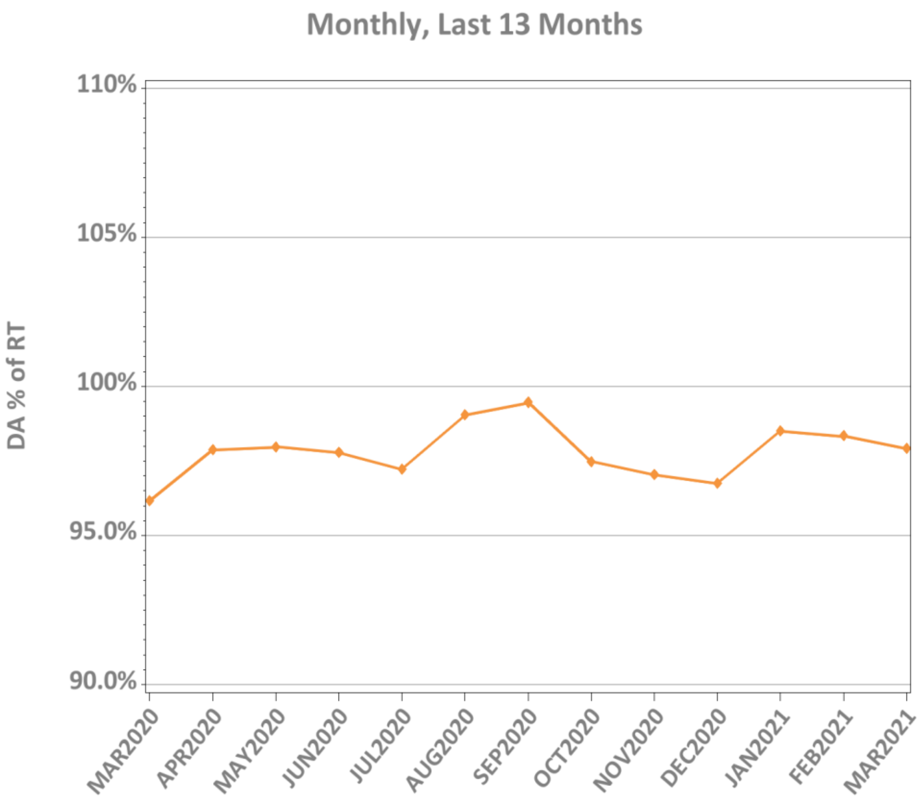
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

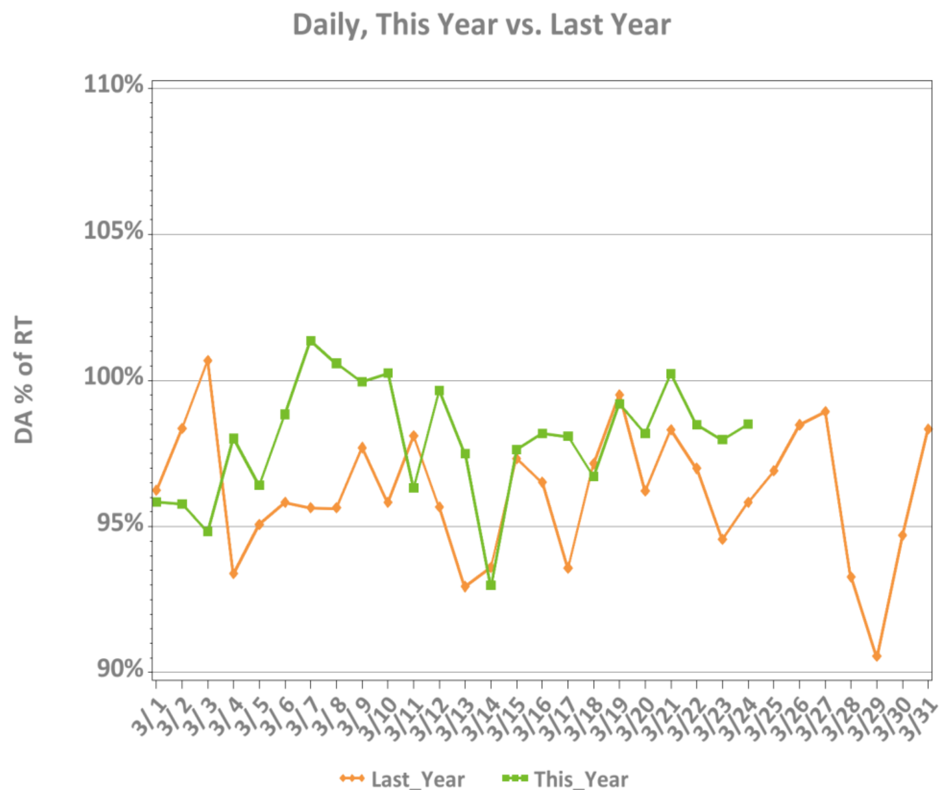




Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

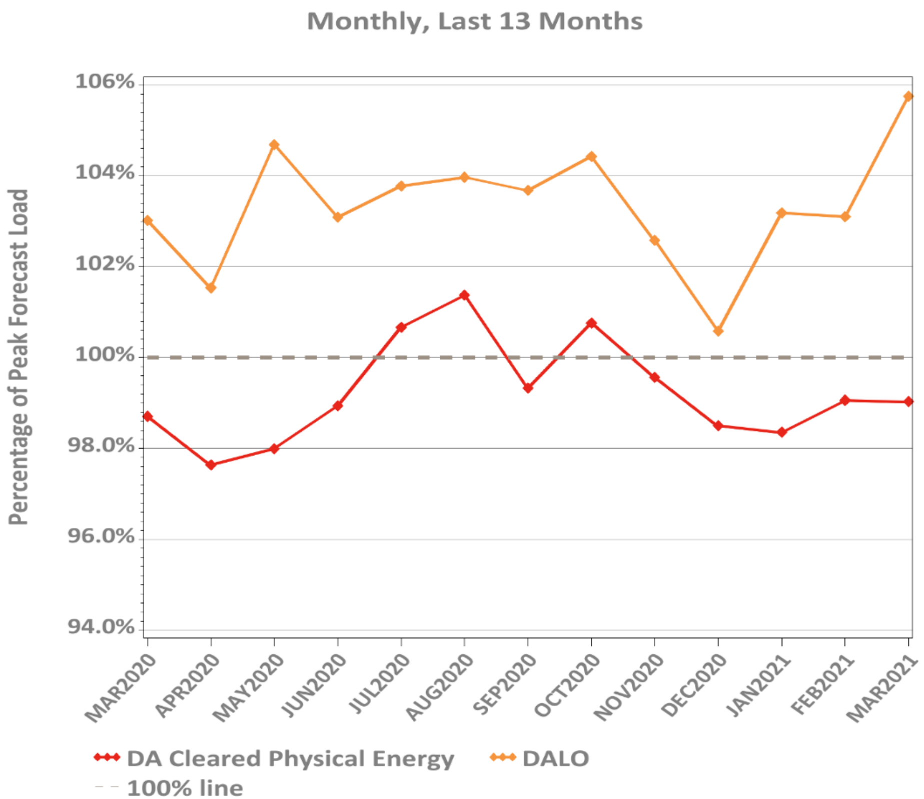
DA vs. RT Load Obligation: March, This Year vs. Last Year

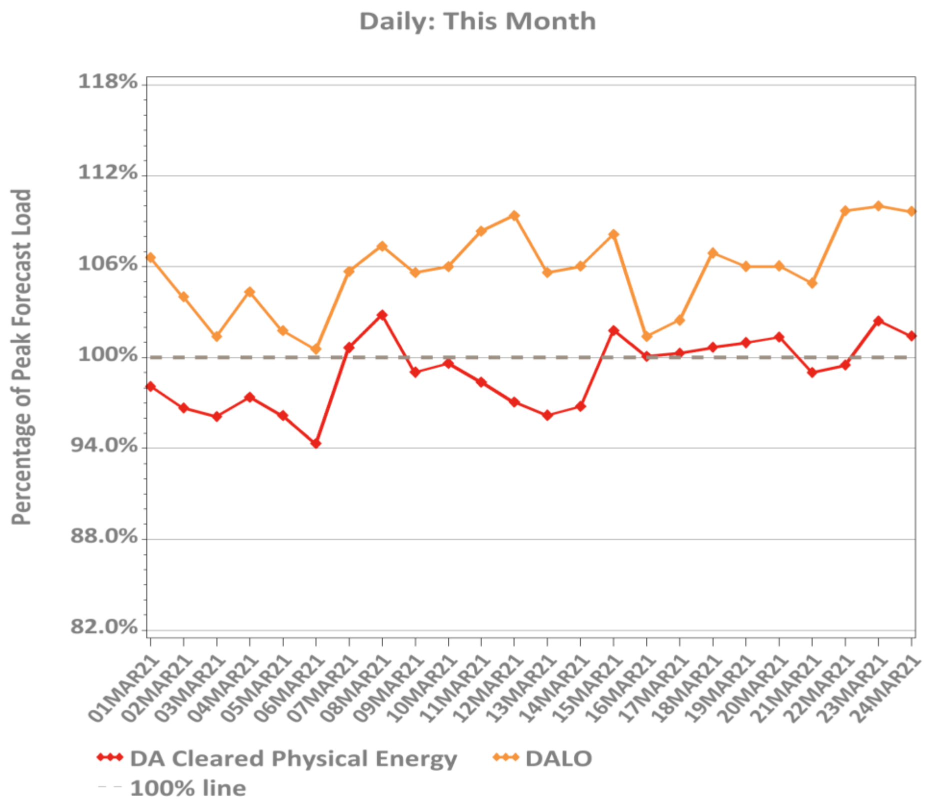




*Hourly average values

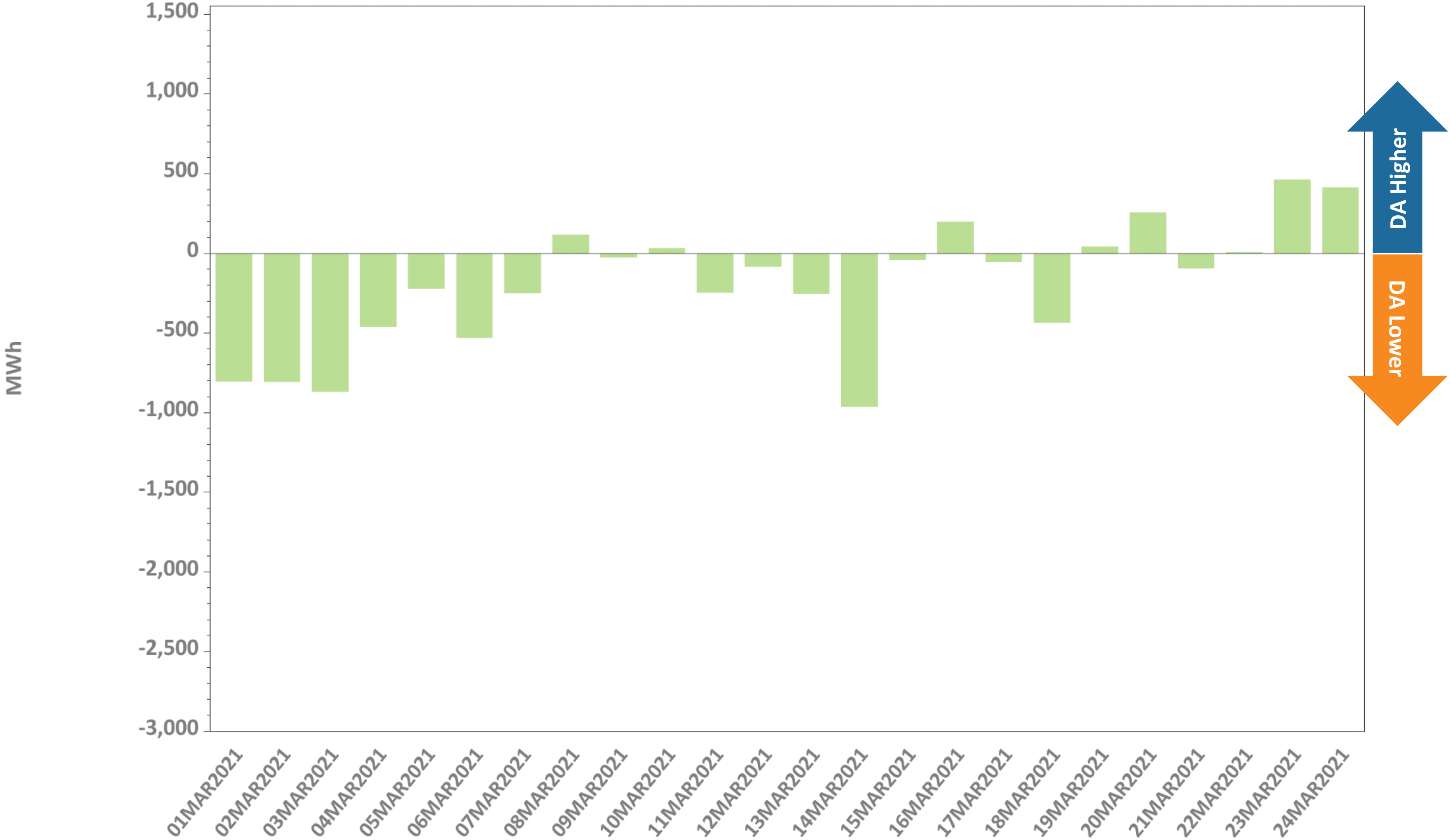
DA Volumes as % of Forecast in Peak Hour





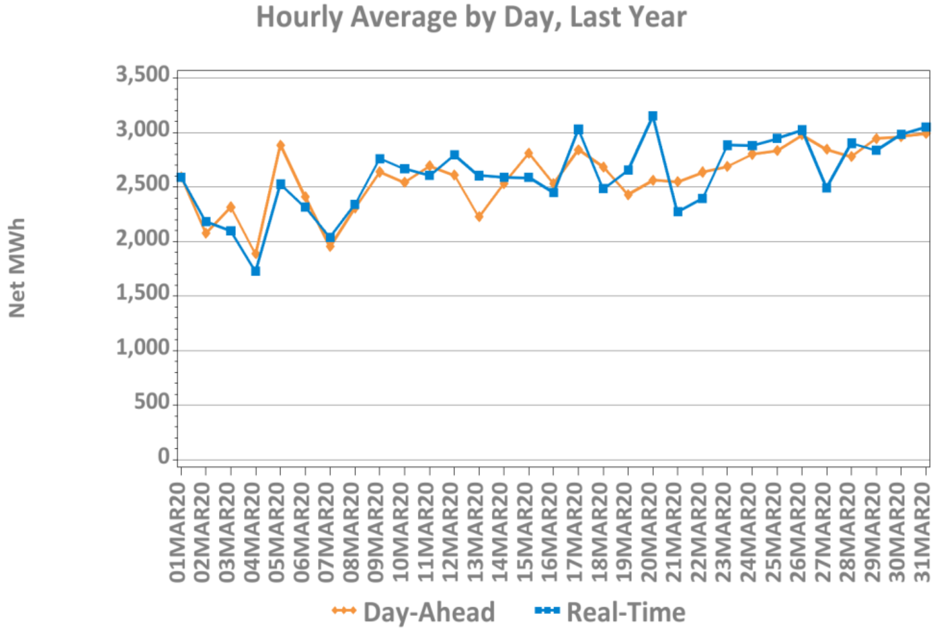
Note: There were no instances of system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) during March.

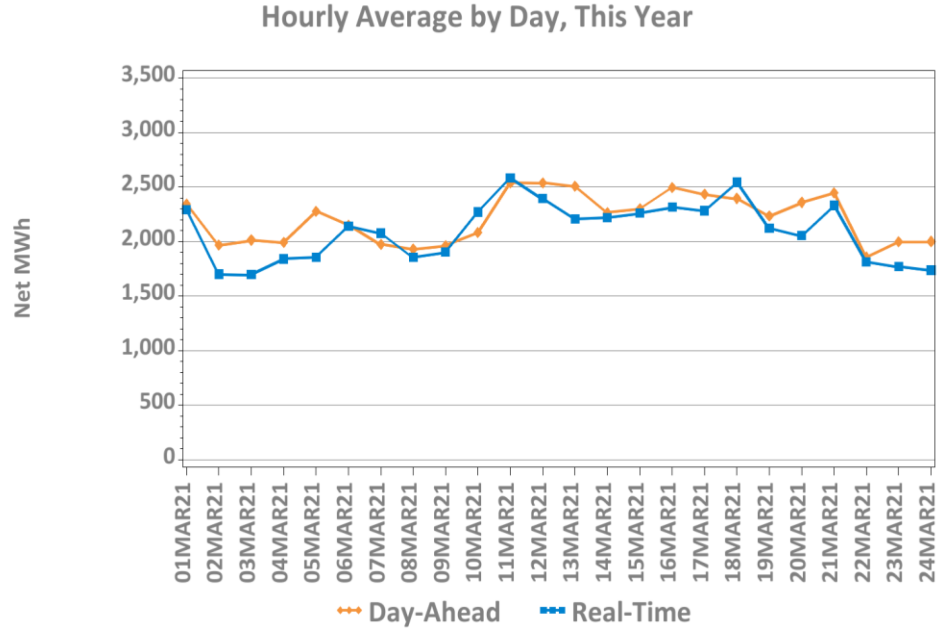
DA Cleared Physical Energy Difference from RT System Load at Peak Hour*



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

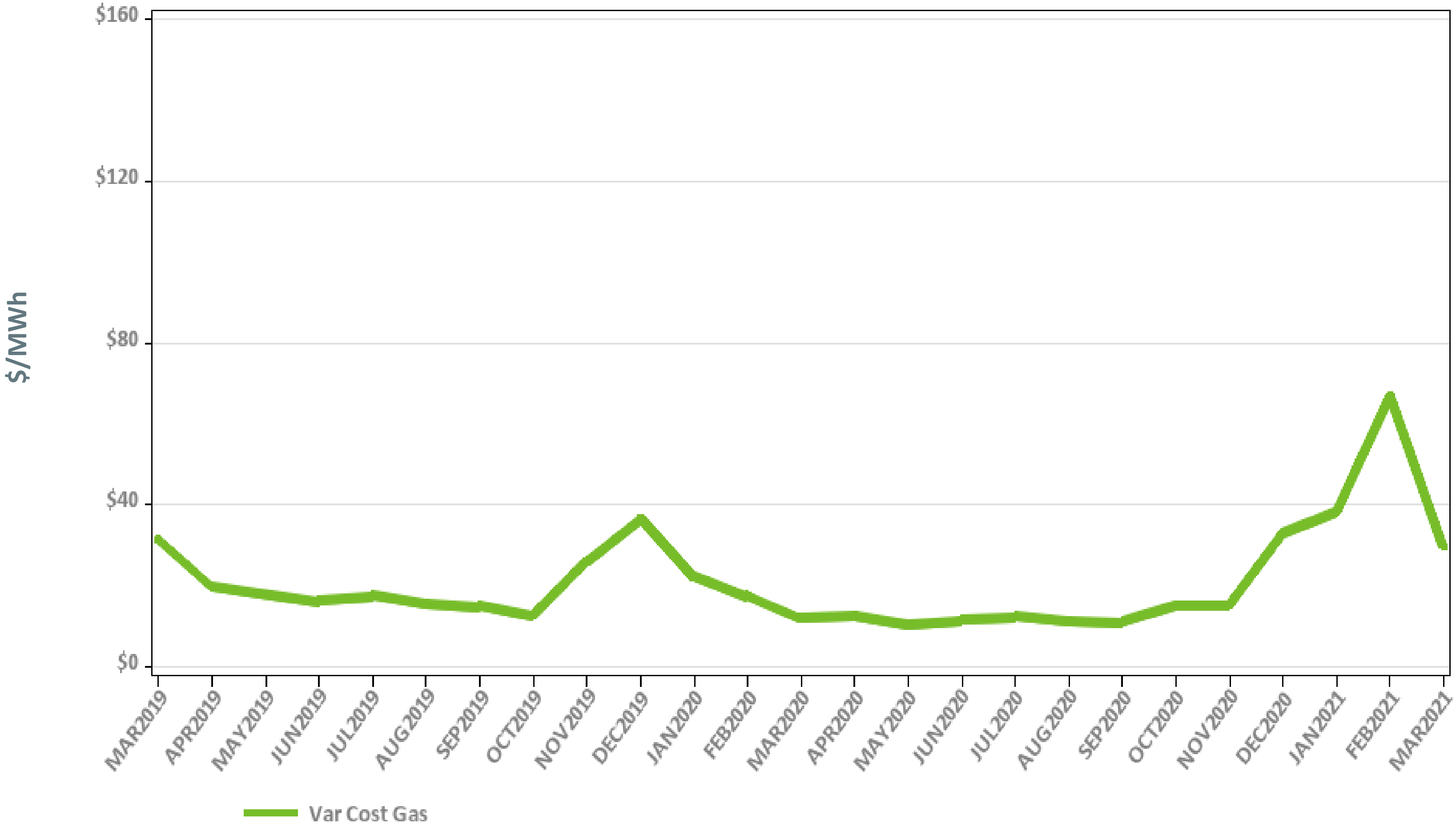
DA vs. RT Net Interchange March 2020 vs. March 2021





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

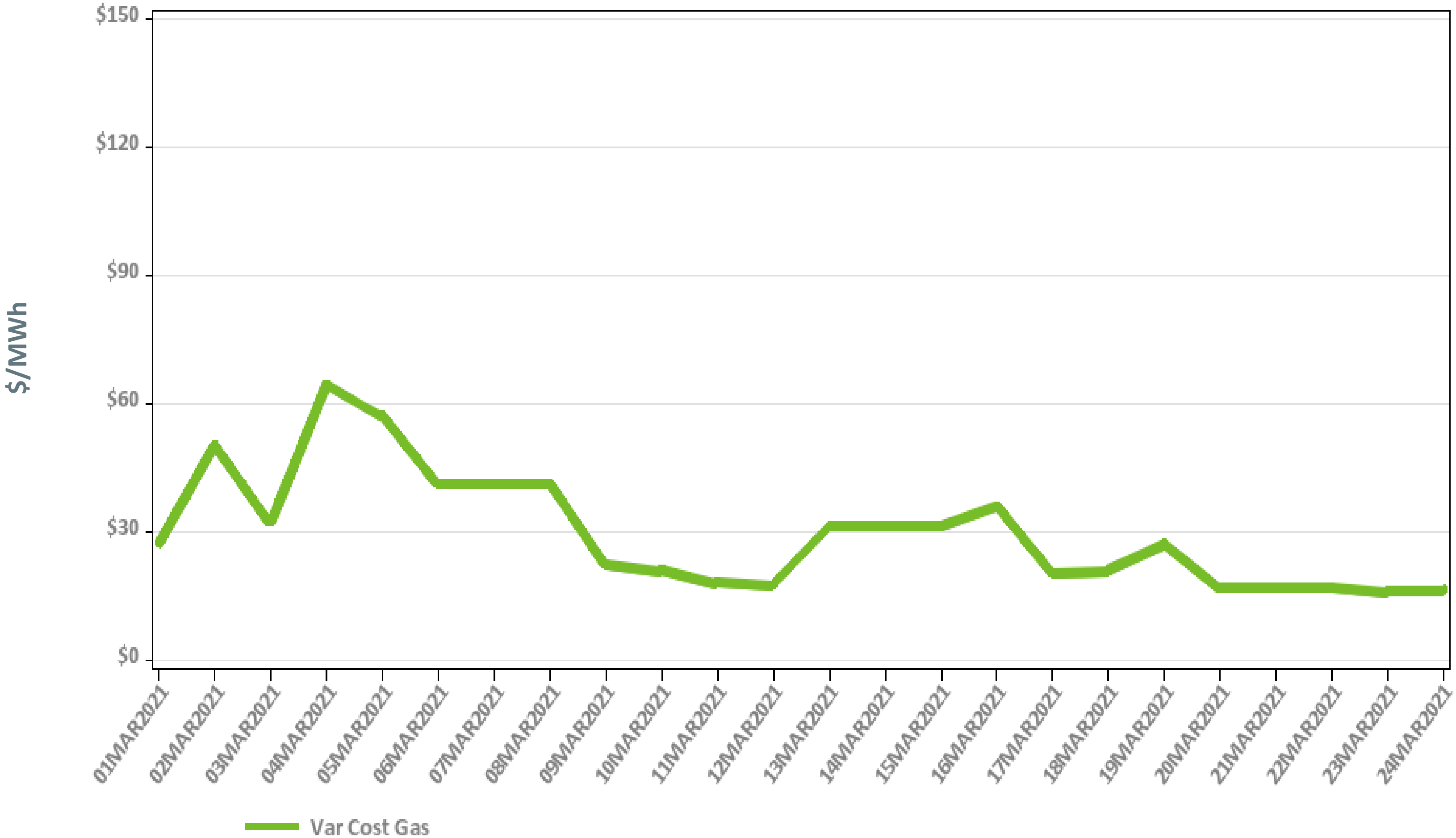


Underlying natural gas data furnished by:

ice Global markets in clear view

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

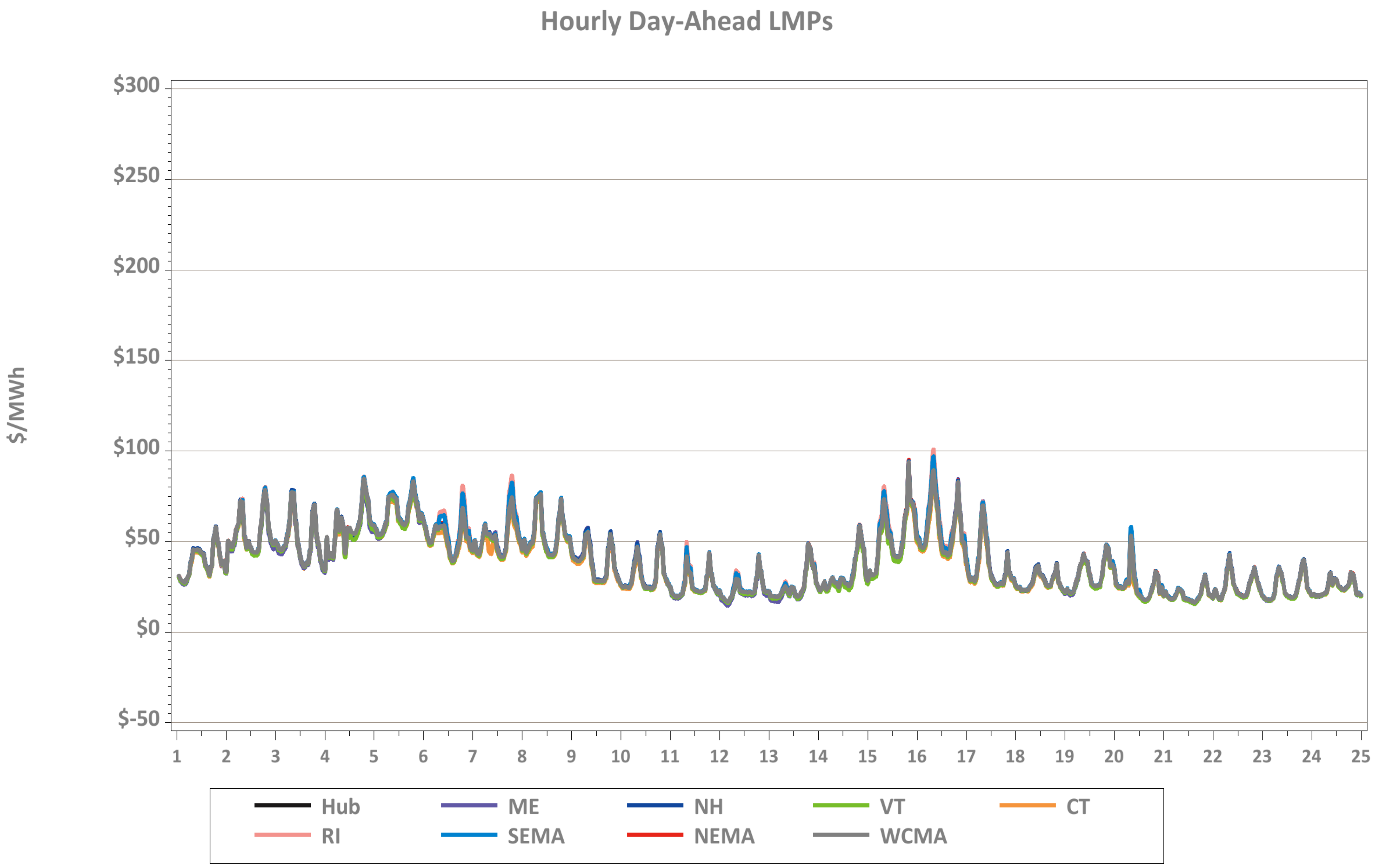
Variable Production Cost of Natural Gas: Daily



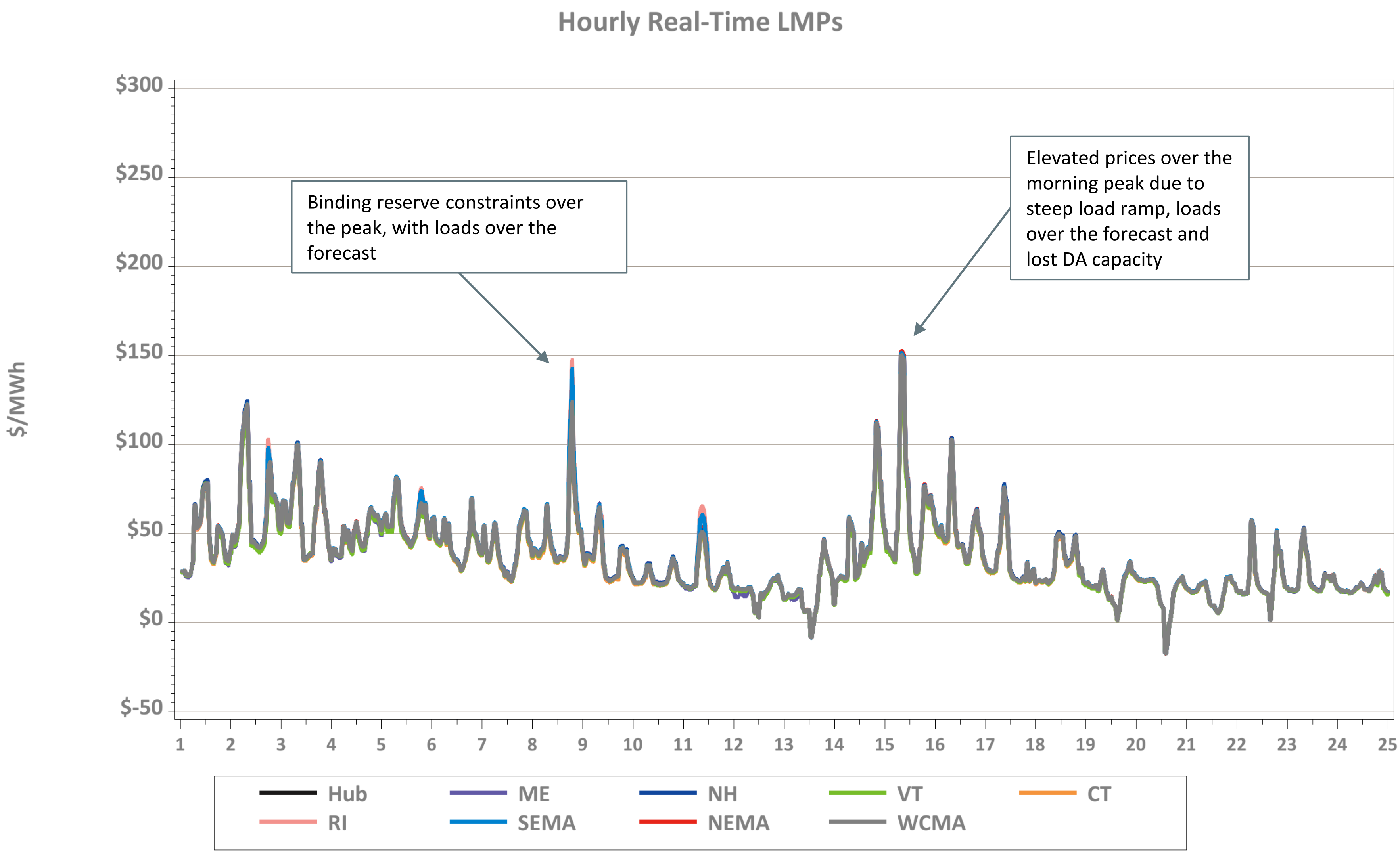
Underlying natural gas data furnished by:

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

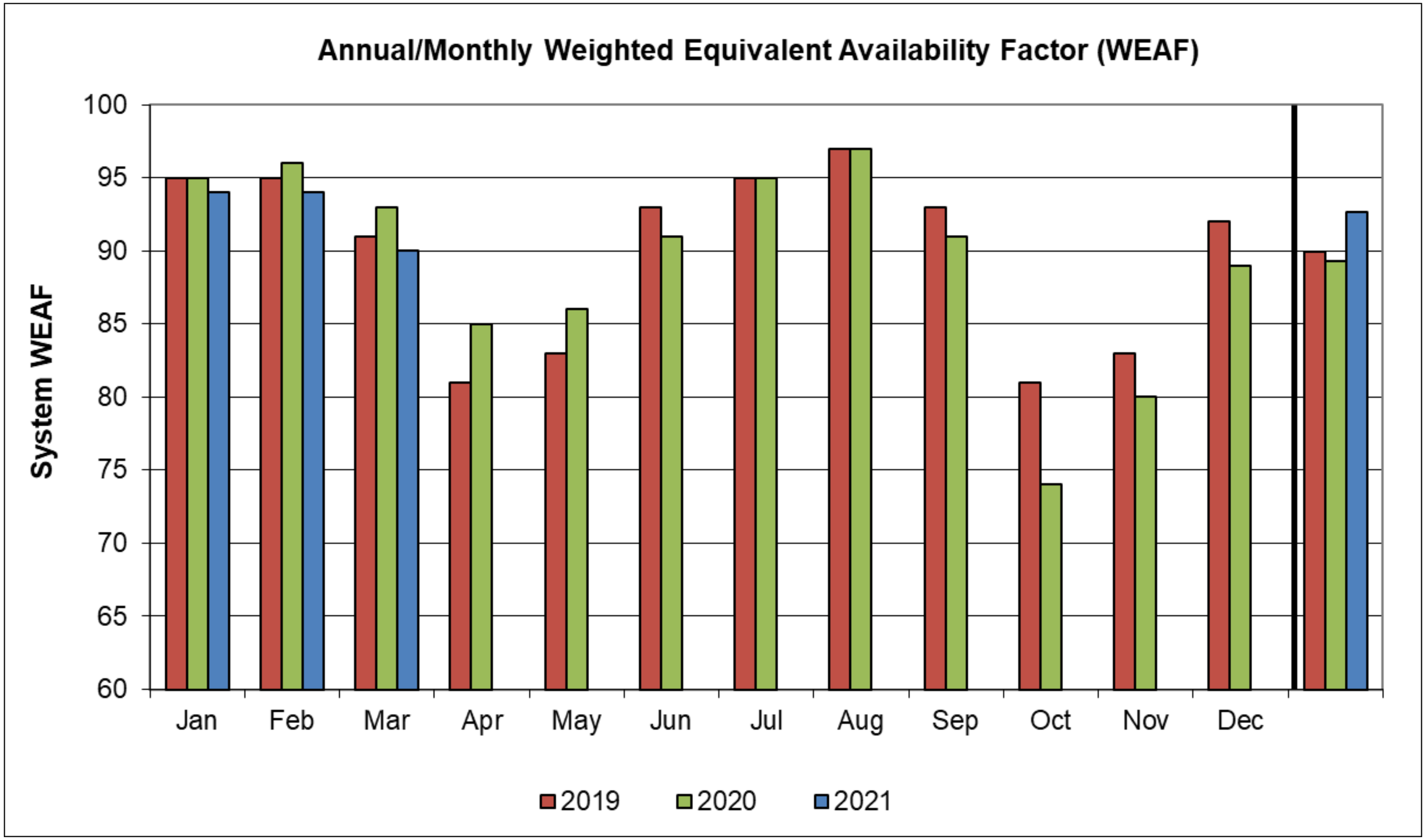
Hourly DA LMPs, March 1-24, 2021



Hourly RT LMPs, March 1-24, 2021



System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2021	94	94	90										93
2020	95	96	93	85	86	91	95	97	91	74	80	89	89
2019	95	95	91	81	83	93	95	97	93	81	83	92	90

Data as of 3/24/2021

BACK-UP DETAIL

DEMAND RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for April 2021

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	77.4	144.5	0.0	222.0
NH	37.1	149.2	0.0	186.2
VT	31.8	102.9	0.0	134.7
CT	104.3	161.8	549.2	815.3
RI	39.1	270.7	0.0	309.7
SEMA	44.9	432.4	0.0	477.3
WCMA	80.9	467.4	45.3	593.6
NEMA	61.8	815.0	0.0	876.8
Total	**477.3**	**2,543.8**	**594.5**	**3,615.7**

*** Active Demand Capacity Resources**
NOTE: CSO values include T&D loss factor (8%).

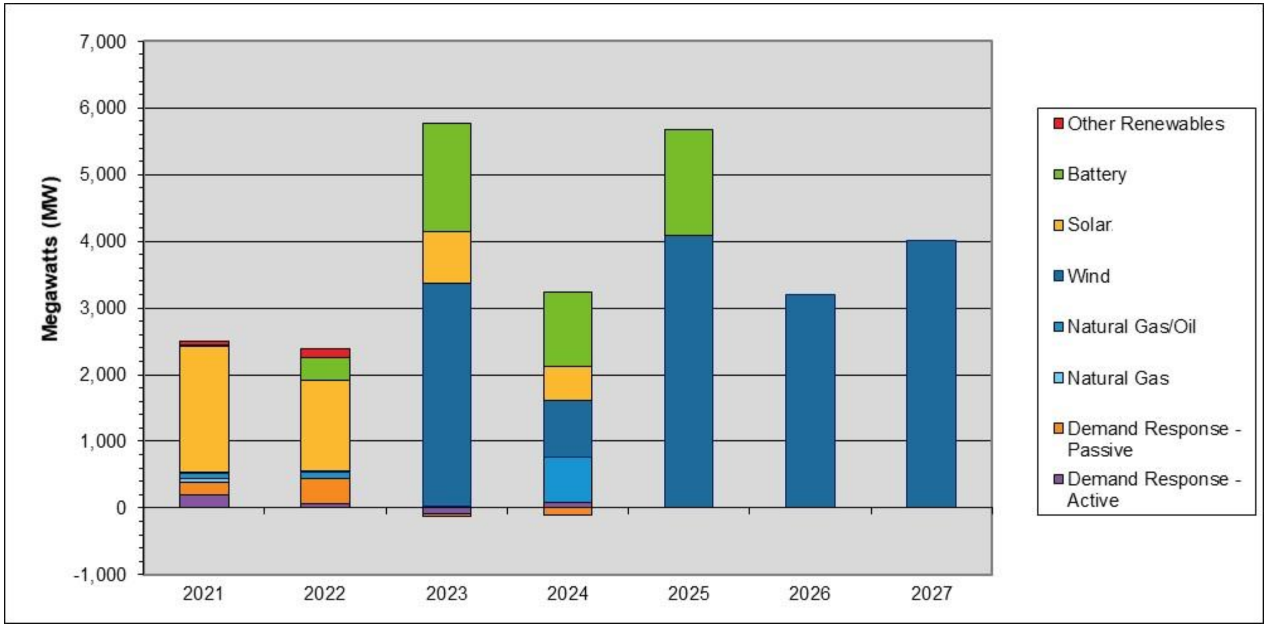
NEW GENERATION

New Generation Update
Based on Queue as of 3/26/21

- Twelve new projects totaling 1,577 MW applied for interconnection study since the last update
  - They consist of eight new battery storage projects, three battery addition and hydro increase projects and one offshore wind increase project with in-service dates ranging from 2022 to 2026
- No projects went commercial and five projects were withdrawn
- In total, 272 generation projects are currently being tracked by the ISO, totaling approximately 25,873 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



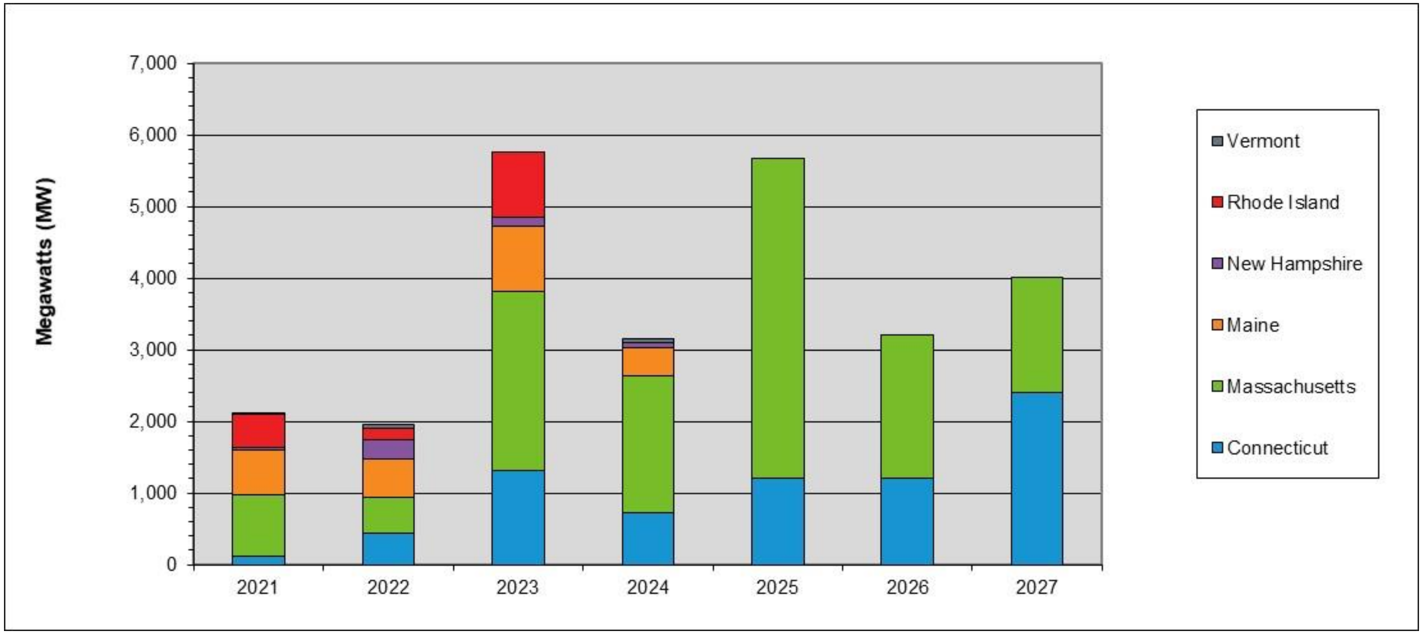
	2021	2022	2023	2024	2025	2026	2027	Total MW	% of Total[1]
Other Renewables	56	142	0	0	0	0	0	198	0.7
Battery	34	340	1,616	1,116	1,579	0	0	4,685	17.6
Solar[2]	1,882	1,361	772	516	0	0	0	4,531	17.1
Wind	19	20	3,355	852	4,087	3,200	4,013	15,546	58.5
Natural Gas/Oil[3]	76	89	23	672	0	0	0	860	3.2
Natural Gas	53	0	0	0	0	0	0	53	0.2
Demand Response - Passive	184	380	-28	-114	0	0	0	422	1.6
Demand Response - Active	204	62	-94	86	0	0	0	258	1.0
Totals	**2,508**	**2,394**	**5,644**	**3,128**	**5,666**	**3,200**	**4,013**	**26,553**	**100.0**

[1] Sum may not equal 100% due to rounding
[2] This category includes both solar-only, and co-located solar and battery projects
[3] The projects in this category are dual fuel, with either gas or oil as the primary fuel

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

Actual and Projected Annual Generator Capacity Additions

By State



	2021	2022	2023	2024	2025	2026	2027	Total MW	% of Total[1]
Vermont	15	40	0	50	0	0	0	105	0.4
Rhode Island	466	160	921	0	0	0	0	1,547	6.0
New Hampshire	30	281	126	80	0	0	0	517	2.0
Maine	625	523	907	387	0	0	0	2,442	9.4
Massachusetts	871	500	2,500	1,907	4,466	2,000	1,613	13,857	53.6
Connecticut	113	448	1,312	732	1,200	1,200	2,400	7,405	28.6
Totals	**2,120**	**1,952**	**5,766**	**3,156**	**5,666**	**3,200**	**4,013**	**25,873**	**100.0**

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

New Generation Projection

By Fuel Type

	Total		Green		Yellow	
Unit Type	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	1	8	1	8	0	0
Battery Storage	30	4,685	0	0	30	4,685
Fuel Cell	4	54	1	10	3	44
Hydro	3	99	2	71	1	28
Natural Gas	5	53	0	0	5	53
Natural Gas/Oil	7	860	1	14	6	846
Nuclear	1	37	0	0	1	37
Solar	197	4,531	10	154	187	4,377
Wind	23	15,546	1	15	22	15,531
Total	271	25,873	16	272	255	25,601

- 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	8	132	3	23	5	109
Intermediate	9	822	1	14	8	808
Peaker	231	9,373	11	220	220	9,153
Wind Turbine	23	15,546	1	15	22	15,531
Total	271	25,873	16	272	255	25,601

- 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

Unit Type	Total		Baseload		Intermediate		Peaker		Wind Turbine	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	1	8	1	8	0	0	0	0	0	0
Battery Storage	30	4,685	0	0	0	0	30	4,685	0	0
Fuel Cell	4	54	4	54	0	0	0	0	0	0
Hydro	3	99	2	33	0	0	1	66	0	0
Natural Gas	5	53	0	0	4	47	1	6	0	0
Natural Gas/Oil	7	860	0	0	5	775	2	85	0	0
Nuclear	1	37	1	37	0	0	0	0	0	0
Solar	197	4,531	0	0	0	0	197	4,531	0	0
Wind	23	15,546	0	0	0	0	0	0	23	15,546
Total	271	25,873	8	132	9	822	231	9,373	23	15,546

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

FORWARD CAPACITY MARKET

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	584.35	-10.201
	Passive Demand	2,791.02	2,835.354	44.334	2,883.767	48.413	2,964.695	80.928
Demand Total		**3,210.95**	**3,276.575**	**65.625**	**3,478.318**	**201.743**	**3,549.045**	**70.727**
Generator	*Non-Intermittent*	30,494.80	30,064.23	-430.569	30,159.891	95.661	2,9678.995	-480.896
	Intermittent	894.217	823.796	-70.421	809.571	-14.225	689.524	-120.047
Generator Total		**31,389.02**	**30,888.027**	**-500.993**	**30,969.462**	**81.435**	**30,368.519**	**-600.943**
Import Total		**1,235.40**	**1,622.037**	**386.637**	**1,609.844**	**-12.193**	**1,124.6**	**-485.244**
Grand Total*		**35,835.37**	**35,786.64**	**-48.731**	**36,057.624**	**270.984**	**35,042.164**	**-1015.46**
Net ICR (NICR)		**34,075**	**33,660**	**-415**	**33,520**	**-140**	**32,205**	**-1,315**

* 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	603.776	-55.361		
Demand	*Passive Demand*	2,975.36	3,045.073	69.713	31,23.232	78.159		
Demand Total		**3,599.81**	**3,704.21**	**104.4**	**37,27.008**	**22.798**		
Generator	*Non-Intermittent*	29,130.75	29,244.404	113.654	28,620.245	-624.159		
Generator	*Intermittent*	880.317	806.609	-73.708	660.932	-145.677		
Generator Total		**30,011.07**	**30,051.013**	**39.943**	**29,281.177**	**-769.836**		
Import Total		**1,217**	**1,305.487**	**88.487**	**1,307.587**	**2.10**		
Grand Total*		**34,827.88**	**35,060.710**	**232.83**	**34,315.772**	**-744.94**		
Net ICR (NICR)		**33,725**	**33,550**	**-175**	**32,320**	**-230**		

* 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	683.116	-2.438				
	Passive Demand		3,354.69	3,407.507	52.817				
Demand Total			**4,040.244**	**4,090.623**	**50.38**				
Generator		*Non-Intermittent*	28,586.498	27,868.341	-718.157				
		Intermittent	1,024.792	901.672	-123.12				
Generator Total			**2,9611.29**	**28,770.013**	**-841.28**				
Import Total			**1,187.69**	**1,292.41**	**104.72**				
Grand Total*			**34,839.224**	**34,153.046**	**-686.18**				
Net ICR (NICR)			**33,750**	**32,465**	**-1,285**				

* 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**						

* 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 15

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*		677.673						
	Passive Demand		3,212.865						
Demand Total			**3,890.538**						
Generator		*Non-Intermittent*	28,154.203						
		Intermittent	1,089.265						
Generator Total			**29,243.468**						
Import Total			**1,487.059**						
Grand Total*			**34,621.065**						
Net ICR (NICR)			**33,270**						

* 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	2,375.422	370.734	2,746.156
2020-21	Active	334.634	85.294	419.928
	Passive	2,236.73	554.292	2,791.02
	Grand Total	2,571.361	639.586	3,210.947
2021-22	Active	480.941	143.504	624.445
	Passive	2,604.79	370.568	2,975.36
	Grand Total	3,085.734	514.072	3,599.806
2022-23	Active	598.376	87.178	685.554
	Passive	2,788.33	566.363	3,354.69
	Grand Total	3,386.703	653.541	4,040.244
2023-24	Active	560.55	31.493	592.043
	Passive	3,035.51	291.565	3,327.07
	Grand Total	3,596.056	323.058	3,919.114
2024-25	Active	674.153	3.520	677.673
	Passive	3,046.064	166.801	3,212.865
	Grand Total	**3,720.217**	**170.321**	**3,890.538**

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

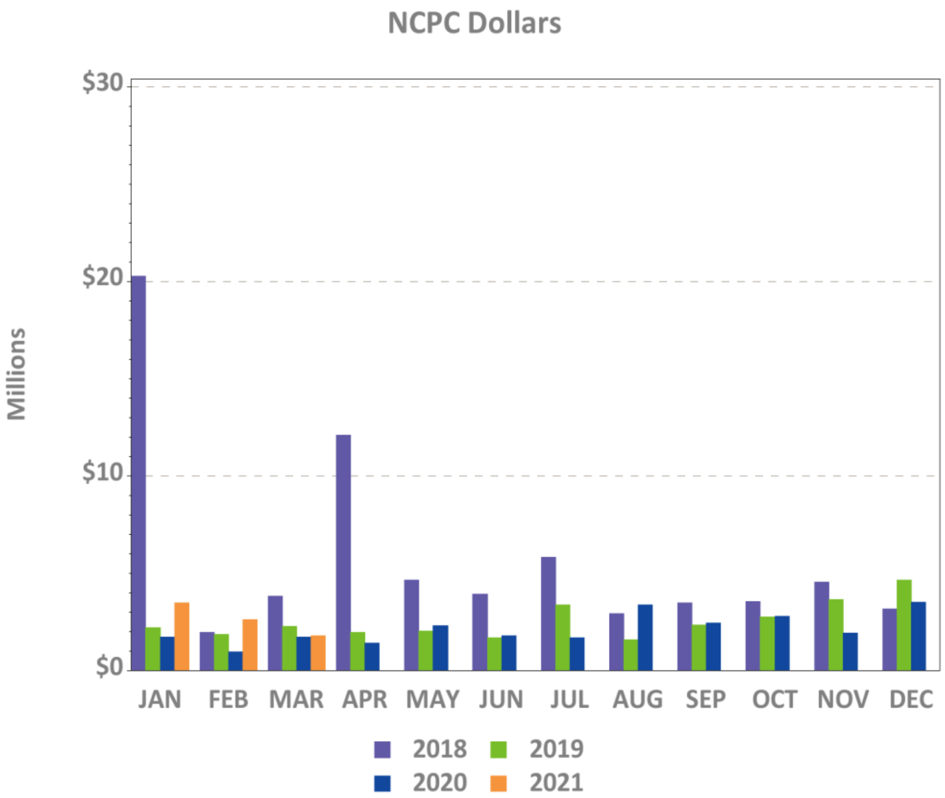
Definitions

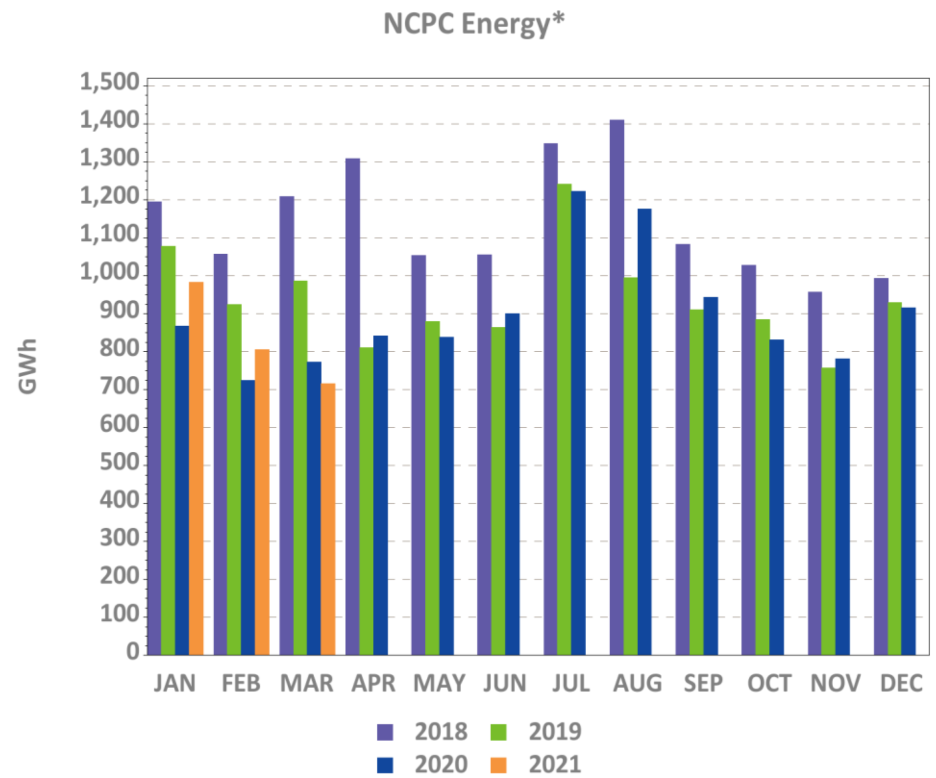
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing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

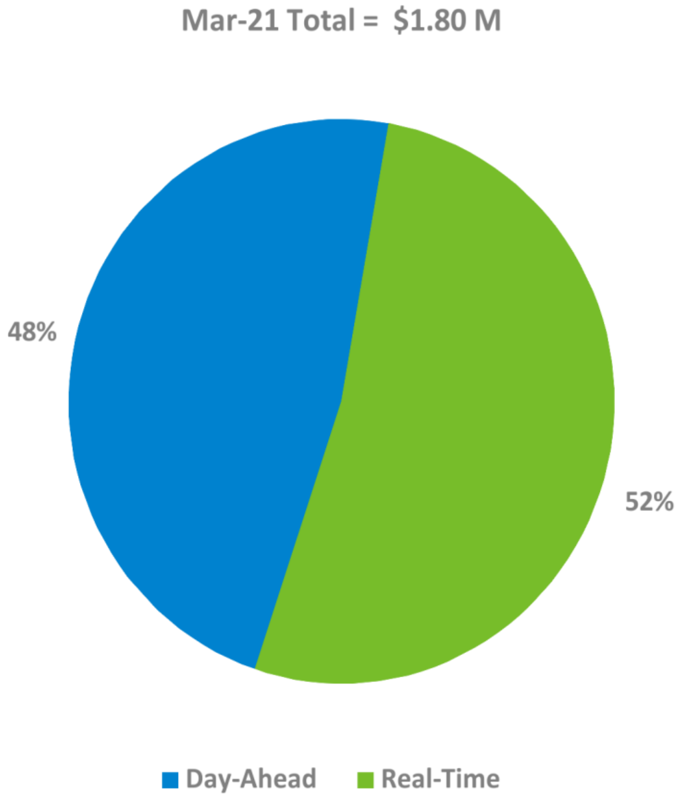
Year-Over-Year Total NCPC Dollars and Energy



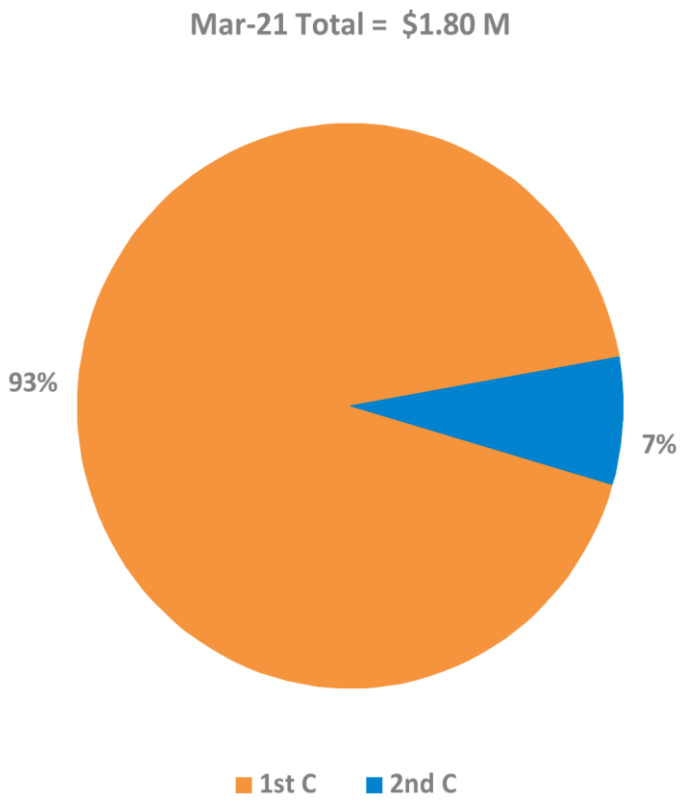


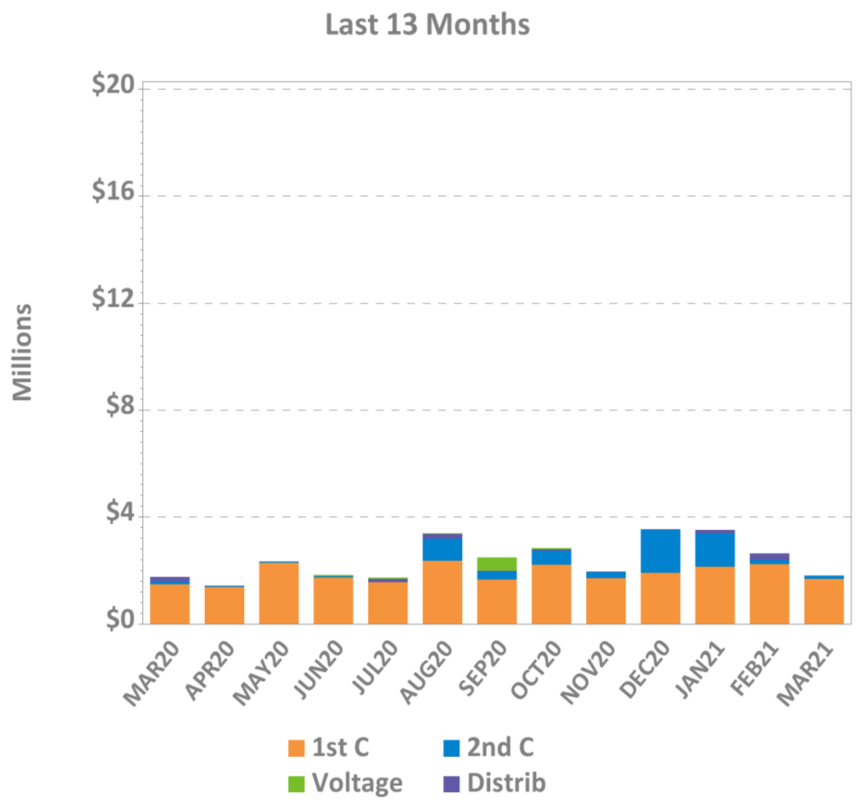
*** NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

DA and RT NCPC Charges



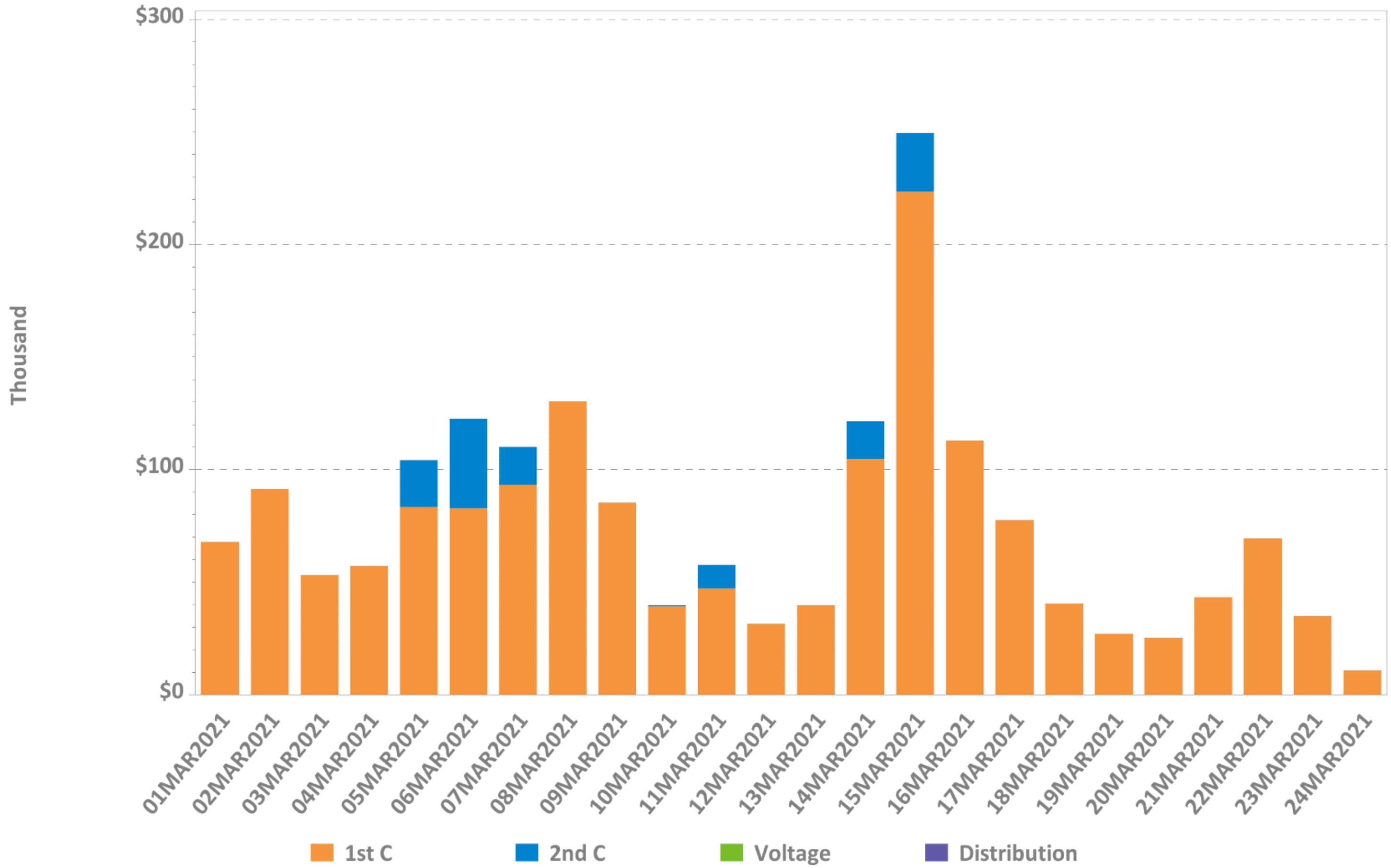
NCPC Charges by Type



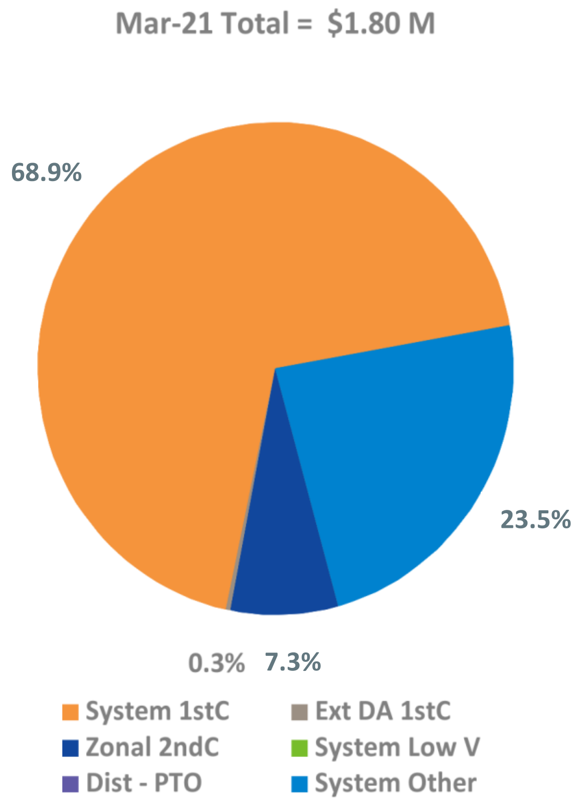


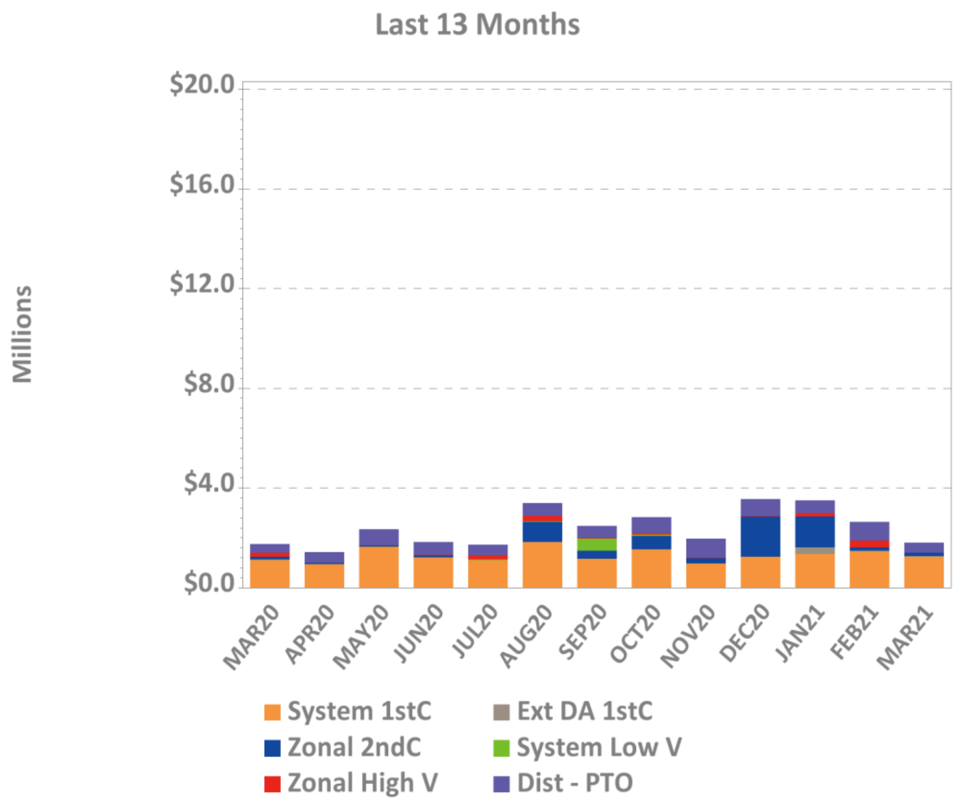
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



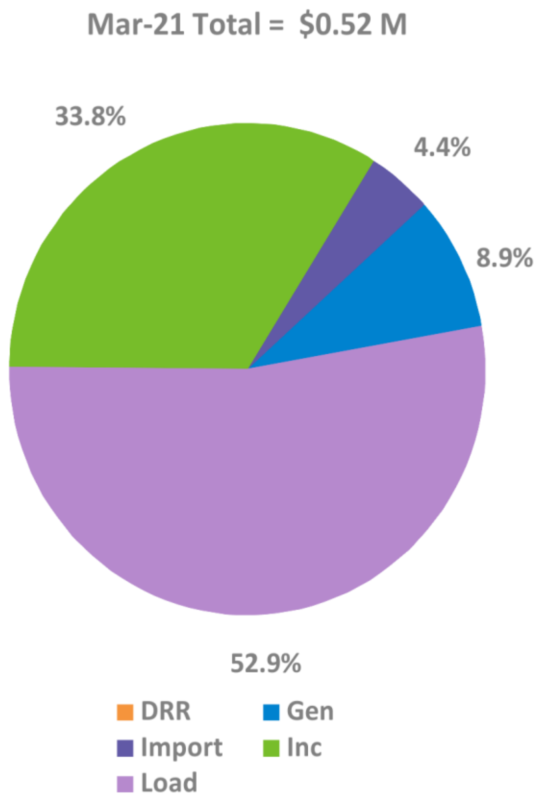
NCPC Charges by Allocation

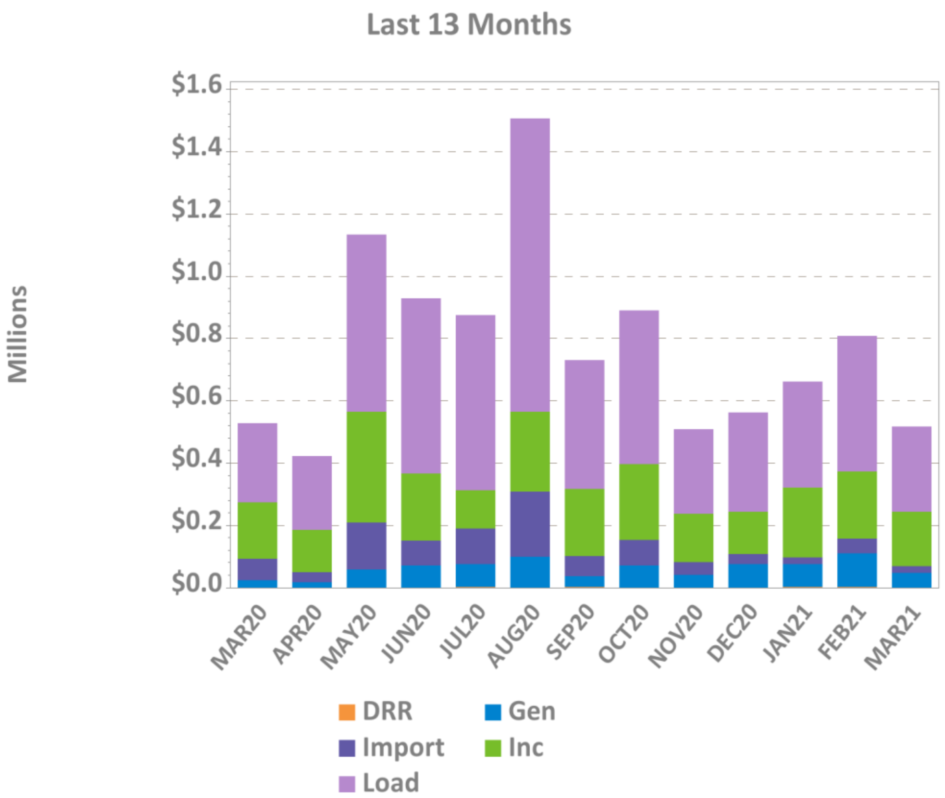




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

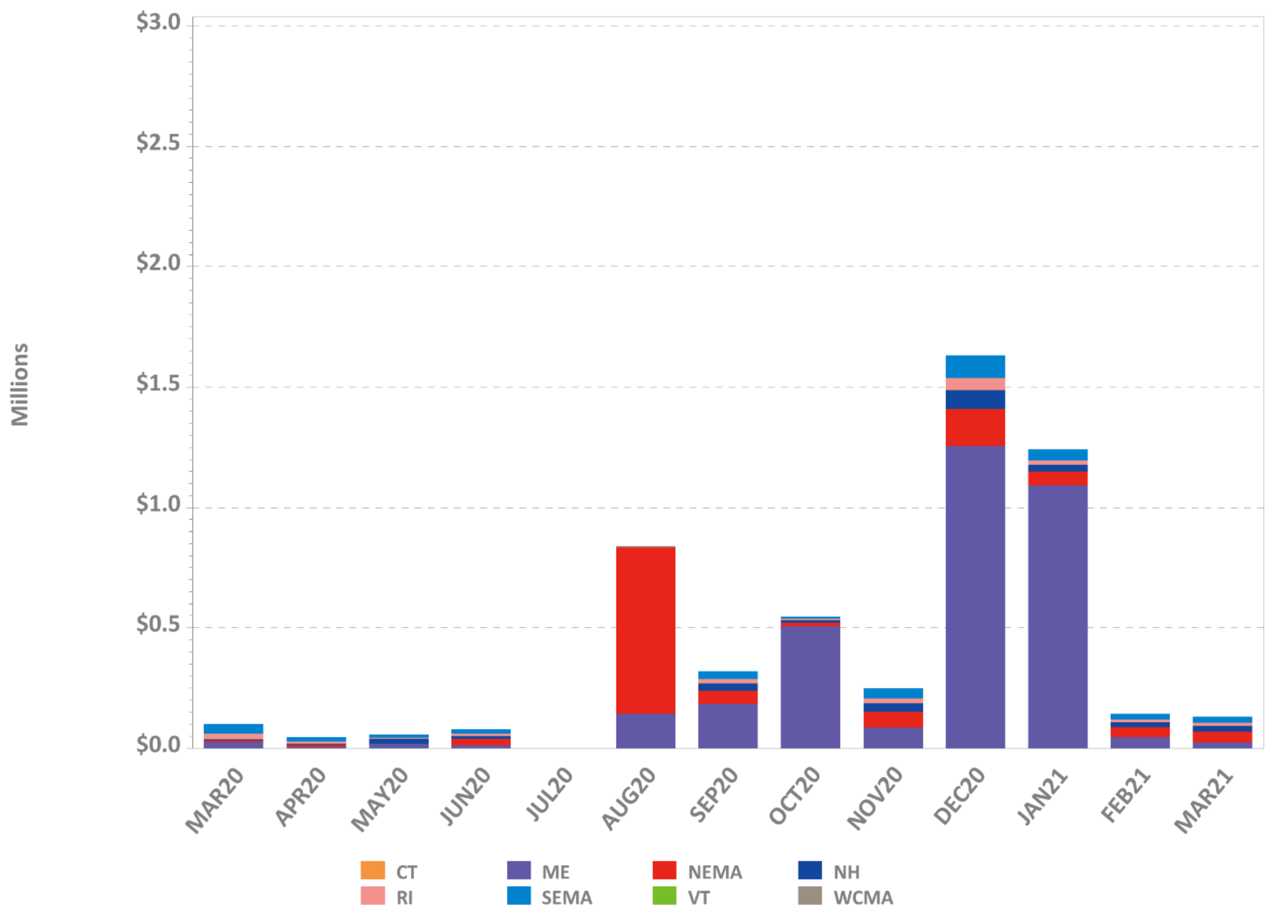
RT First Contingency Charges by Deviation Type





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

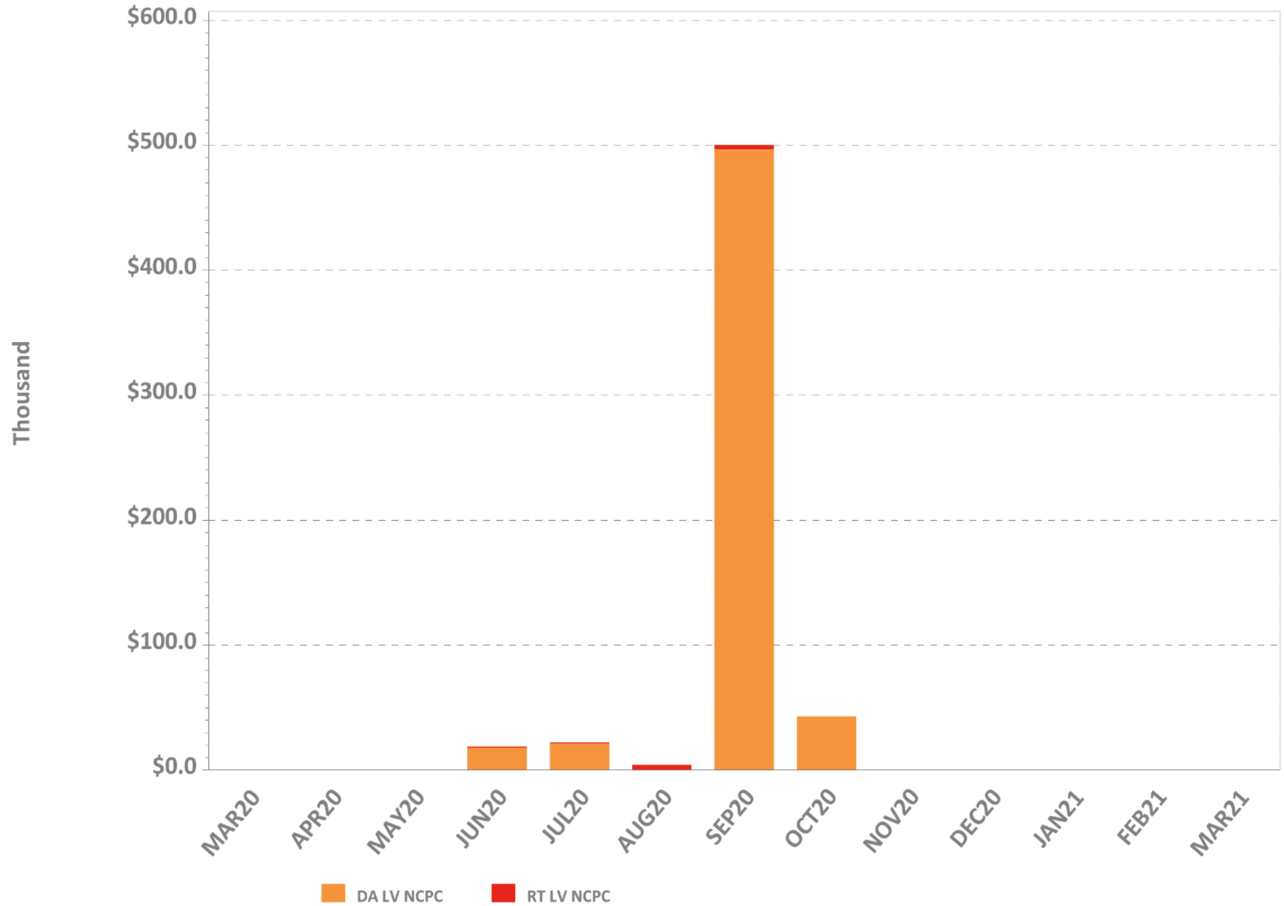
LSCPR Charges by Reliability Region



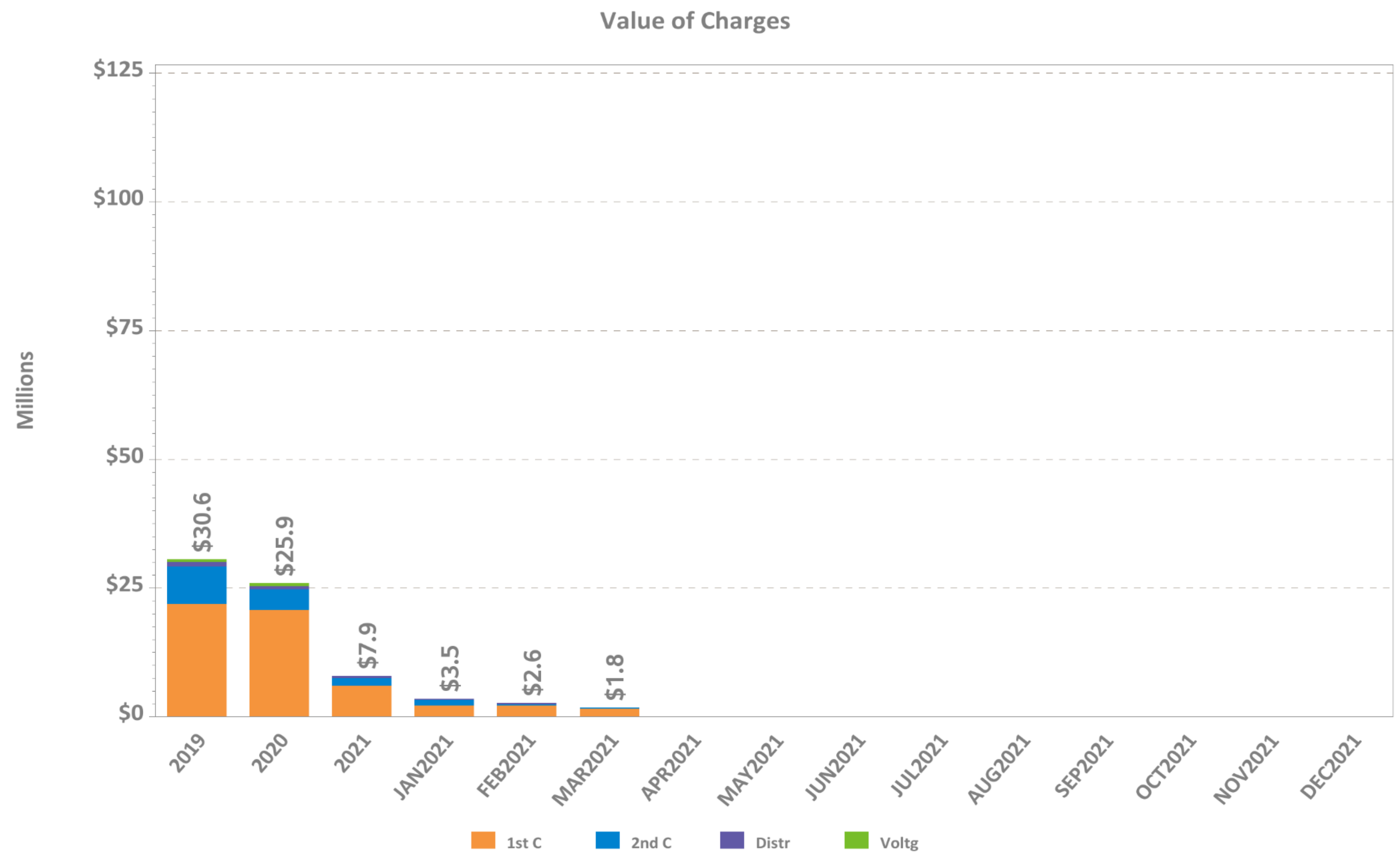
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

SEMA – Southeast Massachusetts Region
WCMA – Western/Central Massachusetts Region
NEMA – Northeast Massachusetts Region

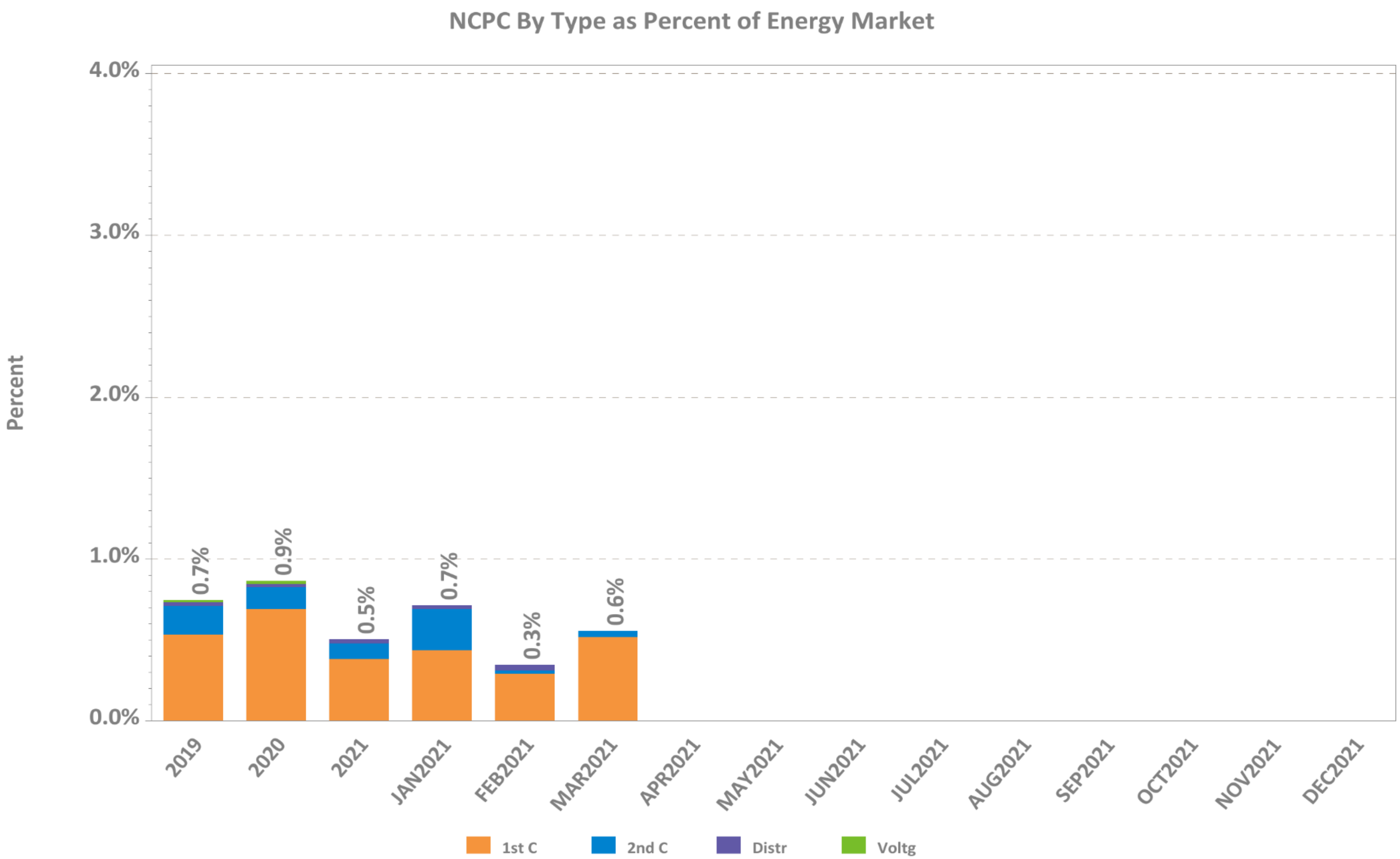
NCPC Charges for Voltage Support and High Voltage Control



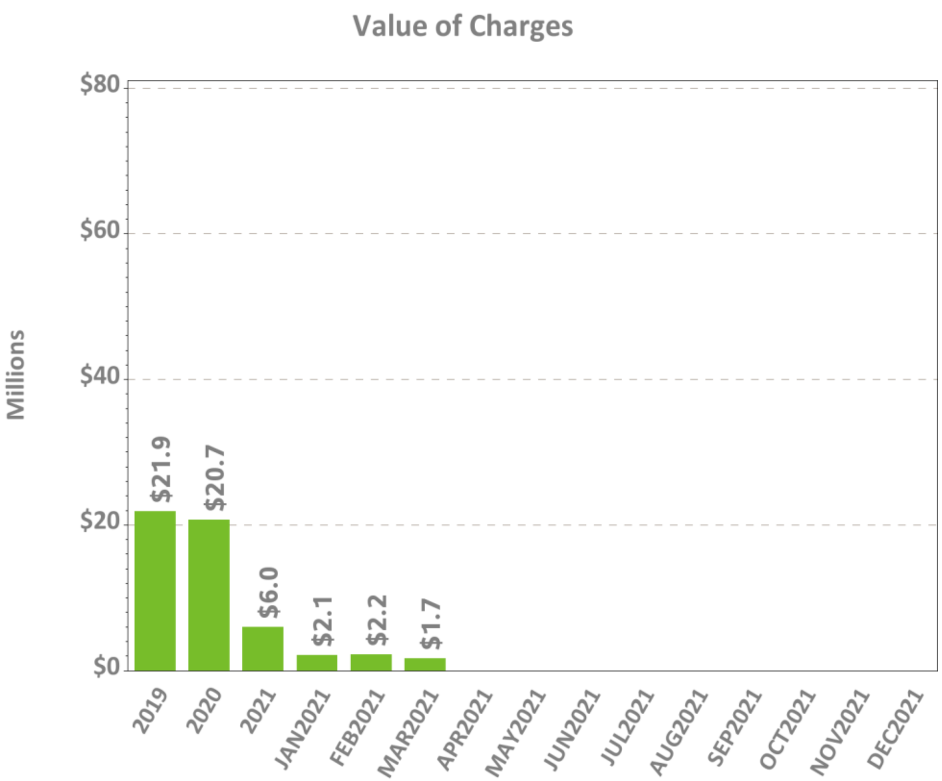
NCPC Charges by Type

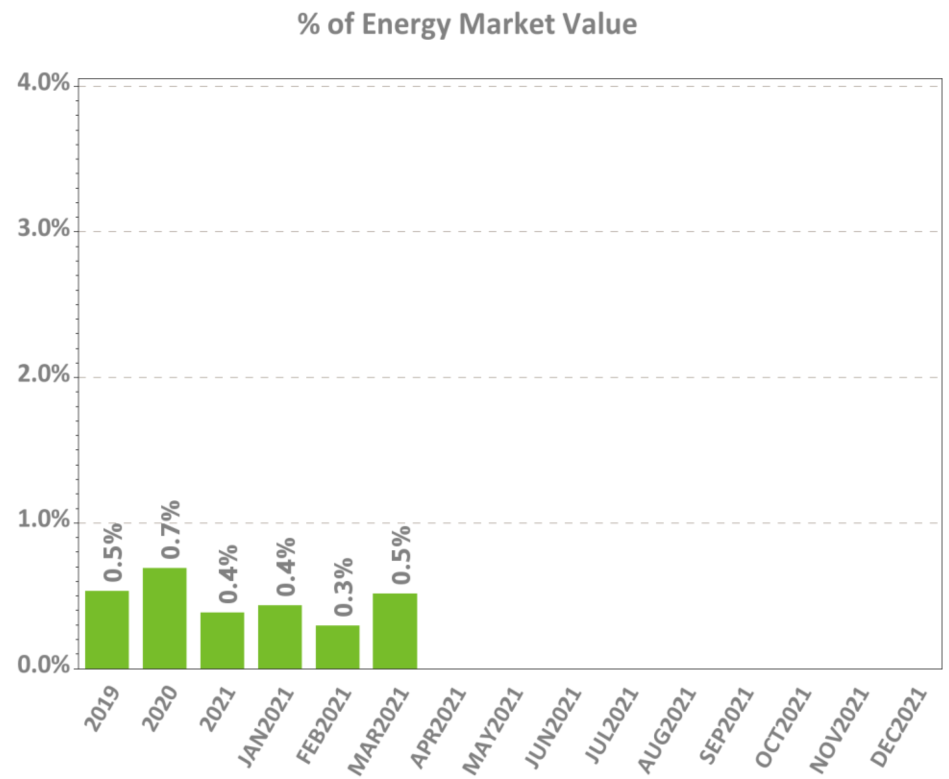


NCPC Charges as Percent of Energy Market



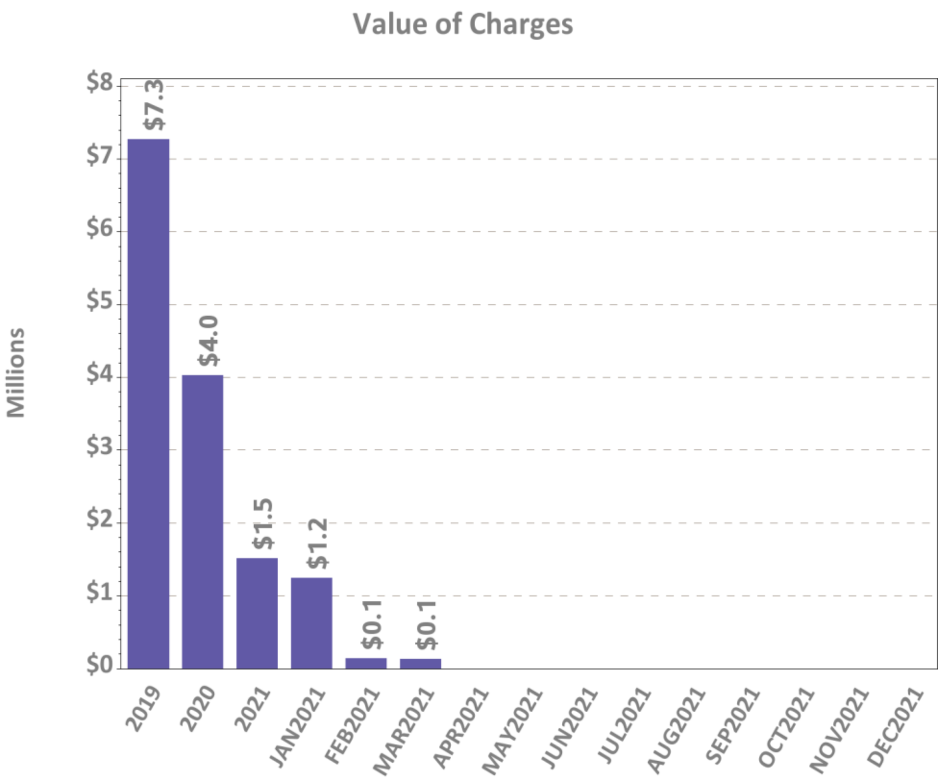
First Contingency NCPC Charges

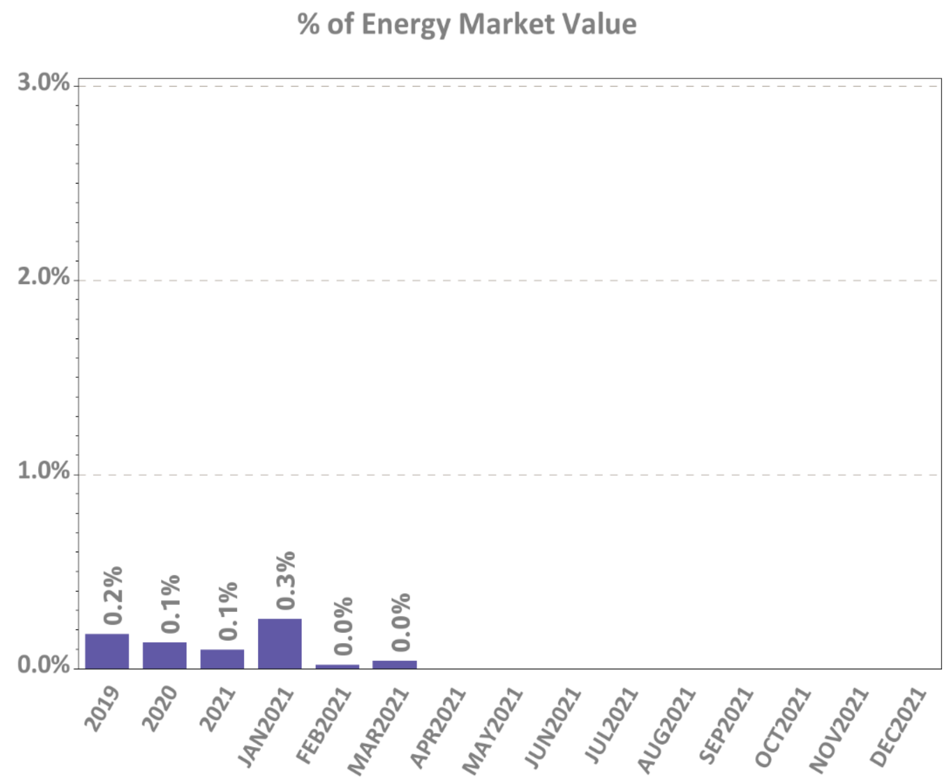




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

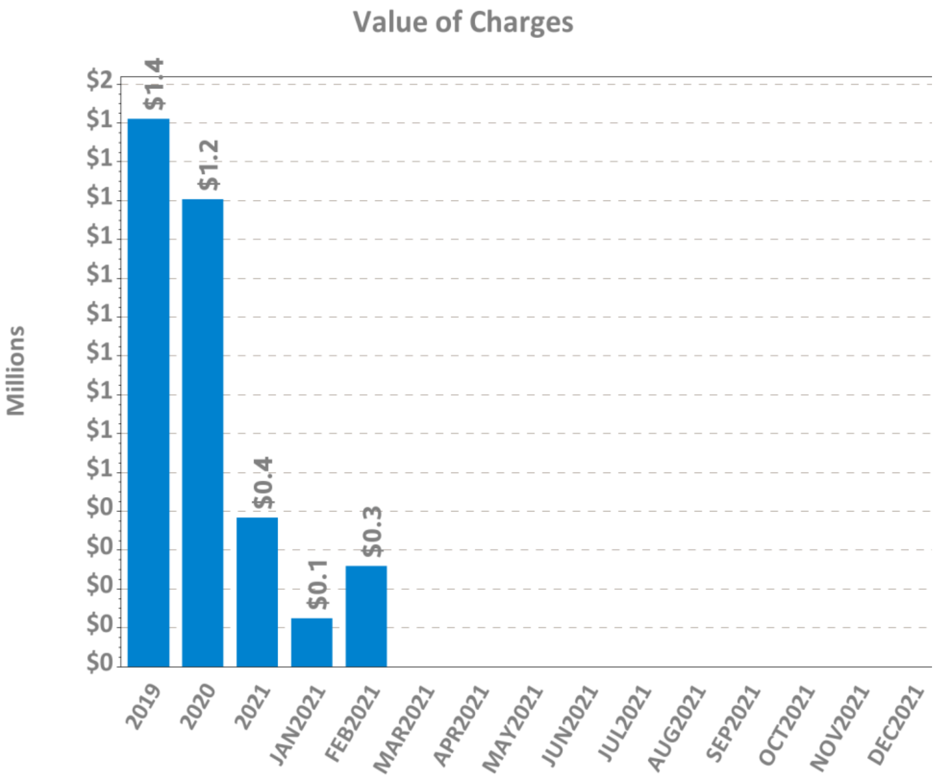
Second Contingency NCPC Charges

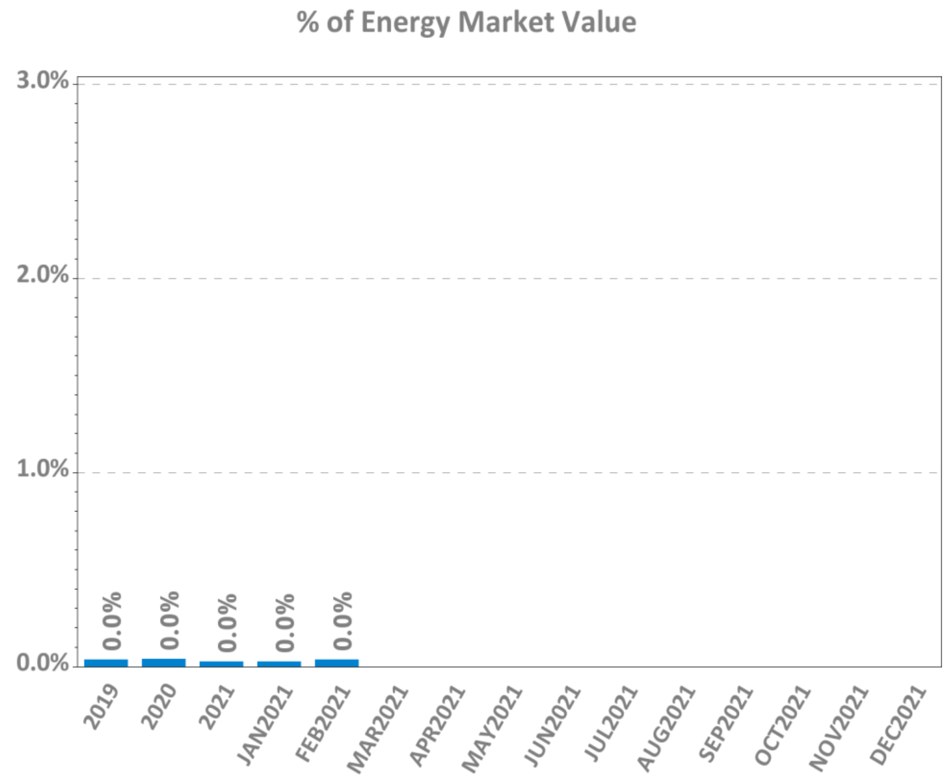




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

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

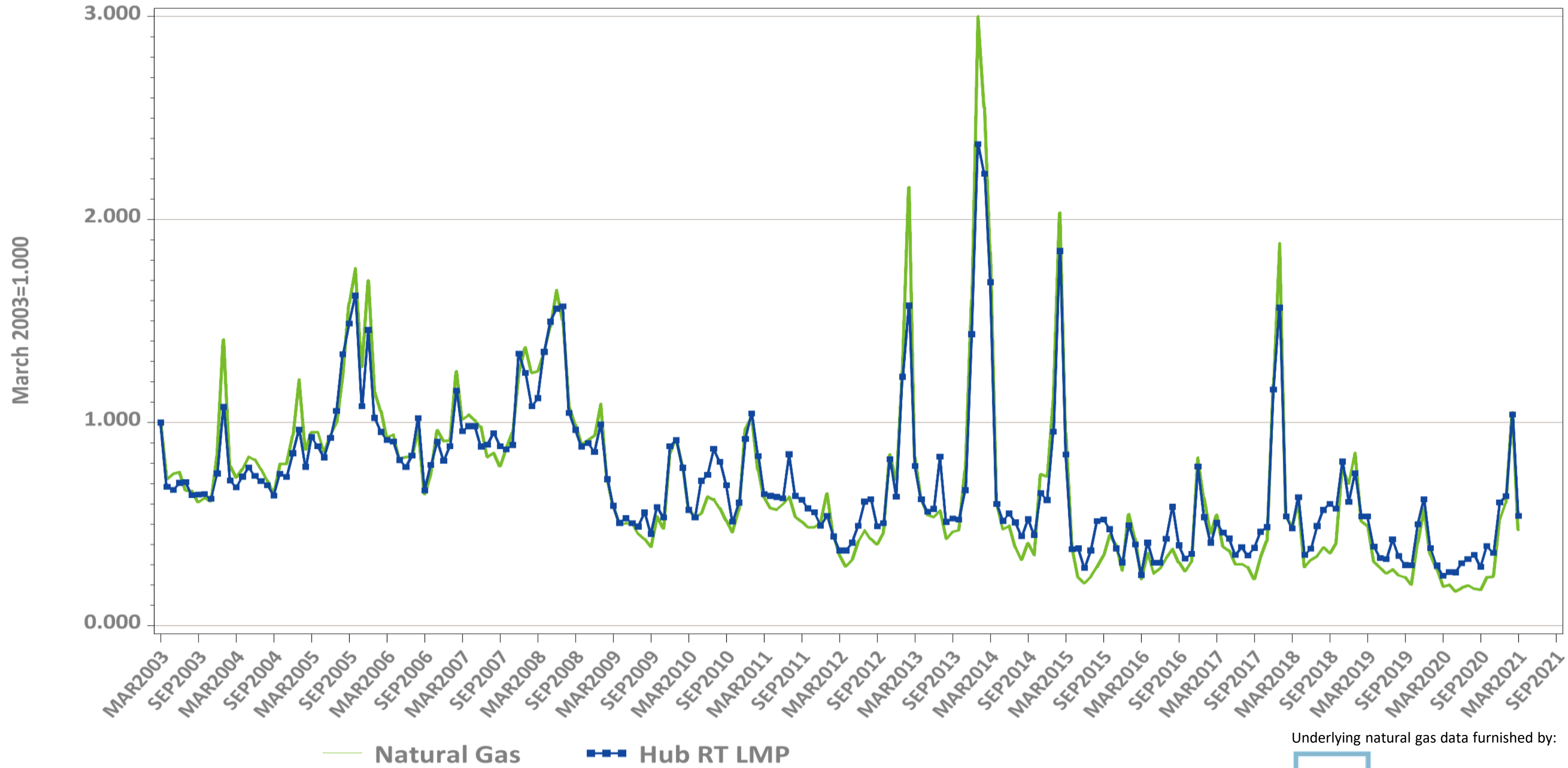
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 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%
Year 2020	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$23.62	$22.59	$23.27	$23.50	$22.76	$23.27	$23.57	$23.30	$23.32
Real-Time	$23.62	$22.91	$23.23	$23.54	$22.90	$23.29	$23.56	$23.37	$23.38
RT Delta %	0.0%	1.4%	-0.2%	0.2%	0.6%	0.1%	-0.1%	0.3%	0.3%

March-20	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$17.38	$16.72	$17.07	$17.17	$16.65	$17.12	$17.40	$17.16	$17.18
Real-Time	$17.00	$16.47	$16.74	$16.80	$16.23	$16.79	$17.02	$16.79	$16.82
RT Delta %	-2.2%	-1.5%	-1.9%	-2.1%	-2.5%	-1.9%	-2.1%	-2.2%	-2.1%
March-21	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$39.16	$37.47	$38.34	$38.98	$37.92	$39.32	$39.42	$38.85	$38.83
Real-Time	$37.48	$36.07	$36.75	$37.31	$36.18	$37.36	$37.55	$37.12	$37.10
RT Delta %	-4.3%	-3.7%	-4.2%	-4.3%	-4.6%	-5.0%	-4.7%	-4.4%	-4.4%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	125.3%	124.1%	124.6%	127.0%	127.7%	129.7%	126.6%	126.4%	126.0%
Yr over Yr RT	120.5%	119.0%	119.5%	122.1%	122.9%	122.6%	120.6%	121.1%	120.6%

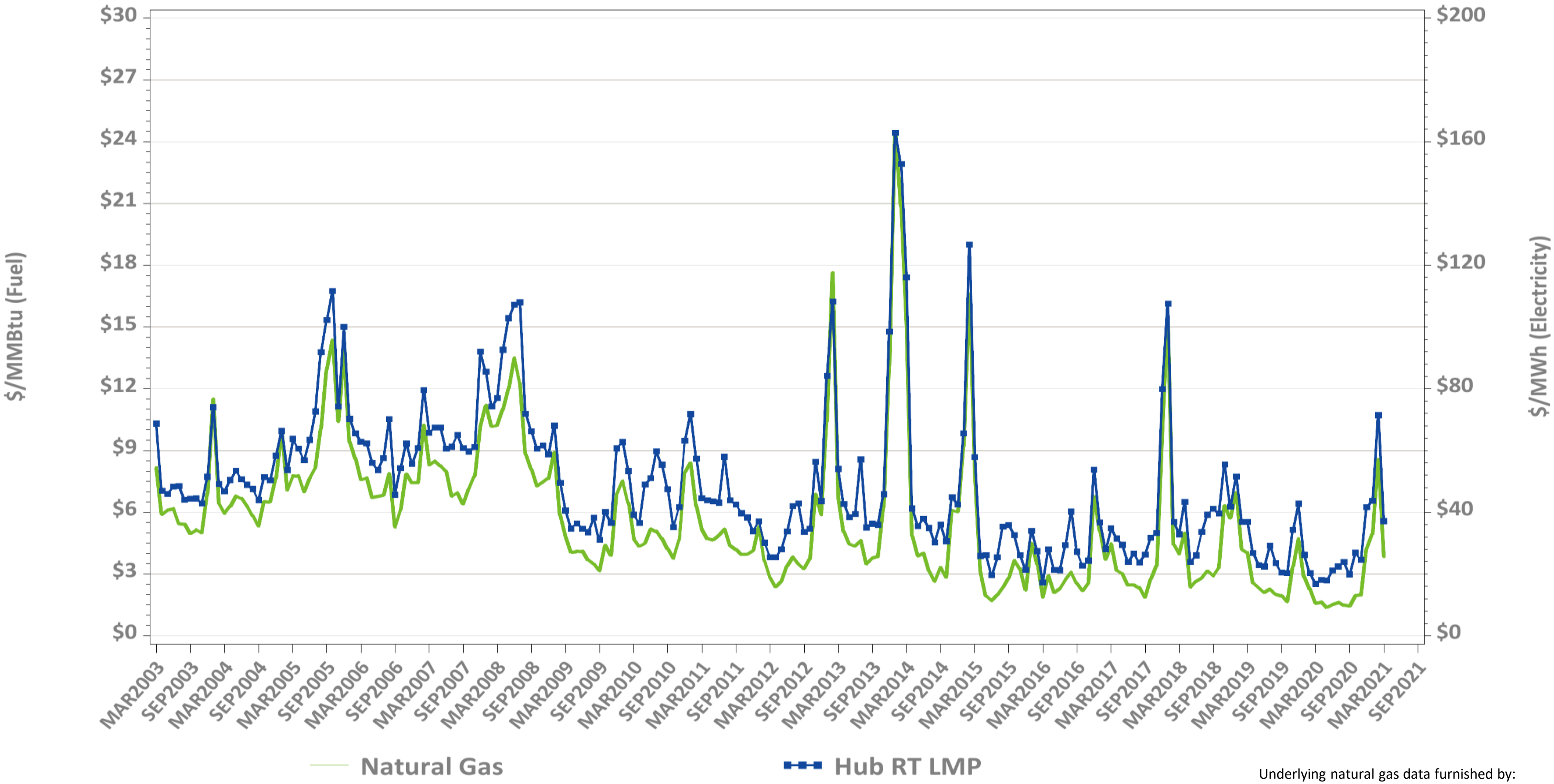
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ICE Global markets in clear view

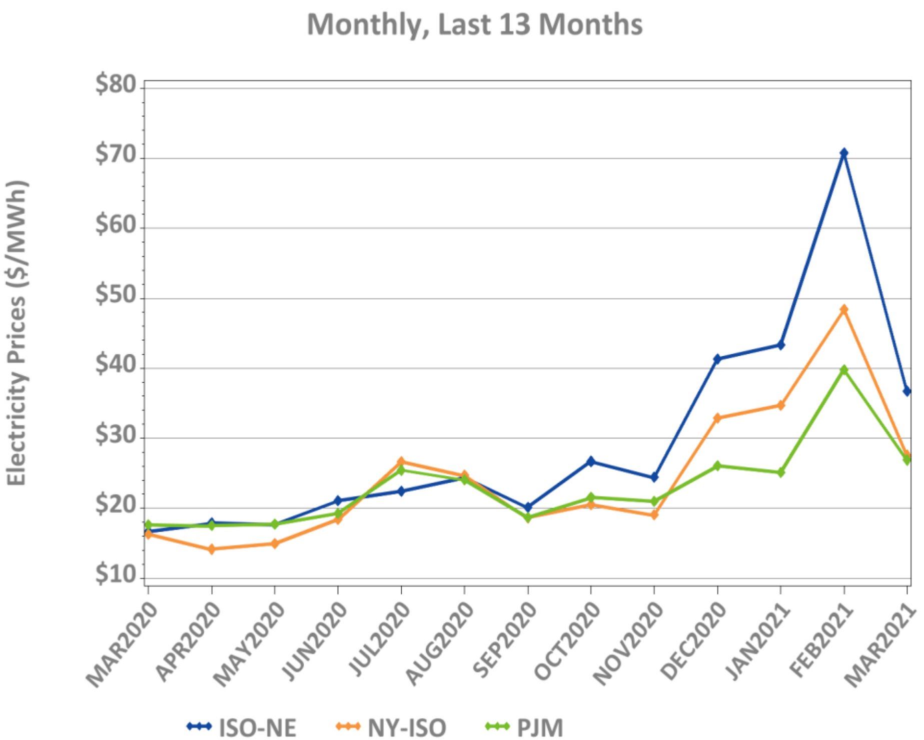
Monthly Average Fuel Price and RT Hub LMP



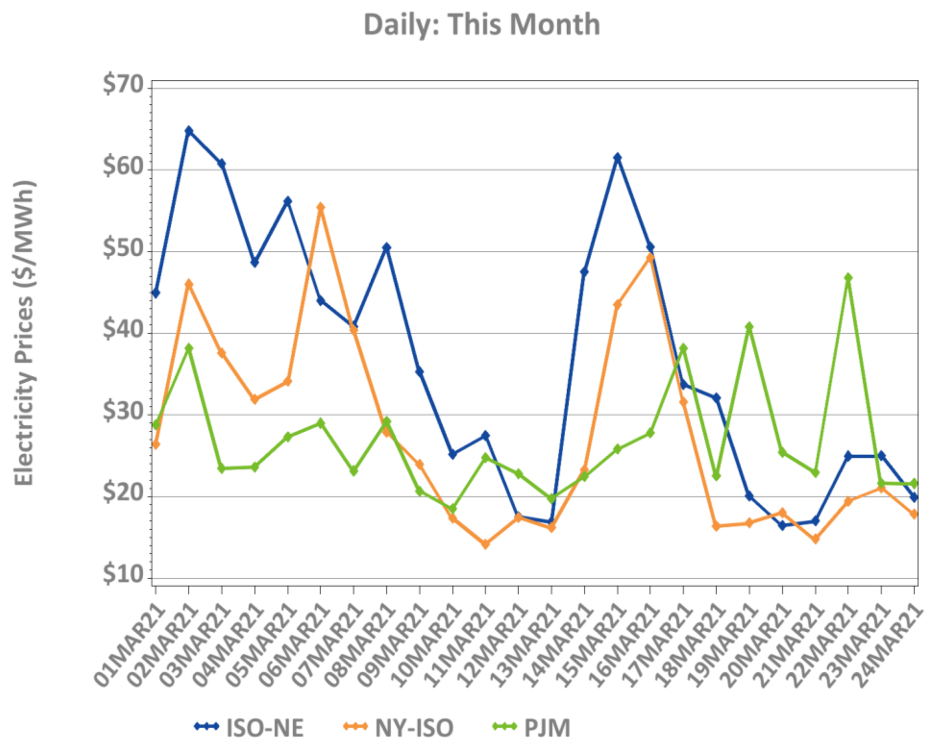
Underlying natural gas data furnished by:

ICE Global markets in clear view

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

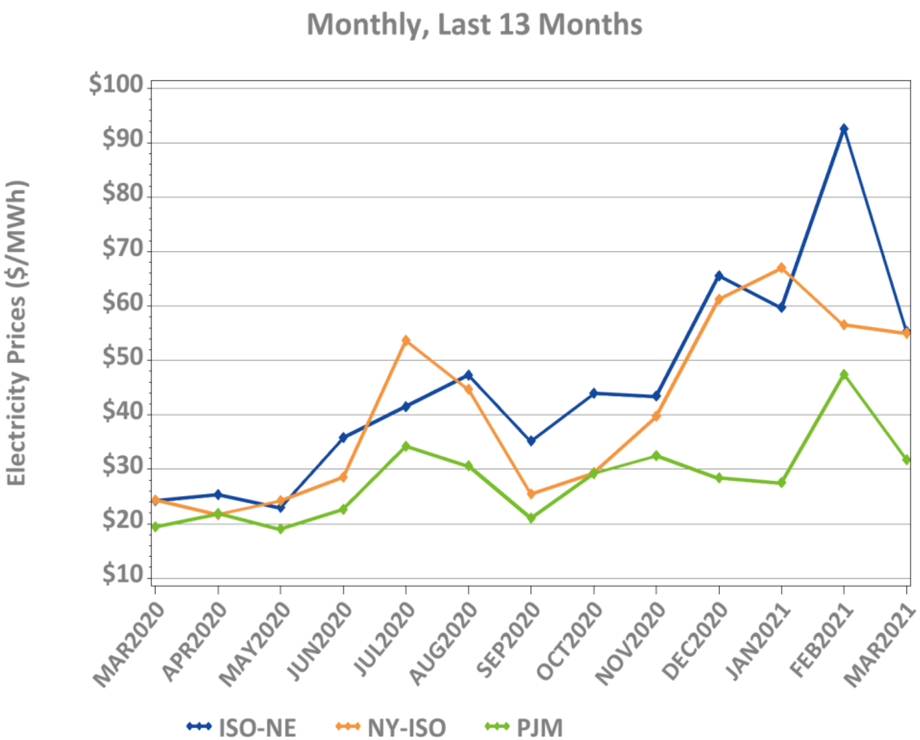


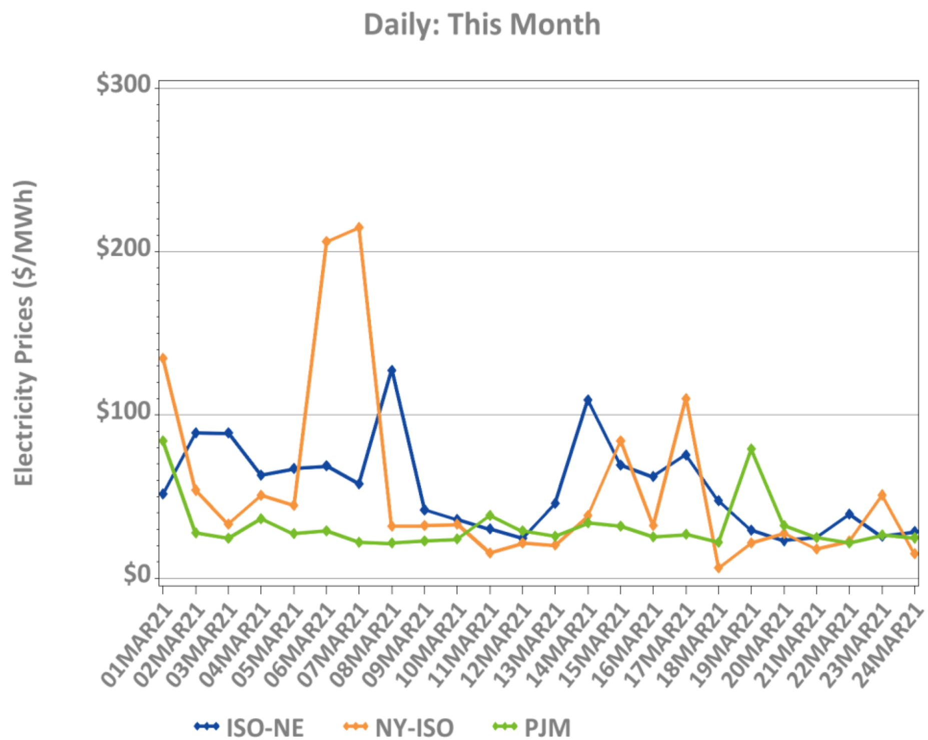
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





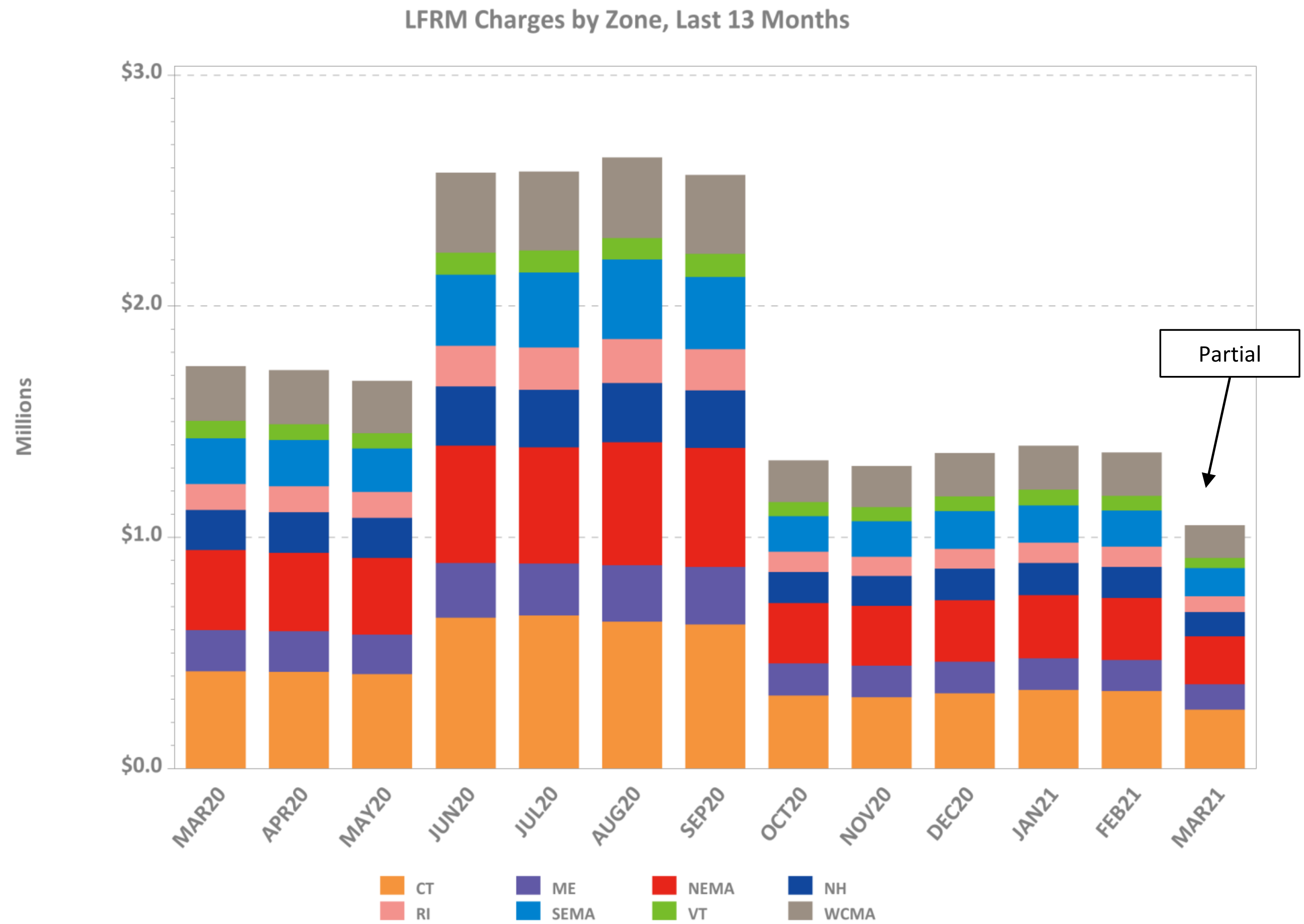
*Forecasted New England daily peak hours reflected

Reserve Market Results – March 2021

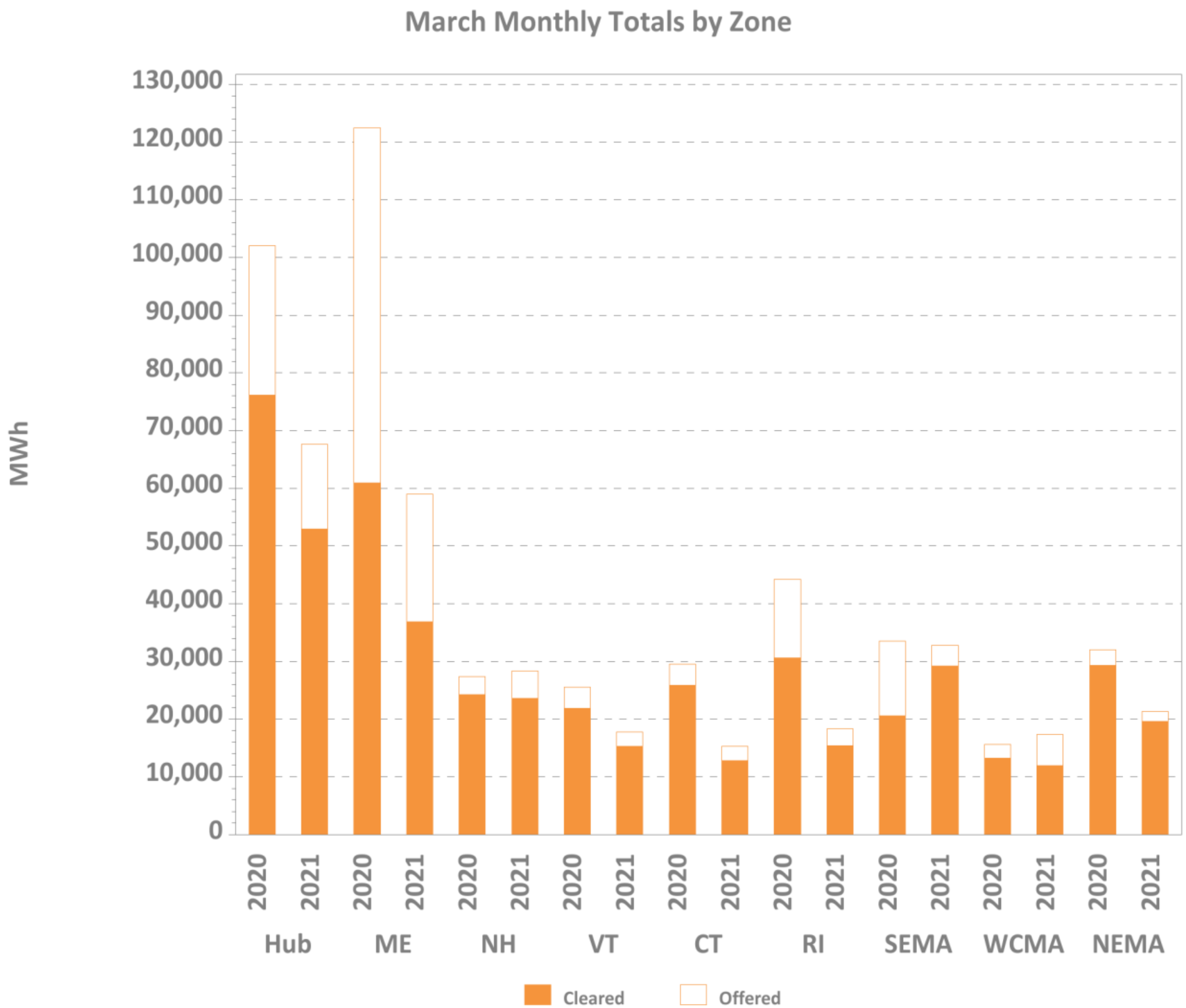
- Maximum potential Forward Reserve Market payments of $1.1M were reduced by credit reductions of $25K, failure-to-reserve penalties of $37K and no failure-to-activate penalties, resulting in a net payout of $1.1M or 95% of maximum
  - Rest of System: $0.76M/0.82M (93%)
  - Southwest Connecticut: $0.03M/0.03M (100%)
  - Connecticut: $0.2M/0.2M (100%)
- $332K total Real-Time credits were not reduced by any Forward Reserve Energy Obligation Charges for a net of $332K in Real-Time Reserve payments
  - Rest of System: 162 hours, $240K
  - Southwest Connecticut: 162 hours, $54K
  - Connecticut: 162 hours, $25K
  - NEMA: 162 hours, $12K

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.

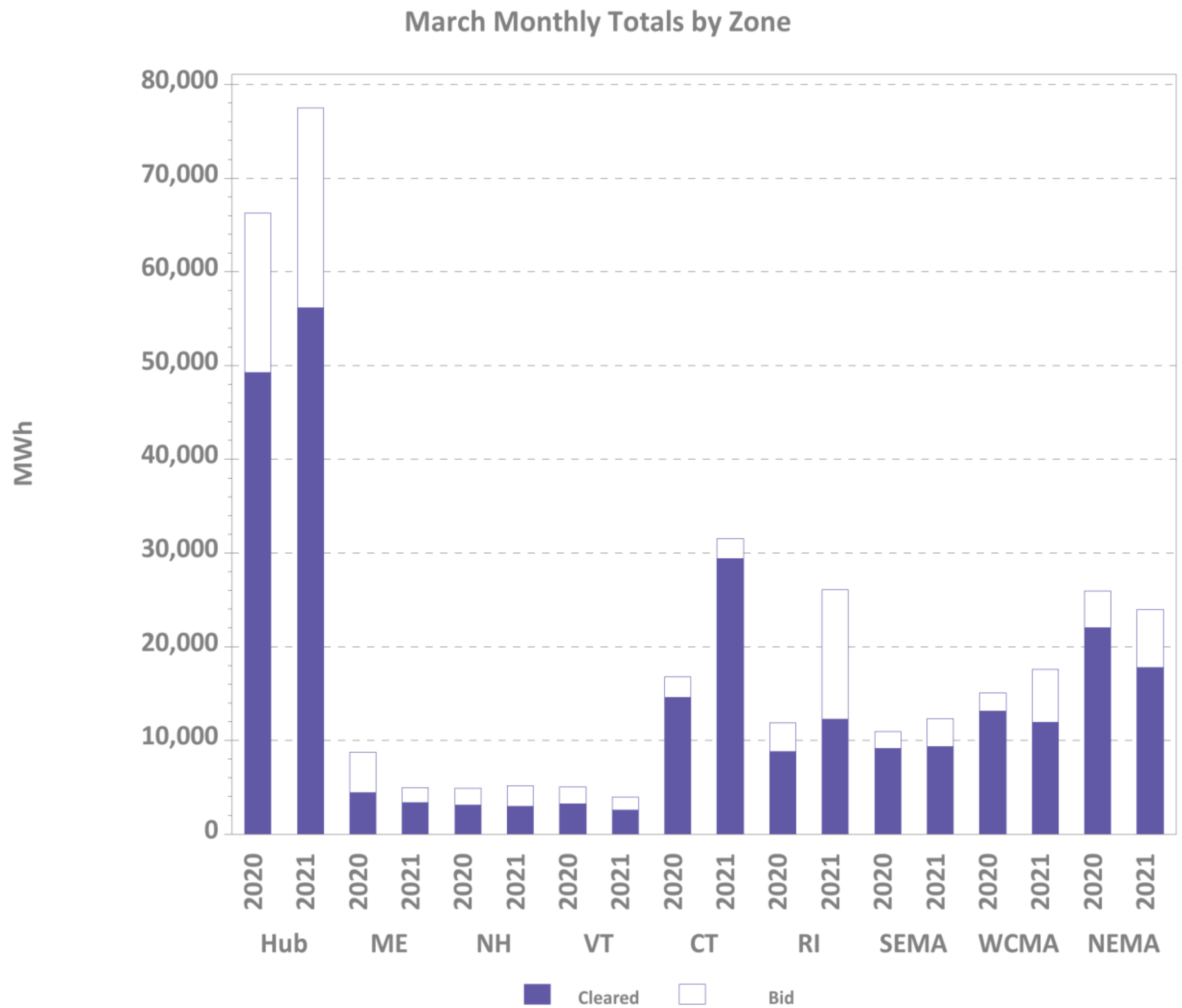
LFRM Charges to Load by Load Zone ($)



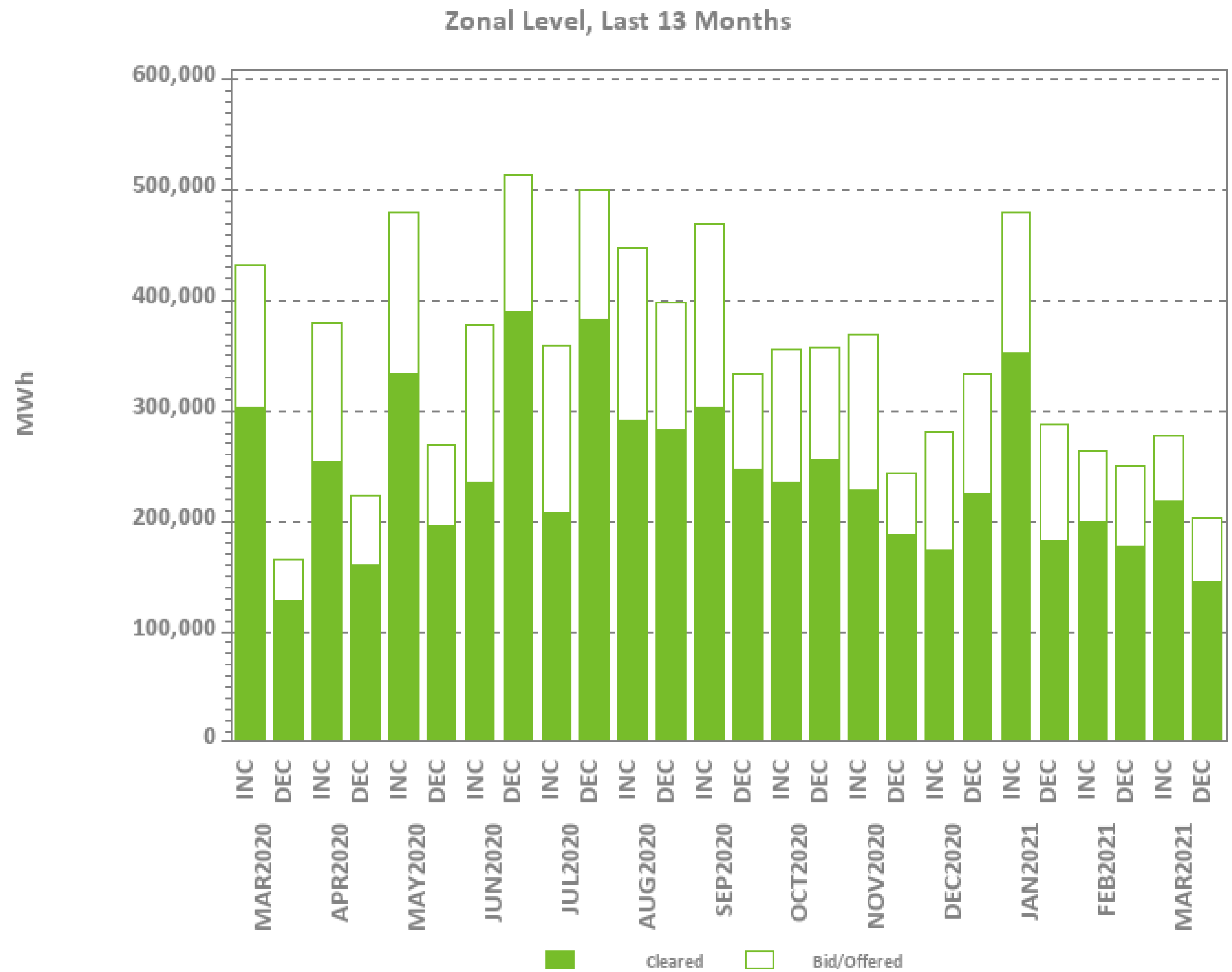
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

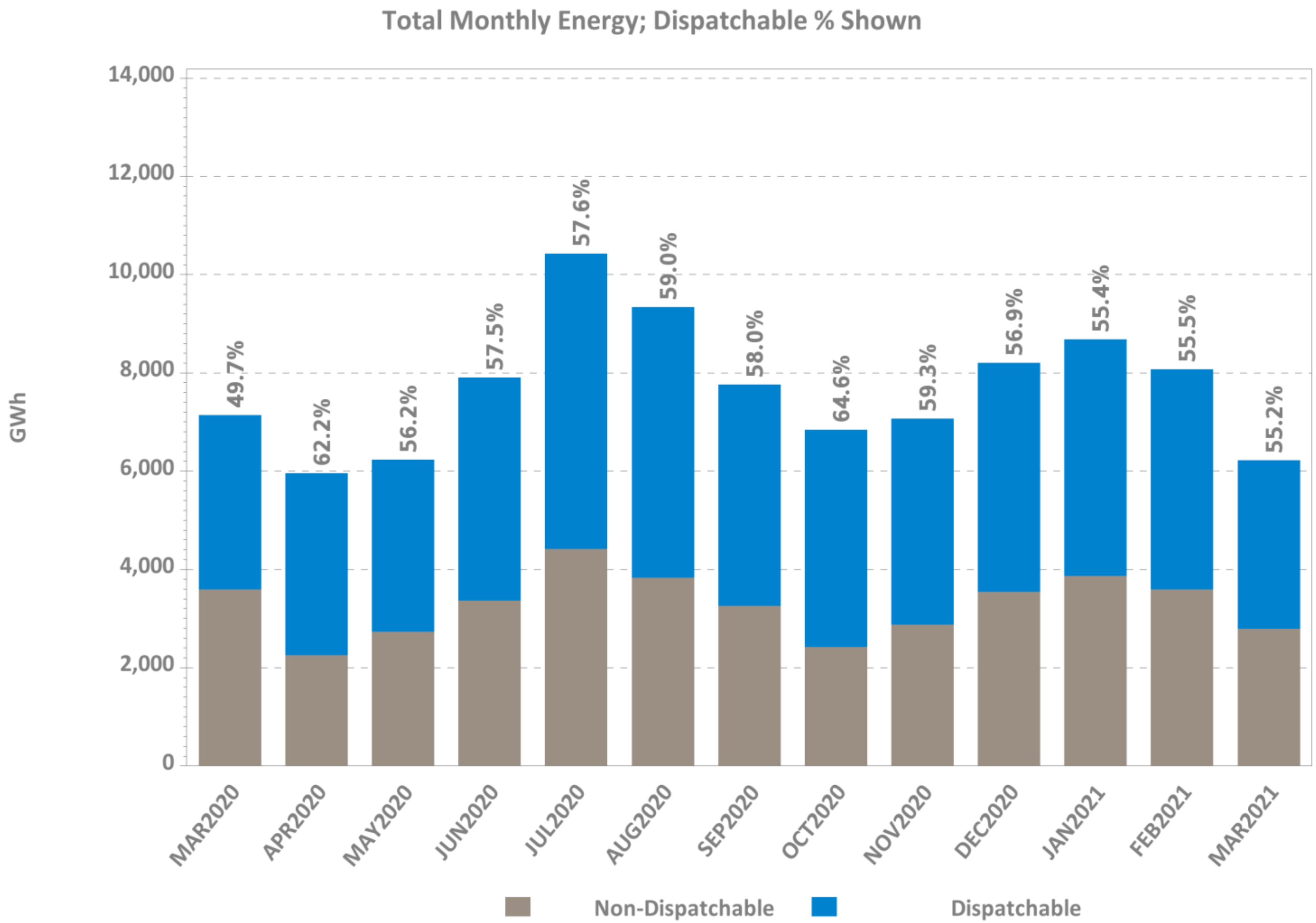


Total Increment Offers and Decrement Bids



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)

Regional System Plan (RSP)

- 2021 is an RSP publication year (RSP21)
  - Anticipated Key Messages were presented to PAC in March
- Goal is to improve value and usability of the RSP report
  - The ISO received valuable stakeholder feedback as part of the spring 2020 survey
- Target is for RSP21 to be 50% shorter in length than RSP19
  - Static information found in the RSP to be moved to the ISO-NE website
  - Dynamic information found in the RSP to be included in the report but at a high level
- ISO will improve the reporting of information related to the New England regional system planning process with:
  - Better utilization of the ISO-NE website
  - More frequent reporting
  - Tables/graphics in a format that is easily downloadable
- RSP21 Public Meeting date is set for October 6
  - Venue and format have yet to be decided

Planning Advisory Committee (PAC)

- April 14 PAC Meeting Agenda Topics*
  - Final 2021 Load Forecast: Regional Energy and Peak Demand Forecasts
  - Environmental Update
  - SEMA/RI 2030 Minimum Load Needs Assessment Scope of Work
  - Annual NGA Presentation
  - Boston 2028 RFP and Order 1000 Lessons Learned Update
  - 2021 Economic Study Request
  - Southern New Hampshire 2029 Preliminary Preferred Solution
  - Overnight Costs of New Generating Technologies

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

Transmission Planning for the Clean-Energy Transition

- On 9/24/20 the ISO initiated discussions with the PAC about proposed refinements to study assumptions that better reflect long-term trends, such as increased amounts of distributed-energy resources (primarily solar PV), offshore wind generation, and battery energy storage
- A follow-up presentation at the 11/19/20 PAC meeting outlined a proposal for a pilot study, with the following goals:
  - Explore transmission reliability concerns that may result from various system conditions possible by 2030
  - Quantify trade-offs necessary between transmission system reliability/flexibility and transmission investment cost
  - Inform future discussions on transmission planning study assumptions
- An overview of the system conditions and dispatch assumptions for the pilot study was discussed at the 12/16/20 and 1/21/21 PAC meetings
- Study work is in progress, with results expected in Q2 or Q3

Economic Studies

- 2020 Economic Study Request
  - Study proponent is National Grid
  - Study simulations are complete, and results have been presented to PAC
    - Additional sensitivities may be addressed as part of the Future Grid Reliability Study
    - Ancillary Services simulations will not be performed
    - Report to be completed by June 1
- 2021 Economic Study Request
  - Submitted in accordance with Attachment K, Section 4.1(b) of the Tariff
  - FGRS Phase 1 Study will be the only 2021 economic study, which was submitted by NEPOOL
    - Discussions will shift in April to the PAC rather than the RC/MC stakeholder meetings

Future Grid Reliability Study (FGRS)

- Phase 1
  - Studies include: Production Cost Simulations; Ancillary Services Simulations; Resource Adequacy Screen; and Probabilistic Resource Availability Analysis
  - Framework Document and supporting assumptions table, which describe study scenarios and objectives, have been developed by stakeholders
  - The ISO is working on model development by reviewing assumptions with NEPOOL
  - Production Cost Simulations to commence in the April timeframe and initial results expected in early summer
  - Phase 1 work was submitted as the only 2021 economic study
- Phase 2
  - Studies include: Revenue Sufficiency Analysis and Transmission Security
  - Studies will be delayed as the Pathways and 2050 Transmission studies are further defined
  - Studies likely to be performed by a consultant
  - Embellishment of the study scope continues at the MC/RC

2019 Electric Generator Air Emissions Report

- The final *2019 Electric Generator Air Emissions Report* was posted to the ISO-NE website on March 26
  - This annual report provides a comprehensive analysis of New England electric generator air emissions (NO_X, SO_2, and CO_2) and a review of relevant system conditions
  - Report includes:
    - New England Native Generation System Emissions
      - Total (ktons)
      - Rates (lbs/MWh)
    - New England Locational Marginal Unit Marginal Emissions
      - Both unweighted and load-weighted analyses
      - Rates (lbs/MWh)
    - Does not include import emissions
- An updated Emissions Report, that includes import emissions, will be posted in the May timeframe

Environmental Matters – Reset on Federal Environmental Priorities

EPA Administrator Michael Regan Prioritizing Climate & Enforcement

- Power sector expected to see new regulatory and increased enforcement activity, including:
  - Reconsideration of technology standards for emissions of criteria (ozone) and hazardous air pollutants
  - Coal ash disposal
  - Greater scrutiny of wastewater discharges
  - Greater enforcement over discharges onto wetlands, streams and other water resources
- Regional impacts include greater permitting scrutiny and additional and more substantive analyses for generators of air pollution, land and water use impacts
  - Affects <u>both</u> fossil and renewable resources

Proposed Climate Rules Affecting Generators Expected Late in 2021

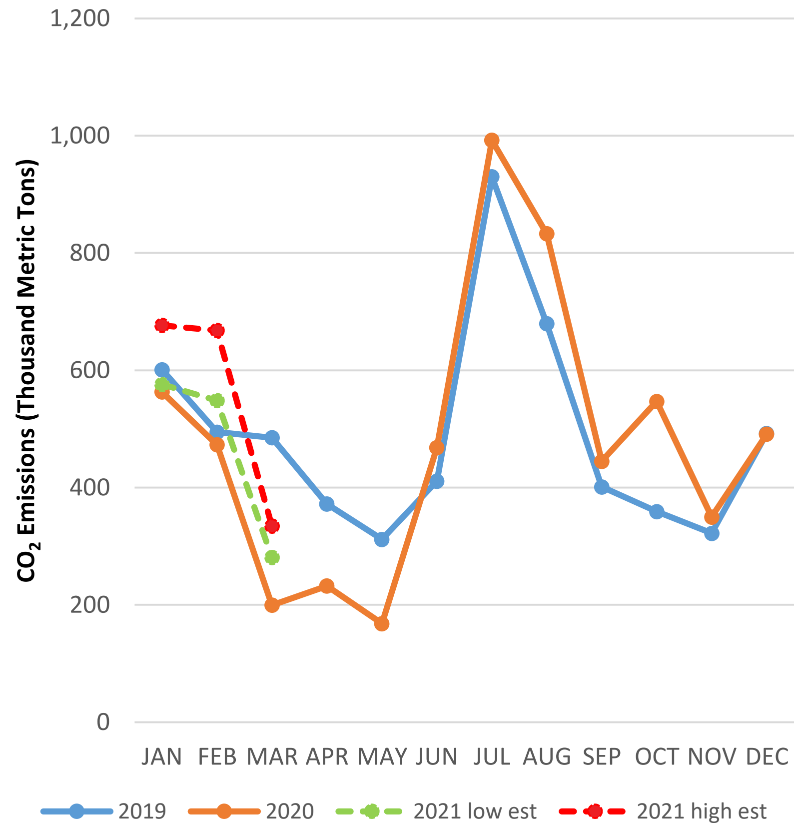
- Initial focus on unwinding Trump regulatory actions and laying groundwork for unified climate regulatory actions
  - 2/26/21: Interim carbon price of $51 announced to be used in cost benefit analyses
- Biden Administration using legal defeats of Trump rules (e.g., Affordable Clean Energy Rule) to reconsider emissions standards and permitting rules
  - Changing rules expected to average 18 months from proposal to final action

Environmental Matters – Massachusetts CO_2 Generator Emissions Cap

2021 CO_2 Emissions Trending Higher Than Past 1st Quarters

- As of 3/21/21, YTD 2021 estimated CO_2 emissions range between 1.4 and 1.7 million metric tons (MMT):
  - 1.6 MMT in 2019; 1.2 MMT in 2020
  - 17% to 20% of the 8.23 MMT 2021 cap
- 3/11/21: GWSA auction clearing price was \$6.50 per metric ton
  - GWSA allowances valued below RGGI allowances (RGGI allowances \$7.21 per metric ton (direct comparison to GWSA metric ton allowance) or \$7.95 per short ton)
- 12/16/20: GWSA auction clearing price was \$7.25 per metric ton

2019-2021 Estimated Monthly Emissions (Thousand Metric Tons)



GWSA - Global Warming Solutions Act

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.

Southwest Connecticut (SWCT) Projects

Status as of 3/24/2021

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 3/24/2021

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)	Nov-20	4
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 3/24/2021

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 3/24/2021

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)	Feb-21	4

Southwest Connecticut Projects, cont.

Status as of 3/24/2021

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 3/24/2021

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-22	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 3/24/2021

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	Sep-20	4
Install third 115 kV line from West Walpole to Holbrook	Sep-20	4
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 3/24/2021

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	May-21	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	May-21	3

*Mystic to Chelsea line portion of the project is a present stage 4 as of October 2020.

Greater Boston Projects, cont.

Status as of 3/24/2021

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	May-22	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 3/24/2021

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

SEMA/RI Reliability Projects

Status as of 3/24/2021

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

Upgrade	Expected/ Actual In-Service	Present Stage
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	Oct-20	4
Conduct remote terminal station work at the Wampanoag and Pawtucket substations for the new Grand Army GIS switching station	Oct-20	4
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	Oct-20	4
Increase clearances on E-183E & F-184 lines between Brayton Point and Grand Army substations	Nov-19	4
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 3/24/2021

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

Upgrade	Expected/ Actual In-Service	Present Stage
Add 115 kV circuit breaker at Robinson Ave substation and re-terminate the Q10 line	Dec-21	3
Install 45.0 MVAR capacitor bank at Berry Street substation	Cancelled*	N/A
Separate the N12/M13 DCT and reconductor the N12 and M13 between Somerset and Bell Rock substations	May-25	2
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	Jun-23	2
Extend the Line 114 from the Dartmouth town line (Eversource-NGRID border) to Bell Rock substation	Dec-23	2
Reconductor L14 and M13 lines from Bell Rock substation to Bates Tap	Cancelled*	N/A

*Cancelled per ISO-NE PAC presentation on August 27, 2020

SEMA/RI Reliability Projects, cont.

Status as of 3/24/2021

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

Upgrade	Expected/ Actual In-Service	Present Stage
Build a new 115 kV line from Bourne to West Barnstable substations which includes associated terminal work	Dec-23	1
Separate the 135/122 DCT from West Barnstable to Barnstable substations	Dec-21	3
Retire the Barnstable SPS	Dec-21	3
Build a new 115 kV line from Carver to Kingston substations and add a new Carver terminal	Dec-22	1
Install a new bay position at Kingston substation to accommodate new 115 kV line	Dec-22	1
Extend the 114 line from the Eversource/National Grid border to the Industrial Park Tap	Dec-23	1

SEMA/RI Reliability Projects, cont.

Status as of 3/24/2021

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

Upgrade	Expected/ Actual In-Service	Present Stage
Install 35.3 MVAR capacitors at High Hill and Wing Lane substations	Dec-21	3
Loop the 201-502 line into the Medway substation to form the 201-502N and 201-502S lines	Jan-23	2
Separate the 325/344 DCT lines from West Medway to West Walpole substations	Cancelled**	N/A
Reconductor and upgrade the 112 Line from the Tremont substation to the Industrial Tap	Jun-18	4
Reconductor the 108 line from Bourne substation to Horse Pond Tap*	Oct-18	4
Replace disconnect switches on 323 line at West Medway substation and replace 8 line structures	Aug-20	4

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

** Cancelled per ISO-NE PAC presentation on August 27, 2020

SEMA/RI Reliability Projects, cont.

Status as of 3/24/2021

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

Upgrade	Expected/ Actual In-Service	Present Stage
Rebuild the Middleborough Gas and Electric portion of the E1 line from Bridgewater to Middleborough	Apr-19	4
Reconductor the J16S line	Jun-22	2
Replace the Kent County 345/115 kV transformer	Mar-22	2
West Medway 345 kV circuit breaker upgrades	Dec-21	3
Medway 115 kV circuit breaker replacements	Nov-20	4

Eastern CT Reliability Projects

Status as of 3/24/2021

Project Benefit: Addresses system needs in the Eastern Connecticut area

Upgrade	Expected/ Actual In-Service	Present Stage
Reconductor the L190-4 and L190-5 line sections	Dec-26	1
Install a second 345/115 kV autotransformer (4X) and one 345 kV breaker at Card substation	Mar-23	2
Upgrade Card 115 kV to BPS standards	Mar-23	2
Install one 115 kV circuit breaker in series with Card substation 4T	Mar-23	2
Convert Gales Ferry substation from 69 kV to 115 kV	Dec-23	1
Rebuild the 100 Line from Montville to Gales Ferry to allow operation at 115 kV	Dec-21	1

Eastern CT Reliability Projects, cont.

Status as of 3/24/2021

Project Benefit: Addresses system needs in the Eastern Connecticut area

Upgrade	Expected/ Actual In-Service	Present Stage
Re-terminate the 100 Line at Montville station and associated work. Energize the 100 Line at 115 kV	Dec-23	1
Rebuild 400-1 Line section to allow operation at 115 kV (Tunnel to Ledyard Jct.)	Dec-22	1
Add one 115 kV circuit breaker and re-terminate the 400-1 line section into Tunnel substation. Energize 400 Line at 115 kV	Dec-23	1
Rebuild 400-2 Line section to allow operation at 115 kV (Ledyard Jct. to Border Bus with CMEEC)	Dec-21	3
Rebuild the 400-3 Line Section to allow operation at 115 kV (Gales Ferry to Ledyard Jct.)	Dec-21	1
Install a 25.2 MVAR 115 kV capacitor and one capacitor breaker at Killingly	Mar-22	2

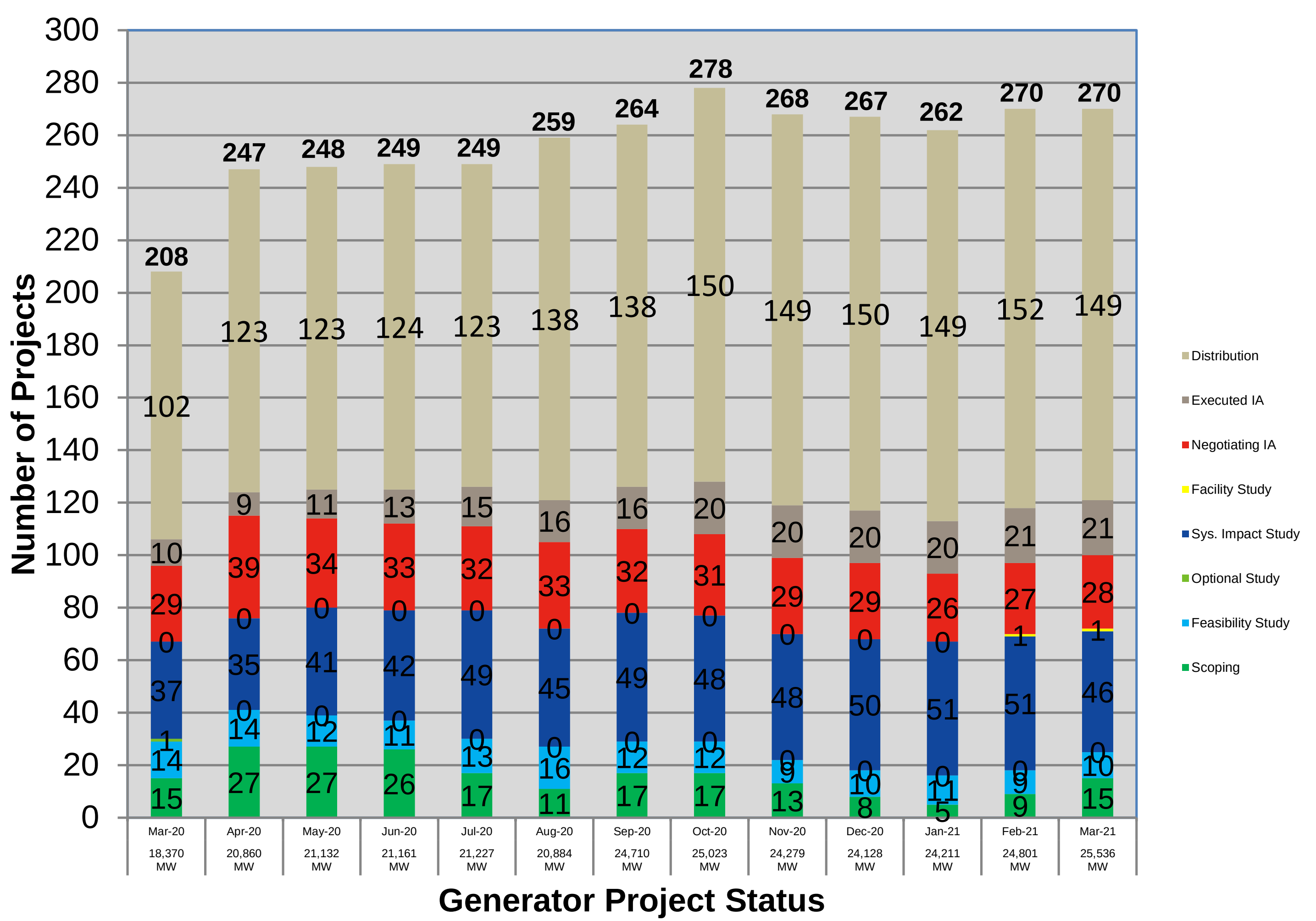
Eastern CT Reliability Projects, cont.

Status as of 3/24/2021

Project Benefit: Addresses system needs in the Eastern Connecticut area

Upgrade	Expected/ Actual In-Service	Present Stage
Install one 345 kV series breaker with the Montville 1T	June-22	2
Install a 50 MVAR synchronous condenser with two 115 kV breakers at Shunock	Dec-24	1
Install a 1% series reactor with bypass switch at Mystic, CT on the 1465 Line	Dec-22	1
Convert the 400-2 Line Section to 115 kV (Border Bus to Buddington), convert Buddington to 115 kV	Dec-23	1

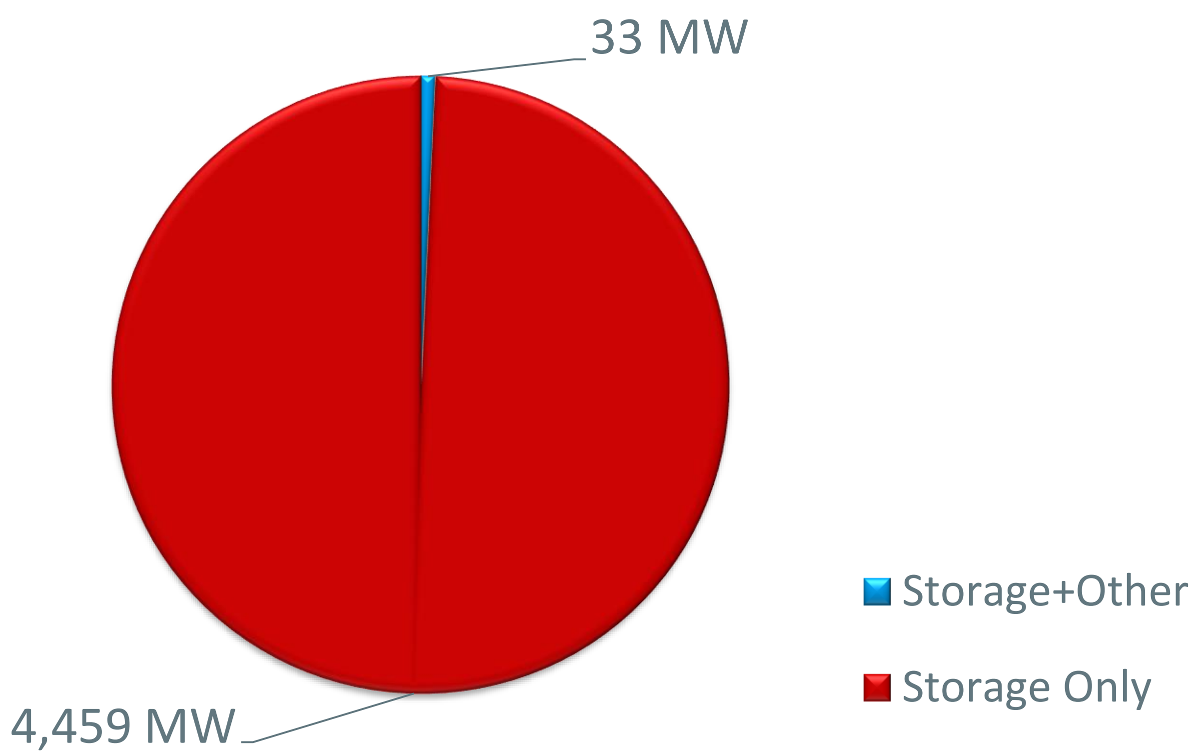
Status of Tariff Studies



Note: March 2021 is based on partial data.
As of March 2021, there is 1 ETU in Scoping, 0 in FS, 3 in SIS, 0 in OIS, 0 in FAC, 0 Negotiating IA, and 2 with Executed IA.
https://irtt.iso-ne.com/external.aspx

What is in the Queue (as of March 22, 2021)

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



OPERABLE CAPACITY ANALYSIS

Spring 2021 Analysis

Spring 2021 Operable Capacity Analysis

50/50 Load Forecast (Reference)	May - 2021[2] CSO (MW)	May - 2021[2] SCC (MW)
Operable Capacity MW [1]	30,506	33,534
Active Demand Capacity Resource (+) [5]	509	434
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,025	1,025
Non Commercial Capacity (+)	6	6
Non Gas-fired Planned Outage MW (-)	2,616	2,915
Gas Generator Outages MW (-)	2,411	2,694
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)	23,619	25,990
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	18,118	18,118
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	20,423	20,423
Operable Capacity Margin	3,196	5,567

[1]Operable Capacity is based on data as of **March 22, 2021** 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 **March 22, 2021.**

[2] Load forecast that is based on the 2020 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 8, 2021.**

[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 2021 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	May - 2021[2] CSO (MW)	May - 2021[2] SCC (MW)
Operable Capacity MW [1]	30,506	33,534
Active Demand Capacity Resource (+) [5]	509	434
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,025	1,025
Non Commercial Capacity (+)	6	6
Non Gas-fired Planned Outage MW (-)	2,616	2,915
Gas Generator Outages MW (-)	2,411	2,694
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)	23,619	25,990
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	19,612	19,612
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	21,917	21,917
Operable Capacity Margin	1,702	4,073

[1] Operable Capacity is based on data as of **March 22, 2021** 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 **March 22, 2021.**

[2] Load forecast that is based on the 2020 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 8, 2021.**

[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 2021 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

March 26, 2021 - 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]
4/3/2021	30319	442	1105	6	3803	1701	2700	0	23668	16134	2305	18439	5229
4/10/2021	30319	442	1105	6	5235	1833	2700	0	22104	15870	2305	18175	3929
4/17/2021	30319	442	1105	6	5172	1549	2700	0	22451	15335	2305	17640	4811
4/24/2021	30319	442	1105	6	4226	1347	2700	0	23599	15057	2305	17362	6237
5/1/2021	30506	509	1125	6	3038	1444	3400	0	24264	15029	2305	17334	6930
5/8/2021	**30506**	**509**	**1025**	**6**	**2616**	**2411**	**3400**	**0**	**23619**	**18118**	**2305**	**20423**	**3196**
5/15/2021	30506	509	1025	6	1389	1756	3400	0	25501	19152	2305	21457	4044
5/22/2021	30506	509	1025	6	1169	1158	3400	0	26319	20113	2305	22418	3901

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 2020 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 25,125 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 2021 Operable Capacity Analysis
90/10 Forecast (Extreme)

ISO-NE OPERABLE CAPACITY ANALYSIS

March 26, 2021 - 90-10 FORECAST using CSO

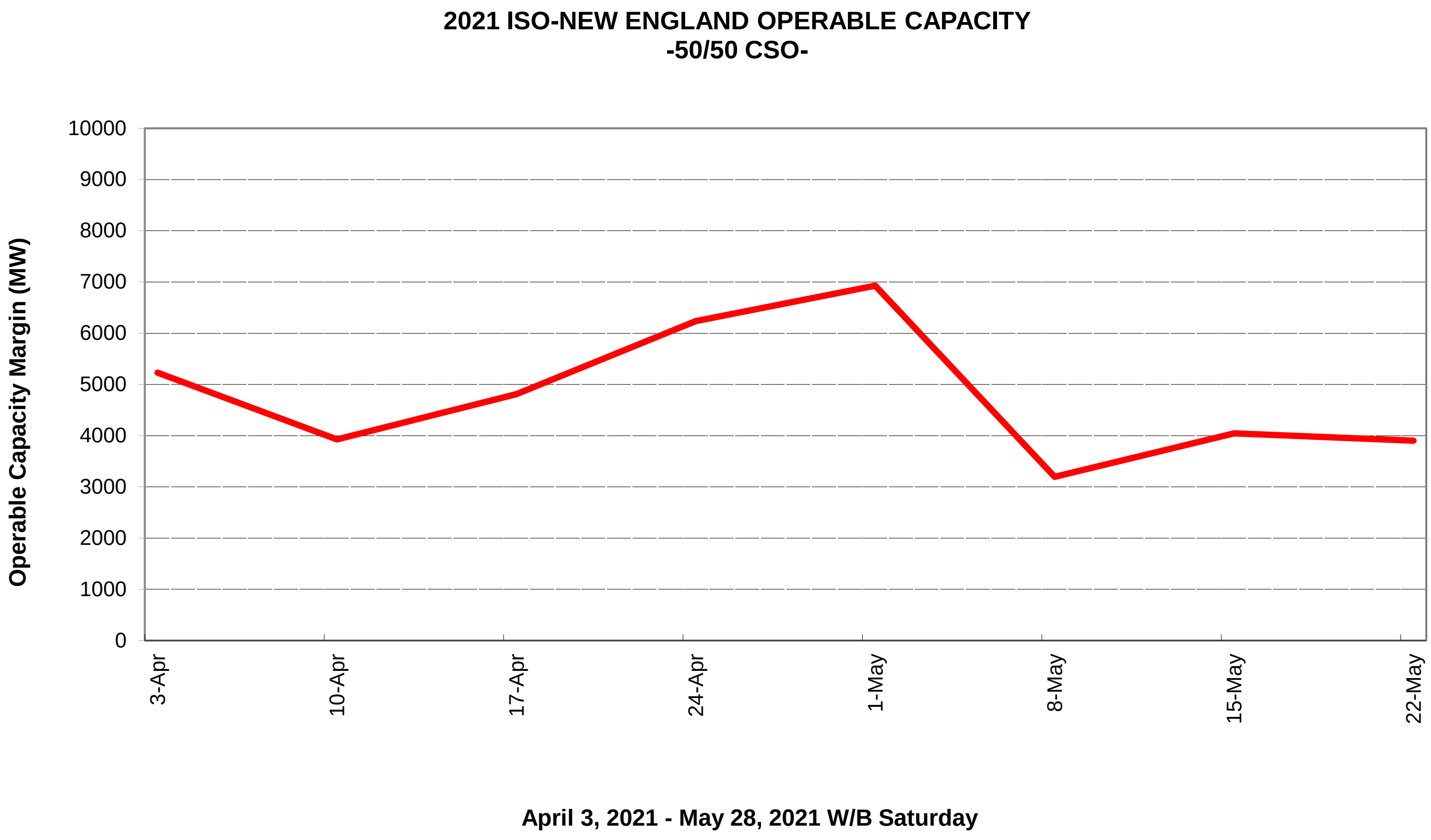
This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, August, and Mid September

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	Active Capacity Demand MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERATOR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
4/3/2021	30319	442	1105	6	3803	1701	2700	0	23668	16667	2305	18972	4696
4/10/2021	30319	442	1105	6	5235	1833	2700	0	22104	16395	2305	18700	3404
4/17/2021	30319	442	1105	6	5172	1549	2700	0	22451	15846	2305	18151	4300
4/24/2021	30319	442	1105	6	4226	1347	2700	0	23599	15560	2305	17865	5734
5/1/2021	30506	509	1125	6	3038	1444	3400	0	24264	15531	2305	17836	6428
5/8/2021	**30506**	**509**	**1025**	**6**	**2616**	**2411**	**3400**	**0**	**23619**	**19612**	**2305**	**21917**	**1702**
5/15/2021	30506	509	1025	6	1389	1756	3400	0	25501	20716	2305	23021	2480
5/22/2021	30506	509	1025	6	1169	1158	3400	0	26319	21741	2305	24046	2273

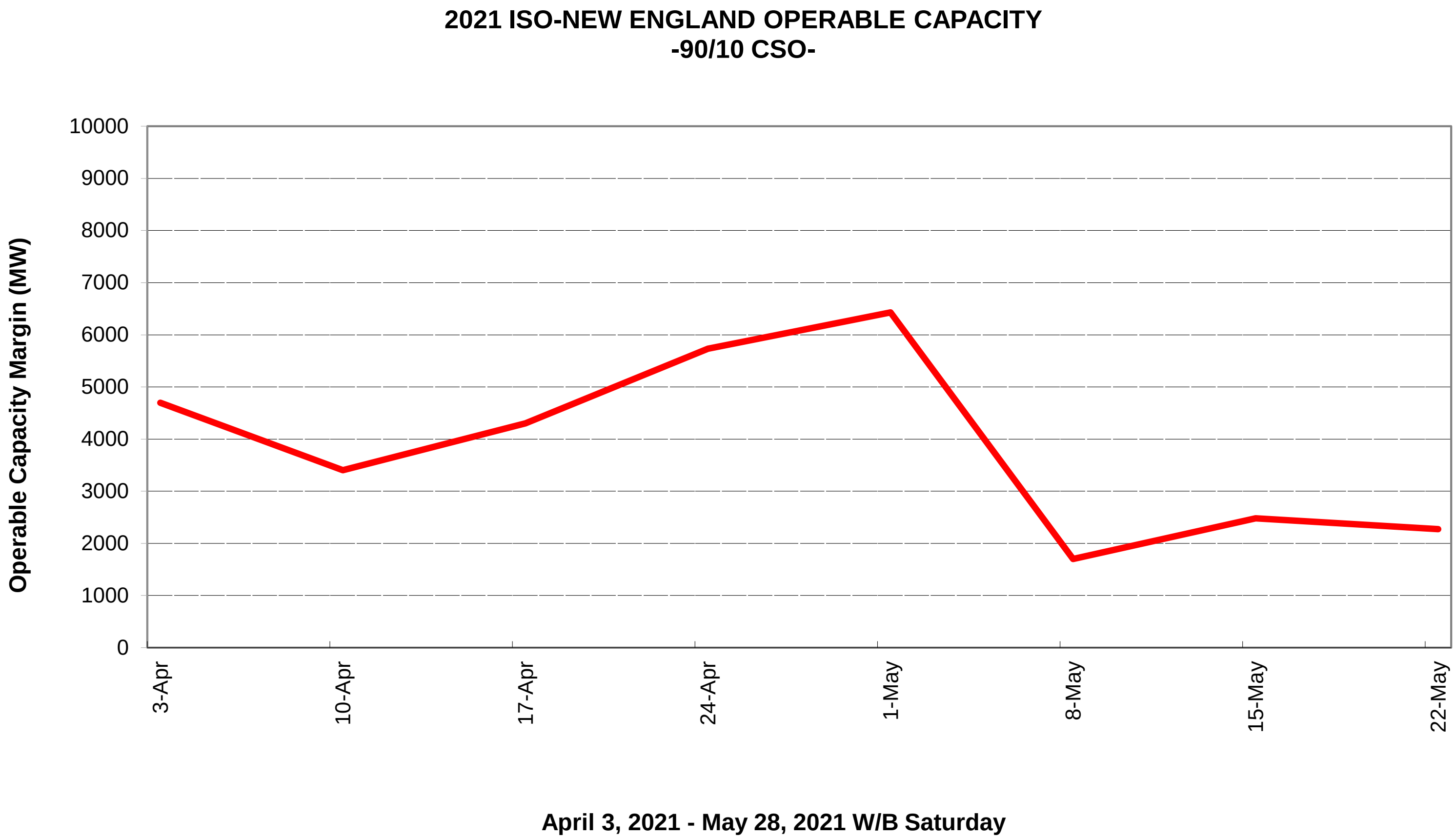
1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity Market (FCM). 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 2020 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 27,084 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 2021 Operable Capacity Analysis
50/50 Forecast (Reference)



Spring 2021 Operable Capacity Analysis
90/10 Forecast (Extreme)



OPERABLE CAPACITY ANALYSIS

Preliminary Summer 2021 Analysis

Preliminary Summer 2021 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Sep. - 2021[2] CSO (MW)	Sep. - 2021[2] SCC (MW)
Operable Capacity MW [1]	29,059	30,174
Active Demand Capacity Resource (+) [5]	520	434
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,208	1,208
Non Commercial Capacity (+)	6	6
Non Gas-fired Planned Outage MW (-)	2,411	2,946
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,100	2,100
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	26,282	26,776
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	24,981	24,981
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	27,286	27,286
Operable Capacity Margin	-1,004	-510

[1]Operable Capacity is based on data as of **March 22, 2021** 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 **March 22, 2021.**

[2] Load forecast that is based on the 2020 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **September 11, 2021.**

[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 2021 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	Sep. - 2021[2] CSO (MW)	Sep. - 2021[2] SCC (MW)
Operable Capacity MW [1]	29,059	30,174
Active Demand Capacity Resource (+) [5]	520	434
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,208	1,208
Non Commercial Capacity (+)	6	6
Non Gas-fired Planned Outage MW (-)	2,411	2,946
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,100	2,100
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	26,282	26,776
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	26,959	26,959
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	29,264	29,264
Operable Capacity Margin	-2,982	-2,488

[1]Operable Capacity is based on data as of **March 22, 2021** 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 **March 22, 2021.**

[2] Load forecast that is based on the 2020 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **September 11, 2021.**

[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 2021 Operable Capacity Analysis 50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

March 26, 2021 - 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	Active Capacity Demand MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERATOR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
5/29/2021	29059	520	1208	6	201	506	2800	0	27286	24981	2305	27286	0
6/5/2021	29059	520	1208	6	24	0	2800	0	27969	24981	2305	27286	683
6/12/2021	29059	520	1208	6	44	0	2800	0	27949	24981	2305	27286	663
6/19/2021	29059	520	1208	6	32	0	2800	0	27961	24981	2305	27286	675
6/26/2021	29059	520	1208	6	19	0	2800	0	27974	24981	2305	27286	688
7/3/2021	29059	520	1208	6	31	0	2100	0	28662	24981	2305	27286	1376
7/10/2021	29059	520	1208	6	90	0	2100	0	28603	24981	2305	27286	1317
7/17/2021	29059	520	1208	6	70	0	2100	0	28623	24981	2305	27286	1337
7/24/2021	29059	520	1208	6	28	0	2100	0	28665	24981	2305	27286	1379
7/31/2021	29059	520	1208	6	31	0	2100	0	28662	24981	2305	27286	1376
8/7/2021	29059	520	1208	6	28	0	2100	0	28665	24981	2305	27286	1379
8/14/2021	29059	520	1208	6	28	0	2100	0	28665	24981	2305	27286	1379
8/21/2021	29059	520	1208	6	41	0	2100	0	28652	24981	2305	27286	1366
8/28/2021	29059	520	1208	6	18	0	2100	0	28675	24981	2305	27286	1389
9/4/2021	29059	520	1208	6	1318	0	2100	0	27375	24981	2305	27286	89
9/11/2021	**29059**	**520**	**1208**	**6**	**2411**	**0**	**2100**	**0**	**26282**	**24981**	**2305**	**27286**	**-1004**

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 2020 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 25,125 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 2021 Operable Capacity Analysis 90/10 Forecast (Extreme)

ISO-NE OPERABLE CAPACITY ANALYSIS

March 26, 2021 - 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]
5/29/2021	29059	520	1208	6	201	506	2800	0	27286	26959	2305	29264	-1978
6/5/2021	29059	520	1208	6	24	0	2800	0	27969	26959	2305	29264	-1295
6/12/2021	29059	520	1208	6	44	0	2800	0	27949	26959	2305	29264	-1315
6/19/2021	29059	520	1208	6	32	0	2800	0	27961	26959	2305	29264	-1303
6/26/2021	29059	520	1208	6	19	0	2800	0	27974	26959	2305	29264	-1290
7/3/2021	29059	520	1208	6	31	0	2100	0	28662	26959	2305	29264	-602
7/10/2021	29059	520	1208	6	90	0	2100	0	28603	26959	2305	29264	-661
7/17/2021	29059	520	1208	6	70	0	2100	0	28623	26959	2305	29264	-641
7/24/2021	29059	520	1208	6	28	0	2100	0	28665	26959	2305	29264	-599
7/31/2021	29059	520	1208	6	31	0	2100	0	28662	26959	2305	29264	-602
8/7/2021	29059	520	1208	6	28	0	2100	0	28665	26959	2305	29264	-599
8/14/2021	29059	520	1208	6	28	0	2100	0	28665	26959	2305	29264	-599
8/21/2021	29059	520	1208	6	41	0	2100	0	28652	26959	2305	29264	-612
8/28/2021	29059	520	1208	6	18	0	2100	0	28675	26959	2305	29264	-589
9/4/2021	29059	520	1208	6	1318	0	2100	0	27375	26959	2305	29264	-1889
9/11/2021	**29059**	**520**	**1208**	**6**	**2411**	**0**	**2100**	**0**	**26282**	**26959**	**2305**	**29264**	**-2982**

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.
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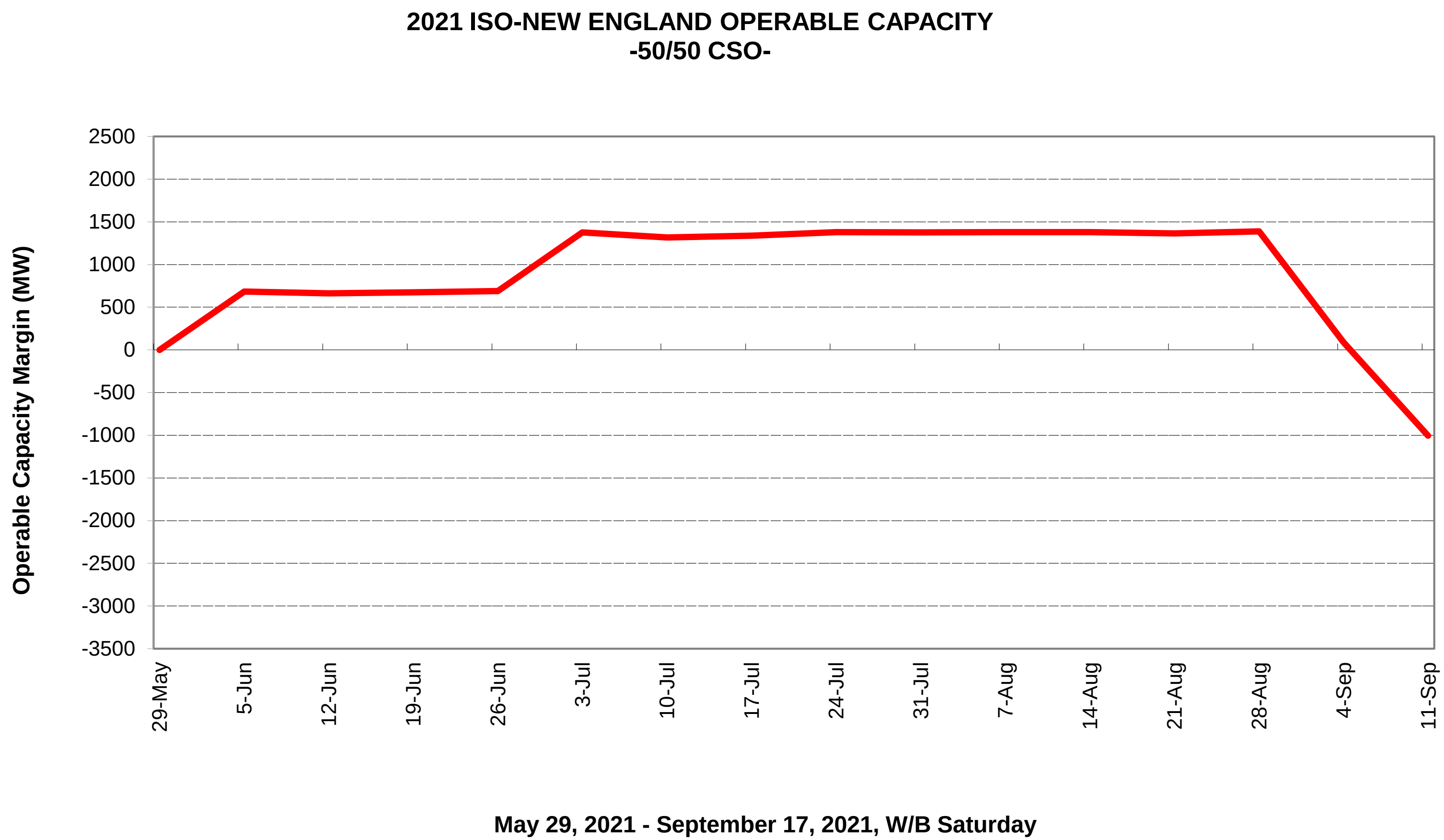
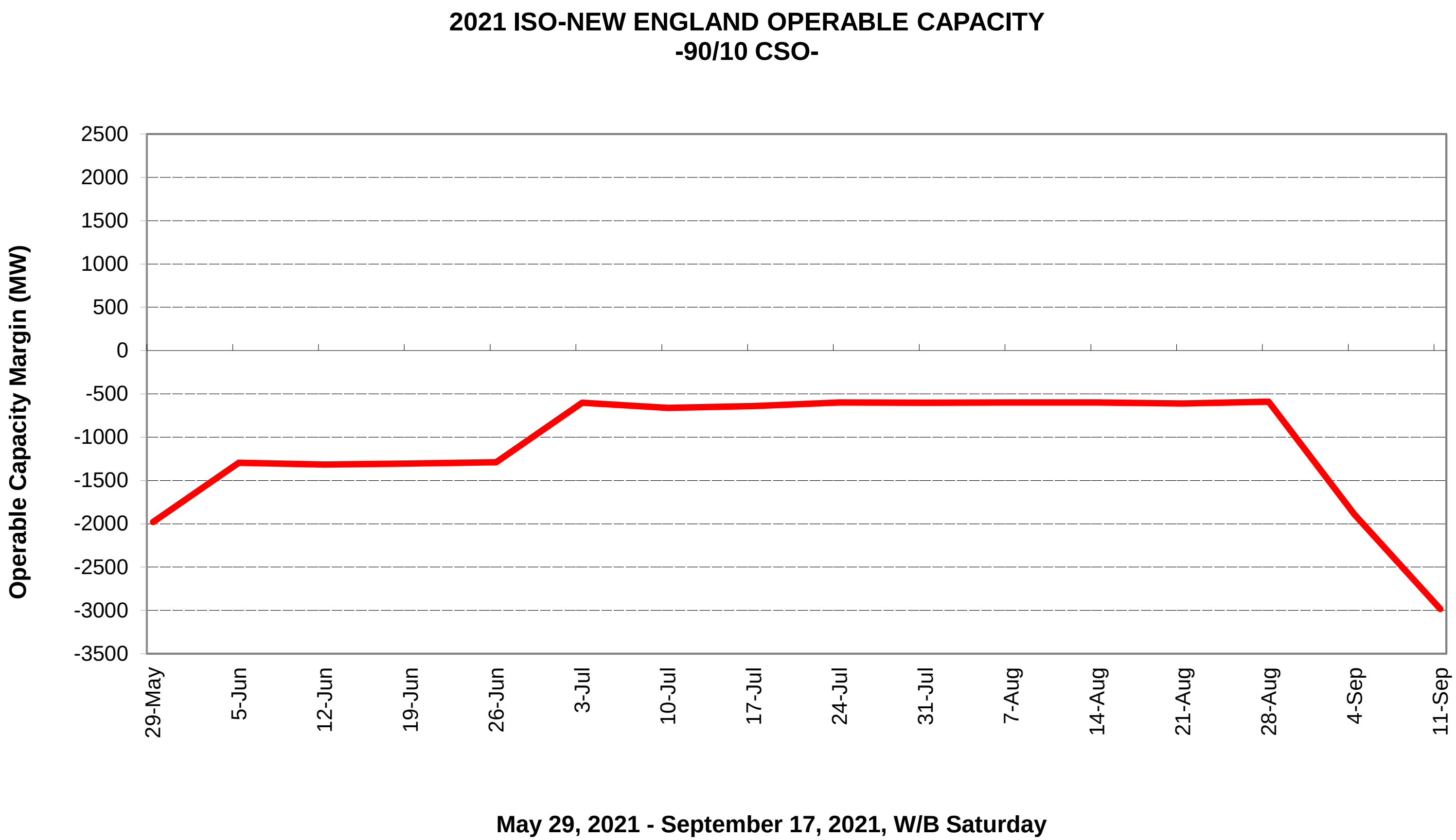
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 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 2020 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 27,084 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**

Preliminary Summer 2021 Operable Capacity Analysis 50/50 Forecast (Reference)



Preliminary Summer 2021 Operable Capacity Analysis
90/10 Forecast (Extreme)



OPERABLE CAPACITY ANALYSIS

Appendix

Possible Relief Under OP4: Appendix A

OP 4 Action Number	Page 1 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
1	Implement Power Caution and advise Resources with a CSO to prepare to provide capacity and notify “Settlement Only” generators with a CSO to monitor reserve pricing to meet those obligations. Begin to allow 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

Review of February 2021 Extreme Cold Weather Event – ERCOT Presentation

Bill Magness
President & Chief Executive Officer
ERCOT

Urgent Board of Directors Meeting

ERCOT Public
February 24, 2021

Disclaimer

Information in this presentation is preliminary and represents the best available data at the time it was created.

ERCOT Corporate Governance

- **Founded in 1970**
- **Texas non-profit corporation with members from seven market segments:**
  - Consumers (Commercial, Industrial, Residential)
  - Cooperatives
  - Independent Generators
  - Independent Power Marketers
  - Independent Retail Electric Providers
  - Investor-Owned Utilities
  - Municipals
- **The Texas Legislature enacted laws which govern all activities of ERCOT – See Public Utility Regulatory Act (PURA) Section 39.151.**
- **The Public Utility Commission of Texas (PUC) has complete authority over ERCOT's finances, budget and operations, with oversight by the Texas Legislature.**
  - Approves ERCOT Bylaws
- **16-member ERCOT Board composition is established by law:**
  - 5 Unaffiliated Directors (independent from ERCOT Market Participants); all must be approved by the PUC for three-year terms with a maximum of two renewals
  - 8 Directors each elected annually by different Market Segments
  - Office of Public Utility Counsel (represents Residential Consumer Market Segment)
  - ERCOT Chief Executive Officer
  - PUC Chairman (non-voting)

ERCOT's Role

- **Fulfills four responsibilities required by law as the independent organization certified by the PUC (PURA Section 39.151):**
  - Maintain electric system reliability
  - Facilitate a competitive wholesale market
  - Ensure open access to transmission
  - Facilitate a competitive retail market
- **Manages the flow of electric power over the bulk power system to approximately 26 million Texas end-use customers.**
  - About 90% of the state's electric load
  - Over 680 generation units
  - Over 46,500 miles of transmission lines
- **Must, at all times (24/7/365), balance all consumer demand in the ERCOT region (load) and the power supplied by companies who generate electricity (generation) while maintaining system frequency of 60 Hz.**
- **Performs financial settlement for the competitive wholesale bulk power market and administers retail switching for nearly 8 million premises in competitive choice areas.**

ERCOT's Role (continued)

ERCOT does **not**:

- Own, operate or have any enforcement authority over any electric generation facilities or any electric transmission or distribution lines or substations.
- Sell or send bills for retail electricity to residences or businesses.
- Control or operate electric service to local areas, neighborhoods or individual premises.
- Establish pricing or rates for retail electric customers.
- Have any direct customer relationships with the public.

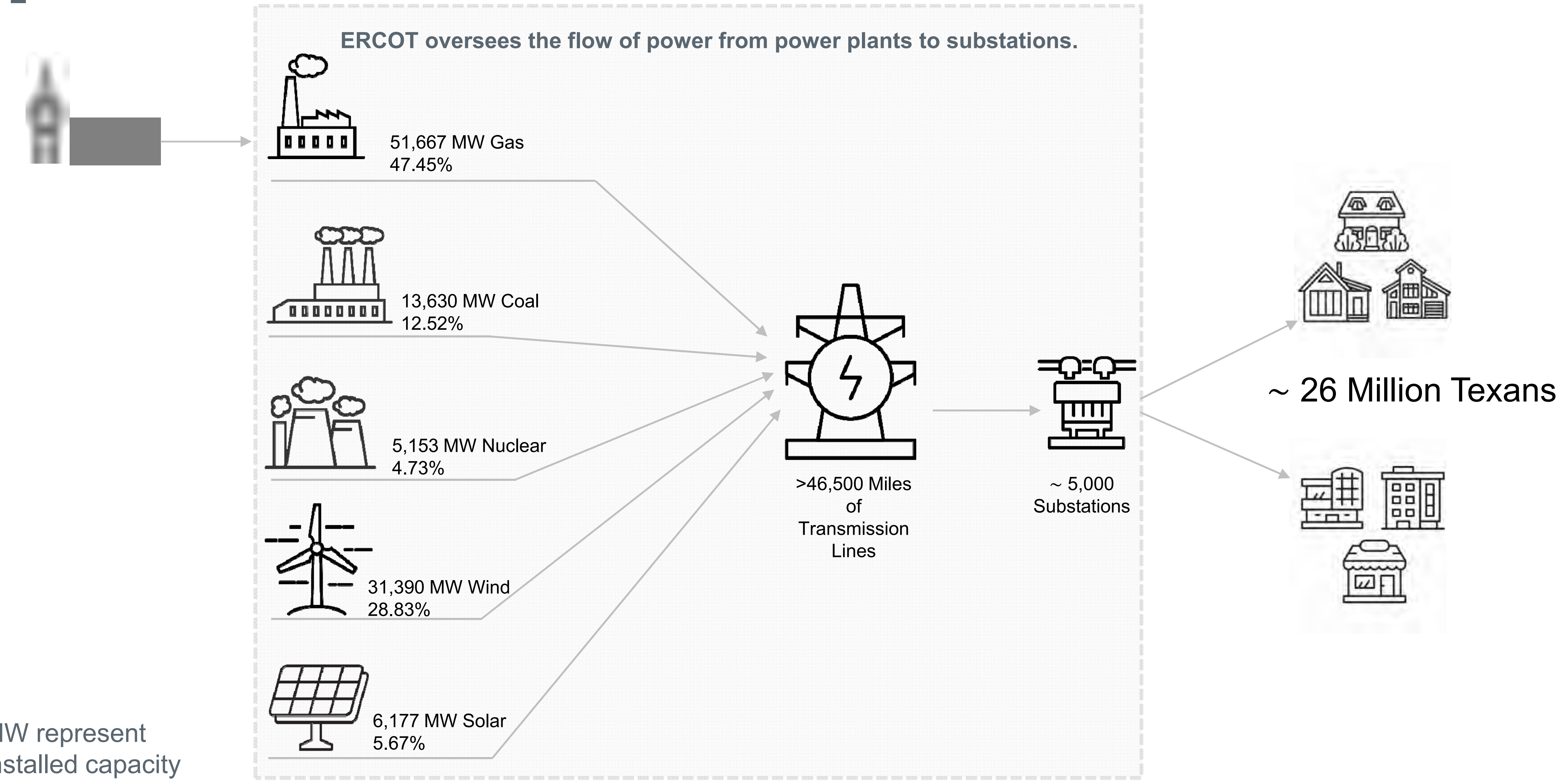
ERCOT Budget & Funding

- **Budget is approved by the Board and the PUC biennially.**

- **Funded by a System Administration Fee to cover its system costs.**
  - Current fee is 55.5 cents per megawatt hour (MWh).
  - One megawatt of electricity can power about 200 Texas homes during periods of peak demand.
  - Average cost of $7/year (50-60 cents/month) for residential households.

- **ERCOT does not set consumer electric rates.**
  - Rates are either set by the PUC or companies that sell electricity at retail to end-use customers.
  - Additional transmission costs are proportionally passed on to customers.

Electric Generation, Transmission & Distribution Overview



MW represent installed capacity

Pre-Event Operational Preparation

- Canceled transmission maintenance outages affecting over 1,600 transmission devices and delayed other outages.
- Reviewed planned generation outages for potential early return to service.
- Noted potential for 11,100 MW of forced outages due to gas restrictions based on gas company communications – more units affected during this event compared to previous cold weather events.
- Began using maximum icing potential for wind forecasts.
- Waived COVID restrictions and brought additional support staff on-site.
- Prepared facilities for extended on-site staffing, activated additional remote engineering/support staff.
- Began regular calls with Chief System Operators (18 over 8 days).
- Requested TCEQ/DOE enforcement discretion for power plant emissions during anticipated event.
- Supported Railroad Commission of Texas review of natural gas priority.

All available generation was online on February 14.

Pre-Event Communications

November 5	ERCOT meteorologist issues winter outlook for Market Participants and public noting the “very good” chance for an extreme cold weather event during winter 2020/2021.
February 3	ERCOT meteorologist warns Market Participants and the public of coldest weather of the year. Weather updates continue.
February 8	Operating Condition Notice issued for extreme cold weather event, posted on public website.
February 10	Advisory issued for extreme cold weather event posted on public website. Issued grid conditions update for market media representatives.
February 11	Watch issued for cold weather event (hotline calls made, notice to Market Participants, posted on public website). News release on extreme weather expected, social media outreach.
February 12	Texas Energy Reliability Council meeting.
February 13	State Operations Center news conference: forecast Conservation Alert. Emergency notice issued for extreme cold weather event, posted on public website. Texas Energy Reliability Council meeting.
February 14	Issued conservation appeal by news release, performed social media outreach, held media briefing.

Overview of Cold Weather Event

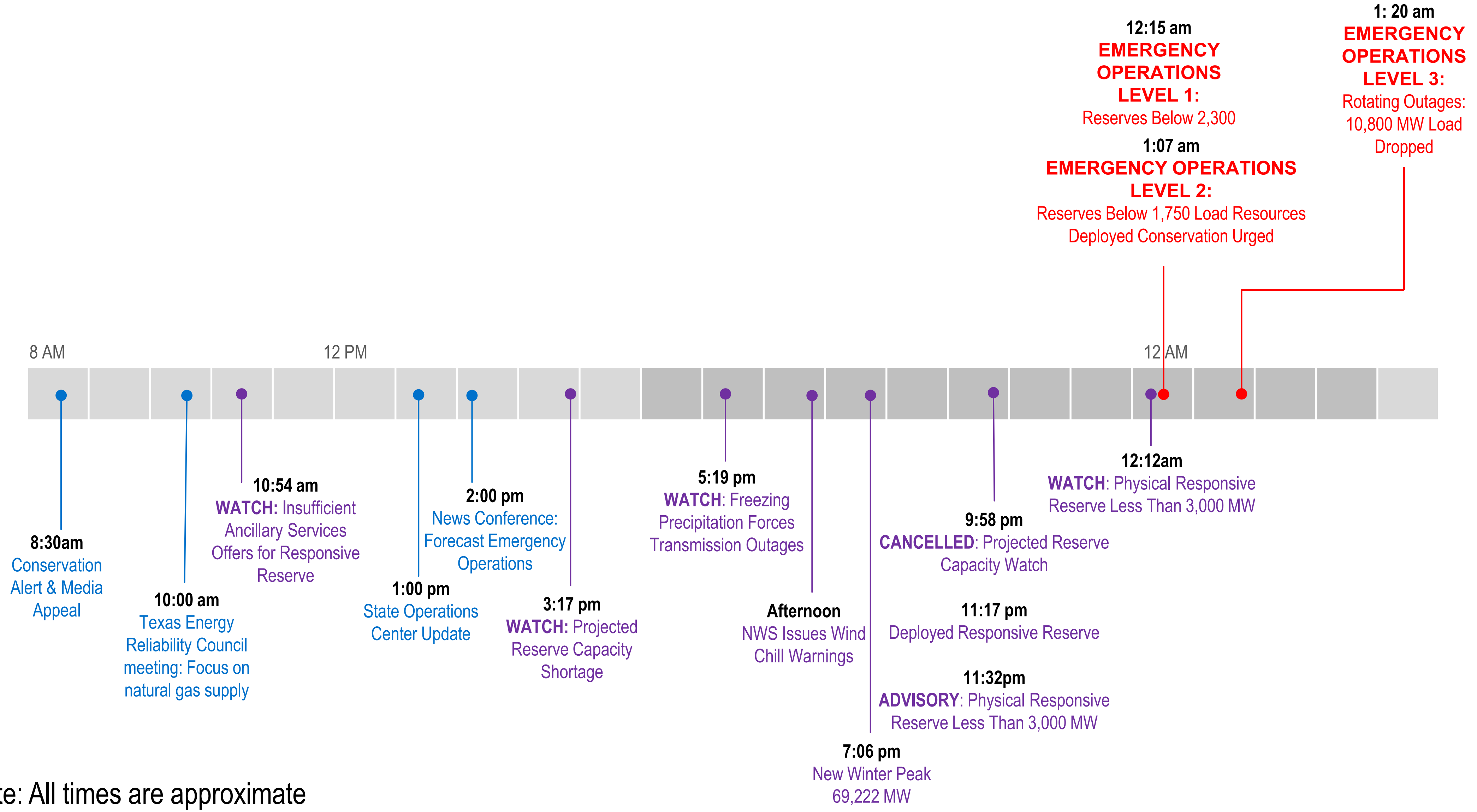
- Record-setting, sub-freezing temperatures and wind chills across the state.

- Approximately 48.6% of generation was forced out at the highest point due to the impacts of various extreme weather conditions.

- Controlled outages were implemented to prevent statewide blackout.
  - Electric demand had to be limited to available generation supply.

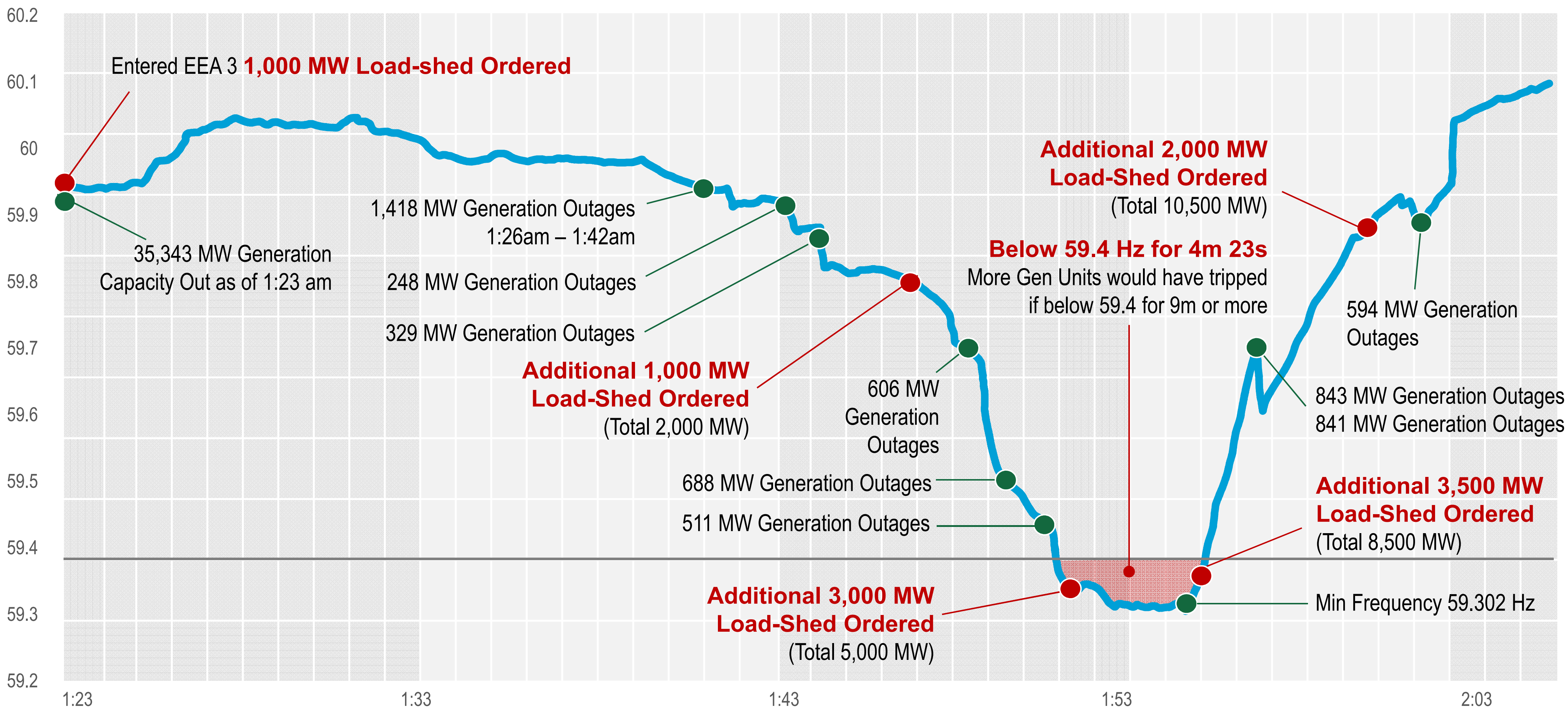
- Local utilities were limited in their ability to rotate outages due to the magnitude of generation unavailability and the number of circuits with critical load.

Sunday, February 14 – Monday, February 15

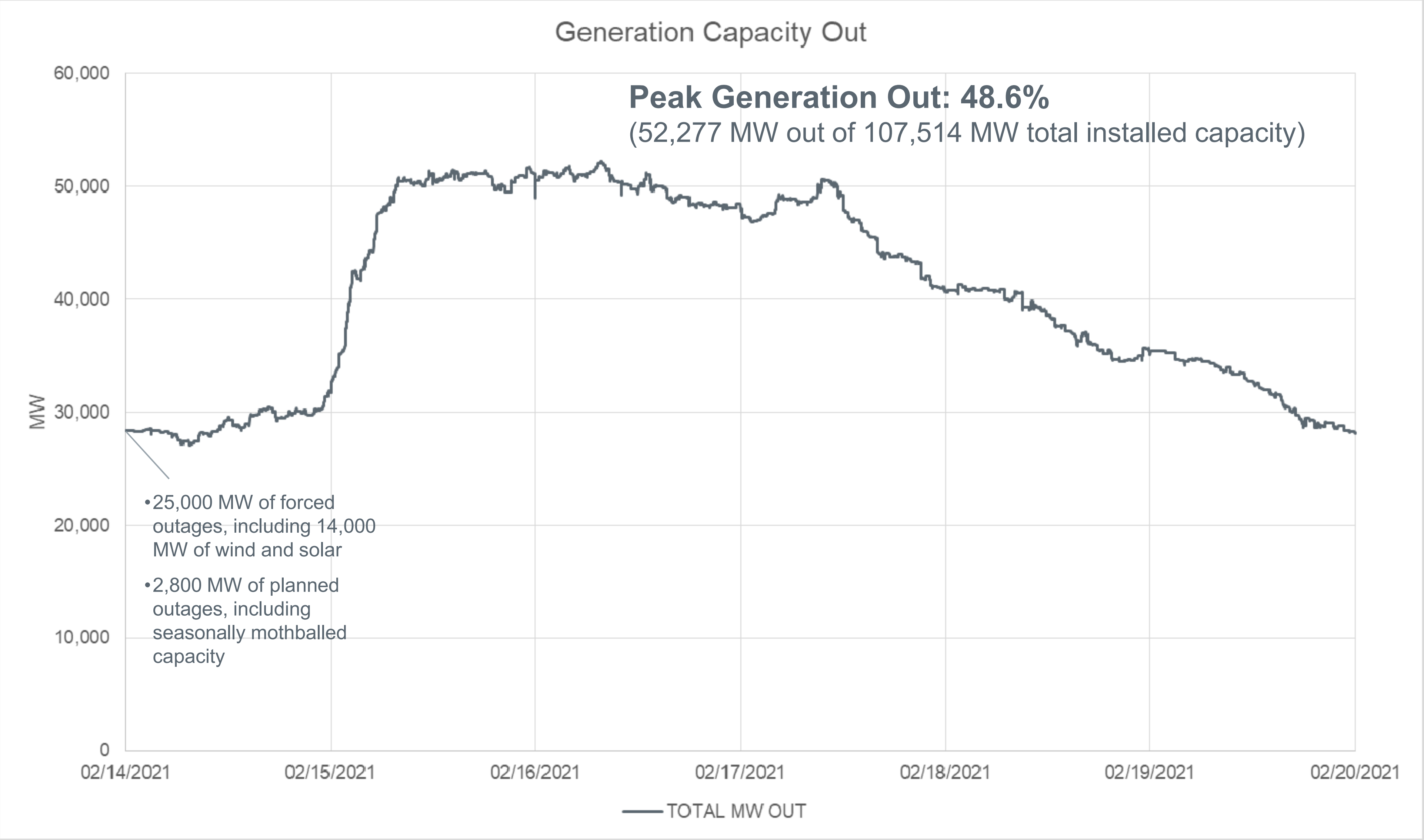


Note: All times are approximate

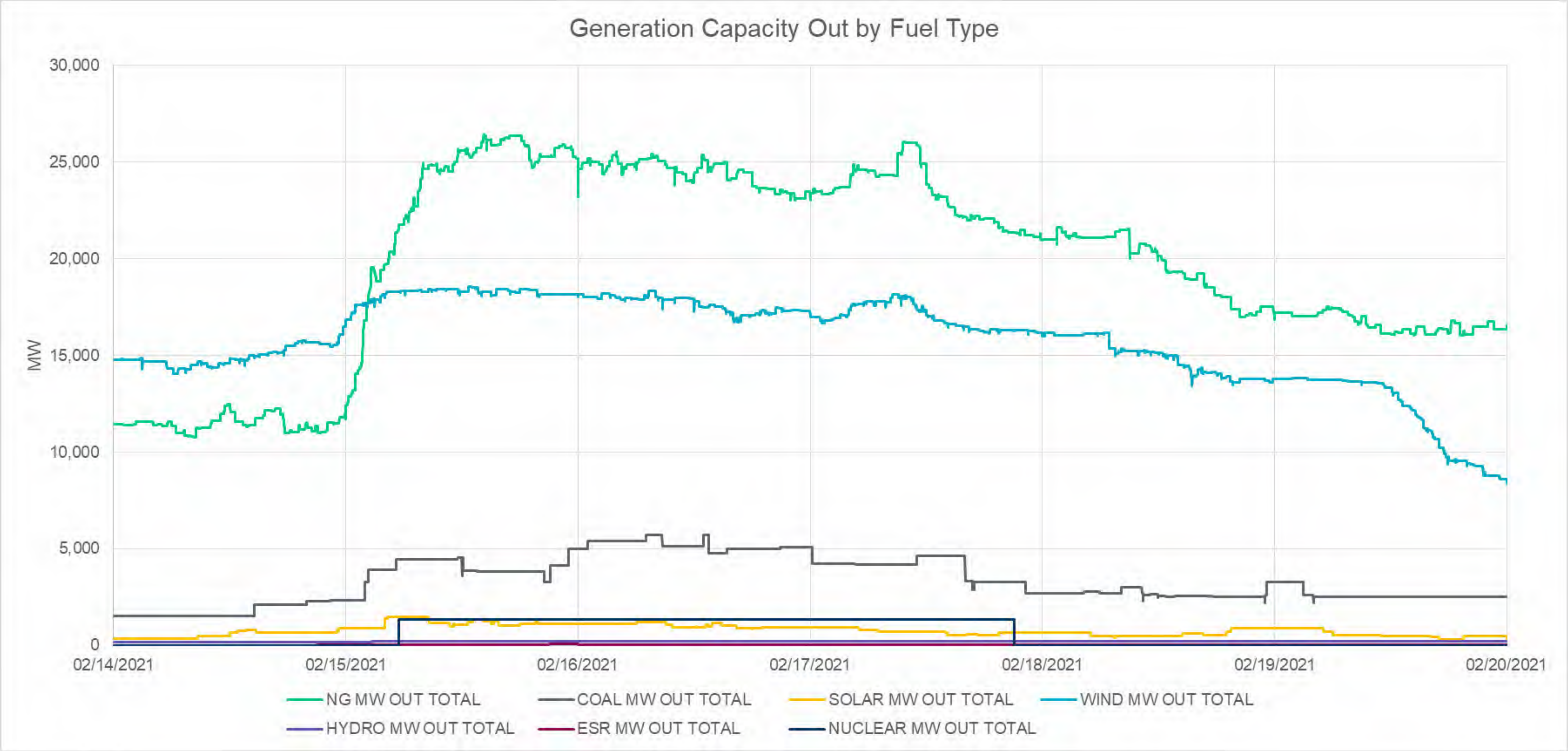
Rapid Decrease in Generation Causes Frequency Drop



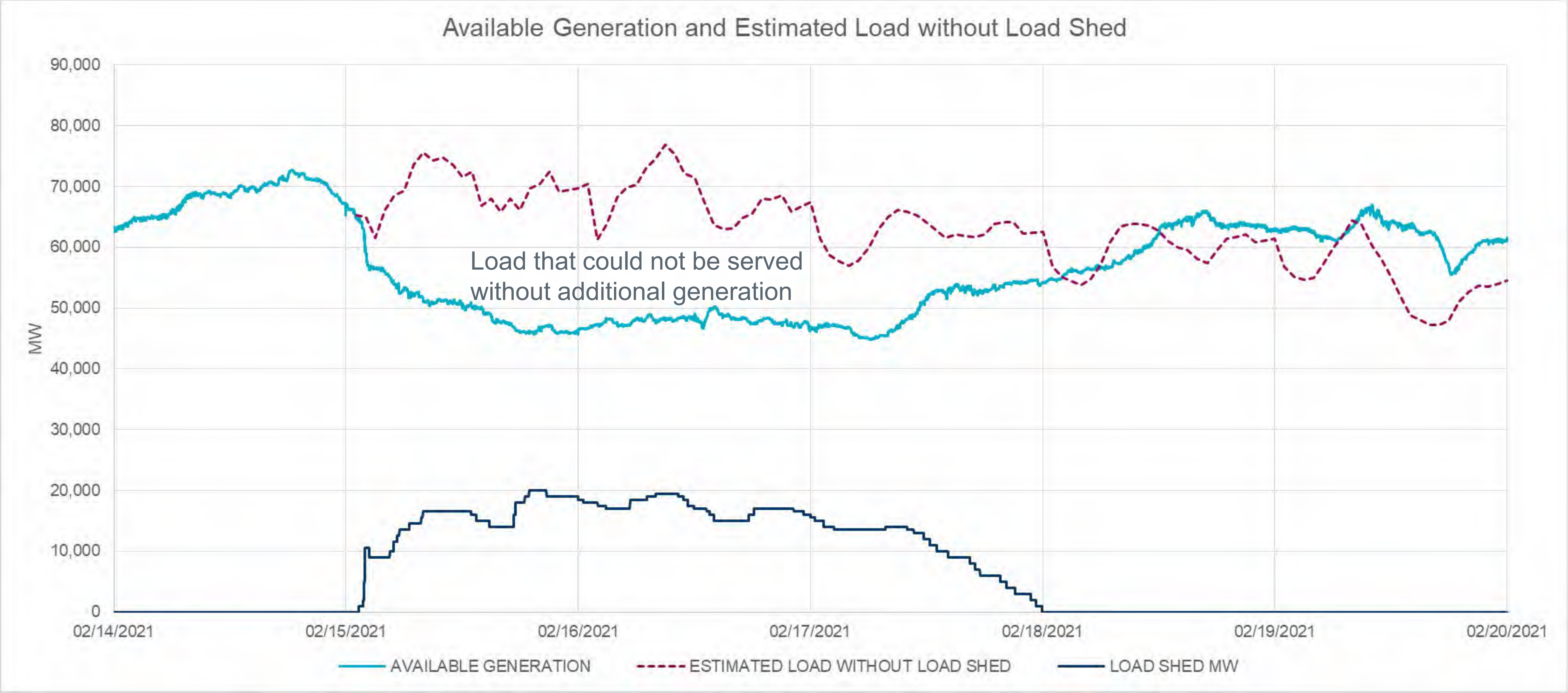
Generation Capacity Out February 14 – 19, 2021



Generation Capacity Out by Fuel Type



Available Generation and Estimated Load Without Load Shed



Available Generation shown is the total HSL of Online Resources, including Quick Starts in OFFQS. The total uses the current MW for Resources in Start-up, Shut-Down, and ONTEST.

Key Events (Monday, February 15 – Friday, February 19)

- More than 16,500 control room calls with generators and transmission owners (normal: ~5,000/week).
- Multiple daily coordinating calls between transmission owners and operations management.
- Monday, February 15
  - Up to an additional ~24,000 MW net generation unavailable due to extreme weather; loss of generation was 52,277 MW (approximately 48.6%) at the highest point.
  - 20,000 MW peak load shed.
  - Limited gas availability for gas-fired power plants.
  - Multiple DC-Tie constraints due to neighboring area emergencies.
  - Daily Texas Energy Reliability Council meetings.
- Tuesday, February 16
  - No net gain in generation as some generators were restored and others became unavailable.
  - Decreased volume of controlled outages during the day, increased for evening peak.
- Wednesday, February 17
  - Moderating temperatures allowed reduction in controlled outages, small net gain in generation.
- Thursday, February 18
  - Continued gain in generation.
  - 12:42 a.m. - Canceled last controlled outage orders - some outages remained due to ice storm damage; need for manual restoration and return of large industrial facilities.
- Friday, February 19 (all times approximate)
  - 9 a.m. - Returned to emergency operations level 2
  - 10 a.m. – Returned to emergency operations level 1
  - 10:35 a.m. – Returned to normal operations

Generation Weatherization

- Generation owners and operators are not required to implement any minimum weatherization standard or perform an exhaustive review of cold weather vulnerability. No entity, including the PUC or ERCOT, has rules to enforce compliance with weatherization plans or enforce minimum weatherization standards.

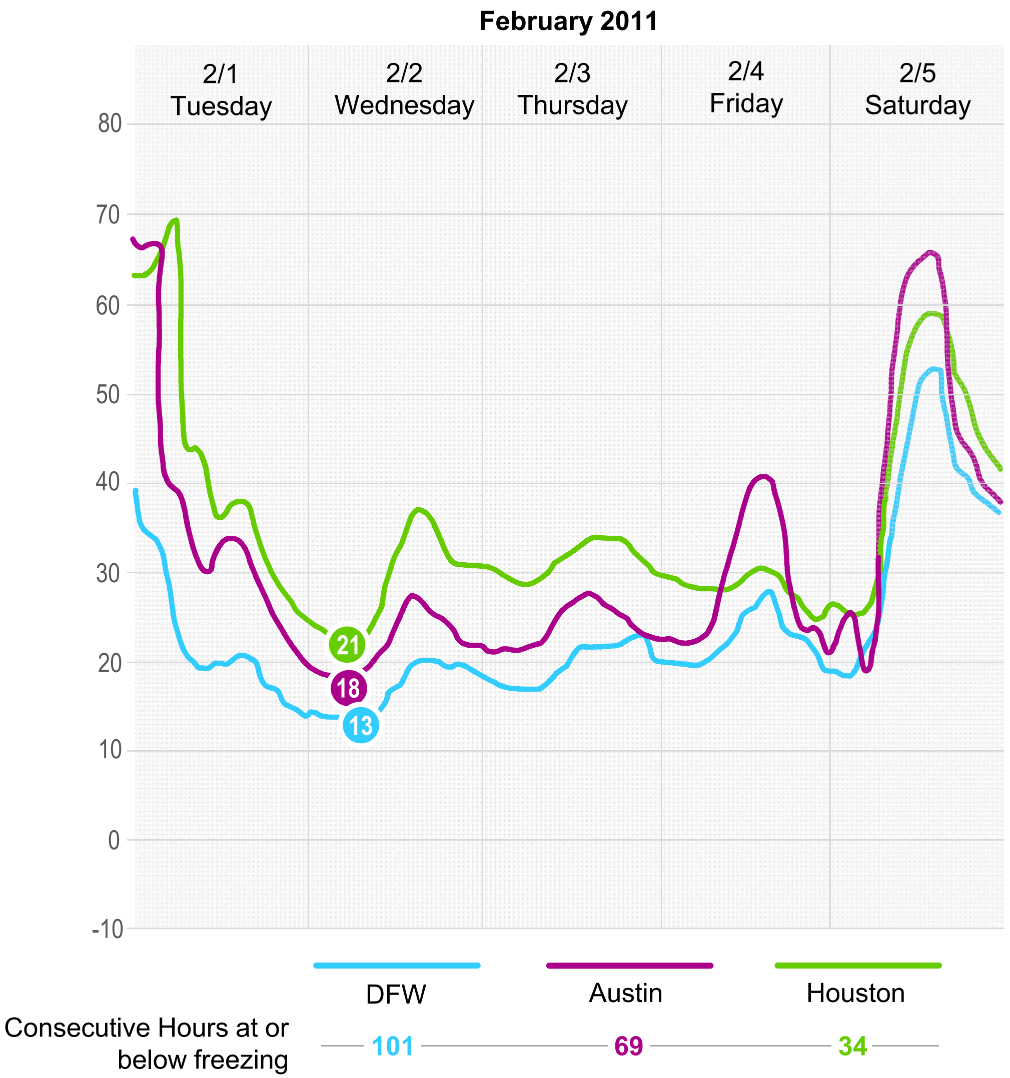
- In 2011, the PUC amended its rules to authorize ERCOT to conduct generator site visits to review compliance with weatherization plans. Spot checks include reviewing the weatherization plan, verifying that plant personnel are following the plan and providing recommendations based on PUC requirements, lessons learned or best practices.

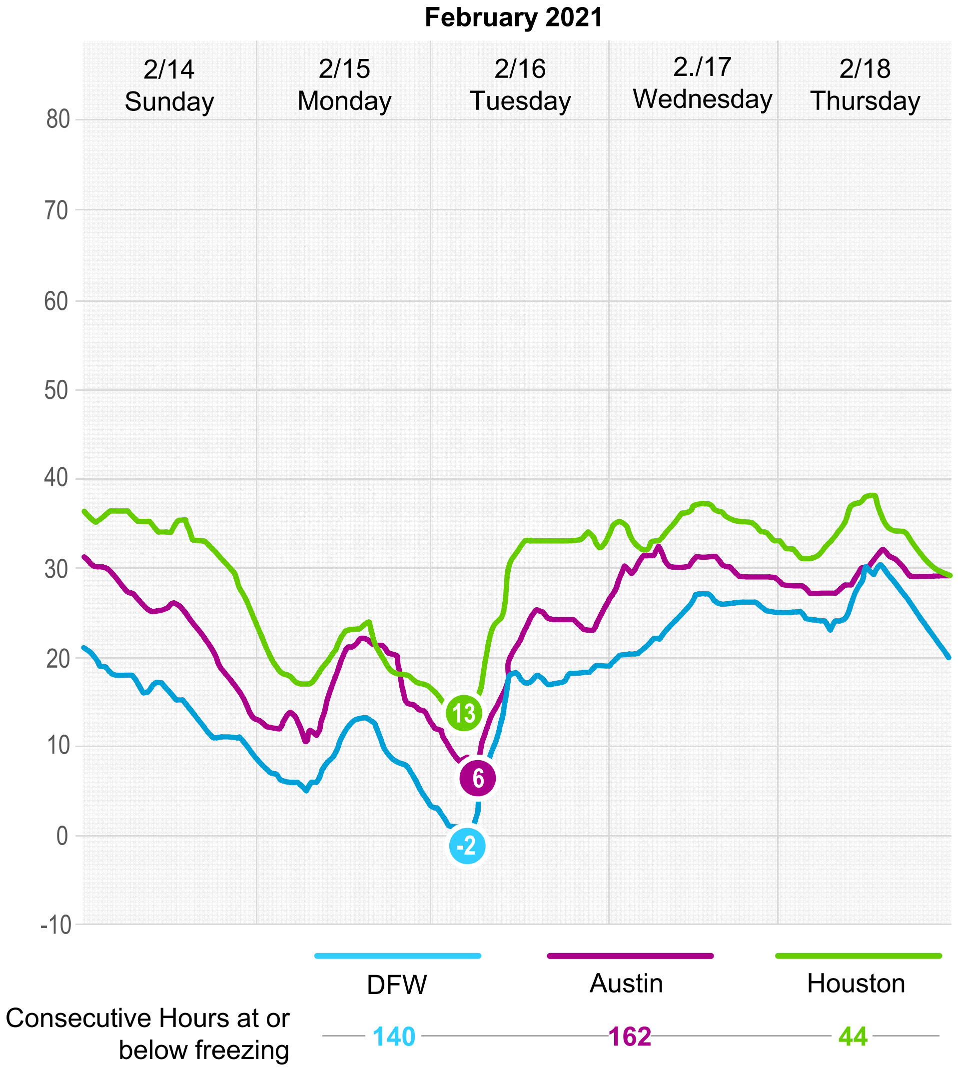
- We currently perform spot checks at power plant units at the rate of about 80/year. Whenever possible, a Texas Reliability Entity (TRE) representative joins ERCOT for these spot checks.

- While we request and review detailed plant records, the only entity that can confirm that a plant is “weatherized” to any particular standard is the entity that owns or operates the plant.

- Each year, TRE and ERCOT host an annual workshop on weatherization with generation owners to review lessons learned and best practices.

2011 vs. 2021 Event Temperature Comparison





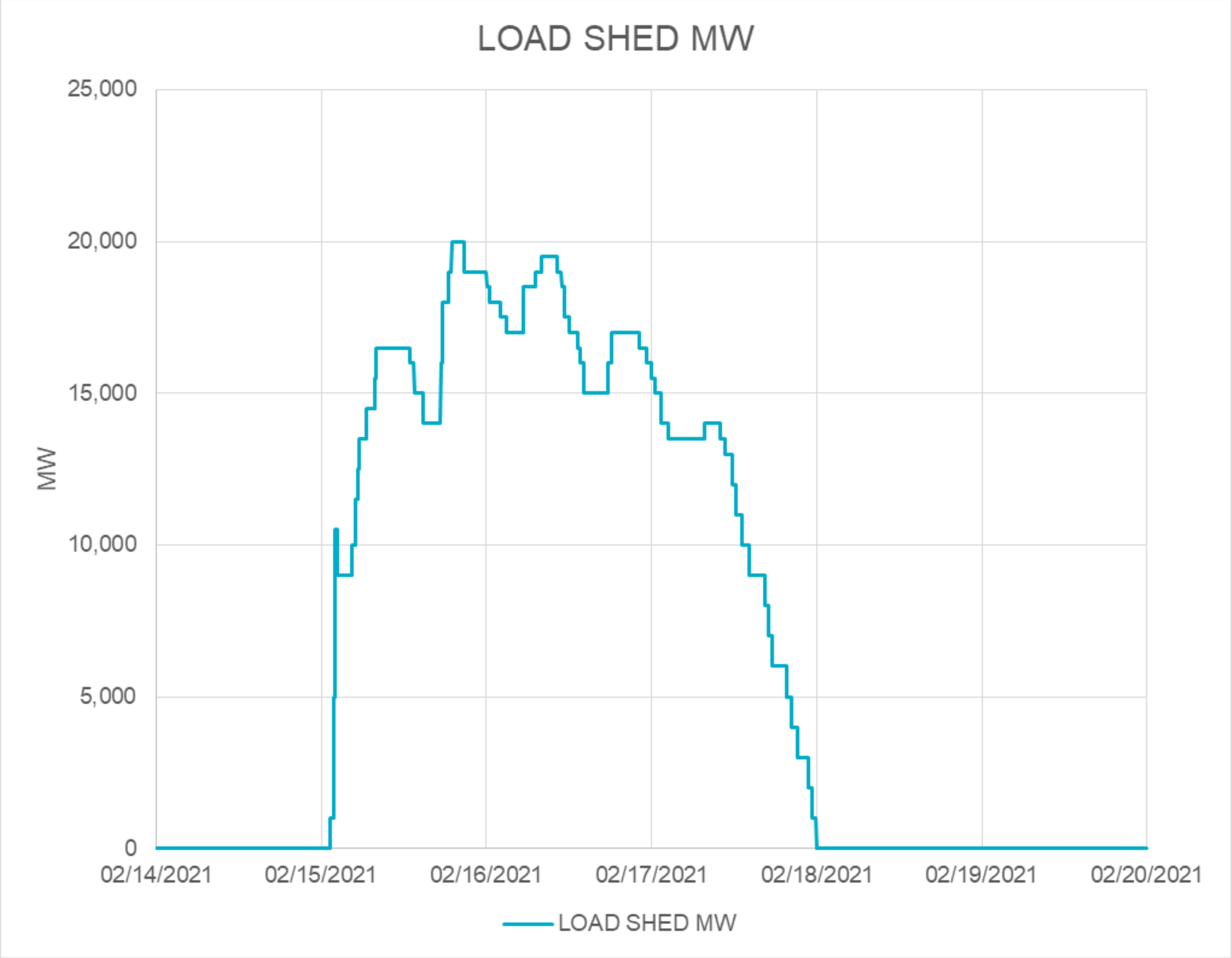
2011 vs. 2021 Event Comparison

	2011	2021
Maximum generation capacity forced out at any given time (MW)	14,702	52,277
Generation forced out one hour before start of EEA3 (MW)	1,182	2,489
Cumulative generation capacity forced out throughout the event (MW)	29,729	46,249*
Cumulative number of generators outaged throughout the event	193	356
Cumulative gas generation de-rated due to supply issues	1,282	9,323
Lowest frequency	59.58	59.30
Maximum load shed requested (MW)	4,000	20,000
Duration load shed request (hours)	7.5	70.5
Estimated peak load (without load shed)	59,000	76,819

*Note: “Cumulative” values for 2021 were calculated using NERC 2011 report methodology.
Cumulative amount for 2021 starts at 00:01 on February 14, 2021

Load Shed Ordered By Transmission Owner

Transmission Operator	% of MW
AEP Texas Central Company	8.7
Brazos Electric Power Cooperative Inc.	4.95
Brownsville Public Utilities Board	0.37
Bryan Texas Utilities	0.51
CenterPoint Energy Houston Electric LLC	24.83
City of Austin DBA Austin Energy	3.71
City of College Station	0.28
City of Garland	0.75
CPS Energy (San Antonio)	6.79
Denton Municipal Electric	0.48
GEUS (Greenville)	0.15
Lamar County Electric Cooperative Inc*	0.07
LCRA Transmission Services Corporation	5.96
Oncor Electric Delivery Company LLC	36.01
Rayburn Country Electric Cooperative Inc.	1.3
South Texas Electric Cooperative Inc.	2.52
Texas-New Mexico Power Company	2.62
ERCOT Total	**100.00**



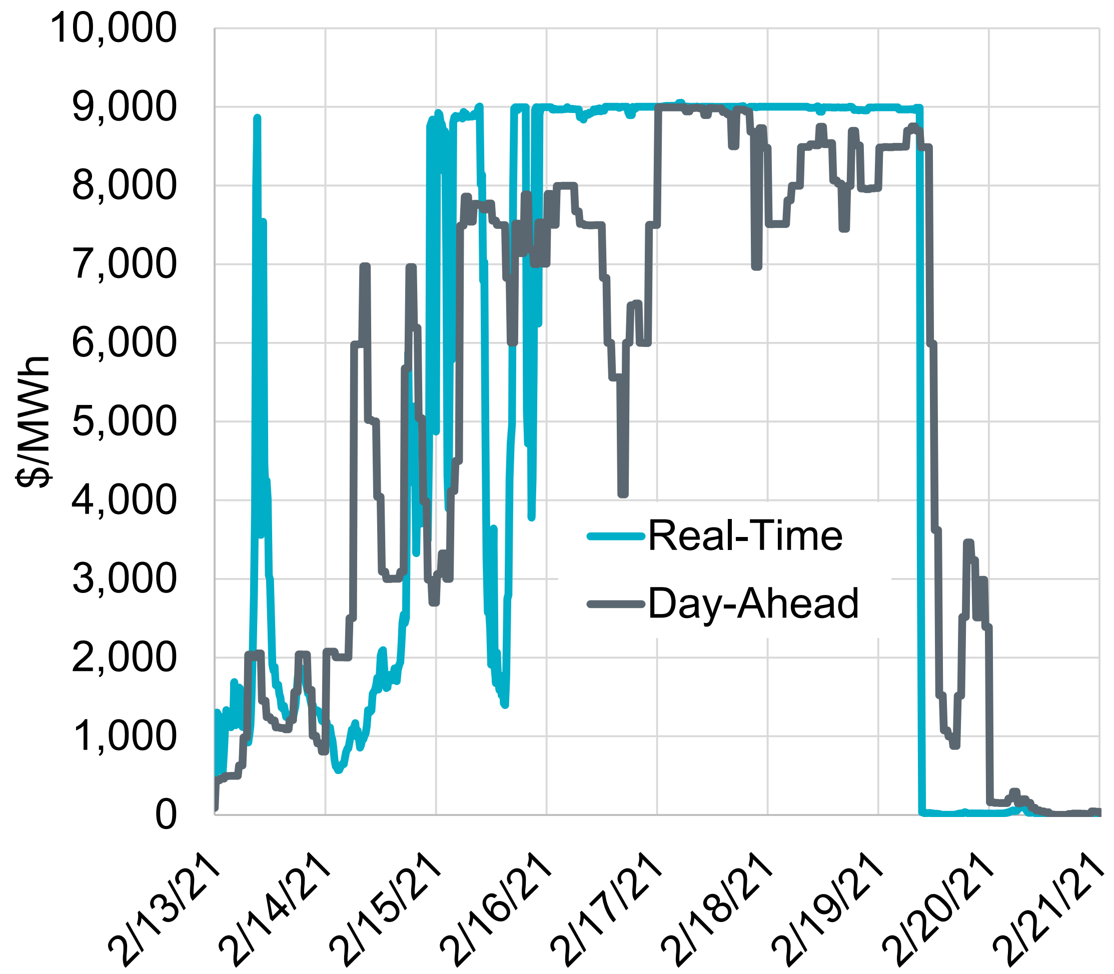
Status of Recommendations After February 2011

A report published by the North American Electric Reliability Corporation following the February 2011 cold weather event contained several recommendations applicable to ERCOT. Over the past 10 years, ERCOT has made changes that support those recommendations.

Significant modifications include:

- Implemented the Seasonal Assessment of Resource Adequacy report that includes an analysis for extreme winter weather.
- Began a resource weatherization process that includes an annual workshop, review of resource weatherization plans and spot checks of facilities.
- Added additional staff (Shift Engineer and Resource Reliability Desk) in the control room.
- Modified the Ancillary Services procurement to allow additional procurement in anticipation of severe weather.
- Established the Gas Electric Working Group and created a notification procedure for QSEs to notify ERCOT if there are anticipated fuel restrictions.
- Modified the survey sent to natural gas generators that collects fuel switching capability for some resources in preparation for each winter season.
- Changed the rules and processes for withdrawing approval of resource outages in anticipation of severe weather.

Real-Time and Day-Ahead System-Wide Pricing



Average system-wide pricing around the event relative to other historical periods (in $/MWh)

Date Range	Real-Time	Day-Ahead
2/14/21 2/19/21	$6,579.59	$6,612.23
January '21	$20.79	$21.36
February '20	$18.27	$17.74

This data is using the ERCOT Hub Average 345-kV Hub prices

Hedging by Market Participants

- ERCOT has limited visibility into other methods of hedging that Market Participants may engage in, including but not limited to commodities exchanges and bilateral contracts.

- With the information available to ERCOT, the level of energy hedging by Load Serving Entities varied from fairly long to fairly short relative to their physical load. This could also vary by operating day for the same entity.

- These positions would have been affected by load reductions resulting from the instructed firm load shed and other losses of load, as well as loss of generation through de-ratings or outages that occurred during the event.

POTOMAC ECONOMICS

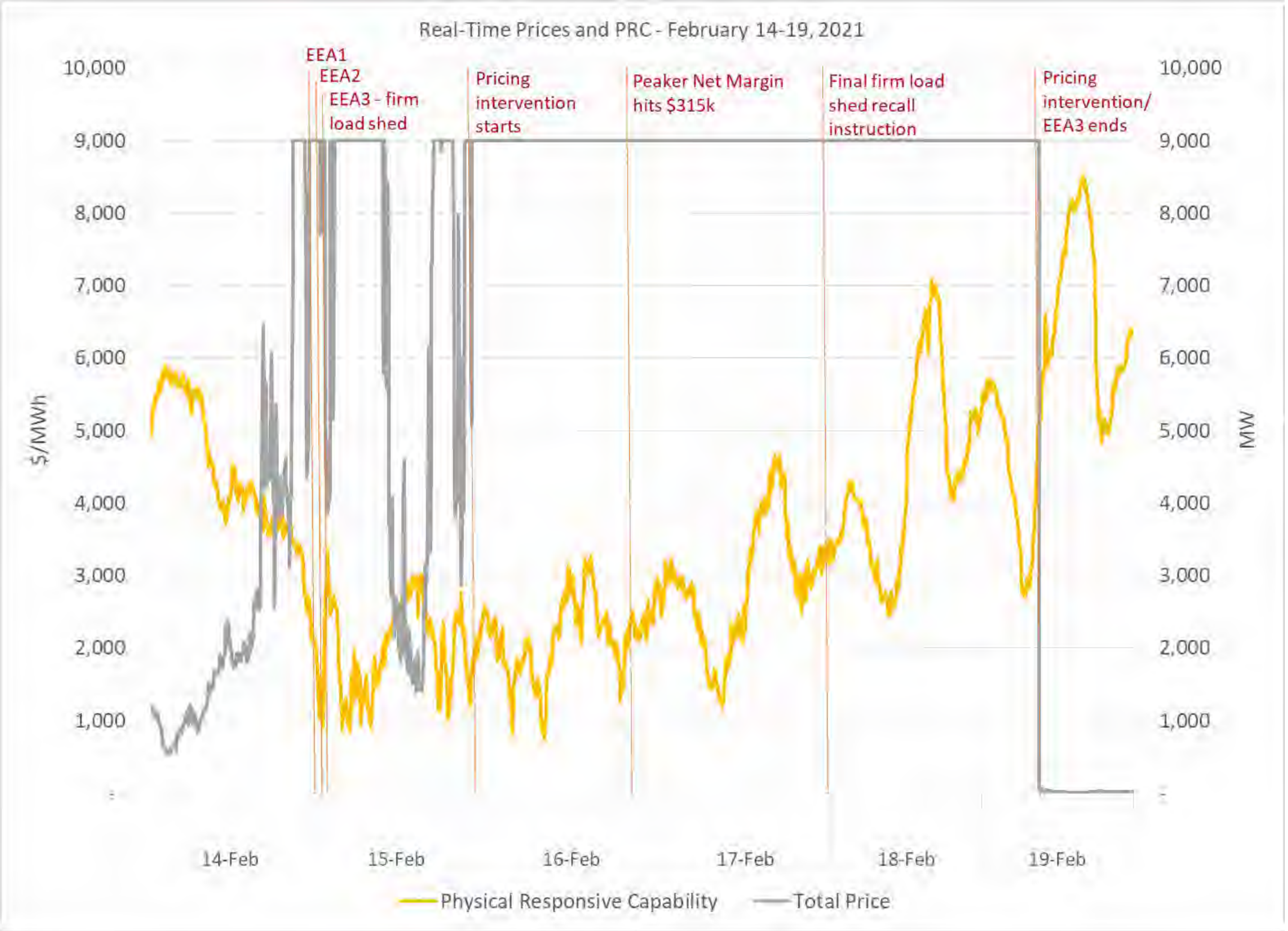
Item 2.3: Market Financial Matters

Carrie Bivens
ERCOT IMM Director
cbivens@potomaceconomics.com

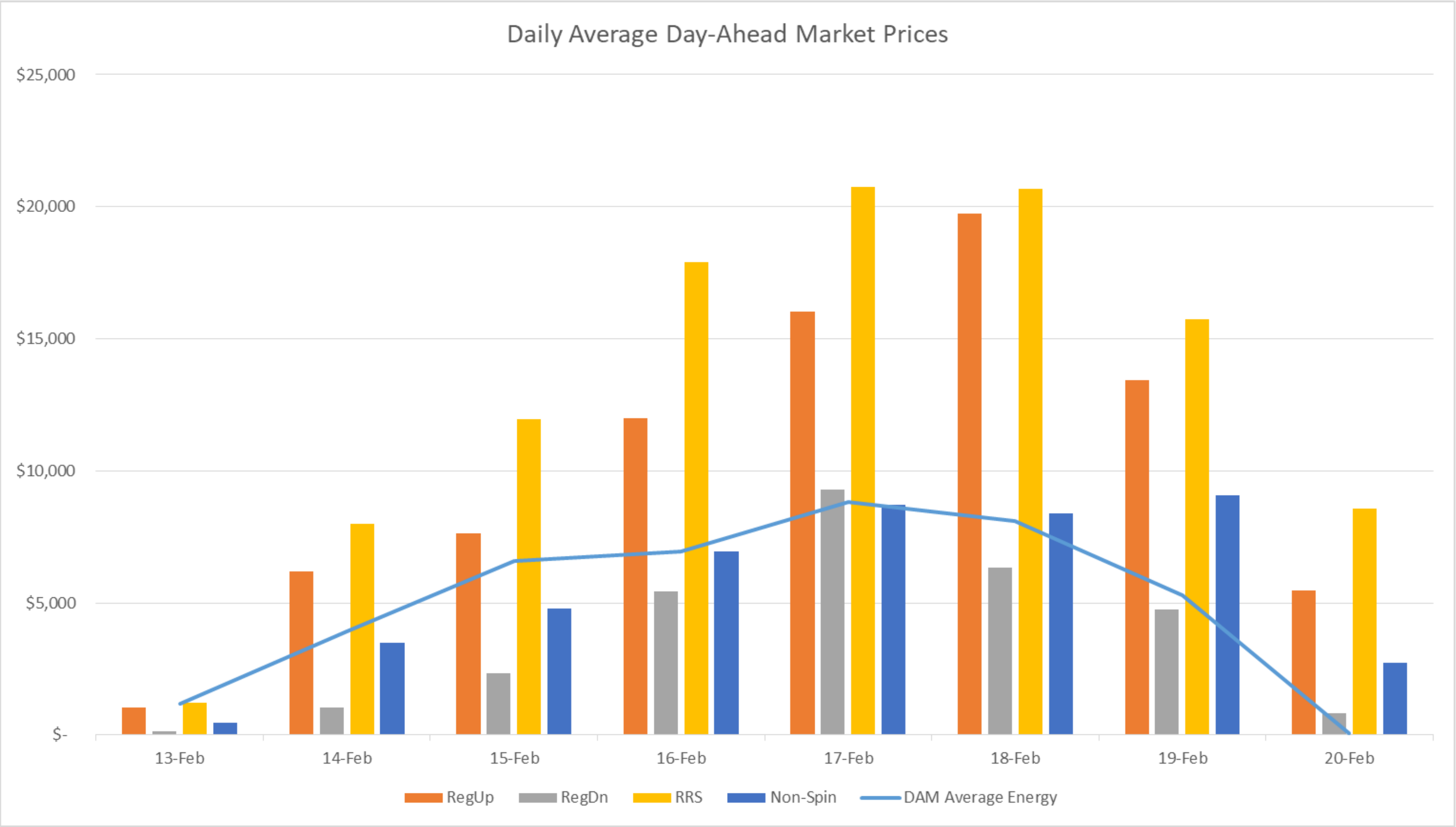
Urgent Board of Directors Meeting

ERCOT Public
February 24, 2021

Real-Time Energy Prices



Day-Ahead Prices



Item 2.3
ERCOT Public

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Sebastian Lombardi and Rosendo Garza, NEPOOL Counsel

DATE: March 25, 2021

RE: ISO's Proposal to Remove Appendix B from Market Rule 1 and Delete Associated Tariff Provisions

At the April 1, 2021 Participants Committee meeting, you will be asked to consider the ISO's proposal to remove Appendix B from Market Rule 1 and to delete associated Tariff provisions (the "ISO's Appendix B Proposal"). A copy of the ISO's proposed Tariff revisions are provided as Attachment A and the ISO's Voting Memo is included with this memorandum as Attachment B.

THE ISO'S APPENDIX B PROPOSAL

By way of background, Appendix B established the procedures and standards by which the ISO can impose sanctions (if subsequently approved by the FERC) for sanctionable conduct, e.g., failure to respond to the ISO's dispatch instructions. The ISO is proposing to remove Appendix B from the Tariff in light of the Internal Market Monitor's (IMM) view that "Appendix B is unused and is unnecessary given the existing regulatory referral process under [the Tariff's] Appendix A and the Commission's authority to determine violations and sanctions under its Penalty Guidelines."[1] The IMM also expressed the view that Appendix B is "outdated" and possibly "in conflict" with certain FERC orders.[2] To reflect its proposed removal of Appendix B from the Tariff, the ISO also proposes to make conforming changes to the Tariff, such as deleting internal references to Appendix B and Tariff definitions unique to that Appendix.

MARKETS COMMITTEE CONSIDERATION

At its March 9, 2021 meeting, the Markets Committee considered the ISO's Appendix B Proposal. Some Market Participants expressed concern with the proposal to remove all language from the Tariff that provides those Participants with some guidance and information concerning conduct that the ISO finds sanctionable. No amendments were offered, and the motion to recommend Participants Committee support for the ISO's proposal failed with a 59.21% Vote in favor.[3]

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[1] Attachment B at 1.

[2] *Id.*

[3] The individual Sector votes at the Markets Committee were as follows: *Generation* – 0% in favor, 16.7% opposed, 3 abstentions; *Transmission* – 16.7% in favor, 0% opposed, 0 abstention; *Supplier* – 9.11% in favor, 7.59% opposed, 5 abstentions; *Publicly Owned Entity* – 16.7% in favor, 0% opposed, 0

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

> RESOLVED, that the Participants Committee supports removing Appendix B from Market Rule 1 and deleting associated Tariff provisions, as proposed by ISO New England and as circulated to this Committee in advance of this meeting, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

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abstentions; *Alternative Resources* – 0% in favor, 16.5% opposed, 7 abstentions; and *End User* – 16.7% in favor, 0% opposed, 2 abstentions.

I.2 Rules of Construction; Definitions

~~**Administrative Sanctions** are defined in Section III.B.4.1.2 of Appendix B of Market Rule 1.~~

~~**Formal Warning** is defined in Section III.B.4.1.1 of Appendix B of Market Rule 1.~~

~~**Formula-Based Sanctions** are defined in Section III.B.4.1.3 of Appendix B of Market Rule 1.~~

~~**Market Participant Obligations** is defined in Section III.B.1.1 of Appendix B of Market Rule 1.~~

~~**Sanctionable Behavior** is defined in Section III.B.3 of Appendix B of Market Rule 1.~~

STANDARD MARKET DESIGN

III.1.7.18 Ramping.

A Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource dispatched by the ISO pursuant to a control signal appropriate to increase or decrease the Resource's megawatt output, consumption, or demand reduction level shall be able to change output, consumption, or demand reduction at the ramping rate specified in the Offer Data submitted to the ISO for that Resource and shall be subject to ~~sanctions for failure to comply as described in **Appendix B**~~ potential referral under Section III.A.19~~to the Commission for investigation and determination of any appropriate legal remedy or penalty~~.

III.13.6.1.1.2. Requirement that Offers Reflect Accurate Generating Capacity Resource Operating Characteristics.

For each day, Day-Ahead Energy Market and Real-Time Energy Market offers for the listed portion of a resource must reflect the then-known unit-specific operating characteristics (taking into account, among other things, the physical design characteristics of the unit) consistent with Good Utility Practice. Resources must re-declare to the ISO any changes to the offer parameters that occur in real time to reflect the known capability of the resource. A resource failing to comply with this requirement shall be subject to ~~economic penalties described in Appendix B~~ potential referral under Section III.A.19~~to the Commission for investigation and determination of any appropriate legal remedy or penalty~~.

III.13.6.1.5.2. Requirement that Offers Reflect Accurate Demand Response Resource Operating Characteristics.

For each day, Demand Reduction Offers submitted into the Day-Ahead Energy Market and Real-Time Energy Market for a Demand Response Resource associated with an Active Demand Capacity Resource must reflect the then-known operating characteristics of the resource. Consistent with Section III.1.10.9(d), Demand Response Resources must re-declare to the ISO any changes to offer parameters that occur in real time to reflect the operating characteristics of the resource. A resource failing to comply with this requirement shall be subject to ~~economic penalties described in Appendix B~~ potential referral under Section III.A. ~~to the Commission for investigation and determination of any appropriate legal remedy or penalty~~.

SECTION III. MARKET RULE 1. APPENDIX A
MARKET MONITORING,
REPORTING AND MARKET POWER MITIGATION

III.A.2.3. Functions of the Internal Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this ***Appendix A***, the Internal Market Monitor shall perform the following functions:

(a) Maintain ***Appendix A*** and consider whether ***Appendix A*** requires amendment. Any amendments deemed to be necessary by the Internal Market Monitor shall be undertaken after consultation with Market Participants in accordance with Section 11 of the Participants Agreement.

(b) Perform the day-to-day, real-time review of market behavior in accordance with the provisions of this ***Appendix A***.

(c) Consult with the External Market Monitor, as needed, with respect to implementing and applying the provisions of this ***Appendix A.***

(d) Identify and notify the Commission's Office of Enforcement staff of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected Tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, in accordance with the procedures outlined in Section III.A.19 of this ***Appendix A.***

(e) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that ISO's actions have had on the New England Markets. In the event that the Internal Market Monitor uncovers problems with the New England Markets, the Internal Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this ***Appendix A***, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the Internal Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(f) Provide support and information to the ISO Board of Directors and the External Market Monitor consistent with the Internal Market Monitor's functions.

(g) Prepare an annual state of the market report on market trends and the performance of the New England Markets, as well as less extensive quarterly reports, in accordance with the provisions of Section III.A.17 of this ***Appendix A***.

(h) Make one or more of the Internal Market Monitor staff members available for regular conference calls, which may be attended, telephonically or in person, by Commission and state commission staff, by representatives of the ISO, and by Market Participants. The information to be provided in the Internal Market Monitor conference calls is generally to consist of a review of market data and analyses of the type regularly gathered and prepared by the Internal Market Monitor in the course of its business, subject to appropriate confidentiality restrictions. This function may be performed through making a staff member of the Internal Market Monitor available for the monthly meetings of the Market Participants and inviting Commission staff and the staff of state public utility commissions to those monthly meetings.

(i) Be primarily responsible for interaction with external Control Areas, the Commission, other regulators and Market Participants with respect to the matters addressed in this ***Appendix A***.

(j) Monitor for conduct whether by a single Market Participant or by multiple Market Participants acting in concert, including actions involving more than one Resource, that may cause a material effect on prices or other payments in the New England Markets if exercised from a position of market power, and impose appropriate mitigation measures if such conduct is detected and the other applicable conditions for the imposition of mitigation measures as set forth in this ***Appendix A*** are met. The categories of conduct for which the Internal Market Monitor shall perform monitoring for potential mitigation are:

(i) *Economic withholding*, that is, submitting a Supply Offer for a Resource that is unjustifiably high and violates the economic withholding criteria set forth in Section III.A.5 so that (i) the Resource is not or will not be dispatched or scheduled, or (ii) the bid or offer will set an unjustifiably high market clearing price.

(ii) *Uneconomic production from a Resource*, that is, increasing the output of a Resource to levels that would otherwise be uneconomic, absent an order of the ISO, in order to cause, and obtain benefits from, a transmission constraint.

(iii) *Anti-competitive Increment Offers and Decrement Bids*, which are bidding practices relating to Increment Offers and Decrement Bids that cause Day-Ahead LMPs not to achieve the degree of convergence with Real-Time LMPs that would be expected in a workably competitive market, more fully addressed in Section III.A.11 of this ***Appendix A***.

(iv) *Anti-competitive Demand Bids*, which are addressed in Section III.A.10 of this ***Appendix A.***

(v) Other categories of conduct that have material effects on prices or NCPC payments in the New England Markets. The Internal Market Monitor, in consultation with the External Market Monitor, shall; (i) seek to amend ***Appendix A*** as may be appropriate to include any such conduct that would substantially distort or impair the competitiveness of any of the New England Markets; and (ii) seek such other authorization to mitigate the effects of such conduct from the Commission as may be appropriate.

(k) Perform such additional monitoring as the Internal Market Monitor deems necessary, including without limitation, monitoring for:

(i) Anti-competitive gaming of Resources;

(ii) Conduct and market outcomes that are inconsistent with competitive markets;

(iii) Flaws in market design or software or in the implementation of rules by the ISO that create inefficient incentives or market outcomes;

(iv) Actions in one market that affect price in another market;

(v) Other aspects of market implementation that prevent competitive market results, the extent to which market rules, including this ***Appendix A***, interfere with efficient market operation, both short-run and long-run; and

(vi) Rules or conduct that creates barriers to entry into a market.

The Internal Market Monitor will include significant results of such monitoring in its reports under Section III.A.17 of this ***Appendix A***. Monitoring under this Section III.A.2.3(k) cannot serve as a basis for mitigation under III.A.11 of this ***Appendix A.*** If the Internal Market Monitor concludes as a result of its monitoring that additional specific monitoring thresholds or mitigation remedies are necessary, it may proceed under Section III.A.20.

(l) Propose to the ISO and Market Participants appropriate mitigation measures or market rule changes for conduct that departs significantly from the conduct that would be expected under competitive market conditions but does not rise to the thresholds specified in Sections III.A.5, III.A.10, or III.A.11. In considering whether to recommend such changes, the Internal Market Monitor shall evaluate whether the conduct has a significant effect on market prices or NCPC payments as specified below. The Internal Market Monitor will not recommend changes if it determines, from information provided by Market Participants (or parties that would be subject to mitigation) or from other information available to the Internal Market Monitor, that the conduct and associated price or NCPC payments under investigation are attributable to legitimate competitive market forces or incentives.

(m) Evaluate physical withholding of Supply Offers in accordance with Section III.A.4 below for referral to the Commission~~ in accordance with ***Appendix B*** of this Market Rule l~~.

(n) If and when established, participate in a committee of regional market monitors to review issues associated with interregional transactions, including any barriers to efficient trade and competition.

III.A.2.4. Overview of the Internal Market Monitor's Mitigation Functions.

III.A.2.4.1. Purpose.

The mitigation measures set forth in this ***Appendix A*** for mitigation of market power are intended to provide the means for the Internal Market Monitor to mitigate the market effects of any actions or transactions that are without a legitimate business purpose and that are intended to or foreseeably could manipulate market prices, market conditions, or market rules for electric energy or electricity products. Actions or transactions undertaken by a Market Participant that are explicitly contemplated in Market Rule l (such as virtual supply or load bidding) or taken at the direction of the ISO are not in violation of this ***Appendix A***. These mitigation measures are intended to minimize interference with open and competitive markets, and thus to permit to the maximum extent practicable, price levels to be determined by competitive forces under the prevailing market conditions. To that end, the mitigation measures authorize the mitigation of only specific conduct that exceeds well-defined thresholds specified below. When implemented, mitigation measures affecting the LMP or clearing prices in other markets will be applied *ex ante*. Nothing in this ***Appendix A***, including the application of a mitigation measure, shall be deemed to be a limitation of the ISO's authority to evaluate Market Participant behavior for potential ~~sanctions under ***Appendix B*** of this Market Rule 1~~ referral under Section III.A.19~~to the Commission for investigation and determination of any appropriate legal remedy or penalty~~.

III.A.2.4.2. Conditions for the Imposition of Mitigation.

(a) Imposing Mitigation. To achieve the foregoing purpose and objectives, mitigation measures are imposed pursuant to Sections III.A.5, III.A.10, and III.A.11 below:

~~(b) Notwithstanding the foregoing or any other provision of this ***Appendix A***, and as more fully described in Section III.B.3.2.6 of ***Appendix B*** to this Market Rule 1, certain economic decisions shall not be deemed a form of withholding or otherwise inconsistent with competitive conduct.~~

III.A.2.4.3. Applicability.

Mitigation measures may be applied to Supply Offers, Increment Offers, Demand Bids, and Decrement Bids, as well as to the scheduling or operation of a generation unit or transmission facility.

III.A.2.4.4. Mitigation Not Provided for Under This *Appendix A*.

The Internal Market Monitor shall monitor the New England Markets for conduct that it determines constitutes an abuse of market power but does not trigger the thresholds specified below for the imposition of mitigation measures by the Internal Market Monitor. If the Internal Market Monitor identifies any such conduct, and in particular conduct exceeding the thresholds specified in this ***Appendix A***, it may make a filing under §205 of the Federal Power Act ("§205") with the Commission requesting authorization to apply appropriate mitigation measures. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation, shall propose a specific mitigation measure for the conduct, and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure.

III.A.2.4.5. Duration of Mitigation.

Any mitigation measure imposed on a specific Market Participant, as specified below, shall expire not later than six months after the occurrence of the conduct giving rise to the measure, or at such earlier time as may be specified by the Internal Market Monitor or as otherwise provided in this ***Appendix A*** ~~or in ***Appendix B*** to this Market Rule 1~~.

~~**III.A.13.5. Imposition of Sanctions.**~~

~~***Appendix B*** of Market Rule 1 sets forth the procedures and standards under which sanctions may be imposed for certain violations of Market Participants' obligations under the ISO New England Filed Documents and other ISO New England System Rules. The Internal Market Monitor shall administer ***Appendix B*** in accordance with the provisions thereof.~~

SECTION III. MARKET RULE 1

APPENDIX B

RESERVED FOR FUTURE USE

~~**IMPOSITION OF**~~

~~**SANCTIONS BY THE ISO**~~

~~**APPENDIX B**~~

~~**IMPOSITION OF SANCTIONS BY THE ISO**~~

~~**Table of Contents**~~

~~IMPOSITION OF SANCTIONS BY THE ISO~~

~~III.B.1 Purpose and Objectives~~

~~III.B.1.1. Sanctionable Behavior.~~

~~This ***Appendix B*** sets forth the procedures and standards under which sanctions may be imposed for certain violations ("Sanctionable Behavior" as delineated in Section III.B.3 of this ***Appendix B***) of Market Participants' obligations under the ISO New England Filed Documents and other ISO New England System Rules (collectively, "Market Participant Obligations"). The ISO New England System Rules embody procedures and standards of conduct that are intended to assure short-term reliability and the competitiveness and efficiency of the markets. The authority to impose sanctions under this ***Appendix B*** is intended to deter noncompliance by Market Participants with Market Participant Obligations that: (i) materially impairs or threatens to materially impair short-term reliability, (ii) materially impairs or threatens to materially impair the competitiveness or efficiency of the markets, (iii) involves unexcused failure to follow certain ISO instructions, or (iv) involves unexcused failure to provide to the ISO in certain circumstances accurate and timely information required and requested by the ISO.~~

~~III.B.1.2 Rule Changes.~~

~~If this ***Appendix B*** is inadequate to assure short-term reliability and the efficiency and competitiveness of markets, the ISO may promulgate new or changed rules to address the problem. The sanctions set forth in this ***Appendix B*** are intended to assure compliance by the Market Participants with Market Participant Obligations from time to time in effect, and are not a substitute for the appropriate modification of such Market Participant Obligations. Where an ISO New England Filed Document or other ISO New England System Rule is ambiguous, the ISO will seek clarification of the rule rather than issue a Formal Warning or refer to the Commission conduct that a Market Participant could reasonably believe was in compliance with Market Participant Obligations. Behavior not constituting a violation by a Market Participant of its Market Participant Obligations, and not otherwise specifically made subject to sanction by another rule, is not Sanctionable Behavior under this ***Appendix B***.~~

~~III.B.1.3 Objectives.~~

~~III.B.1.3.1 Equitable Sharing.~~

~~It is an objective of the ISO New England Filed Documents and other ISO New England System Rules to provide for equitable sharing of the responsibilities, benefits and costs resulting from the establishment of~~

~~markets and the maintenance of proper standards of reliability for the New England Control Area. Each Market Participant is entitled to expect performance by other Market Participants of their Market Participant Obligations. This ***Appendix B*** is intended to create an effective deterrent to noncompliance by Market Participants of their Market Participant Obligations. The ISO will not issue a Formal Warning or refer conduct to the Commission if it believes that the consequences of Sanctionable Behavior in the markets are a sufficient deterrent~~

~~III.B.1.3.2 ISO Standard of Conduct.~~

~~In order for the sanctions provided for within this ***Appendix B*** to be an effective deterrent, the application by the ISO of this ***Appendix B*** must be consistent and non-discriminatory.~~

~~III.B.1.4 Interpretation.~~

~~The remaining provisions of this ***Appendix B*** shall be interpreted and applied consistently with this Section III.B.1.~~

~~III.B.2 Application of Sanctions~~

~~III.B.2.1 General Rule.~~

~~If in the course of its activities, the ISO identifies any Market Participant behavior it believes may be in violation of this ***Appendix B***, the ISO will evaluate whether to issue a Formal Warning as discussed in Sections III.B.4.1.1 and III.B.5.2. If after such evaluation, the ISO believes that such conduct could warrant monetary sanctions under this ***Appendix B***, the ISO will refer such potentially Sanctionable Behavior to the Commission for a determination regarding whether monetary sanctions will be imposed under Sections III.B.4.1.2 and III.B.4.1.3. In any case in which the ISO determines that issuance of a Formal Warning is appropriate, the subject conduct will also be referred to the Commission for a determination regarding monetary sanctions. The ISO shall impose monetary sanctions only as directed by the Commission. In addition to any authority afforded the ISO in this ***Appendix B***, the Commission shall have the authority to assess the sanctions set forth and described in this ***Appendix B***. The Commission shall have the authority to remedy a violation under this ***Appendix B*** from the date of the violation. Nothing in this rule shall be deemed to be a limitation or condition on the authority of the Commission or other entity under current law or regulation. Since the ISO is only one possible source of information regarding a suspected sanctionable event, the Commission may impose sanctions under this ***Appendix B*** for conduct not brought to its attention by a referral from the ISO.~~

~~**III.B.2.2 Control of Resources.**~~

~~With respect to a Resource or Demand Resource, sanctions may be imposed on the Market Participant with operating control of the Resource or Demand Resource or authority to submit bids or offers for the Resource or Demand Resource as appropriate.~~

~~**III.B.2.2.1 Operating Control.**~~

~~A Market Participant that has authority to submit bids or offers with respect to a Resource or Demand Resource as to which its non-Market Participant Affiliate has operating control will be deemed to have operating control of such Resource or Demand Resource for purposes of this ***Appendix B***. An Ownership Share that does not provide a right to operating control or authority to submit bids or offers for a Resource or Demand Resource shall not serve as a basis for imposition of sanctions except as set forth in Section III.B.2.2.2.~~

~~**III.B.2.2.2 Special Rule for Contract Rights**.~~

~~With respect to a jointly owned Resource or Demand Resource for which the Market Participant is not the operator of the Resource or Demand Resource:~~

~~(a) The Market Participant with authority to submit bids or offers for such a Resource or Demand Resource is entitled to rely in good faith on operating parameters and information as to availability, capacity and operating conditions supplied by the person with operating control of the Resource or Demand Resource as long as the Market Participant's conduct is consistent with the requirements of due diligence as discussed below in Section III.B.3.7.2.~~

~~(b) A Market Participant that enters into a contract or new transaction under an existing service agreement which is structured in a way that provides such Market Participant authority to submit bids or offers for a Resource or Demand Resource shall include in such contract or a supplement thereto the language with respect to contracts of the type entered into set forth in ***Exhibit 2*** to this ***Appendix B***.~~

~~(c) The Market Participant with authority to submit bids or offers for a Resource or Demand Resource shall use its reasonable efforts to ensure its operation in accordance with Market Participant Obligations, consistent with its rights under its contract. The Market Participant with authority to submit bids or offers shall be subject to sanction as if it were the Market Participant with operating control of such Resource or Demand Resource if (i) the person with operating control is not a Market Participant~~

~~and engages in conduct that would be sanctionable if that person were a Market Participant and (ii) the Market Participant with authority to submit bids or offers fails to use reasonable efforts, consistent with its rights under its contract, to prevent operation that would otherwise be sanctionable.~~

~~III.B.2.3 Transmission Facilities~~~~.~~

~~To the extent identified in this *Appendix B*, a Market Participant with operating control of transmission facilities may be subject to sanction with respect to operation of such facilities.~~

~~III.B.3 Sanctionable Behavior~~

~~An act or omission described in any of Sections III.B.3.1, III.B.3.2, III.B.3.3, III.B.3.4, and III.B.3.5 (any such act or omission being referred to as "Sanctionable Behavior") is subject to sanction under this *Appendix B* pursuant to the process and subject to the standards, exclusions and evaluative factors set forth in Sections III.B.4 and III.B.5; provided that the action is intentional and not excused under sections III.B.3.2.5, III.B.3.2.6, or III.B.3.6.~~

~~III.B.3.1 Failure to Perform~~~~.~~

~~Failure to perform, as described under Sections III.B.3.1.1, III.B.3.1.2, and III.B.3.1.3 of this *Appendix B*, may be determined by the ISO in accordance with the testing and audit procedures provided for in the ISO New England Manuals or other suitable information available to the ISO. Failure to perform is not subject to sanction if a Market Participant makes a timely submission of revised Offer Data or non-price related Supply Offer information to the ISO and performs in accordance with such revised data, but if a Market Participant's revised data submission constitutes a misrepresentation of a Resource's or Demand Resource's ability to perform, this may be subject to sanction under Section III.B.3.2. The ISO may unilaterally modify a Market Participant's Offer Data and non-price related Supply Offer data in accordance with Section 1.11.3(c) of Market Rule 1.~~

~~III.B.3.1.1. Failure to Provide Energy~~~~.~~

~~Failure to provide energy means a failure, in response to a Dispatch Instruction from the ISO, to attain at least 90% of the Resource's Economic Maximum Limit using the ramp rate submitted in the generator's Offer Data.~~

~~III.B.3.1.2 Failure to Provide Services.~~

~~Failure to provide services means a failure, in response to a dispatch instruction from the ISO, to begin to move a Resource that is on line and operating at or above its Economic Minimum Limit to the new~~

~~dispatch point in the dispatch instruction, based on the ramp rate submitted in the generator's Offer Data and the Supply Offer prices submitted, such that the actual output of the generator over one hour is not within 10% of the Dispatch Rate specified.~~

~~III.B.3.1.3 Failure to Respond to Dispatch Instructions.~~

~~For a Fast Start Generator, failure to respond to dispatch instructions means a departure, by more than 25%, in meeting, in response to the Dispatch Instruction from the ISO, the operating response Offer Data time for starting up or shutting down a generating unit and, for all other Resources, failure to respond to Dispatch Instructions means a departure by the lesser of, 25% or 2 hours, in meeting the operating response Offer Data time in starting up a generating unit.~~

~~III.B.3.1.4 [Reserved.]~~

~~III.B.3.1.5 Other Facility Failures Excluded.~~

~~Failure to perform does not include the effect of any failure or other unavailability of transmission, distribution or communications facilities so long as such failure or other unavailability is outside the reasonable control of the Market Participant.~~

~~III.B.3.2 Inaccurate Bid or Operating Information~~

~~III.B.3.2.1 Understatement of Economic Maximum Limit.~~

~~(a) Understatement of a generating Resource's Economic Maximum Limit means that the Resource could currently attain an Economic Maximum Limit value consistent with Good Utility Practice that is at least five percent (or 25 MW, whichever is less) greater than the Economic Maximum Limit value submitted by the Market Participant, including any subsequent revision of the Economic Maximum Limit value, and which submission is not excused under the provisions of Sections III.B.3.2.5, III.B.3.2.6, or III.B.3.6, unless the Market Participant exercised due diligence to prevent such understatement, as discussed below in Section III.B.3.7.2.~~

~~(b) The ability of a Resource to perform for short periods during Emergencies may vary from the long-run performance to be expected in accordance with Good Utility Practice. The demonstration that a Resource is capable of higher output on a short-term basis during Emergencies shall not be evidence of the Resource's long-run performance.~~

~~III.B.3.2.2 Overstatement of Emergency Generating Capability Under Emergency Conditions.~~

~~Overstatement of a generating Resource's maximum generating capability means the submission of a value, including any subsequent revision of such value to be applicable in Emergency Conditions, that the Resource currently could not, consistent with Good Utility Practice, attain at least 95% of such value, unless the Market Participant exercised due diligence to prevent such overstatement, as discussed below in Section III.B.3.7.2.~~

~~III.B.3.2.3 Misrepresentation Regarding Operating Conditions~~~~.~~

~~A misrepresentation regarding operating conditions means the making by a Market Participant of any materially inaccurate statement to the ISO regarding inability or restricted ability of its Resource or Demand Resource to perform, or the unavailability or restricted availability of its transmission facilities, including any statement as to the existence of a forced outage, Force Majeure or Emergency affecting its facilities, unless the Market Participant exercised due diligence to prevent such misrepresentation, as discussed below in Section III.B.3.7.2.~~

~~III.B.3.2.4 Misrepresentation of Resource Availability~~~~.~~

~~Misrepresentation with respect to Resource or Demand Resource availability means a failure by a Market Participant to advise the ISO as soon as reasonably practical that a Resource or Demand Resource that the Market Participant has indicated is available to provide Operating Reserve could not respond upon request in accordance with the Offer Data and Supply Offer submitted by the Market Participant, unless the Market Participant exercised due diligence to prevent such misrepresentation, as discussed below in Section III.B.3.7.2.~~

~~III.B.3.2.5 Performance.~~

~~(a) Resource or Demand Resource performance and availability are subject to, among other factors, climatic variations and emissions, license and other limitations. The Market Participant's Offer Data or a Supply Offer describes the technical abilities of equipment in expected operating conditions and is not subject to sanction if actual operating conditions vary as long as the Market Participant exercised due diligence as discussed below in Section III.B.3.7.2. However, a Market Participant is still expected to provide an appropriate data revision if operating conditions vary materially from the Market Participant's Offer Data or an applicable Supply Offer.~~

~~(b) A Market Participant shall be deemed to have satisfied its obligation to deliver accurate information as to operating conditions or Resource or Demand Resource availability if it exercised due~~

~~diligence as discussed below in Section III.B.3.7.2 to supply accurate, responsive information; inadvertent errors or omissions shall not be Sanctionable Behavior.~~

~~III.B.3.2.6 Certain Economic Decisions Excused.~~

~~Market Participants may make decisions affecting the availability of a Resource or Demand Resource for reasons relating to the economics of operating that Resource or Demand Resource. Such decisions may include, but are not limited to, sale of gas available to the Market Participant as fuel for a Resource or Demand Resource, reducing output temporarily to defer maintenance in response to unanticipated operating difficulties or refueling, or shutting down a Resource or Demand Resource during a period when the Market Participant does not reasonably expect the Resource-specific or Demand Resource-specific New England Market revenues to justify operation of the Resource or Demand Resource in that period. For such decisions, the Market Participant shall not be subject to sanction under III.B.3.2.1, III.B.3.2.2, III.B.3.2.3, or III.B.3.2.4 so long as it provides to the ISO timely information that accurately describes the nature of the Market Participant's decision and result of such decision on the performance of such Resource or Demand Resource and otherwise acts in accordance with the applicable provisions of ISO New England Operating Procedure 5 (Unit Outages) or any other rule that provides for the coordination required to minimize the impact of Resource or Demand Resource unavailability on short-term reliability, including obtaining permission to the extent required by ISO New England Operating Procedure 5 or such other rule. It is not the intent of this Subsection's reference to Operating Procedure 5 or other rules to require a Market Participant to provide services from all or a portion of a Resource or Demand Resource where the Resource-specific or Demand Resource-specific New England Market revenues derived from the provision of such service do not justify the associated operating costs or opportunity costs (whether intertemporal or in non-New England Markets or both) of providing such service from such Resource or Demand Resource. It is also not the intent of this Section to provide a basis for a Market Participant to circumvent the mitigation rules specified in~~ ***~~Appendix A~~*** ~~or any other ISO New England Filed Document or ISO New England System Rule.~~

~~III.B.3.3 Failure to Follow ISO Instructions~~

~~III.B.3.3.1 Failure to Follow Scheduling Procedures.~~

~~Failure to comply with applicable ISO New England System Rules for scheduling or rescheduling Resource maintenance, including failure to follow an established schedule without rescheduling.~~

~~III.B.3.3.2 Failure to Follow Transmission Instructions.~~

~~Failure to follow transmission instructions means (i) failure to follow routine ISO transmission dispatch instructions, or (ii) failure to follow ISO operating instructions during a system Emergency with respect to transmission facilities or (iii) failure to comply with the Transmission, Markets and Services Tariff or applicable ISO New England System Rules for scheduling or rescheduling transmission maintenance, including failure to follow an established schedule without rescheduling.~~

~~III.B.3.4 Failure to Provide Information~~

~~III.B.3.4.1 Routine Reports.~~

~~Failure to provide timely, accurate routine scheduled reports.~~

~~III.B.3.4.2 Emergencies or System Disturbances.~~

~~Failure to provide timely, accurate information in response to ISO inquiries about system Emergencies or disturbances in the New England Control Area.~~

~~III.B.3.4.3 Special Information Requests.~~

~~Failure by a Market Participant to meet an agreed schedule to provide information that the ISO needs to perform its responsibilities to apply and implement ISO New England Filed Documents and other ISO New England System Rules, for purposes other than current operations, that is not contained in routine scheduled reports, or to work in good faith to establish such a schedule that is reasonable based on the complexity of the information request and the urgency of the ISO's need for the information that, in either case, is not excused by Sections III.B.3.4.7 or III.B.3.6.~~

~~III.B.3.4.4 Market Settlement Information.~~

~~Failure to provide timely or accurate billing or metering information or similar information used in settlement, which is not excused by Sections III.3.4.7 or III.B.3.6.~~

~~III.B.3.4.5 Resource Information.~~

~~Failure to provide, in response to an ISO inquiry, pertinent information about the ability of a Market Participant's Resource or Demand Resource to perform, which failure is not excused under the provisions of Sections III.B.3.4.7 or III.B.3.6, unless the Market Participant exercised due diligence to prevent such failure, as discussed below in Section III.B.3.7.2.~~

~~III.B.3.4.6 [Reserved.]~~

~~III.B.3.4.7 Timeliness and Accuracy.~~

~~(a) If a Market Participant, for good cause, requests an extension of time to deliver information subject to a routine scheduled report or a special information request, the ISO shall grant a reasonable extension, and failure to provide information by the original delivery date shall not be Sanctionable Behavior.~~

~~(b) A Market Participant shall be deemed to have satisfied its obligation to deliver accurate information if it has exercised due diligence as discussed below in Section III.B.3.7.2 to supply accurate, responsive information; inadvertent errors or omissions shall not be Sanctionable Behavior.~~

~~III.B.3.5 Relationship with and Failure to Comply with *Appendix A*.~~

~~Certain Market Participant conduct may be both Sanctionable Behavior and a basis for imposing a mitigation remedy under ***Appendix A***. Provided that the necessary findings are made and the applicable procedures under this ***Appendix B*** are followed, sanctions may be imposed under this ***Appendix B*** for Sanctionable Behavior without regard to whether the ISO also imposes or seeks to impose any mitigation remedy on the Market Participant for the same conduct under ***Appendix A***. In addition, provided that the ISO makes the necessary findings and follows the applicable procedures under ***Appendix A***, the ISO may impose one or more mitigation remedies under ***Appendix A*** without regard to whether sanctions are imposed under this ***Appendix B*** for Sanctionable Behavior that forms the basis for a mitigation remedy. To the extent that compliance with an ***Appendix A*** remedy requires specific actions by a Market Participant, and such mitigation remedy is not currently the subject of ADR review under ***Appendix A*** and has not been removed as the result of ADR review, a sanction may be pursued under this ***Appendix B*** for a failure by that Market Participant to comply with such mitigation remedy whether or not such failure is intentional, unless such failure is excused under the provisions of III.B.3.6.~~

~~III.B.3.6. Certain Behavior Excused.~~

~~III.B.3.6.1 Force Majeure.~~

~~No failure by a Market Participant to perform Market Participant Obligations shall be Sanctionable Behavior to the extent and for the period that the Market Participant's inability to perform is caused by an event or condition of Force Majeure affecting the Market Participant; provided that the Market Participant gives notice to the ISO of the event or condition as promptly as possible after it knows of the event or condition and makes all reasonable efforts to cure, mitigate or remedy the effects of the Force Majeure event or condition.~~

~~III.B.3.6.2 Safety, Licensing or Other Requirements~~~~.~~

~~No failure by a Market Participant to perform Market Participant Obligations shall be Sanctionable Behavior if the Market Participant is acting in good faith to preserve the safety of persons or the safety or integrity of equipment subject to Dispatch Instructions or to comply with facility licensing, environmental or other requirements of law.~~

~~III.B.3.6.3 Emergencies.~~

~~No failure by a Market Participant to perform Market Participant Obligations shall be Sanctionable Behavior if the Market Participant is acting in good faith and consistent with Good Utility Practice to preserve system reliability in a system Emergency or other system disturbance; provided that a Market Participant shall not override direct ISO instructions except in cases described in Section III.B.3.6.2.~~

~~III.B.3.6.4 Conflicting Directives~~~~.~~

~~To the extent that any action or omission by a Market Participant is specifically required or provided for by Market Rule 1 or by ISO instructions, such action or omission shall not be Sanctionable Behavior.~~

~~III.B.3.6.5 Time Limitation~~~~.~~

~~No failure by a Market Participant to perform Market Participant Obligations shall be subject to sanction if the Market Participant's failure occurred more than six months prior to the ISO providing written notice to the Market Participant pursuant to Section III.B.5.5 of the ISO's belief that such failure may constitute Sanctionable Behavior.~~

~~III.B.3.7 Interpretation.~~

~~III.B.3.7.1 Intent.~~

~~Where any subsection of Section III.B.3 requires that behavior be intentional to constitute Sanctionable Behavior, a finding may be made that behavior is intentional if there is (i) direct evidence of intent, (ii)~~

~~evidence of reckless endangerment of short-term reliability or (iii) evidence of a pattern of unexcused behavior or circumstances from which it may be reasonably inferred that the behavior was intentional. In making an inference as to intent pursuant to clause (iii) above, the financial benefits or detriments to the Market Participant of its behavior and the adequacy of any alternative explanation provided by the Market Participant for its behavior shall be considered. Actions taken by a Market Participant in good faith shall not be viewed as part of a pattern of unexcused behavior or otherwise serve as the basis of a finding of intent. The degree to which the Market Participant's behavior materially impaired or threatened to materially impair short-term reliability or the competitiveness or efficiency of the markets shall also be considered, and intent pursuant to clause (iii) above shall not be inferred unless a finding is made that the Market Participant's behavior materially impaired or threatened to materially impair short-term reliability or the competitiveness or efficiency of the markets. Behavior that would materially impair short-term reliability or the competitiveness or efficiency of the markets if it were engaged in on a widespread basis by other Market Participants to the same degree and at the same time as by the Market Participant engaging in the behavior, shall be deemed to threaten to materially impair short-term reliability or the competitiveness or efficiency of the New England Markets, as the case may be.~~

~~III.B.3.7.2 Due Diligence~~~~.~~

~~Where any subsection of Section III.B.3 requires a determination regarding the exercise of due diligence by a Market Participant with regard to providing information to the ISO, such determination shall be made consistent with the Commission's Market Behavior Rule 3, incorporated in this Market Rule 1 below.~~

~~Market Behavior Rule 3 (Communications)~~

~~Seller will provide accurate and factual information and not submit false or misleading information, or omit material information, in any communication with the Commission, Commission-approved market monitors, Commission-approved regional transmission organizations, or Commission-approved independent system operators, or jurisdictional transmission providers, unless Seller exercised due diligence to prevent such occurrences.~~

~~III.B.4 Sanctions~~

~~III.B.4.1 Amount and Nature~~~~.~~

~~Exhibit 1~~ ~~to this~~ ***~~Appendix B~~*** ~~sets forth the maximum applicable sanctions with respect to each category of Sanctionable Behavior set forth in Section III.B.3 subject to potential increase under Section III.B.4.3.2 in certain circumstances. There are three categories of sanctions listed below. The first, Formal Warning,~~

~~may be issued at the discretion of the ISO. The second and third, Administrative Sanctions and Formula-Based Sanctions, are monetary sanctions that will be imposed by the ISO only as directed by the Commission.~~

~~III.B.4.1.1 Formal Warning.~~

~~A Formal Warning consists of written notification from the ISO to a Market Participant stating that potentially Sanctionable Behavior has occurred and notifying the Market Participant that the conduct has been referred to the Commission as discussed below in Section III.B.5.4.~~

~~III.B.4.1.2 Administrative Sanctions~~~~.~~

~~Administrative Sanctions consist of fixed, per-event monetary charges set forth in~~ ***~~Exhibit 1~~*** ~~imposed on Sanctionable Behavior.~~

~~III.B.4.1.3 Formula-Based Sanctions.~~

~~Formula-Based Sanctions are monetary charges determined by a formula set forth in~~ ***~~Exhibit 1~~*** ~~imposed on Sanctionable Behavior.~~

~~III.B.4.2 Level of Sanction.~~

~~The Administrative Sanction and Formula-Based Sanction, are intended to be maximum monetary sanctions except as described in III.B.4.3.2 and a sanction in a lesser amount than that specified in~~ ***~~Exhibit 1~~*** ~~may be imposed if a lesser amount will have a sufficient deterrent effect.~~

~~III.B.4.3. Non-Exclusivity and Increases.~~

~~III.B.4.3.1 Cumulative Effect.~~

~~Sanctions imposed under this~~ ***~~Appendix B~~*** ~~are in addition to any mitigation remedies available to the ISO under~~ ***~~Appendix A~~***~~. Both an Administrative Sanction and a Formula-Based Sanction may be imposed with respect to the same Sanctionable Behavior if both sanctions are necessary for appropriate deterrence. If a single event is sanctionable under two different sections or subsections of this~~ ***~~Appendix B~~***~~, monetary sanctions may only be imposed under one of such sections or subsections; provided that if an event is sanctionable under one or more sections or subsections and is also sanctionable under Section III.B.3.5, Administrative Sanctions may be imposed under Section III.B.3.5 and a sanction may be imposed under one other section or subsection. For purposes of this~~ ***~~Appendix B~~*** ~~an "event" means the facts and circumstances constituting a single occurrence of behavior, or multiple occurrences of the same sanctionable behavior within a day, sanctionable under this~~ ***~~Appendix B~~***~~. While a pattern of behavior may~~

~~be reviewed, for example, to make a finding of intent under Subsection III.B.3.7.1, the pattern of behavior may consist of multiple events, each one of which is subject to sanction once a finding of intent is made. With respect to operating behavior, an event relates to a single operating action. For example, if the ISO gives an instruction to ramp up a Resource and the Market Participant fails to ramp up, that failure is a single event even if it continues over several hours and despite repeated instructions. However, providing inaccurate information about the Resource to the ISO in response to questions about the failure to ramp up is a separate event as is failure of the same Resource to ramp down later in the day. Failure to provide information relates to a particular report or a particular request for information, and separate inaccuracies in the same report or in response to the same information request are not separate events.~~

~~III.B.4.3.2 Increased Sanctions~~~~.~~

~~Administrative Sanctions and Formula-Based Sanctions may be increased to an amount up to triple the base amount of the sanction in the following circumstances:~~

~~(a) If Sanctionable Behavior occurs during a system Emergency; or~~

~~(b) If a determination is made that the Sanctionable Behavior is part of a continuing pattern of Sanctionable Behavior for which one or more monetary sanctions have previously been imposed upon the Market Participant; or~~

~~(c) If the Sanctionable Behavior is a failure by a Market Participant to comply with any market mitigation remedy the ISO has imposed on such Market Participant pursuant to~~ ***~~Appendix A~~*** ~~that is not currently the subject of ADR review under~~ ***~~Appendix A~~*** ~~and has not been removed as the result of such ADR review.~~

~~III.B.4.4 Costs.~~

~~In addition to applicable sanctions, if a monetary sanction is imposed, the ISO may charge to the sanctioned Market Participant the reasonable costs of the ISO's investigation of the Sanctionable Behavior.~~

~~III.B.4.5 Disclosure.~~

~~Except as provided in this Section III.B.4.5, the ISO will not disclose the imposition of particular sanctions on a particular Market Participant, but will make periodic reports of monetary sanctions imposed and the Sanctionable Behavior upon which such sanctions were imposed that do not identify Market Participants by name or provide a basis for identifying such Market Participants. However, the~~

~~ISO will make disclosure of monetary sanctions imposed on a particular Market Participant if so directed by the Commission based on the Commission's determination that such disclosure is warranted by the nature of the Sanctionable Behavior and monetary sanctions previously imposed on the Market Participant have been unsuccessful in deterring repeated Sanctionable Behavior. The ISO shall notify the Market Participant before making disclosure.~~

~~III.B.5 Process For Imposing Sanctions~~

~~III.B.5.1 Observation and Communication.~~

~~III.B.5.1.1 Observation.~~

~~If, in the conduct of system operations or settlement, in auditing Resource or Demand Resource performance under the ISO New England Manuals of this *Appendix B*, in making inquiry of Market Participants about operating problems, in monitoring the competitiveness and efficiency of the markets, or otherwise in the receipt of information relevant to the performance of its duties, the ISO discovers behavior that it believes may constitute Sanctionable Behavior, the ISO shall make a record of the information leading to ISO's belief that Sanctionable Behavior may have occurred.~~

~~III.B.5.1.2 Communication.~~

~~The ISO shall thereafter contact the Market Participant whose behavior is in question, inform the Market Participant of the information leading to the ISO's belief that Sanctionable Behavior may have occurred, and provide the Market Participant the opportunity to discuss the behavior observed or documented by the ISO and to offer additional facts or explanation of circumstances as follows~~

~~(a) that tend to show that no Sanctionable Behavior occurred, or~~

~~(b) that should be weighed in determining whether to impose a sanction and, if so, what level of sanction to impose.~~

~~III.B.5.1.3 Other Information.~~

~~The ISO may make use of information provided by third parties in forming the basis for an inquiry to a Market Participant about possible Sanctionable Behavior, and is not required to reveal the identity or existence of such third parties. However, unsubstantiated statements by third parties may not serve as the basis for the imposition of sanctions.~~

~~III.B.5.2 Consideration by ISO in determining whether to issue a Formal Warning~~

~~(a) Based upon information in its possession and information provided by the Market Participant, the ISO shall first determine if it believes Sanctionable Behavior has occurred. To conclude that potentially Sanctionable Behavior has occurred under any specific subsection of Section III.B.3, the ISO must make (i) a written finding with respect to each element of such Sanctionable Behavior, as set forth in the relevant subsection, including the basis of any finding as to intent or state of knowledge under Section III.B.3.7, (ii) a written finding with respect to the duration of the conduct and (iii) a written finding that the conduct is not excused by any specific provision of Section III.B.3.~~

~~(b) The ISO shall evaluate any information provided by the Market Participant as promptly as practicable and shall seek to make the determination required by this Section within 60 days of making a record of the information leading to the ISO's belief that Sanctionable Behavior may have occurred pursuant to Section III.B.5.1.1. In no event shall the ISO issue a Formal Warning more than six months after a record is made of the information leading to the belief that Sanctionable Behavior may have occurred pursuant to Section III.B.5.1.1.~~

~~(c) If the ISO believes that Sanctionable Behavior has occurred, the ISO may consider the following factors in determining whether to issue a Formal Warning under Section III.B.4.1.1:~~

~~(i)The nature of the potentially Sanctionable Behavior and the degree of impact on short-term reliability or the competitiveness and efficiency of markets;~~

~~(ii)The Market Participant's past history of Sanctionable Behavior and the nature of sanctions previously imposed; and~~

~~(iii)The promptness and effectiveness of the Market Participant's response in correcting the potentially Sanctionable Behavior.~~

~~III.B.5.3 Dispute of Formal Warning.~~

~~A Market Participant may dispute the issuance of a Formal Warning by delivering to the ISO within 30 days of the issuance of the Formal Warning a written statement of its reasons for disputing the imposition of the Formal Warning. The ISO shall retain any such written statement with its record of the imposition of the Formal Warning. If a Formal Warning serves as a basis for imposing a monetary sanction for subsequent Sanctionable Behavior, the written statement shall also be made part of the record relating to~~

~~the subsequent Sanctionable Behavior. The ISO may, but is not obligated to, reconsider its decision to issue the Formal Warning upon receipt of the written statement. If the ISO determines to withdraw the Formal Warning, it shall so notify the Market Participant in writing, and the Formal Warning shall not be referred to in any subsequent proceeding or report or made the basis for any subsequent action.~~

~~III.B.5.4 Referral of Potentially Sanctionable Behavior to the Commission.~~

~~In any case where the ISO issues a Formal Warning, the record regarding the conduct that is the subject of the Formal Warning will be referred to the Commission for a determination regarding the imposition of monetary sanctions pursuant to this~~ ***~~Appendix B~~***~~. If after evaluating potentially Sanctionable Behavior, the ISO does not issue a Formal Warning, but nonetheless believes that monetary sanctions could be warranted, the ISO will refer the record regarding the subject conduct to the Commission for a determination regarding the imposition of monetary sanctions pursuant to this~~ ***~~Appendix B~~***~~. Any referral to the Commission of potentially Sanctionable Behavior may include recommendations regarding whether and what level of monetary sanctions should be imposed. Potentially Sanctionable Behavior may be referred to the Commission before the issuance of a Formal Warning by the ISO.~~

~~III.B.5.5 Notice and Payments.~~

~~As directed by the Commission, the ISO shall give written notice to the Market Participant of the imposition of any monetary sanction, together with the written findings as required under Section III.B.5.1. The ISO's invoice for the amount of a sanction will be sent to the sanctioned Market Participant with the notice of the sanction. Payments of sanctions received shall be reflected as a credit to charges under Section IV of the Transmission, Markets and Services Tariff for Market Participants other than the sanctioned Market Participant (allocated in proportion to total charges under the Transmission, Markets and Services Tariff in the month the payment is received). The Market Participant shall pay the amount of the sanction to the ISO.~~

~~III.B.5.6 No Limitations on Other Rights of the ISO.~~

~~Nothing contained in this~~ ***~~Appendix B~~*** ~~shall limit the ability of the ISO to collect information from Market Participants or to institute new rules pursuant to Section 11 of the Participants Agreement.~~

~~III.B.6 Tracking and Reporting~~

~~The ISO shall track its time and expenses in pursuing sanctionable behavior on a case-by-case basis and shall post such information on its web site and publish it in its annual review of the operations of the New England markets made pursuant to Section III.A.9.3 of~~ ***~~Appendix A~~***~~. Such information shall be posted~~

~~and published without disclosing the identity of Market Participants investigated or other details that enable such Market Participants to be identified.~~

~~The ISO shall include in the quarterly submission it provides to the Commission pursuant to Section III.A.9.2.2 of ***Appendix A*** information about the functioning of this ***Appendix B*** including the identities of the sanctioned parties, the reason for the sanction, and the method by which the amount of the sanction was calculated.~~

~~Exhibit 1~~

~~Sanctionable Events~~

~~SANCTIONABLE EVENT~~	~~ADMINISTRATIVE SANCTION~~	~~FORMULA-BASED SANCTION~~
~~Failure to Perform in Markets as Defined in Section 3.1:~~		
• ~~Failure to Provide Energy as defined in Subsection III.B.3.1.1:~~		
• ~~Failure to attain High Operating Limit~~	~~$1000/Event(which can be an hour or per day, depending on the circumstances)~~	~~MW Dev. * ½ LMP * Hrs~~
• ~~Failure to Provide Services as defined in Subsection III.B.3.1.2:~~		
• ~~Failure to Move to Desired Dispatch Point~~	~~$1000/Event~~	~~MW Dev. * ½ LMP * Hrs~~
• ~~Failure to Activate Operating Reserve~~	~~$1500/Event~~	~~N/A~~
• ~~Failure to Respond to Dispatch Instructions as defined in Subsection III.B.3.1.3:~~		
• ~~Failure to start Generator~~	~~$500/Event~~	~~N/A~~
• ~~Failure to shut down Generator~~	~~$500/Event~~	~~N/A~~
~~Inaccurate Bid or Operating Information as Defined in Section 3.2:~~		
• ~~Understatement of High Operating Limit as defined in Subsection III.B.3.2.1~~		
• ~~On Supply Offer~~	~~$1000/Event~~	~~MW Dev. * ½ LMP * Hrs.~~
• ~~On Revised Supply Offer~~	~~$2000/Event~~	~~MW Dev. * ½ LMP * Hrs~~

~~**SANCTIONABLE EVENT**~~	~~**ADMINISTRATIVE SANCTION**~~	~~**FORMULA-BASED SANCTION**~~
• ~~Overstatement of maximum capability under Emergency Conditions in Subsection III.B.3.2.2:~~	~~$1000/Event~~	~~MW Dev. * ½ LMP * Hrs.~~
• ~~Misrepresentation of Operating Conditions as defined in Subsection III.B.3.2.3:~~	~~$5000/Event~~	~~MW Dev. * ½ LMP * Hrs.~~
• ~~Misrepresentation of Resource or Demand Resource Availability as defined in Subsection III.B.3.2.4:~~	~~$1000/Event~~	~~MW Dev. * ½ LMP * Hrs.~~

~~**SANCTIONABLE EVENT**~~	~~**ADMINISTRATIVE SANCTION**~~	~~**FORMULA-BASED SANCTION**~~
~~**Failure to Follow ISO Instructions as Defined in Section 3.3:**~~		
• ~~Failure to Follow Scheduling Procedures as defined in Subsection III.B.3.3.1:~~		
• ~~Maintenance Scheduling Procedures~~	~~$1000/Event~~	~~N/A~~
• ~~Failure to Follow Transmission Instructions as defined in Subsection III.B.3.3.2:~~		
• ~~Routine Dispatch~~	~~$1000/Event~~	~~N/A~~
• ~~During System Emergency~~	~~$5000/Event~~	~~N/A~~
• ~~Maintenance Scheduling Procedures~~	~~$1000/Event~~	~~N/A~~
~~Failure to Provide Information as Defined in Section 3.4:~~		
• ~~Routine, Scheduled Reports as defined in Subsection III.B.3.4.1:~~		
• ~~Late~~	~~$500/Event~~	~~N/A~~
• ~~Inaccurate~~	~~$1000/Event~~	~~N/A~~

~~SANCTIONABLE EVENT~~	~~ADMINISTRATIVE SANCTION~~	~~FORMULA BASED SANCTION~~
• ~~Emergencies or System Disturbances as defined in Subsection III.B.3.4.2:~~	~~$2000/Event~~	~~N/A~~
• ~~Special Information Requests as defined in Subsection III.B.3.4.3:~~	~~$1000/Event~~	~~N/A~~
• ~~Market Settlement Information as defined in Subsection III.B.3.4.4:~~		
• ~~Late~~	~~$2000/day~~	~~N/A~~
• ~~Inaccurate~~	~~$2000/Event~~	~~N/A~~
• ~~Resource or Demand Resource Information as defined in Section III.B.3.4.5.~~	~~$1500/Event~~	~~N/A~~
• ~~Disregard of Mitigation Remedies as Defined in Section III.B.3.5.~~	~~$1500/day~~	~~N/A~~

~~Exhibit 2~~

~~Market Participants shall include language substantially as follows in contracts for services from entities which are not Market Participants:~~

~~Article __. Compliance with the Market Rules~~

~~Seller agrees that it is familiar with the applicable ISO New England Filed Documents and other ISO New England System Rules relating to the offering of its Resources into the New England Markets. Seller further agrees to comply in all respects with these rules, and to exercise the degree of diligence required by Good Utility Practice to assure that Offer Data and Supply Offer data or any other bid or offer information provided to purchaser as to Resource or Demand Resource availability, capacity and operating conditions are accurate. Seller acknowledges that market settlement consequences and sanctions may be imposed on the purchaser by ISO New England for seller's failure to meet offer or bid parameters or to respond to operating instructions in accordance with ISO New England System Rules and for seller's actions that would constitute Sanctionable Behavior, as defined in the Tariff. Seller agrees to comply with ISO dispatch instructions and to provide such information as the ISO reasonably requests in order for the ISO to maintain short term reliability and determine whether seller's Resource or Demand Resource is in compliance with its offer or bid parameters or whether Sanctionable Behavior has occurred.~~

SECTION III. MARKET RULE 1
APPENDIX I
FORM OF COST-OF-SERVICE AGREEMENT

ARTICLE 5
MARKET MONITORING

5.1. Mitigation.

Although this Agreement provides for Supply Offers that do not exceed thresholds identified in Appendix A, Market Rule 1, nothing herein shall preclude the ISO from otherwise applying any provision of Appendix A ~~or Appendix B~~ to Market Rule 1 to Owner or Lead Participant, any Affiliate of Owner or Lead Participant, the Resource, or any other resources of Owner or Lead Participant or any Affiliate of Owner or Lead Participant, including mitigation of Supply Offers for Resources covered by this Agreement to the applicable Stipulated Variable Cost as defined in Section 3.4.

ATTACHMENT D

ISO New England Information Policy

2.2 Treatment of Confidential Information

The Governance Participants shall take reasonable measures to assure that all of their employees, representatives, or agents who by virtue of their participation on, or as an alternate on, a Stakeholder Committee have access to *Confidential Information* of another entity that furnished the information, including, as appropriate, a Furnishing Governance Participant, a DR Information Provider or the ISO (the "Furnishing Entity") (1) do not disclose such *Confidential Information* to any other employee, representative, or agent of the same Governance Participant or any other person except as permitted under this Section 2.2 and (2) use such information solely for the purpose of satisfying that person's responsibilities on the Stakeholder Committee. Each Governance Participant shall, upon request by the Participants Committee, provide assurance that the terms of this Section 2.2 are complied with. Any Governance Participant that has furnished *Confidential Information* to Stakeholder Committees may require each recipient to return all or any portion of the *Confidential Information* once it is no longer needed by such recipient to fulfill its responsibilities under the Filed Documents.

Notwithstanding the foregoing, the ISO, the Participants Committee or any Governance Participant may disclose *Confidential Information* of another Governance Participant or the ISO only: **(1)** if such disclosure is permitted in writing by the Furnishing Entity, DR Information Provider or the ISO, as the case may be, or **(2)** if disclosure is required by order of a court or regulatory agency of competent jurisdiction or dispute resolution pursuant to the Filed Documents, or **(3)** as otherwise specifically permitted by this Policy. Any entity subject to this Information Policy shall provide prompt written notice to the Furnishing Entity if that entity either is compelled by order of a court or regulatory agency of competent jurisdiction to disclose, or receives a request seeking to compel disclosure of, *Confidential Information* for which it is not the Furnishing Entity. Further, in recognition that certain Governance Participants are subject to public records and open meeting laws and that certain other demands may be placed on Governance Participants to disclose *Confidential Information*, a recipient of *Confidential Information* of another Governance Participant or the ISO may disclose such *Confidential Information* if and to the extent required by law or requested in writing pursuant to a public records demand or other legal discovery process, provided in either event that the disclosing Governance Participant gives the Furnishing Governance Participant or the ISO prompt written notice of the circumstances that may require such disclosure in time so that the Furnishing Governance Participant or the ISO has a reasonable opportunity to seek a protective order to prevent disclosure.

Notwithstanding anything to the contrary contained in this Section 2.2, the ISO, the Participants Committee, or any Governance Participant may disclose *Confidential Information* to an alternate dispute resolution ("ADR") neutral in an ADR proceeding required or permitted by any New England market rule, including Appendix A, "Market Monitoring, Reporting and Market Power Mitigation," ~~and Appendix B, "Imposition of Sanctions,"~~ to Market Rule 1, or to an arbitrator in an arbitration proceeding under the Filed Documents. In addition, the ISO or any Governance Participant may disclose *Confidential Information* to a Dispute Representative as defined in, and permitted by, Section 5 of the Billing Policy. Any such ADR neutral, arbitrator or Dispute Representative must agree to be bound by this Information Policy.

Notwithstanding anything to the contrary in this Information Policy, resource-specific information contained in the data fields of the Forward Capacity Tracking System, but not information provided to the ISO as separate attachments via the Forward Capacity Tracking System, will be shared with subsequent Lead Market Participants or Project Sponsors for that resource.

Notwithstanding anything to the contrary in the ISO New England Information Policy, the ISO, the Participants Committee, or any Governance Participant may disclose *Confidential Information* as required or permitted to satisfy the "Minimum Criteria for Market Participation" set forth in Section II.A of the ISO New England Financial Assurance Policy.

Notwithstanding anything to the contrary in the ISO New England Information Policy and consistent with the Commission's Order No. 787, the ISO may disclose *Confidential Information* concerning natural gas-fueled generation from resources located within the New England Control Area to the operating personnel of an interstate natural gas pipeline company that operates a pipeline provided that: (a) *Confidential Information* regarding specific generators will be shared only with the pipeline serving that generator directly and (b) the ISO has determined that it is operationally necessary to ensure reliability to disclose the *Confidential Information*.

ISO new england

memo

To: NEPOOL Markets Committee

From: Timothy Helwick, Assistant General Counsel-Market Monitoring, ISO New England

Date: March 3, 2021

Subject: Remove Appendix B of Market Rule 1 (WMPP ID: 152)

The ISO is requesting a vote at the March 9, 2021 MC meeting on its proposal to remove Appendix B of Market Rule 1 regarding the imposition of sanctions by the ISO and to clarify that resource owners are subject to a referral to the Office of Enforcement of the Federal Energy Regulatory Commission (the "Commission") for determination of potential sanctions in accordance with Appendix A of the Tariff.

By way of background, Appendix B sets forth a procedure for the ISO to issue Formal Warnings and impose sanctions on market participants, only if approved by the Commission through the referral process, for sanctionable behavior, such as failure to perform in the markets or to follow ISO instructions. Given that all potential violations of the Tariff, FERC Orders, or regulations are already subject to referral from the Internal Market Monitor ("IMM") to the Commission under Appendix A of the Tariff and FERC regulation 18 C.F.R. § 35.28(g)(3)(iv), neither the ISO, the IMM, nor the Commission uses the Appendix B sanctions procedure.

The ISO proposes to remove Appendix B of the Tariff and update other tariff references to Appendix B to instead refer to the referral process under Appendix A of the Tariff. As noted, Appendix B is unused and is unnecessary given the existing regulatory referral process under Appendix A and the Commission's authority to determine violations and sanctions under its Penalty Guidelines. In addition, Appendix B is outdated and (maybe) in conflict with orders from the Commission regarding rulings on the lack of affirmative defenses and economic excuses.

While the ISO understands that in place of Appendix B some participants may wish to have training materials indicating "guardrails" for behavior that may not rise to a referral (*e.g.* understatement of Economic Maximum, failure to provide energy or to follow/respond to dispatch instructions), the ISO cannot advise participants on exemptions to following its rules, standards and procedures. The ISO uses its trainings to help guide participants on how to interact with and do business with the ISO consistent with the Tariff, but it does not advise participants on specific actions and always refers participants to the Tariff and other governing documents as the official source of information. Stakeholders may find it helpful to use the Commission's "No-Action Letter" process to gain FERC staff's view on whether a particular transaction, practice or situation would be subject to agency enforcement action. The Commission's No-Action Letter process is an effective tool for entities to reduce the risk of failing to comply with the rules, standards and procedures the ISO administers.

The specific proposal for the committee's consideration at its March 9, 2021 meeting has been presented previously to the Markets Committee at the meeting dates outlined below.

- December 8, 2020, agenda item 5: https://www.iso-ne.com/event-details?eventId=140271
- January 12, 2021, agenda item 5: https://www.iso-ne.com/event-details?eventId=143978
- February 9-10, 2021, agenda item 3: https://www.iso-ne.com/event-details?eventId=143983

ISO new england

memo

To: NEPOOL Participants Committee

From: Jay Dwyer, Acting Secretary, NEPOOL Markets Committee (MC)

Date: March 10, 2021

Subject: Actions of the MC

This memo is notification to the Participants Committee of the following actions taken by the MC at its March 9, 2021 meeting. All sectors had a quorum.

1. **(Agenda Item 1A) Approval of Minutes of the January 12, 2021, January 19, 2021, and February 9-10, 2021 NEPOOL Markets Committee Meeting Minutes**

   ACTION: APPROVED

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

   > RESOLVED, that the Markets Committee approves the minutes of the NEPOOL Markets Committee for the January 12, 2021, January 19, 2021, and February 9-10, 2021 meetings as circulated for the March 9, 2021 meeting, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

   The motion was voted and passed on a voice vote with no opposition and no abstentions recorded.

2. **(Agenda Item 2) Deletion of Appendix B of Section III of the Tariff**

   ACTION: MOTION FAILED

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

   > RESOLVED, that the Markets Committee recommends that the Participants Committee support the deletion of Appendix B of Market Rule 1 and revisions to Sections I.2.2, III.1.7, III.13.6, III.A.2, III.A.13, and Article 5.1 of Appendix I of Market Rule 1, as proposed by ISO New England and as circulated for the March 9, 2021 meeting, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

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The motion was then voted. The motion failed to pass with a vote of 59.21% in favor. The individual Sector votes were Generation (0.00% in favor, 16.70% opposed, 3 abstentions), Transmission (16.70% in favor, 0.00% opposed, 0 abstentions), Supplier (9.11% in favor, 7.59% opposed, 5 abstentions), Publicly Owned Entity (16.70% in favor, 0.00% opposed, 0 abstentions), Alternative Resources (0.00% in favor, 16.50% opposed, 7 abstentions), and End User (16.70% in favor, 0.00% opposed, 2 abstentions).

3. (Agenda Item 4(b)) Meter Readers Working Group Referral Request

ACTION: REFERRED

The request was referred to the NEPOOL Meter Readers Working Group by the Markets Committee to discuss and consider:

1) What would be required to accomplish the proposed reporting for wholesale market settlement of distributed energy resource (DER) aggregations, meter data acquired from either meter reader or third party owned sub-meters of DER devices located within end-use customer facilities.

2) What would be required to accomplish the proposed reconstitution of such DER devices' sub-metered consumption or generation to the remaining loads reported for settlement of the Load Assets in which the end-use customers with DERs are associated, such that the DER device's consumption or generation is not also reflected in the reported load of those Load Assets.

3) Meter Reader and Host Participant's current capabilities and identification of any increased capabilities needed to provide interval meters and daily reads of those meters for any end-use customer who seeks to be a part of a DER aggregation.

The MRWG will report its initial observations and recommendations for addressing these metering topics at the April 6-7, 2021 MC meeting.

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EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of March 30, 2021

The following activity, as more fully described in the attached litigation report, has occurred since the report dated March 3, 2021 ("last Report") was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

COVID-19

No Activity to Report

I. Complaints/Section 206 Proceedings

	2	Green Development DAF Charges Complaint Against National Grid (ER21-47)	Mar 23	Green Development, SEIA answer National Grid's answer
	3	NECEC/Avangrid Complaint Against NextEra/Seabrook (EL21-6)	Mar 26	Avangrid amends its still-pending Complaint to reflect that aspects of the relief originally requested in its Complaint are no longer feasible within the timeline previously sought; Avangrid requests a FERC order on or before May 7, 2021

II. Rate, ICR, FCA, Cost Recovery Filings

	8	FCA15 Results Filing (ER21-1226)	Mar 4-25	NEPOOL, Calpine, Dominion, Exelon, MA AG, National Grid, NRG, MA DPU intervene
			Mar 15-29	More than 30 private citizens submit comments comment date ***Apr 12, 2021***
	9	Bucksport CIP IROL (Schedule 17) Cost Recovery Period Filing (ER21-957)	Mar 17	FERC accepts filing and rate schedule, eff. Mar 29, 2021
	9	Stonepeak Kestrel CIP IROL (Schedule 17) Cost Recovery Period Filing (ER21-956)	Mar 17	FERC accepts filing and rate schedule, eff. Mar 29, 2021
	9	Mystic 8/9 Cost of Service Agreement (ER18-1639)	Mar 18	CT Parties, ENECOS, Public Systems protest Feb 2021 Compliance Filing
*	11	ISO Securities: Authorization for Future Drawdowns (ES21-34)	Mar 26	ISO requests continued authorization for drawdowns under new Revolving Credit Line and Payment Default Shortfall Fund; comment date ***Apr 16, 2021***

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

*	11	eTariff § I.2 Corrections (ER21-1513)	Mar 25	ISO-NE submits corrections to § I.2 to remove FERC-rejected changes included in subsequent eTariff filing; comment date ***Apr 15, 2021***
			Mar 26	NEPOOL intervenes
	11	Elimination of Price Lock and Zero-Price Offer Rule for New Entrants Starting in FCA16 (ER21-1010)	Mar 8	MA DPU intervenes out-of-time
	12	EER Exemption from PFP Settlement (ER21-943)	Mar 8	Exelon, MA DPU intervene out-of-time
	12	Updated CONE, Net Cone and PPR Values (eff. FCA16) (ER21-787)	Mar 30	ISO-NE files responses to Mar 1 deficiency letter; comment date ***Apr 20, 2021***

V. OATT Amendments / TOAs / Coordination Agreements

*	13	ISO-NE/NYISO Coordination Agreement (ER21-1278)	Mar 5	ISO-NE and NEPOOL file changes that move the ISO-NE/NYISO List of Interconnection Facilities from Schedule A of the Agreement to ISO-NE's website
			Mar 25	National Grid intervenes

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes

	13	Schedule 20A NEP-Vitol Phase I/II HVDC-TF Service Agreement (ER21-1180)	Mar 5	FERC accepts Agreement, eff. Nov 1, 2020
	14	Schedule 21-VP: 2019 Annual Update Settlement Agreement (ER15-1434-004)	Mar 24	Versant Power submits a letter requesting FERC action on uncontested settlement agreement filed Mar 19, 2020

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

	15	Capital Projects Report - 2020 Q4 (ER21-1109)	Mar 4-5	Eversource and National Grid (out-of-time) intervene
*	16	ISO-NE FERC Form 715 (undocketed)	Mar 29	ISO-NE submits 2020 annual report of total MWh of trans. service

IX. Membership Filings

*	16	Suspension Notice – Manchester Methane, LLC (not docketed)	Mar 19	ISO-NE files notice of suspension of Manchester Methane, LLC from the New England Markets

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

	17	Revised Rel. Standards: CIP-013-2, CIP-005-7, CIP-010-4 (RD21-2)	Mar 18	FERC approves revised standard, eff. Oct 1, 2022
	17	CIP Standards Development: Info. Filings on Virtualization and Cloud Computing Services Projects (RD20-2)	Mar 15	NERC submits quarterly informational filing, reporting no change in schedule since that reported in Nov (Reliability Standards assoc. with Projects 2016-02 and 2019-02 to be filed in Dec 2021)

XI. Misc. - of Regional Interest

	19	203 Application: Exelon Generation (EC21-57)	Mar 4, 18	EDF, Old Dominion intervene
			Mar 18	Joint PJM Consumer Advocates file protest
*	20	LGIA Cancellation: CMP / Rumford Power (ER21-1457)	Mar 16	CMP files a notice of cancellation of an expired and replaced LGIA with Rumford Power; comment date ***Apr 6, 2021***
*	19	D&E Agreement: NSTAR/Vineyard Wind (ER21-1285)	Mar 5	Vineyard Wind files D&E Agreement
			Mar 23	MA DPU intervenes
*	20	Related Facilities Agreement: PSNH / NECEC (ER21-1151)	Mar 5	National Grid intervenes

*	20	D&E Agreement: PSNH/NECEC (ER21-1147)	Mar 5	National Grid intervenes
	20	SGIA Cancellation: CL&P/Covanta Wallingford (ER21-867)	Mar 11	FERC accepts notice of cancellation, eff. Jan 11, 2021
	20	LGIA Cancellation: Mt. Tom (ER21-845)	Mar 5	FERC accepts notice of cancellation, eff. Mar 8, 2021
	21	*Orders 864/864-A* (Public Util. Trans. ADIT Rate Changes): New England Compliance Filings (various)	Mar 8 Mar 8 Mar 8 Mar 12	*ER21-1325 (NHT)*. NHT submits changes to Sched. 21-NHT *ER21-1295 (Eversource).* Eversource submits changes to Sched. 21-ES *ER21-1293 (NSTAR)*. NSTAR supplements earlier compliance filings *ER20-2133 (Versant Power)*. Versant responds to Feb 11 deficiency letter

XII. Misc. - Administrative & Rulemaking Proceedings

	22	Resource Adequacy - Modernizing Electricity Mkt Design (AD21-10)	Mar 9 Mar 23 Mar 29	FERC issues supplemental notice of Mar 23, 2021 tech conf FERC holds resource adequacy tech conf; speaker materials posted in eLibrary Ohio PUC Commissioner Conway submits written comments
	22	The Office of Public Participation (AD21-9)	Mar 17-25	FERC holds virtual listening sessions; workshop scheduled ***Apr 16, 2021***
	23	Offshore Wind Integration in RTOs/ISOs Tech Conf (Oct 27, 2020) (AD20-18)	Mar 11	FERC issue notice inviting post-technical conference comments; comment date ***May 10, 2021***
	25	NOPR: Cybersecurity Incentives (RM21-3)	Mar 25	Bureau of Reclamation files comments; comment date ***Apr 6, 2021***
	25	NOPR: Managing Transmission Line Ratings (RM20-16)	Mar 17-23	Over 50 parties file comments, including by ISO-NE, DC Energy, Dominion, EDF, ENEL/EnerNOC, Eversource, Exelon, NRDC, Vistra, EEI, EPRI, EPSA, New England State Agencies, NRECA/LPPC, and Potomac Economics
	26	*Order 2222/2222-A*: DER Participation in ISO/RTO Markets (RM18-9)	Mar 18	FERC issues *Order 2222-A*, addressing arguments on rehearing and setting aside and clarifying in part *Order 2222*
	28	*Order 860/860-A*: Data Collection for Analytics & Surveillance and MBR Purposes (RM16-17)	Mar 18	FERC issues notice seeking comments on proposed changes to the MBR Data Dictionary; delays effectiveness of *Order 860* by 3 months (to Jul 1, 2021); issues supplemental notice of tech workshop to discuss the functionality and features of the MBR Database, moving tech conf to ***Apr 25, 2021***
	32	NOI: Certification of New Interstate Natural Gas Facilities (PL18-1)	Mar 15	Joint Associations request 45-day extension of time to submit comments on NOI; NOI comment date still ***Apr 26, 2021***

XIII. FERC Enforcement Proceedings

*	33	Rover Pipeline, LLC and Energy Transfer Partners, L.P. (IN19-4)	Mar 18 Mar 23 Mar 29	FERC issues show cause order directing Rover and ETP to show cause why they should not be found to have violated Section 157.5 of the FERC's regulations and why they should not be assessed civil penalties in the amount of ***$20.16 million***. Rover/ETP request 60-day extension of time to respond FERC Staff comments on request for extension of time

XIV. Natural Gas Proceedings

34	Atlantic Bridge Project (CP16-9)	Mar 19, 22	Algonquin, NGSA/Center for Liquefied Natural Gas, America and Energy Infrastructure Council request rehearing of Briefing Order
		Mar 23	Cheniere Energy submits comments supporting requests for rehearing
		Mar 5-30	Footprint Power, Town of Weymouth, Weymouth Town Council, 5 private citizens submit comments; initial briefs due ***April 5, 2021***; reply briefs, ***May 5, 2021***

XV. State Proceedings & Federal Legislative Proceedings

37	New England States' Vision Statement / On-Line Technical Forums	Mar 18	Equity and Environmental Justice discussion held; comments due ***Apr 29, 2021***

XVI. Federal Courts

38	CIP IROL Cost Recovery Rules (20-1389)	Mar 8	Cogentrix and Vistra submit corrected Petitioners' Brief
38	Mystic 8/9 Cost of Service Agreement (20-1343; 20-1361, 20-1362; 20-1365, 20-1368) (consolidated)	Mar 25	Court issues order returning this proceeding to its active docket
		Mar 26	Court grants MMWEC, NHEC, NESCOE and ENECOS interventions
39	CASPR (20-1333, 20-1331) (consolidated)	Mar 24	Court grants NEPOOL's intervention in this case; established briefing schedule
		Mar 26	Petitioners request that this case be held in abeyance for 180 days
40	2013/14 Winter Reliability Program Order on Compliance and Remand (20-1289, 20-1366)	Mar 12	FERC files Respondent Brief
40	ISO-NE's Inventoried Energy Program (Chapter 2B) Proposal (19-1224) (consol.)	Mar 30	Petitioners file Reply Brief
41	Order 872 (20-72788) (consol.)	Mar 5	SEIA moves to lift the stay in this proceeding
		Mar 25	Court grants SEIA motion and establishes briefing schedule
41	PennEast Project (18-1128)	Mar 23	Parties file Joint Status Report reporting that none of the events "constitute any of the conditions … triggering an obligation to file a motion governing future proceedings"
42	Opinion 569/569-A: FERC's Base ROE Methodology (16-1325) (consol.)	Mar 10	Petitioners' Briefs filed
		Mar 17	New England Parties file motion to participate as amicus curiae New England Parties file amicus brief in support of Transmission Owning Petitioners
		Mar 24	Intervenors in Support of Petitioners filed their Brief

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 30, 2021

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 30, 2021. If you have questions, please contact us.

COVID-19

- **Jul 8-9 Tech Conf: Impacts of COVID-19 on the Energy Industry (AD20-17)**

On July 8-9, 2020, the FERC convened a Commissioner-led technical conference to explore the potential longer-term impacts of the emergency conditions caused by COVID-19 on FERC-jurisdictional entities "in order to ensure the continued efficient functioning of energy markets, transmission of electricity, transportation of natural gas and oil, and reliable operation of energy infrastructure today and in the future, while also protecting consumers". The conference included consideration of: (i) the energy industry's ongoing and potential future operational and planning challenges due to COVID-19 and as the situation evolves moving forward; (ii) the potential impacts of changes in electric demand on operations, planning, and infrastructure development; (iii) the potential impacts of changes in natural gas and oil demand on operations, planning, and infrastructure development; and (iv) issues related to access to capital, including credit, liquidity, and return on equity. Comments and speaker opening statements are posted in eLibrary.

Interested parties were invited to file, on or before August 31, 2020, post-technical conference comments on any or all of the topics discussed at the July 8-9 technical conference, as well as to respond to the questions outlined in the July 1, 2020 supplemental notice of technical conference. Comments were filed by AEP, APPA, America Forest & Paper, America's Power, EEI, IEEE Power & Energy Society, Clearview Energy Partners, TAPS, Assoc. of Oil Pipelines, Pilot Travel Centers, and Process Gas. This matter remains pending before the FERC.

- **Remote ALJ Hearings (AD20-12)**

All hearings before Administrative Law Judges ("ALJs") are being held remotely through video conference software (WebEx and SharePoint) until further notice.[2] The Presiding Judge in each remote hearing will ensure that the participants have access to an "IT Day" prior to the hearing to allow all participants, witnesses, and the public who will attend the hearing to learn more about the remote hearing software and to get their technical questions answered by the appropriate FERC staff. Uniform Hearing Rules for all Office of the ALJ hearings were adopted effective September 15, 2020.[3] The "Remote Hearing Guidance

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

[2] *Chief Administrative Law Judge's Notices to the Public*, Docket No. AD20-12 (June 17, 2020).

[3] *Chief Administrative Law Judge's Notices to the Public*, Docket No. AD20-12 (Sep. 1, 2020).

for Participants" was revised on September 23, 2020 to make three changes.[4] The Uniform Hearing Rules and Remote Hearing Guidance for Participants are publicly available in this proceeding in eLibrary and on the FERC's Administrative Litigation webpage.

- **Extension of Filing Deadlines (AD20-11)**

On January 22, 2021, the wavier of FERC regulations that require that filings with the FERC be notarized or supported by sworn declarations was further ***extended through July 30, 2021***.[5] The January 25 notice extended the waiver first noticed in May[6] and extended on August 20, 2020.[7] As previously reported, Entities may also seek waiver of FERC orders, regulations, tariffs and rate schedules, including motions for waiver of regulations that govern the form of filings, as appropriate, to address needs resulting from steps they have taken in response to the coronavirus.[8]

- **Blanket Waiver of ISO/RTO Tariff In-Person Meeting and Notarization Requirements (EL20-37)**

On January 25, 2021, the extension of the blanket waivers of ISO/RTO Tariff *in-person*[9] meeting and notarization requirements was further ***extended through July 30, 2021***.[10] The January 25 order extended the blanket waivers first granted in the FERC's April 2, 2020 order and extended in an August 20, 2020 order.[11]

I. Complaints/Section 206 Proceedings

- **Green Development DAF Charges Complaint Against National Grid (EL21-47)**

On February 10, 2021, Green Development, LLC ("Green Development") filed a Complaint against New England Power Company and Narragansett Electric Company (together, "National Grid" or "Grid") requesting a finding that Grid's assessment of Direct Assignment Facility ("DAF") charges for Green Development's projects is unauthorized under the ISO-NE Tariff. Summarizing at highest level, Green Development asserts that the upgrades associated with the interconnection of its distribution-level, sate jurisdictional projects are not DAF as defined in the ISO-NE Tariff. Grid's answer, as well as comments and interventions with respect to the Green Development DAF Complaint were due March 2, 2021. Grid filed its answer on March 2. Solar Energy Industries Association ("SEIA") and Dry Bridge Solar submitted comments supporting the Complaint. Doc-less interventions were filed by Avangrid, Energy Development Partners and New York Transmission Owners ("NY TOs"). On March 23, Green Development and SEIA answered National Grid's March 2 answer. This matter remains pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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[4] *Chief Administrative Law Judge's Notices to the Public*, Docket No. AD20-12 (Sep. 23, 2020) (removing law clerk requirement to share screen when moving exhibits, revising procedures for requesting Live Litigation, and revising witness communication guidance to require that "[c]ommunications with a witness through concealed channels of communications are prohibited while the witness is providing testimony on the witness stand. Communications with a witness are allowed during breaks and when they are not on the witness stand.")

[5] See *Extension of Non-Statutory Deadlines*, Docket No. AD20-11-000 (Jan. 25, 2021).

[6] *Extension of Non-Statutory Deadlines*, Docket No. AD20-11-000 (May 8, 2020).

[7] See *Extension of Non-Statutory Deadlines*, Docket No. AD20-11-000 (Aug. 20, 2020).

[8] *Extension of Non-Statutory Deadlines*, Docket No. AD20-11-000 (Apr. 2, 2020).

[9] The waiver only applies to a specific requirement that meetings be held *in person*. Other than the in-person requirement, such meetings must still be held consistent with the tariff, but should be conducted by other means (e.g. telephonically).

[10] *Temporary Action to Facilitate Social Distancing*, 174 FERC ¶ 61,047 (Jan. 25, 2021).

[11] *Temporary Action to Facilitate Social Distancing*, 171 FERC ¶ 61,004 (Apr. 2, 2020) (waiving notarization requirements through Sep. 1, 2020, contained in any tariff, rate schedule, service agreement, or contract subject to the FERC's jurisdiction under the Federal Power Act ("FPA"), the Natural Gas Act ("NGA"), or the Interstate Commerce Act); *Temporary Action to Facilitate Social Distancing*, 172 FERC ¶ 61,151 (Aug. 20, 2020) (extending the waivers through Jan. 29, 2021).

- **NEPGA Net CONE Complaint (EL21-26)**

Still pending before the FERC is NEPGA's December 11, 2020 complaint against ISO-NE. The Complaint alleged that ISO-NE violated its Tariff and the filed-rate doctrine by recalculating and reviewing with NEPOOL a Net CONE value methodology demonstrably inconsistent with the Tariff and prior practice. NEPGA sought an order directing ISO-NE to recalculate, review with NEPOOL stakeholders, and file with the FERC a Net CONE value consistent with the existing Tariff definition. Should its requested relief be granted, NEPGA asked the FERC to find unjust and unreasonable the Net CONE value for FCAs 16-18 (filed on December 31, *see* ER21-787 in Section III below) and, should there not be sufficient time to allow for completion of stakeholder review before the beginning of the FCA16 calendar (March 2021), NEPGA asked that ISO-NE be directed to apply the Tariff-defined annual adjustment factors to the FCA15 Net CONE value to be used for the FCA16 Net CONE value.

ISO-NE's answer, comments and interventions with respect to the Net CONE Complaint were due December 31, 2020. In its answer, ***ISO-NE*** explained why it acted legally and consistent with its Tariff, and requested a FERC order summarily dismissing or denying NEPGA's Complaint. ***NEPOOL*** filed comments explaining why the Complaint was premature and should be rejected so that NEPGA's arguments could be properly addressed in response to ISO-NE's filing of its proposed updates to CONE, Net CONE and the PPR values. NEPOOL's comments, alternatively, suggested that the Complaint proceeding be held in abeyance pending the outcome of ISO-NE's December 31 Updated CONE, Net CONE and PPR Values filing. Protests were also filed by ***NESCOE***, ***NECOS/ENE***[12] and ***CT State Agencies***.[13] ***EPSA*** filed comments supporting NEPGA's Complaint. Doc-less interventions only were filed by Avangrid, Calpine, Dominion, Eversource, FirstLight, LS Power, MA AG, MMWEC, National Grid, NHEC, NRG, MA DPU, RI PUC, and Public Citizen. On January 8, 2021, NEPGA answered ISO-NE's Answer and the comments and protests filed in response to its Complaint. ISO-NE answered NEPGA's answer on January 25, 2021. 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).

- **NECEC/Avangrid Complaint Against NextEra/Seabrook (EL21-6)**

On March 26, 2021, NECEC Transmission LLC ("NECEC") and Avangrid Inc. (together, "Avangrid") amended their still-pending October 13, 2020 complaint ("Complaint") against NextEra,[14] to reflect that aspects of the relief originally requested in the Complaint are no longer feasible within the timeline previously sought. Avangrid continues to seek expeditious FERC action, requesting in its March 26 filing a FERC order on or before May 7, 2021. As previously reported, the Complaint requested FERC action "to stop NextEra from unlawfully interfering with the interconnection of the New England Clean Energy Connect transmission project ("NECEC Project")." The Complaint sought, among other things, an initial, expedited order that would grant certain relief[15] and direct NextEra to immediately commence engineering, design, planning and procurement activities that are necessary

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[12] "NECOS/ENE" are: Belmont Municipal Light Department, Block Island Utility District, Braintree Electric Light Department, Georgetown Municipal Light Department, Groveland Electric Light Department, Hingham Municipal Lighting Plant, Littleton Electric Light Department, Merrimac Municipal Light Department, Middleborough Gas & Electric Department, Middleton Electric Light Department, North Attleborough Electric Department, Norwood Light & Broadband Department, Reading Municipal Light Department, Rowley Municipal Lighting Plant, Stowe Electric Department, Taunton Municipal Lighting Plant, and Wallingford Department of Public Utilities Electric Division (collectively, "NECOS"); and Energy New England, LLC ("ENE").

[13] "CT Agencies" are: the Connecticut Department of Energy and Environmental Protection ("CT DEEP"), William Tong, Attorney General for the State of Connecticut ("CT AG"), the Connecticut Public Utilities Regulatory Authority ("CT PURA") and the Connecticut Office of Consumer Counsel ("CT OCC")

[14] For purposes of this Complaint proceeding, "NextEra" is short for NextEra Energy Resources, LLC ("NextEra Energy Resources"), NextEra Energy Seabrook, LLC ("NextEra Seabrook"), FPL Energy Wyman LLC ("Wyman"), and FPL Energy Wyman IV LLC ("Wyman IV").

[15] Directing NextEra to comply with the ISO-NE OATT, to comply with open access requirements, and to cease and desist unlawful interference with the NECEC Project; and to have the FERC temporarily revoke NextEra's blanket waiver under Part 358 of the FERC's regulations and to initiate an investigation and require NextEra to preserve and provide documents related to the interconnection of the NECEC Project.

for NextEra to construct the generator owned transmission upgrades during Seabrook Station's Planned 2021 Outage.

Comments on the Complaint were due on or before November 2, 2020. On November 2, NextEra submitted an answer to the Complaint (requesting the FERC dismiss or deny the Complaint) and National Grid filed comments. Doc-less interventions were filed by Dominion, Eversource, Calpine, Exelon, HQ US, MA AG, MMWEC National Grid, NESCOE, NRG, and Public Citizen. On November 17, Avangrid submitted an answer to NextEra's November 2 Answer. On November 30, NextEra answered Avangrid's November 17 answer ("supplemental answer"), repeating its request that the FERC dismiss or deny the Complaint. Avangrid answered the November 30 supplemental answer on December 7, 2020. 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).

- **NextEra Energy Seabrook Declaratory Order Petition re: NECEC Elective Upgrade Costs Dispute (EL21-3)**

In a related matter initiated a week earlier, NextEra Energy Seabrook, LLC ("Seabrook") filed a Petition for a Declaratory Order ("Petition") "by which it seeks to understand the scope of its FERC-jurisdictional regulatory obligations with respect to the project ("NECEC Elective Upgrade"), and to resolve its dispute with NECEC". Specifically, Seabrook asked the FERC to declare that: (1) Seabrook is not required to incur a financial loss to upgrade, for NECEC's sole benefit, a 24.5 kV generator circuit breaker and ancillary equipment ("Generation Breaker") at Seabrook Station; (2) "Good Utility Practice" for replacement of the nuclear plant Generation Breaker is defined in terms of the practices of the nuclear power industry, such that Seabrook's proposed definition of that term is appropriate for use in a facilities agreement with NECEC; and (3) Seabrook will not be liable for consequential damages for the service it provides to NECEC under a facilities agreement (collectively, the "Requested Declarations"). Alternatively, Seabrook asked that the FERC declare that nothing in ISO-NE's Tariff requires Seabrook to enter into an agreement to replace the Generation Breaker, and therefore, Seabrook and the Joint Owners are entitled to bargain for appropriate terms and conditions to recover their costs, to define Good Utility Practice, and to limit liability associated with providing the service ("Alternative Declaration").

Comments on Seabrook's Petition were due on or before November 4, 2020, and were filed by Eversource, MMWEC and NEPGA. Avangrid and NECEC Transmission ("Avangrid") protested the Declaratory Order. Doc-less interventions were filed by Avangrid, Dominion, Eversource, Calpine, Exelon, HQ US, National Grid, NESCOE, NRG, and Public Citizen. On November 19, NextEra answered Avangrid's protest. On December 4, Avangrid answered NextEra's November 19 answer. This matter is also pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **New England Generators' Exelon Complaint (EL20-67)**

Still pending is the New England Generators'[16] August 25, 2020 complaint against Exelon.[17] As previously reported, the Complaint requested that, if and to the extent the FERC does not grant all relief requested by the New England Generators in its August 27, 2020 request for clarification and/or rehearing of the *July 17 Orders* in the Mystic 8/9 Cost of Service Agreement ("COS Agreement") proceeding (*see* ER18-1639 below), the FERC should find that the new information about Exelon's two new queue positions and Exelon's intention to continue to operate Everett beyond the term of the Mystic Agreement makes the existing rate in the Mystic Agreement unjust and unreasonable. New England Generators further requested that the FERC change the Mystic Agreement to: (i) apply the clawback mechanisms to Exelon's two new interconnection queue positions (to prevent Exelon from using interconnection queue positions for "new" or "repowered" units to skirt restrictions imposed on Mystic's recovery of costs pursuant to the COS Agreement); (ii) delete or give no meaning to the words "that were expensed" (in order to prevent Exelon from shielding costs paid for by captive ratepayers from the application of

[16] "New England Generators" are Vistra, Dynegy Marketing and Trade, NextEra Energy Resources, NRG Power Marketing, LS Power Associates, FirstLight Power, and Cogentrix Energy Power Management.

[17] For purposes of this Complaint, "Exelon" is short for Constellation Mystic Power, LLC ("Mystic"), Exelon Generation Company, LLC ("Exelon Generation") and Exelon Corporation ("Exelon Corp.").

the COS Agreement's clawback provision); and (iii) require that Mystic return any of the undepreciated Everett repair and capital expenditure costs in the event that Mystic 8 or 9 return to the market after the end of the COS Agreement.

Exelon's answer and all interventions or protests were due on or before September 14, 2020. In addition to Exelon's answer, comments supporting the Complaint were filed by NESCOE, Public Systems[18] and Connecticut Parties.[19] On September 28, NEPGA answer Exelon's answer. Calpine, ENE, Eversource, Massachusetts Attorney General ("MA AG") National Grid, and Public Citizen filed doc-less interventions. The Complaint, as well as all of the pleadings in response, remain 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).

- **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 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%

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[18] "Public Systems" are Mass. Municipal Wholesale Elec. Co. ("MMWEC") and New Hampshire Elec. Coop., Inc. ("NHEC").

[19] "Connecticut Parties" are CT PURA, CT DEEP, and the CT OCC.

[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 clarif.*, 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" (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, 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.

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 the four currently pending New England proceedings (*see*, however, *Opinion 569-A*[30] (EL14-12; EL15-45) in Section XI below). The FERC established a paper hearing on how its proposed methodology should apply to the four pending ROE proceedings.[31]

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

[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*").

[30] *Ass'n of Buss. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569-A, 171 FERC ¶ 61,154 (2020) ("*Opinion 569-A*"). The refinements to the FERC's ROE methodology included: (i) the use of the Risk Premium model instead of only relying on the DCF model and CAPM under both prongs of FPA Section 206; (ii) adjusting the relative weighting of long- and short-term growth rates, increasing the weight for the short-term growth rate to 80% and reducing to 20% the weight given to the long-term growth rate in the two-step DCF model; (iii) modifying the high-end outlier test to treat any proxy company as high-end outlier if its cost of equity estimated under the model in question is more than 200% of the median result of all the potential proxy group members in that model before any high- or low-end outlier test is applied, subject to a natural break analysis. This is a shift from the 150% threshold applied in *Opinion 569*; and (iv) calculating the zone of reasonableness in equal thirds, instead of using the quartile approach that was applied in *Opinion 569*.

[31] *Id.* at P 19.

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%.[32] 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[33] 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, 2019. 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.

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*[34] 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, 2020, EMCOS and CAPs opposed the TOs' request and brief.

These matters remain 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).

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[32] *Id.* at P 59.

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

[34] *Ass'n of Buss. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569, 169 FERC ¶ 61,129 (2019) ("*MISO ROE Order*"), *order on reh'g*, Opinion No. 569-A, 171 FERC ¶ 61,154 (May 21, 2020).

II. Rate, ICR, FCA, Cost Recovery Filings

- **FCA15 Results Filing (ER21-1226)**

On February 26, 2021, ISO-NE filed the results of the fifteenth FCA ("FCA15") held February 8, 2021. ISO-NE reported the following highlights:

- ♦ FCA15 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), the Maine Capacity Zone (the Maine Load Zone) and the Rest-of-Pool ("ROP") 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.
- ♦ FCA15 commenced with a starting price of $13.932/kW-mo. and concluded for all Capacity Zones after five rounds.
- ♦ Capacity Clearing Prices were as follows (prices expressed per kw-mo.): SENE - $3.980; NNE and Maine - $2.477; ROP - $2.611; imports over the NY AC Ties (684 MW) and the Phase I/II HQ Excess external interface (517 MW) - $2.611; imports over Highgate (60 MW) and New Brunswick (226 MW) - $2.477.
- ♦ 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 FCA15 rates and results, effective June 26, 2021.

Comments on this filing are due on or before April 12, 2021. Thus far, NEPOOL, NESCOE, Calpine, Dominion, Exelon, MA AG, National Grid, NRG, MA DPU, and Public Citizen have filed doc-less interventions. Comments from more than 30 individual citizens have also been filed, largely focused on environmental issues, and the Merrimack Generating Station in particular. 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).

- **Essential Power Newington CIP IROL (Schedule 17) Cost Recovery Period Filing (ER21-1171)**

On February 18, 2021, Essential Power Newington, LLC ("EP Newington") requested FERC acceptance of a proposed rate schedule to allow EP Newington to begin the recovery period for certain Interconnection Reliability Operating Limits Critical Infrastructure Protection costs under Schedule 17 of the ISO-NE Tariff ("CIP-IROL Costs"). EP Newington stated that the rate schedule will provide interested parties notice of EP Newington's intent to recover CIP-IROL Costs for each affiliated facility designated as an IROL-Critical Facility, and an order accepting the rate schedule will provide an effective date after which associated costs incurred can be recovered following completion of the process contemplated by Schedule 17 and a subsequent section 205 filing identifying the specific costs to be recovered. A February 18, 2021 effective date was requested. Comments on this filing were due on or before March 11, 2021; none were filed. NESCOE filed a doc-less intervention. 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).

- **Bucksport CIP IROL (Schedule 17) Cost Recovery Period Filing (ER21-957)**

On March 17, 2021, the FERC accepted, effective March 29, 2021, the rate schedule filed by Bucksport Generation LLC ("Bucksport") to allow it to begin the recovery period for certain CIP-IROL Costs.[35] Unless the March 17 Bucksport order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Stonepeak Kestrel CIP IROL (Schedule 17) Cost Recovery Period Filing (ER21-956)**

Also on March 17, 2021, the FERC accepted effective March 29, 2021, the rate schedule filed by Stonepeak Kestrel Energy Marketing LLC to allow it to begin the recovery period for certain CIP-IROL Costs.[36] Unless the March 17 Stonepeak Kestrel order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Amended and Restated IRH Support and Use Agreements (ER21-712)**

On December 18, 2020, New England Hydro-Transmission Electric Company, Inc.; New England Hydro-Transmission Corporation; New England Electric Transmission Corporation; and Vermont Electric Transmission Company (collectively the "Asset Owners") and the IRH Management Committee ("IMC") on behalf of the renewing Interconnection Rights Holders ("IRH") submitted for approval an Offer of Settlement that amends and restates four Support Agreements and an Agreement with Respect to Use of Québec Interconnection ("Use Agreement")[37] to provide for ongoing financial support of, and related rights and obligations with respect to, the United States portion of the 2,000 MW high-voltage, direct current ("HVDC") transmission facilities interconnecting New England and Québec. The initial term of the existing Support Agreements was scheduled to end on October 31, 2020, and the Use Agreement by its own terms will remain in effect though the term of the last Support Agreement to expire. The filing extends the term of those Support Agreements (and thereby the Use Agreement) another 20 years, until October 31, 2040. A January 1, 2021 effective date was requested. Comments on this filing were due on or before January 8, 2021; none were filed. Avangrid, ENE, NESCOE, and Eversource (out-of-time) filed doc-less interventions. This matter is still pending before the FERC. If you have any questions concerning these matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

As previously reported, the FERC issued four orders in this proceeding in July 2020 (three on July 17 (together, the "*July 17 Orders*"); one on July 28, 2020). Each of the orders addressed in part or in whole the Cost-of-Service Agreement ("COS Agreement")[38] among Constellation Mystic Power ("Mystic"), Exelon Generation Company ("ExGen") and ISO-NE, which is to provide compensation for the continued operation of the Mystic 8 & 9 units from June 1, 2022 through May 31, 2024. As noted in Section XV below, each of the *July*

[35] *Bucksport Generation LLC*, Docket No. ER21-957 (Mar. 17, 2021) (unpublished letter order).

[36] *Stonepeak Kestrel Energy Marketing LLC*, Docket No. ER21-956 (Mar. 17, 2021) (unpublished letter order).

[37] The Support Agreements are separate contracts between the IRH and each of the Asset Owners under which the IRH agree to financially support the elements of the Phase I/II HVDC-TF owned by each Asset Owner in exchange for rights to use the transmission capacity of the Phase I/II HVDC-TF to transmit power to and from the HQ system ("Use Rights"). The Use Agreement is a contract among the IRH that provides the rules for the exercise of the Use Rights, for making the Use Rights available to others, and for the collective management of those individual contractual rights through the IRH Management Committee.

[38] 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.

17 Orders[39] (and the earlier, underlying orders) have been appealed to the DC Circuit. Three aspects of this proceeding are pending before the FERC:

ROE Paper Hearings (-000). The *Dec 2018 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, 2019, Mystic, CT Parties,[40] ENECOS,[41] MA AG, and FERC Trial Staff filed initial briefs. On July 18, 2019, Constellation Mystic Power, CT Parties, ENECOS, MA AG, National Grid, FERC Trial Staff filed reply briefs. In a July 28, 2020 order,[42] the FERC reopened the record to allow parties an opportunity to present written evidence applying the FERC's *Opinion 569-A* ROE methodology to the facts of this proceeding. CT Parties, EMCOS, MA AG, and FERC Trial Staff filed their initial "Opinion 569-A" briefs on September 28, 2020. Responses to those initial briefs were due October 28, 2020 and were filed by Mystic, CT Parties, ENECOS, and FERC Trial Staff. The ROE issue is now pending before the Commission.

Sep 2020 Compliance Filing (-007). On September 15, 2020, Mystic filed a revised COS Agreement in response to the requirements of the *July 17 Compliance Order*. Also included were typographical edits proposed by NESCOE in its protest of the First Compliance Filing. Mystic also filed revisions to the Fuel Security Agreement ("FSA") for informational purposes because some of the compliance directives required changes to the FSA. Comments on the Sep 2020 Compliance Filing were due on or before October 6, 2020. CT Parties and ENECOS protested the compliance filing. On October 21, 2021, Mystic answered the CT Parties' and ENECOS' protests. The September compliance filing remains pending before the FERC.

Feb 2021 Compliance Filing (-008). On February 25, 2021, Mystic filed a revised COS Agreement in a third compliance filing, this time in response to the requirements of the FERC's *Dec 21, 2020 Third Compliance Order*.[43] The Feb 2021 Compliance Filing proposes changes to section 2.4 of the COS Agreement to align that section with the FERC's direction that the Agreement's clawback mechanism apply to costs "that are incurred" rather than those that "that were expensed." Comments on the third compliance filing were due on or before March 18, 2021. CT Parties, ENECOS and Public Systems[44] filed protests of the third compliance filing, which is also pending before the FERC.

If you have questions on any aspect of 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 Settlement Agreement (ER15-1429-014)**

On December 28, 2020, Versant Power submitted an uncontested Joint Offer of Settlement between itself, MPUC, MOPA, and the MCG to resolve certain issues raised by the MPUC and the MCG with regards to Versant Power's annual charges update under the Open Access Transmission Tariff for Maine Public District

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[39] The "*July 17 Orders*" are the *July 2018 Rehearing Order, Dec 2018* Rehearing *Order* and the *July 17 Compliance Order. Constellation Mystic Power, LLC,* 164 FERC ¶ 61,022 (July 13, 2018) ("*July 2018 Order*"), *clarif. granted in part and denied in part, reh'g denied*, 172 FERC ¶ 61,043 (July 17, 2020) ("*July 2018 Rehearing Order*"); *Constellation Mystic Power, LLC*, 165 FERC ¶ 61,267 (Dec. 20, 2018) ("*Dec 2018 Order*"), *set aside in part, clarification granted in part and clarification denied in part*, 172 FERC ¶ 61,044 (July 17, 2020) ("*Dec 2018* Rehearing *Order*"); *Constellation Mystic Power, LLC*, 172 FERC ¶ 61,045 (July 17, 2020) ("*July 17 Compliance Order*") (order on compliance and directing further compliance).

[40] "CT Parties" are: Conn. Pub. Utils. Regulatory Authority ("CT PURA"), the Conn. Dept. of Energy and Envir. Protection ("CT DEEP"), and the Conn. Office of Consumer Counsel ("CT OCC").

[41] "ENECOS" are: Braintree, Concord, Georgetown, Hingham, Littleton, Middleborough, Middleton, Norwood, Pascoag, Reading, Taunton, and Wellesley.

[42] *Constellation Mystic Power, LLC*, 172 FERC ¶ 61,093 (July 28, 2020), *order addressing arguments on reh'g*, 173 FERC ¶ 61,261 (Dec. 21, 2020).

[43] *Constellation Mystic Power, LLC*, 173 FERC ¶ 61,261 (2020) ("*Dec 21, 2020 Third Compliance Order*")

[44] "Public Systems" are Mass. Mun. Wholesale Electric Co. ("MMWEC") and New Hampshire Elec. Coop. ("NHEC").

("MPD OATT"), as filed in Docket No. ER15-1429-000 on May 1, 2019, and revised on May 16, 2019 (together, the "2019 Annual Update").[45] Initial comments and reply comments were due January 18 and 27, 2021, respectively; none were filed. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **ISO Securities: Authorization for Future Drawdowns (ES21-34)**

On March 26, 2021, ISO-NE requested the necessary FERC authorization for drawdowns under a new $20 million Revolving Credit Line and a new $4 million line of credit supporting the Payment Default Shortfall Fund, each of which are with TD Bank, are for a term of three years ending June 30, 2024, and replace similar arrangements that will expire June 30, 2021.[46] Comments on this filing are due on or before April 18. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

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

- **eTariff § I.2 Corrections (ER21-1513)**

On March 25, 2021, ISO-NE filed corrections to its eTariff to remove from Section I.2 previously-rejected changes (proposed in the April 15, 2020 Energy Security ("ESI") Initiatives filing (ER20-1567)) that were also included as part of an April 16, 2020 filing accepted by the FERC that extended the implementation date of the Settlement-Only Generator Dispatchability Changes (ER20-1582). Comments on this filing are due on or before April 15, 2021. Thus far, NEPOOL has intervened doc-lessly. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Elimination of Price Lock and Zero-Price Offer Rule for New Entrants Starting in FCA16 (ER21-1010)**

In response to the requirements of the *December 2 Order*,[47] ISO-NE submitted on February 1, 2021, Tariff revisions eliminating the price lock and associated zero-price offer rule for new entrants starting in FCA16. The ISO-NE's proposed compliance changes were supported by the Participants Committee at its February 4 meeting (Consent Agenda Item No. 4). Comments on ISO-NE's filing were due on or before February 22, 2021. Comments supporting the Tariff revisions were filed by NEPOOL (February 9) and NEPGA (February 23). No adverse comments were filed. Doc-less interventions were filed by BSW ProjectCo, Calpine, Eversource, National Grid, NESCOE, and NRG. On March 8, the MA DPU intervened out-of-time. This matter is pending before the FERC.

As described in previous Reports, the FERC, in response to a February 2, 2018 remand by the United States Court of Appeals for the District of Columbia Circuit ("DC Circuit"),[48] found preliminarily that ISO-NE's new entrant

[45] As previously reported, MCG moved to strike the true-up to actuals portion of the 2019 Annual Update to the extent that the true-up proposed 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 the formula rate, otherwise required to effect only prospectively).

[46] *See ISO New England Inc.*, 139 FERC ¶ 62,248 (June 22, 2012) (initially authorizing borrowings through June 30, 2014); *ISO New England Inc.*, 147 FERC ¶ 62,091 (May 6, 2014) (continuing authorization through June 30, 2015); *ISO New England Inc.*, 151 FERC ¶ 62,185 (June 15, 2015) (continuing authorization through June 30, 2017); *ISO New England Inc.*, 159 FERC ¶ 62,143 (May 9, 2017) (continuing authorization through June 30, 2019); *ISO New England Inc.*, 163 FERC ¶ 62,144 (June 1, 2018) (continuing authorization through May 31, 2020); *ISO New England Inc.*, 172 FERC ¶ 62,017 (July 13, 2020) (continuing authorization through July 12, 2022).

[47] *ISO New England Inc.*, 173 FERC ¶ 61,198 (Dec. 2, 2020) ("*December 2 Order*") (finding the price-lock mechanism and zero-price offer rule ("New Entrant Rules") no longer just and reasonable and directing ISO-NE to remove the New Entrant Rules from the Tariff).

[48] *New England Power Generators Assoc. v FERC*, 881 F.3d 202 (DC Cir. 2018) (granting NEPGA's and Exelon's petitions for review of orders accepting the Forward Capacity Market's ("FCM") 7-year price lock-in (EL14-7) and capacity-carry-forward rules (EL15-23) after finding that the FERC did not adequately explain why it allowed ISO-NE to forego an offer floor for its seven-year price lock period despite previously rejecting PJM's request to remove the offer floor for its three-year price lock period).

rules may be unjust and unreasonable.[49] The FERC established paper hearing procedures, which included one round of briefs and reply briefs submitted in the late summer and early fall of 2020.[50] The *December 2 Order* found the New Entrant Rules no longer just and reasonable and directed ISO-NE to remove them from the Tariff.[51]

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).

- **EER Exemption from PFP Settlement (ER21-943)**

On January 26, 2021, ISO-NE filed revisions to the Tariff (including related revisions to the FAP) to exclude energy efficiency resources ("EERs") from Pay-for-Performance ("PFP") obligations and settlement in all hours. EER capacity base payments are unaffected. The EER Exemption was considered, but not supported, by the Participants Committee at its October 2, 2020 meeting. The related FAP revisions were considered but were supported by the Participants Committee at the same meeting. An April 1, 2021 effective date was requested.[52] Comments on this filing were due on or before February 16, 2021. Comments supporting the revisions were filed by: NEPOOL; the ISO-NE Internal Market Monitor ("IMM"); LS Power Development, Helix Maine Wind Development, Ocean State Power, and Wallingford Energy (collectively, the "LS Power companies"); and NEPGA. AEE filed comments protesting the revisions, which ISO answered on March 3, 2021. Doc-less interventions were filed by Calpine, Dominion; Eversource, MA AG, National Grid, NESCOE, NRG, and Vistra. On March 8, Exelon and the MA DPU intervened 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).

- **Updated CONE, Net Cone and PPR Values (eff. FCA16) (ER21-787)**

On December 31, 2020, ISO-NE filed changes to update the Cost of New Entry ("CONE"), Net CONE, and Payment Performance Rate ("PPR") values beginning with FCA16. The values in this filing are the same CONE, Net CONE and PPR values that the NPC approved at its December 5 meeting as part of a broader FCM updates package; however, this filing did not include the updated Offer Review Trigger Prices ("ORTPs"), which were part of the broader package, and on which NEPOOL and ISO-NE will propose alternative values in a jump ball filing to be submitted later this month. ISO-NE explained in its filing that, if the schedule for FCA16 is to be maintained, the updated CONE, Net CONE and PPR values need to be acted on by the FERC and become effective by early March, 2010 (a March 2, 2021 effective date was requested). ISO-NE stated that the revised ORTPs and related Tariff changes, however, do not need to be effective until slightly later in the FCA16 qualification process (thereby permitting a slightly later submission of, and FERC action on, the various ORTPs and related Tariff changes). Because NEPOOL did not vote on the CONE, Net CONE and PPR values separately, but rather as part of a broader package with the alternative ORTP provisions, NEPOOL did not join this ISO-NE filing but will provide comments in response to the filing explaining the December 5 NEPOOL vote on the package of proposed FCM parameters.

Comments on this ISO-NE filing were due on or before January 21, 2021. Comments were filed by NEPOOL, MMWEC, NESCOE, and CT Agencies. Protests were filed by CPV Towantic, Dominion, FirstLight, NEPGA,

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[49] *ISO New England Inc.*, 172 FERC ¶ 61,005 (July 1, 2020) ("*FCM Pricing Rules Complaints Remand Order*").

[50] Initial briefs, due Aug. 24, 2020, were filed by ISO-NE, ISO-NE External Market Monitor ("EMM"), MA AG, NEPGA, NRG, and RENEW Northeast. NEPOOL filed limited comments (urging the FERC, should it conclude that the Tariff is unjust and unreasonable and/or unduly discriminatory, to allow sufficient time and flexibility to permit meaningful opportunities for New England stakeholders to work with ISO-NE to develop any required market adjustments through the complete NEPOOL Participant Processes). Responses to the initial briefs were due Sept. 23, 2020 and were filed by Responses to the initial briefs were due September 23, 2020 and were filed by ISO-NE, BSW Project Co, MA AG, NEPGA, MA AG, CT PURA, PJM IMM, and RENEW/ESA. No additional answers or briefs were permitted. No additional answers or briefs were permitted.

[51] *December 2 Order* at PP 1, 77.

[52] ISO-NE requested in the alternative, that the revisions be accepted effective with FCA16 (June 1, 2025) should the FERC not grant an Apr. 1, 2021 effective date.

and NEI. Doc-less interventions were filed by Avangrid, Brookfield, BSW Project Co, Calpine, Cogentrix, Dominion, Eversource, CT AG, CT OCC, CT DEEP, CT PURA, LS Power, MA AG, National Grid (out-of-time), NESCOE, NHEC, NRG, Vistra, EPSA, and MA DPU (out-of-time). On February 12, ISO-NE answered the protests filed. On February 16 and 17, answers to ISO-NE's February 12 answer were filed by EPSA, NEPGA and CPV Towantic.

March 1, 2021 Deficiency Letter. On March 1, 2021, the FERC issued a deficiency letter, directing ISO-NE to provide within 30 days additional information, including the following: (i) an example of a potential site for the reference unit (in or near New London County, CT) that is two miles from both a main natural gas transmission line and the point of interconnection to the electric grid; (ii) an estimate of NOx emissions limit and whether those limits affect the reference unit's revenues; and (iii) additional support for the assumption that the reference unit always runs on natural gas rather than oil in the dispatch model. The responses to the Deficiency Letter were due on or before March 31, 2021 and were filed by ISO-NE on March 30, 2021. ISO-NE's submission of the additional information re-set the 60-day deadline for FERC action on this filing.

If you have any questions concerning this proceeding, please contact Dave Doot (dtdoot@daypitney.com; 860-275-0102), Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

IV. OATT Amendments / TOAs / Coordination Agreements

- **ISO-NE/NYISO Coordination Agreement (ER21-1278)**

On March 5, 2021, ISO-NE and NEPOOL jointly filed changes to the ISO-NE/NYISO Coordination Agreement to move the ISO-NE/NYISO Interconnection Facilities List, including associated descriptions of the Interties and common metering points, from Schedule A of the ISO-NE/NYISO Coordination Agreement to ISO-NE's public website. The Participants Committee unanimously supported the Coordination Agreement changes at its November 5, 2020 meeting (Consent Agenda Item No. 2). Comments on this filing were due on or before March 26, 2021; none were filed. National Grid filed a doc-less motion to intervene. 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).

- ***Order 676-I* Compliance Filing (ER21-941)**

On January 26, 2021, ISO-NE and NEPOOL, in response to *Order 676-I*, jointly filed changes to incorporate by reference in Schedule 24 of the OATT 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"). The Participants Committee unanimously supported the *Order 676-I* revisions at its May 7, 2020 meeting. Comments on this filing were due on or before February 16, 2021; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes

- **Schedule 20A NEP-Vitol Phase I/II HVDC-TF Service Agreement (ER21-1180)**

On February 19, 2021, New England Power Company ("NEP") submitted a new Phase I/II HVDC-TF Service Agreement between NEP and Vitol Inc. ("Vitol"). The Service Agreement, based on the *pro forma* Phase I/II HVDC-TF Service Agreement set forth in Schedule 20A-Common Attachment A, provides for firm point-to-point transmission service over the Phase I/II HVDC transmission facilities ("Phase I/II HVDC-TF") for the November 1, 2020 to November 1, 2025 period. The Agreement was filed separately because it contains potentially non-conforming terms that provide Vitol a right to terminate the Agreement if it finds unacceptable the terms and conditions of the Amended and Restated IRH Support and Use Agreements pending in ER21-712 (*see* Section II above). NEP requested a November 1, 2020 effective date for Agreement. Comments on this filing were due on or before March 12, 2021; none were filed. Vitol submitted a doc-less intervention. This matter is pending before the FERC. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Schedule 20A-VP: Versant Power-Vitol Phase I/II HVDC-TF Service Agreement (ER21-827)**

On March 5, the FERC accepted the non-conforming Phase I/II HVDC-TF Service Agreement for firm service under Schedule 20A-VP between Versant Power and Vitol Inc. ("Vitol").[53] The Agreement was accepted effective as of November 1, 2020, as requested. Unless the March 5 order is challenged, this proceeding will be concluded. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Schedule 21-VP: 2019 Annual Update Settlement Agreement (ER15-1434-004)**

Emera Maine's (now Versant Power) joint offer of settlement, filed March 19, 2020, between itself and the MPUC to resolve all issues raised by the MPUC in response to Emera Maine's 2019 annual charges update filed, as previously reported, on June 10, 2019 (the "Emera 2019 Annual Update Settlement Agreement"). Under Part V of Attachment P, "Interested Parties shall have the opportunity to conduct discovery seeking any information relevant to implementation of the [Attachment P] Rate Formula. . . ." and follow a dispute resolution procedure set forth there. In accordance with those provisions, the MPUC identified certain disputes with the 2019 Annual Update, all of which are resolved by the Emera 2019 Annual Update Settlement Agreement. Comments on the Emera 2019 Annual Update Settlement Agreement were due on or before April 9, 2020; none were filed. Since the last Report, on March 24, 2021, Versant Power filed a letter requesting FERC action. This matter continues to be pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-VP: 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 Order,*[54] and certified by Settlement Judge Dring[55] to the Commission,[56] 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 of the BHD OATT and $260,000 under the MPD OATT. If you

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[53] *Versant Power*, Docket No. ER21-827 (Mar. 5, 2021) (unpublished letter order).

[54] *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.

[55] 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.

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

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

- **Schedule 21-GMP Annual True Up Calculation Forecast Info Report (ER12-2304)**

  On January 15, 2021, pursuant to Section 4 of Schedule 21-GMP, Green Mountain Power ("GMP") supplemented its annual informational filing containing the forecast of its costs for the January 1, 2021 through December 31, 2021 time period. The supplement does not change the 2021 forecasted rates previously filed, but does contain a material accounting change to adjust the 2021 charges billed under the Formula Rate in connection with the sale of its share of the Highgate facility. GMP also disclosed that it is not using historical ADIT for this forecast. The FERC will not notice this filing for public comment, and absent further activity, no further FERC action is expected. If there are questions on this matter, 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*[57] *and 531-B*[58] 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).

- **Capital Projects Report - 2020 Q4 (ER21-1109)**

  On February 11, 2021, ISO-NE filed its Capital Projects Report and Unamortized Cost Schedule covering the fourth quarter ("Q4") of calendar year 2020 (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 II ($4.79 million); (ii) Integrated Market Simulator Phase 1 ($1.6 million); (iii) FCM Qualification Enhancements ($1.2 million); (iv) CIP Electronic Security Perimeter Redesign ($1.1 million); (v) Sub-accounts for FTR Market ($0.98 million); (vi) Enterprise Phone System Upgrade ($701,300); (vii) Wireless Infrastructure Upgrade ($548,900); (viii) Time Entry System Upgrade ($398,200); (ix) Ownership Transfer & External Registration ($382,700); (x) PI Historian for Short-term PMU Data Repository ($368,800); (xi) Annual Maintenance

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

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

Schedule Automation ($315,800); and (xii) FERC Form 1, 3-Q and 714 Project ($162,400). There were no significant changes for Chartered Projects in 2020 Q4. Comments on this filing are due on or before March 4, 2021. NEPOOL filed comments on February 17 supporting the Q4 Report. Eversource and National Grid (out-of-time) submitted doc-less interventions. 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).

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

On March 29, ISO-NE submitted its 2020 Annual Transmission Planning and Evaluation Report. These filings are not noticed for public comment.

IX. Membership Filings

- **March 2021 Membership Filing (ER21-1228)**

On February 26, 2021, NEPOOL requested that the FERC accept: (i) the membership of Trafigura Trading LLC (Supplier Sector); (ii) the termination of Axon Energy (Supplier Sector) and Springfield Power [Related Person to Stored Solar J&WE, LLC (AR Sector)]; and (iii) to reflect Titan Gas LLC's d/b/a as CleanSky Energy. Comments on this filing were due on or before February 19, 2021; none were filed. This matter is pending before the FERC.

- **February 2021 Membership Filing (ER21-1008)**

On January 29, 2021, NEPOOL requested that the FERC accept: (i) the memberships of the following: Axpo U.S. LLC (Supplier Sector); Catalyst Power & Gas, LLC (Supplier Sector); Palm Energy LLC (Provisional Member); Madison ESS, LLC [Related Person to Madison BTM and New England Battery Storage (Generation Group Seat)]; Rumford ESS, LLC [Related Person to Madison BTM and New England Battery Storage (Generation Group Seat)]; Vineyard Reliability LLC (Generation Group Seat); West Medway II, LLC [Related Person to Exelon Generation Company and Constellation NewEnergy, Inc. (Supplier Sector)]; and Dick Brooks (End User Sector, Governance Only Member); (ii) the termination of the Participant status of: Energy Federation Inc. ("EFI") (AR Sector, LR Sub-Sector, Small LR Group Seat); Great American Power, LLC (Supplier Sector); Oasis Power, LLC d/b/a Oasis Energy [Related Person to Spark Energy et al., (Supplier Sector)]; Praxair, Inc. (End User Sector); Rubicon NYP Corp. (Supplier Sector); and Verde Group, LLC (Provisional Member); and (iii) the Name change of Utility Services of Vermont (f/k/a Utility Services, Inc.). Comments on this filing were due on or before February 22, 2021; none were filed. This matter is pending before the FERC.

- **Invenia Additional Conditions Informational Filing (ER20-2001)**

Still pending before the FERC is the June 5, 2020 informational filing submitted by ISO-NE pursuant to Section II.A.1(b) of the FAP identifying the additional condition (supplemental financial assurance) required of Invenia for participation in the New England Markets. The additional condition was supported, and made a condition of Invenia's membership, by the Participants Committee at its June 4, 2020 meeting. A doc-less intervention was submitted by Public Citizen. This informational filing is still pending before the FERC.

- **Suspension Notice (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 Market Participant was suspended from the New England Markets on the date indicated (at 8:30 a.m.) due to a Financial Assurance Default:

Date of Suspension/ FERC Notice	*Participant Name*	*Default Type*	*Date Reinstated*
Mar 17/19	Manchester Methane, 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).

- **Revised Reliability Standard: FAC-008-5 (RD21-4)**

On February 19, 2021, NERC filed for approval proposed changes to Reliability Standard FAC-008-5 (Facility Ratings). FAC-008-5 reflects the retirement of Requirement R7, recommended as part of NERC's Standards Efficiency Review because of its redundancy with requirements in other Reliability Standards. NERC asked that FAC-008-5 become effective (and the currently effective versions be retired) on the first day of the first calendar quarter that is three months following FERC approval. Comments on FAC-008-5 were due on or before March 22, 2021; none were filed. This matter is pending before the FERC.

- **Revised Reliability Standards: CIP-013-2, CIP-005-7, CIP-010-4 (RD21-2)**

On March 18, 2021, the FERC approved changes to Reliability Standards CIP-013-2, CIP-005-7, and CIP-010-4 (the "Supply Chain Standards").[59] The Supply Chain Standards address supply chain cybersecurity risk management, broadening requirements to include Electronic Access Control or Monitoring Systems ("EACMS") and Physical Access Control Systems ("PACS") as applicable systems. The Supply Chain Standards will become effective (and the currently effective versions be retired) on October 1, 2022 (the first day of the first calendar quarter that is 18 months following FERC approval). Unless the March 18 order is challenged, this proceeding will be concluded.

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

As previously reported, NERC is required to file on an informational basis quarterly status updates regarding the development of new or modified Reliability Standards pertaining to virtualization and cloud computing services (resulting from Projects 2016-02 (Modifications to CIP Standards) and 2019-02 (BES Cyber System Information Access Management)). NERC filed its fifth informational filing on March 15, 2021, reporting no change in schedule for either project from that reported in its supplemental November 2020 filing -- filing of proposed Reliability Standards in December 2021 for both Projects (2019-02 and 2016-02).

- **NOI: Enhancements to CIP Standards (RM20-12)**

On June 18, 2020, the FERC issued a notice of inquiry ("NOI") seeking comments on certain potential enhancements to the currently-effective CIP Reliability Standards. In particular, the FERC asked for comments on whether the CIP Standards adequately address: (i) cybersecurity risks pertaining to data security, (ii) detection of anomalies and events, and (iii) mitigation of cybersecurity events. In addition, the FERC asked for comments on the potential risk of a coordinated cyberattack on geographically distributed targets and whether FERC action including potential modifications to the CIP Standards would be appropriate to address such risk.

Comments were filed by NERC, the ISO/RTO Council ("IRC"), APPA/LPPC, Canadian Electricity Assoc. ("CEA"), Cogentrix, EEI/EPSA, Forescout Technologies, MISO TOs, NJ BPU, NRECA, Reliable Energy Analytics, Southwestern Power Administration, SEIA, Siemen's Energy, Southern Companies, TAPS, U.S. Bureau of Reclamation, U.S Corp of Army Engineers, Western Area Power Administration ("WAPA"), Wolverine Power Supply Cooperative, XTec, and J. Applebaum, J. Christopher/T. Conway, and J. Cotter. No reply comments were filed. This matter is pending before the FERC.

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

On February 20, 2020, the FERC issued a NOI 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

59 *N. Am. Elec. Rel. Corp.*, 174 FERC ¶ 61,193 (Mar. 18, 2021).

("BES") operations; and (ii) whether the CIP Reliability Standards impede the voluntary adoption of virtualization or cloud computing services.[60] On March 25, 2020, Joint Associations[61] requested an extension of time to submit comments and reply comments. On April 2, the FERC granted Joint Associations' request and extended the deadline for initial comments on the NOI to July 1, 2020; the deadline for reply comments, July 31, 2020. Comments were filed by NERC, the IRC, Accenture, Amazon Web Services ("Amazon"), Bonneville, the Bureau of Reclamation, Barry Jones, Georgia System Operations, GridBright, Idaho Power, Microsoft, MISO, MISO Transmission Owners, Siemens Energy Management, Tri-State Generation and Transmission Association, VMware, Inc., AEE, American Association for Laboratory Accreditation ("A2LA"), APPA, Canadian Electricity Assoc., EEI, NRECA, and Waterfall Security Solutions. Reply comments were due on or before July 31, 2020, and were filed by AEE, Amazon and Microsoft.

In part in response the comments filed, the FERC, in a December 17, 2020 order,[62] directed NERC to begin a formal process to assess, and to make an informational filing in a little over one year (January 1, 2022) that addresses, the feasibility of voluntarily conducting BES operations in the cloud in a secure manner, as well as the status and schedule for any plans to modify the standards.

- ***Order 873*** **- Retirement of Reliability Standard Requirements (Standards Efficiency Review) (RM19-17; RM19-16)**

On September 17, 2020, the FERC approved the retirement of the 18 Reliability Standard requirements through the retirement of four Reliability Standards and the modification of five Reliability Standards,[63] concluding that the 18 requirements "(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."[64] The FERC also approved the associated violation risk factors, violation severity levels, implementation plan, and effective dates proposed by NERC. Because it was not persuaded by NERC's justification for the retirement of FAC-008-4 requirement R8, the FERC remanded the retirement of requirements R7 and R8 to NERC for further consideration.[65]

The FERC left for another day its final action on the remaining 56 requirements for which the FERC proposed to approve retirement in the *Retirements NOPR*[66] (the "MOD A Reliability Standards"). The FERC intends to coordinate the effective dates for the retirement of the MOD A Reliability Standards with successor North

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

[61] "Joint Associations" are for purposes of this proceeding: EEI, APPA, NRECA, and LPPC.

[62] *Virtualization and Cloud Computing Services*, 173 FERC ¶ 61,243 (Dec. 17, 2020) ("*Order Directing Jan 2022 Info. Filing*").

[63] *Elec. Rel. Org. Proposal to Retire Reqs. in Rel. Standards Under the NERC Standards Efficiency Review*, Order No. 873, 172 FERC ¶ 61,225 (Sep. 17, 2020) ("*Order 873*"). The four Reliability Standards being eliminated in their entirety are 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-020-0 (Providing Interruptible Demands and Direct Control Load Management Data to System Operations and Reliability Coordinators). The five modified Reliability Standards are INT-006-5 (Evaluation of Interchange Transactions), INT-009-3 (Implementation of Interchange) and PRC-004-6 (Protection System Misoperation Identification and Correction), IRO-002-7 (Reliability Coordination—Monitoring and Analysis), TOP-001-5 (Transmission Operations).

[64] *Order 873* at P 2.

[65] *Order 873* at P 5. Pursuant to FPA section 215(d)(4), if the FERC disapproves a modification to a Reliability Standard in whole or in part, it must remand the entire Reliability Standard to NERC for further consideration. Accordingly, although it was satisfied here with the justification for the retirement of R7, the FERC was required to remand both R7 and R8 so that its concerns with the retirement of Requirement R8 could be addressed.

[66] *Electric Reliability Organization Proposal to Retire Requirements in Rel. Standards Under the NERC Standards Efficiency Review*, 170 FERC ¶ 61,032 (Jan. 23, 2020) ("*Retirements NOPR*") (proposing to approve the retirement of 74 of 77 Reliability Standard requirements requested to be retired by NERC in these two dockets in connection with the first phase of work under NERC's Standards Efficiency Review, an initiative begun in 2017 that 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). As previously reported, NERC withdrew its proposed changes to VAR-001-6 on May 14, 2020, reducing to 76 the number of requirements proposed to be retired.

American Energy Standards Board ("NAESB") business practice standards (v. 003.3) that include Modeling business practices pending in the *NAESB WEQ v. 003.3 Standards NOPR* (*see* Section XII below).[67]

- **Amended and Restated NERC Bylaws (RR21-1)**

Still pending is NERC's October 14, 2020 petition for FERC approval of its amended and restated Bylaws. As previously reported, NERC stated that the amendments (i) address governance matters relating to the composition of NERC's membership Sectors, certain rules relating to the Member Representatives Committee, as well as the qualification of independent trustees for the Board; (ii) update certain provisions to conform with applicable state law; and (iii) improve internal consistency and introduce ministerial changes within the Bylaws with respect to capitalizing defined terms consistently and removing inoperative provisions. No comments on the Amended and Restated Bylaws were filed. As noted, this matter remains pending before the FERC.

XI. Misc. - of Regional Interest

- **203 Application: Exelon Generation (EC21-57)**

On February 25, 2021, Exelon Generation Company, LLC ("ExGen"), on behalf of its public utility subsidiaries, requested authorization for a "spin" transaction in which, after completion of an internal reorganization, the ownership of Applicants' intermediate holding company owner, HoldCo, will be distributed to the shareholders of Applicants' current ultimate upstream owner, Exelon Corporation (the "Transaction"). Following the Transaction, Exelon Corporation and its remaining subsidiaries will retain no interest in or affiliation with ExGen or the ExGen Utility Subsidiaries; Exelon Corporation and HoldCo will be separate publicly-traded companies. Comments on this filing were due on or before March 18, 2021. Joint PJM Consumer Advocates[68] filed a protest requesting, among other things, that the FERC direct Applicants to file supplemental materials that include a market power analysis and addresses the vertical market power concerns that Joint PJM Consumer Advocates raised in its comments. Doc-less interventions only were filed by PJM, PJM IMM, EDF, Old Dominion, and Public Citizen. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **LGIA Cancellation: CMP / Rumford (ER21-1457)**

On March 16, 2021, CMP filed a notice of cancellation of an Interconnection Agreement between CMP and Rumford Power that expired by its own terms on October 31, 2020 and was replaced by a new, three-party Large Generator Interconnection Agreement ("Renewed LGIA") between ISO-NE, CMP and Rumford Power. An October 22, 2020 effective date was requested. Comments on this filing are due on or before April 6, 2021. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement: NSTAR/Vineyard Wind (ER21-1285)**

On March 5, 2021, NSTAR filed a Preliminary Agreement for Design, Engineering and Construction services (the "D&E Agreement") between itself and Vineyard Wind LLC ("Vineyard Wind"). The D&E Agreement sets forth the terms and conditions under which NSTAR would advance certain design, engineering and cost estimating activities of the civil and below-grade and above-grade electrical substation work at NSTAR's new proposed Bourne 345 kV substation plus the associated line work and substation upgrades at West Barnstable Station to interconnect two new underground 345 kV lines at West Barnstable Station. NSTAR requested that the D&E Agreement be accepted for filing as of the day after the filing, or March 6, 2021. Comments on this filing were due on or before March 26, 2021; none were filed. MA DPU filed a doc-

[67] *Standards for Bus. Practices and Communication Protocols for Pub. Utils.*, 85 Fed. Reg. 55201 (Sep. 4, 2020).

[68] "Joint PJM Consumer Advocates" are: the Office of the People's Counsel for the District of Columbia, Citizens Utility Board, the Delaware Division of the Public Advocate, Maryland Office of the People's Counsel, New Jersey Division of Rate Counsel, and the Pennsylvania Office of Consumer Advocate.

less intervention. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Related Facilities Agreement: PSNH / NECEC (ER21-1151)**

On February 16, 2021, Public Service Company of New Hampshire ("PSNH") filed a Related Facilities Agreement ("RFA") between PSNH and NECEC for the purpose of providing the terms and conditions governing NSTAR's activities, and NECEC's associated cost responsibility, in completing the Related Facilities.[69] A February 16, 2021 effective date was requested. Comments on this filing were due on or before March 9, 2021; none were filed. National Grid and NECEC filed doc-less interventions. This matter is pending before the FERC. If there are questions on this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement: PSNH/NECEC (ER21-1147)**

On February 16, 2021, PSNH filed a Preliminary Agreement for Design, Engineering and Construction services (the "D&E Agreement") between itself and NECEC. The D&E Agreement sets forth the terms and conditions under which PSNH will undertake certain design, engineering and procurement activities for the mitigation of violations identified in the preliminary initial interconnection analysis summary for Queue Position #979, and other services as may be requested in writing by NECEC to support engineering, design, and procurement activities related to Affected System upgrades needed on the PSNH system for reliable interconnection of the Project. PSNH requested that the D&E Agreement be accepted for filing as of the day of the filing, or February 16, 2021. Comments on this filing were due on or before March 9, 2021; none were filed. Doc-less interventions were filed by NECEC and National Grid. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **SGIA Cancellation: CL&P/Covanta Wallingford (ER21-867)**

On March 11, 2021, the FERC accepted a notice of cancellation of the Small Generator Interconnection Agreement ("SGIA") between CL&P and Covanta Projects of Wallingford, L.P. ("Covanta Wallingford") (designated as service agreement IA-NU-16 and accepted in Docket No. ER10-1654), reflecting the request of Covanta Wallingford, whose Non-Price Retirement request notice was accepted by ISO-NE on December 17, 2014.[70] The SGIA notice of cancellation was accepted effective as of January 11, 2021, as requested. Unless the March 11 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **LGIA Cancellation: Mt. Tom (ER21-845)**

On March 5, 2021, the FERC accepted the notice of cancellation of the Large Generator Interconnection Agreement ("LGIA") governing the interconnection of Mt. Tom Station.[71] As previously reported, Engie Energy Marketing NA, Inc. formally retired the Mt. Tom Station from the New England Markets on June 1, 2018. Decommissioning work on the facility began in 2018 and was substantially completed as of February 2020. The interconnection rights for Mt. Tom Station terminated upon the date of its retirement. This filing terminated the Original Service Agreement. The notice of cancellation was accepted as of March 8, 2021, as requested. Unless the March 5 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

[69] The "Related Facilities" are certain upgrades of facilities on PSNH's electric transmission system needed to support the construction by NECEC of a 1,200 MW unidirectional +/- 320 kV, symmetrical monopole High Voltage Direct Current line from the 735 kV Appalaches Substation in Quebec to CMP's 345 kV Larrabee Road Substation in Lewiston, ME.

[70] *The Conn. Light and Power Co.*, Docket No. ER21-867-000 (Mar. 11, 2021) (unpublished letter order).

[71] *ISO New England Inc. and Eversource Energy Service Co.*, Docket No. ER21-845 (Mar. 5, 2021) (unpublished letter order).

- ***Orders 864/864-A*** **(Public Util. Trans. ADIT Rate Changes):** ***New England Compliance Filings*** **(various)**

In accordance with *Order 864*[72] and *Order 864-A,*[73] and extensions of time granted, New England's public utilities with transmission have submitted their *Order 864* compliance filings, with the specific dockets and filing dates identified in the following table (all remain pending):

Date Filed	Docket	Transmission Provider	Date Accepted
Mar 11, 2021	ER21-1325	NHT	pending
Mar 8, 2021	ER21-1295	Eversource (CL&P, PSNH, NSTAR)	pending
Feb 16, 2021	ER21-1154	Fitchburg Gas & Electric ("FG&E")	pending
Oct 30, 2020	ER21-311	Green Mountain Power	pending
Aug 5, 2020	ER20-2614	New England Power Support Agreement	pending
Aug 5, 2020	ER20-2610	CL&P	pending
Aug 5, 2020	ER20-2609	NSTAR	pending
Aug 5, 2020	ER20-2608	PSNH	pending
Aug 4, 2020	ER20-2607	NEP – Seabrook Transmission Support Agreement	pending
Jul 31, 2020	ER20-2594	VTransco	pending
Jul 30, 2020	ER20-2551	New England Power	pending
Jul 30, 2020	ER20-2553	NEP – LSA with MECO/Nantucket	pending
Jul 30, 2020	ER20-2572 ER21-1130	New England TOs	pending
Jul 15, 2020	ER20-2429	CMP	pending
Jun 29, 2020	ER20-2219	New England Power	pending
Jun 23, 2020 Mar 22, 2021	ER20-2133 -001	Versant Power	pending
May 18, 2020 Jan 7, 2021	ER20-1839	VETCO	pending
Feb 26, 2020 Dec 11, 2020	ER20-1089	New England Elec. Trans. Corp.	pending
Feb 26, 2020 Dec 11, 2020	ER20-1088	New England Hydro Trans. Elec. Co.	pending
Feb 26, 2020 Dec 11, 2020	ER20-1087	New England Hydro Trans. Corp.	pending

Since the last Report, *Order 864*-related activity included:

◆ ***ER21-1325 (NHT).*** New Hampshire Transmission ("NHT") submits a compliance filing to supplement the TO's July 30 Compliance Filing in ER20-2572 with respect to local service provided by NHT under Schedule 21-NHT of the ISO-NE OATT during the January 1, 2020 to December 31, 2021 period.

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[72] *Public Util. Trans. Rate Changes to Address Accumulated Deferred Income Taxes*, Order No. 864, 169 FERC ¶ 61,139 (Nov. 21, 2019), *reh'g denied and clarification granted in part,* 171 FERC ¶ 61,033 (Apr. 16, 2020) ("*Order 864*"). *Order 864* requires 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.

[73] *Public Util. Trans. Rate Changes to Address Accumulated Deferred Income Taxes*, 171 FERC ¶ 61,033, Order No. 864-A (Apr. 16, 2020) ("*Order 864-A*").

◆ ***ER21-1295 (Eversource).*** Eversource supplemented its earlier compliance filings (ER20-2608, ER20-2609, ER20-2610) with changes to Schedule 21-ES reflecting the FERC's order approving RNS/LNS Rates and Rate Protocols Settlement Agreement II.[74]

◆ ***ER21-1293 (NSTAR).*** NSTAR supplemented its earlier compliance filings.

◆ ***ER20-2133 (Versant Power).*** ON March 12, 2021, Versant Power responded to the FERC's February 11 deficiency letter.

XII. Misc. - Administrative & Rulemaking Proceedings

- **Electrification and the Grid of the Future: Apr 29 Technical Conference (AD21-12)**

On March 2, 2021, the FERC issued a notice that a Commissioner-led technical conference will be convened electronically on April 29, 2021 to discuss electrification—the shift from non-electric to electric sources of energy at the point of final consumption (e.g., to fuel vehicles, heat and cool homes and businesses, and provide process heat at industrial facilities). The purpose is to "initiate a dialog between Commissioners and stakeholders on how to prepare for an increasingly electrified future." Specifically, the conference will address: projections, drivers, and risks of electrification in the US; the extent to which electrification may influence or necessitate additional transmission and generation infrastructure; whether and how newly electrified sources of energy demand (e.g., electric vehicles, smart thermostats, etc.) could provide grid services and enhance reliability; and the role of state and federal coordination as electrification advances. A supplemental notice will be issued prior to the conference with further details regarding the agenda and organization.

- **Resource Adequacy - Modernizing Electricity Mkt Design (Mar 23 tech conf) (AD21-10)**

A Commissioner-led technical conference was convened electronically on March 23, 2021 to provide input to the Commission on resource adequacy in the evolving electricity sector. The FERC issued on March 9 a supplemental notice that included a final conference program (with questions to be posed during panel discussion). Speaker materials from the March 23 technical conference have been posted to eLibrary. On March 29, Ohio PUC Commission Dan Conway submitted written comments. No notice or deadline for written comments has yet been published.

- **Office of Public Participation: Apr 16 Workshop (AD21-9)**

On February 22, 2021, the FERC issued a notice that a Commissioner-led workshop will be convened electronically on April 16, 2021 to provide input to the Commission on the creation of the Office of Public Participation ("OPP"). The Commission intends to establish and operate the Office of Public Participation to "coordinate assistance to the public with respect to authorities exercised by the Commission," including assistance to those seeking to intervene in Commission proceedings, pursuant to FPA section 319. The Commission plans to hear input on the following considerations in forming the OPP, including: (1) the office's function and scope as authorized by FPA section 319; (2) the office's organizational structure and approach, including the use of equity assessment tools; (3) participation by tribes, environmental justice communities, and other affected individuals and communities, including those who have not historically participated before the Commission; and (4) intervenor compensation.

The following virtual listening sessions were held from March 17, 2021 to March 25, 2021 to solicit public input on how the Commission should establish and operate the OPP: (1) Landowners and Communities Affected by Infrastructure Development (Mar 17): (2) Environmental Justice Communities and Tribal Interests (Mar 22); (3) Tribal Governments (Mar 24); and (4) Energy Consumers and Consumer Advocates (Mar 25). Written comments may also be submitted by April 23, 2021.

[74] *ISO New England Inc., et al.*, 173 FERC ¶ 61,270 (Dec. 28, 2020).

- **ISO/RTO Credit Principles and Practices (AD21-6)**

On February 25-26, 2021, the FERC held a technical conference to discuss principles and best practices for credit risk management in ISO/RTOs. Panel topics included: Credit Principles and Practices in ISOI/RTO Markets; RTO/ISO Comparison of Risk Management Structure, Credit Enhancements and Lessons Learned; Internal Resources and Expertise within RTOs/ISOs; Impact of Market Design on Credit Risk; Addressing Counterparty Risk: Minimum Participation Requirements and Know Your Customer Protocols; and Collateral, Initial and Variation Margining for FTR and non-FTR positions. Speaker materials are posted in the FERC's eLibrary.

Recall that, as previously reported, Energy Trading Institute[75] requested that the FERC hold a technical conference and conduct a rulemaking to update the requirements adopted in *Order 741*[76] and section 35.47 of the FERC's regulations addressing credit and risk management in the markets operated by ISO/RTOs. The FERC issued a notice of and received comments on ETI's request (AD20-6) in early 2020. The February technical conference was held, in part, in response to that request.

- **Offshore Wind Integration in RTOs/ISOs Tech Conf (Oct 27, 2020) (AD20-18)**

On October 27, 2020, the FERC convened a staff-led technical conference to consider whether and how existing RTO and ISO interconnection, merchant transmission and transmission planning frameworks can accommodate anticipated growth in offshore wind generation in an efficient or cost-effective manner that safeguards open access transmission principles. The conference also provided an opportunity for participants to discuss possible changes or improvements to the current regulatory frameworks that may accommodate such growth. Speaker materials and a transcript of the technical conference are posted in eLibrary. Since the last Report, Advanced Power Alliance filed comments requesting that the FERC issue a notice providing an opportunity for interested persons to submit post-conference comments and to thereafter "take action to facilitate transmission planning and interconnection policies that will enable construction of the cost-effective, efficient, resilient and environmentally-sound transmission infrastructure needed to connect new offshore wind generation to the onshore grid."

On March 11, 2021, the FERC issued a notice inviting interested persons to file, on or before May 10, 2021, post-technical conference comments on the questions listed in the attachment to its Notice or to the questions outlined in the October 22, 2020 supplemental notice of technical conference.

- **Carbon Pricing in RTO/ISO Markets Tech Conf (Sep 30, 2020) (AD20-14)**

On September 30, 2020, the FERC convened a Commissioner-led technical conference to discuss considerations related to state adoption of mechanisms to price carbon dioxide emissions, commonly referred to as carbon pricing, in regions with FERC-jurisdictional organized wholesale electricity markets. The September 30 conference was a response to (i) the April 14, 2020 request by Interest Parties,[77] who asserted that a technical conference "would be helpful to the Commission and stakeholders in the electric energy industry in deciding how best to move forward at the state and regional levels on these issues and in the relevant organized markets"

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[75] 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."

[76] *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.

[77] "Interested Parties" are AEE, the American Council on Renewable Energy, the American Wind Energy Association, Brookfield Renewable, Calpine, CPV, EPSA, the Independent Power Producers of New York ("IPPNY"), LS Power Associates ("LS Power"), the Natural Gas Supply Association ("NGSA"), NextEra, PJM Power Providers Group, R Street Institute, and Vistra Energy Corp.

complementing "state, regional, and national discussions currently taking place" as well as to (ii) the more than 30 sets of comments on the request that were filed. Speaker opening remarks (including those of Gordon van Welie, Matt White, and other New England stakeholders), and comments are posted in eLibrary, as is a transcript of the conference.

Notice of Proposed Policy Statement. Following the technical conference, on October 15, 2020, the FERC issued a Notice of Proposed Policy Statement.[78] The FERC stated that the *Proposed Policy Statement* is "to clarify the Commission's jurisdiction over RTO/ISO market rules that incorporate a state-determined carbon price and to encourage RTO/ISO efforts to explore and consider the benefits of potential [FPA] section 205 filings to establish such rules." Specifically, the FERC proposed "to make it the policy of this Commission to encourage efforts by RTOs/ISOs and their stakeholders—including States, market participants, and consumers—to explore establishing wholesale market rules that incorporate state-determined carbon prices in RTO/ISO markets."[79] The FERC solicited comment on whether the following information and considerations it identified are "germane to the Commission's evaluation of a section 205 filing to determine whether an RTO/ISO's market rules that incorporate a state-determined carbon price in RTO/ISO markets are just, reasonable and not unduly discriminatory or preferential" or whether different or additional considerations may be or must be taken into account:

a. How, if at all, do the relevant market design considerations change depending on the manner in which the state or states determine the carbon price (e.g., price-based or quantity-based methods)? How will that price be updated?

b. How does the FPA section 205 proposal ensure price transparency and enhance price formation?

c. How will the carbon price or prices be reflected in LMP?

d. How will the incorporation of the state-determined carbon price into the RTO/ISO market affect dispatch? Will the state-determined carbon price affect how the RTO/ISO co-optimizes energy and ancillary services? Are any reforms to the co-optimization rules necessary in light of the state-determined carbon price?

e. Does the proposal result in economic or environmental leakage? How does the proposal address any such leakage?

Comments on the *Proposed Policy Statement* were due by November 16, 2020 and were filed by, among others: NEPOOL, NESCOE, AEE, Brookfield, Calpine, Eversource, HQUS, LSP Power, MA AG, National Grid, NEPGA, and NRG. Reply comments were due by December 1, 2020, and were filed by 12 parties, including Covanta, Exelon, EPSA, NRG, the NYPSC. This matter is pending before the FERC.

- **Hybrid Resources (AD20-9)**

On July 23, 2020, the FERC convened a technical conference to discuss technical and market issues prompted by growing interest in projects that are comprised of more than one resource type at the same plant location ("hybrid resources"). The focus was on generation resources and electric storage resources paired together as hybrid resources. Speaker materials and a transcript of the technical conference have been posted to the FERC's eLibrary. Post-technical conference comments were filed by ISO-NE, CAISO, MISO, NYISO, PJM, Enel, American Council on Renewable Energy, AWEA, EEI, EPRI, R Street Institute, Savion, and SEIA.

On January 19, 2021, the FERC issued an order directing each ISO/RTO to submit, within 6 months (or before July 19, 2021), a report that provides: (a) a description of its current practices related to each of the

[78] *Carbon Pricing in Organized Wholesale Electricity Markets*, 173 FERC ¶ 61,062 (Oct. 15, 2020) ("*Proposed Policy Statement*").

[79] *Id.* at P 15.

following four hybrid resource issues: (1) terminology; (2) interconnection; (3) market participation; and (4) capacity valuation (collectively, the Issues); (b) an update on the status of any ongoing efforts to develop reforms related to each of the Issues; and (c) responses to the specific requests for information contained in the order. Public comments in response to the RTO/ISO reports may be submitted within 30 days of the filing of the reports. The FERC will use the reports and comments to determine whether further action is appropriate.

- **NOPR: Cybersecurity Incentives (RM21-3)**

On December 17, 2020, the FERC issued a NOPR[80] proposing to establish rules for incentive-based rate treatment for voluntary cybersecurity investments by a public utility for or in connection with the transmission or sale of electric energy subject to FERC jurisdiction, and rates or practices affecting or pertaining to such rates for the purpose of ensuring the reliability of the Bulk-Power System ("BPS"). Comments on the *Cyber security Incentives NOPR* are due on or before April 6, 2021; reply comments, May 6, 2021.[81] Thus far, comments have been submitted jointly by aDolus Inc., Bureau of Reclamation, Fortress Information Security, GMO GlobalSign Inc., Ion Channel, ReFirm Labs and Reliable Energy Analytics LLC; and George Cotter, Esq.

- **NOPR: Managing Transmission Line Ratings (RM20-16)**

On November 19, 2020, the FERC issued a NOPR[82] proposing to reform both the *pro forma* OATT and its regulations to improve the accuracy and transparency of transmission line ratings. Specifically, the NOPR proposes to require: transmission providers to implement ambient-adjusted ratings on the transmission lines over which they provide transmission service; ISO/RTOSs to establish and implement the systems and procedures necessary to allow transmission owners to electronically update transmission line ratings at least hourly; and transmission owners to share transmission line ratings and transmission line rating methodologies with their respective transmission provider(s) and, in ISO/RTOs, with their respective market monitor(s). Comments on the *Managing Transmission Line Ratings NOPR* were due on or before March 22, 2021.[83] Comments were submitted by over 50 parties, including by ISO-NE, DC Energy, Dominion, EDF, ENEL/EnerNOC, Eversource, Exelon, NRDC, Vistra, EEI, EPRI, EPSA, New England State Agencies,[84] NRECA/LPPC, and Potomac Economics.

- **NOPR: Electric Transmission Incentives Policy (RM20-10)**

Still pending is the FERC's March 20, 2020 NOPR[85] proposing to revise its existing transmission incentives policy and corresponding regulations.[86] The proposed revisions include the following:

- ♦ A shift from risks and challenges to a ***consumers'' benefits test*** that focuses on ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.
- ♦ ***ROEs incentive for Economic Benefits***. A 50-basis-point adder for transmission projects that meet an economic benefit-to-cost ratio in the top 75th percentile of transmission projects examined over a sample period <u>and</u> an additional 50-basis-point adder for transmission projects that demonstrate *ex post* cost savings that fall in the 90th percentile of transmission projects studied over the same sample period, as measured at the end of construction.

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[80] *Cybersecurity Incentives*, 173 FERC ¶ 61,240 (Dec. 17, 2020) ("*Cybersecurity Incentives NOPR*").

[81] The *Cybersecurity Incentives NOPR* was published in the *Fed. Reg.* on Feb. 5, 2021 (Vol. 86, No. 23) pp. 8,309-8,325.

[82] *Managing Transmission Line Ratings*, 173 FERC ¶ 61,165 (Nov. 19, 2020) ("*Managing Transmission Line Ratings NOPR*").

[83] The *Managing Transmission Line Ratings NOPR* was published in the *Fed. Reg.* on Jan. 21, 2021 (Vol. 86, No. 12) pp. 6,420-6,444.

[84] "New England State Agencies" are for purposes of this proceeding: CT Att'y Gen. William Tong, MA AG Maura Healey, the CT Dept. of Energy and Environ. Protection, the CT OCC, MOPA, NH OCA, Peter F. Neronha, RI AG, and Thomas J. Donovan, Jr., VT AG. The Feb 1 comments by the New England State Agencies broadly supported the FERC's proposals.

[85] *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, 170 FERC ¶ 61,204 (Mar. 20, 2020) ("*Electric Transmission Incentives NOPR*").

[86] 18 CFR 35.35 (2021).

- ***ROE for Reliability Benefits***. A 50-basis-point adder for transmission projects that can demonstrate potential reliability benefits by providing quantitative analysis, where possible, as well as qualitative analysis.
- ***Abandoned Plant Incentive***. 100 percent of prudently incurred costs of transmission facilities selected in a regional transmission planning process that are cancelled or abandoned due to factors that are beyond the control of the applicant. Recovery from the date that the project is selected in the regional transmission planning process.
- ***Eliminate Transco Incentives***.
- ***RTO-Participation Inventive*****.** A 100-basis-point increase for transmitting utilities that turn over their wholesale facilities to an RTO, ISO, or Transmission Organization, and available regardless of whether participation is voluntary.
- ***Transmission Technologies Incentives***. Eligible for both a stand-alone, 100-basis-point ROE incentive on the costs of the specified transmission technology project and specialized regulatory asset treatment. Pilot programs presumptively eligible (though rebuttable).
- ***250-Basis-Point Cap***. Total ROE incentives capped at 250 basis points in place of current "zone of reasonableness" limit.
- ***Updated Date Reporting Processes***. Information to be obtained on a project-by-project basis, information collection expanded, updated reporting process.

A more detailed summary of the NOPR was distributed to the Transmission Committee and discussed at the TC's March 25, 2020 meeting. Over 80 sets of comments on the proposed revisions were filed on or before the July 1, 2020[87] comment date, including comments by: Avangrid, EDF Renewables, EMCOS, Eversource, Exelon, LS Power, MMWEC/NHEC/CMEEC, National Grid, NESOCE, NextEra, UCS, CT PURA, and Potomac Economics. Reply comments were filed by AEP, ITC Holding, the N. California Transmission Agency, and WIRES. The NOPR remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Order 2222/2222-A*****: DER Participation in RTO/ISO Markets (RM18-9)**

On September 17, 2020, the FERC issued a final rule ("*Order 2222*")[88] adopting reforms to remove what it found were barriers to the participation of distributed energy resource ("DER")[89] aggregations in the RTO/ISO markets. *Order 2222* requires each RTO/ISO to revise its tariff to ensure that its market rules facilitate the participation of DER aggregations. Specifically, the tariff provisions addressing DER aggregations must:

(1) allow DER aggregations to participate directly in RTO/ISO markets and establish DER aggregators as a type of market participant;

(2) allow DER aggregators to register DER aggregations under one or more participation models that accommodate the physical and operational characteristics of the DER aggregations;

(3) establish a minimum size requirement for DER aggregations that does not exceed 100 kW;

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[87] The *Electric Transmission* Incentives NOPR was published in the *Fed. Reg.* on Apr. 2, 2020 (Vol. 85, No. 64) pp. 18,784-18,810. Requests for extension of time to file comments were filed by American Manufacturers, APPA/TAPS, and State Entities; WIRES and EEI each opposed the requested extensions. No extension of time to file comments was granted.

[88] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 172 FERC ¶ 61,247 (Sep. 17, 2020).

[89] The FERC defined a DER as "any resource located on the distribution system, any subsystem thereof or behind a customer meter. These resources may include, but are not limited to, electric storage resources, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment."

(4) address locational requirements for DER aggregations;

(5) address distribution factors and bidding parameters for DER aggregations;

(6) address information and data requirements for DER aggregations;

(7) address metering and telemetry requirements for DER aggregations;

(8) address coordination between the RTO/ISO, the DER aggregator, the distribution utility, and the relevant electric retail regulatory authorities;

(9) address modifications to the list of resources in a DER aggregation;

(10) address market participation agreements for DER aggregators; and

(11) Accept bids from a DER aggregator if its aggregation includes DERs that are customers of utilities that distributed more than 4 million MWh in the previous fiscal year. An RTO/ISO must not accept bids from a DER aggregator if its aggregation includes DERs that are customers of utilities that distributed 4 million MWhs or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers to be bid into RTO/ISO markets by a DER aggregator.

Each RTO/ISO must file the tariff changes needed to implement the requirements of *Order 2222* on or before July 19, 2021.[90] To the extent that an RTO/ISO proposes to comply with any or all of the requirements in *Order 2222* using its currently effective requirements for DERs, it must demonstrate on compliance that its existing approach meets *Order 2222*'s requirements. Requests for extension of time to comply with *Order 2222* have been filed by MISO, SPP and PJM. Those requests are pending before the FERC. ISO-NE has signaled that it, too, plans to request an extension of time to February 2022 to comply with *Order 2222*.

Requests for Rehearing Denied by Operation of Law. Requests for clarification and/or rehearing of *Order 2222* were filed by Excel Energy Services, the Kansas Corporation Commission, AEE and AEMA, and Public Interest Organizations.[91] On November 19, 2020, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[92] The Notice confirmed that the 60-day period during which a petition for review of *Order 2222* can be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing of *Order 2222*. The Notice also indicated that the FERC would address, as is its right, the rehearing requests in a future order, and may modify or set aside its orders, in whole or in part, "in such manner as it shall deem proper."

Order 2222-A. On March 18, 2021, the FERC issued *Order 2222-A*,[93] which addressed arguments on rehearing and set aside and clarified *Order 2222* in part. Specifically, as is its right under *Allegheny*, the FERC modified the discussion in *Order 2222* and set aside *Order 2222*, in part, by finding that the participation of demand response in DER aggregations is subject to the opt-out and opt-in requirements of *Orders 719* and *719-A,* providing further clarification on the FERC's interconnection policies pertaining to Qualifying Facilities ("QFs"), and

[90] *Order 2222* was published in the *Fed. Reg.* on Oct. 21, 2020 (Vol. 85, No. 204) pp. 67,094-6,158.

[91] For purposes of this proceeding, "Public Interest Organizations" are Sierra Club, Sustainable FERC Project and NRDC.

[92] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Indep. Sys. Operators*, Order No. 2222, 173 FERC ¶ 62,090 (Nov. 19, 2020) (the "Notice").

[93] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Indep. Sys. Operators*, Order No. 2222-A, 174 FERC ¶ 61,197 (Mar. 18, 2021).

modifying § 35.28(g)(12)(i) to make a non-substantive ministerial correction. Challenges, if any, to *Order 2222-A* are due on or before April 19, 2021.

- ***Order 860/860-A*: Data Collection for Analytics & Surveillance and MBR Purposes (RM16-17)**

As previously reported, *Order 860,*[94] issued three years after the FERC's *Data Collection NOPR,*[95] (i) revises the FERC's MBR regulations by establishing a relational database of ownership 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 has posted 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. As recently extended (*see* below), *Order 860* will become effective July 1, 2021, and submitters will have until close of business on November 2, 2021 to make their initial baseline submissions. 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,[96] 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 denied,[97] 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.

Notice Seeking Comments on Change to MBR Database. On March 18, 2021, the FERC issued a notice seeking comments on proposed changes to the MBR Data Dictionary to reflect the affiliations, or lack of affiliation, among Sellers for which their ultimate upstream affiliate is an institutional investor who acquired their securities pursuant to a section 203(a)(2) blanket authorization.[98] Specifically, the FERC proposes to update the MBR Data Dictionary and add the following three new attributes to the Entities table: the blanket authorization docket number, and the utility ID types and the utility IDs of the utilities whose securities were purchased under the corresponding blanket authorization docket number. Appropriate Sellers would be required to submit the docket number of the proceeding in which the FERC granted the section 203(a)(2)

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94 *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).

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

96 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.

97 *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*").

98 *Data Collection for Analytics and Surveillance and Market-Based Rate Purposes*, 174 FERC ¶ 61,214 (Mar. 18, 2021).

blanket authorization and the upstream affiliate whose securities were acquired pursuant to the section 203(a)(2) blanket authorization. Comments on the Notice are due on or before [60 days after date of publication in the *Federal Register*].[99] In light of the proposed changes, the FERC deferred by three months the effective date of *Order 860* and its associated deadlines.

Effective Date Extended a Second Time by 3 Months. On March 18, 2021, the FERC issued a notice extending the effective and associated implementation dates of *Order 860* by an additional *three* months. The new *Order 860* effective date will be July 1, 2021, and the deadline for baseline submissions to and including November 2, 2021. First change in status filings under these new timelines will be due November 30, 2021.

April 22, 2021 Technical Workshop. On March 19, 2021, the FERC issued a supplemental notice of a technical workshop to discuss the functionality and features of the MBR Database. The workshop will now be held electronically on April 22, 2021 from 10 a.m. to 3 p.m. Individuals who are interested in registering for the conference can do so here: https://ferc.webex.com/ferc/j.php?MTID=e6dd18def200b281ff165e57325102ee0.

- **NOPR: NAESB WEQ Standards v. 003.3 - Incorporation by Reference into FERC Regs (RM05-5-029, -030)**

On July 16, 2020, the FERC issued a NOPR proposing to incorporate by reference, with certain enumerated exceptions, the latest version (Version 003.3) of certain Standards for Business Practices and Communication Protocols for Public Utilities adopted by the NAESB Wholesale Electric Quadrant ("WEQ").[100] Despite having only recently incorporated Version 003.2 in its regulations, the FERC proposed to move forward on Version 003.3 because this Version contains a number of major initiatives whose incorporation by reference "will improve the security and the efficiency of business transactions. These include enhanced cybersecurity standards resulting from an assessment by Sandia, improved methodologies for resolving transmission loading relief, and standards for determining available transfer capacity."[101] Comments on the *NAESB WEQ v. 003.3 Standards NOPR* were due on or before November 3, 2020[102] and were filed by Bonneville Power Administration ("BPA"), EEI, the IRC, and Open Access Technology International. The *NAESB WEQ v. 003.3 Standards NOPR* is pending before the FERC.

- **Waiver of Tariff Requirements (PL20-7)**

On May 21, 2020, the FERC issued a Proposed Policy Statement that would clarify its policy regarding requests for waiver of tariff provisions.[103] The *Proposed Policy Statement* sets forth the approach the FERC would take going forward to ensure compliance with the filed rate doctrine and the rule against retroactive making. The proposed policy will both clarify and modify waiver standards, and in some instances, make it harder to obtain waivers.

Specifically, the FERC proposed the following guidance on filing procedures to implement its new approach for granting waivers of tariff provisions and to no longer grant retroactive waivers except as consistent with the *Proposed Policy Statement*:

1. *Style Requests as Requests for Remedial Relief*. Filings seeking relief in connection with actions or omissions that have already occurred prior to the date relief is sought from the FERC would be characterized as a request for remedial relief (rather than as a request for a

[99] The Notice has not yet been published in the *Federal Register.*

[100] *Standards for Business Practices and Communication Protocols for Public Utilities*, 172 FERC ¶ 61,047 (July 16, 2020) ("*NAESB WEQ v. 003.3 Standards NOPR*").

[101] The *NAESB WEQ v. 003.3 NOPR* at P .

[102] The *NAESB WEQ v. 003.3 NOPR* was published in the *Fed. Reg.* on Sep. 4, 2020 (Vol. 85, No. 173) pp. 55,201-55,219.

[103] *Waiver of Tariff Requirements*, 171 FERC ¶ 61,156 (May 21, 2020) ("*Proposed Policy Statement*").

waiver). In response to such a request, the FERC will focus on what remedy, if any, is required to cure acknowledged or alleged deviations from a filed tariff. "Waiver" is to be limited to (a) requests for prospective relief when a requested future deviation from the filed tariff has not yet occurred at the time a request is filed; or (b) petitions for remedial relief when a tariff expressly authorizes regulated entities to seek a remedial waiver from the FERC for past non-compliance with the filed tariff.

2. *Form of Filing*. When the entity requesting remedial relief is the entity that acted (or believes it may have acted) in a manner inconsistent with the tariff, such requests should be filed as petitions for declaratory order under Rule 207 of the FERC's Rules of Practice and Procedure. When the filing entity alleges a different entity has acted in a manner inconsistent with the tariff, such requests should be filed as complaints under Rule 206. Given the filing fees associated with petitions for declaratory order, the industry was encouraged to directly address this aspect of the proposal.

3. *Expressly Request FERC Action pursuant to FPA section 309 or NGA section 16.4*. These provisions have been found to afford the FERC the latitude to remedy past non-compliance "provided the agency's action conforms with the purposes and policies of Congress and does not contravene any terms of the Act."

The FERC acknowledged that this Policy would represent a change from its past approach, particularly in situations where inadvertent failures to comply with ministerial tariff requirements have not been protested. The FERC suggested a few ways tariffs may be modified to avoid what may appear by comparison to be harsh outcomes, including expressly stating in the tariff that a failure to comply with a certain deadline may be waived by order of the FERC or by allowing various kinds of errors to be cured within a reasonable period of time after a default has occurred or an error has been discovered, but is difficult to imagine how feasible or how well these options might work in practice.

The FERC proposed to incorporate its current four-part analysis[104] in considering both requests for prospective waiver and petitions for remedial relief, but cautioned that it would apply that analysis only in those limited circumstances where the request for remedial relief would not violate the filed rate doctrine or the rule against retroactive ratemaking due to adequate prior notice, or the requested relief is within the FERC's authority to grant under FPA section 309 or NGA section 16.

Finally, the FERC proposed requiring a stronger showing when a petitioner is seeking remedial relief for its own failure to comply with a tariff – petitions will be more compelling when the failure to comply was due to something more than inadvertent error or administrative oversight. Petitions for remedial relief will generally be denied when a protestor credibly contends, or the FERC independently determines, that the requested remedial relief will result in undesirable consequences (e.g. harm to third parties).

With respect to prospective requests to waive the 60-day prior notice requirement under FPA section 205(d) (or the 30-day prior notice requirement under NGA section 4(d)), which the FERC has discretion to waive "for good cause shown," the FERC proposes to leave in effect its policy of generally granting such

[104] Under current practice, the FERC grants tariff provision waivers where: (1) the underlying error was made in good faith; (2) the waiver is of limited scope; (3) the waiver addresses a concrete problem; and (4) the waiver does not have undesirable consequences, such as harming third parties.

waivers,[105] to the extent that entities seek an effective date no earlier than the day *after* the date a rate change is submitted to the FERC.

Comments on the Proposed Policy Statement were due on or before June 18, 2020 and were filed by the IRC, AEE, APPA, AWEA/SEIA, EEI, EPSA, Indicated Generators,[106] INGAA, Kansas Electric Power Coop. ("KEPC"), NGA, NGSA, NRECA, Public Citizen, Sunflower Electric Power, and TAPS. Reply comments were filed by APPA, Joint Trade Associations,[107] KEPC, and the Sustainable FERC Project. The proposed Policy Statement is pending before the FERC.

- **FERC's ROE Policy for Natural Gas and Oil Pipelines (PL19-4)**

On May 21, 2020, the FERC issued a Policy Statement that applies to natural gas and oil pipelines, with certain exceptions to account for the statutory, operational, organizational and competitive differences among the electric, natural gas and oil pipeline industries, the FERC's ROE methodology adopted in *Opinion No. 569-A*.[108] Specifically, the FFERC revised its policy and will determine natural gas and oil pipeline ROEs by averaging the results of the DCF and CAPM, but will not use the risk premium model discussed in *Opinion 569/569-A* ("Risk Premium").[109] In addition, the FERC clarified its policies governing the formation of proxy groups and the treatment of outliers in proceedings addressing natural gas and oil pipeline ROEs. Finally, the FERC encouraged oil pipelines to file revised FERC Form No. 6, page 700s for 2019 reflecting the revised ROE policy. This Policy Statement became effective May 27, 2020.[110] On July 7, the FERC issued a notice that pipelines choosing to file updated FERC Form No. 6, page 700 data consistent with the ROE Policy Statement should file such data on or before July 21, 2020.

Complainant-Aligned Parties[111] answered the New England TO's May 10 supplemental comments. On June 15, 2020, Joint Parties[112] submitted supplemental comments arguing that the FERC should use the midpoint, rather than the median, as the measure of central tendency for public utilities that file individually to establish a ROE. Joint Parties' comments were opposed by Six Cities.[113] WIRES submitted supplemental comments on June 18, 2020 requesting that the FERC take further action in this proceeding to "resolve the uncertainty surrounding its base ROE methodology and establish a policy consistent with the recommendations made in these comments" (recommending a framework that employs all four of the

[105] *See Cent. Hudson Gas & Elec. Corp.*, 60 FERC ¶ 61,106, *order on reh'g*, 61 FERC ¶ 61,089 (1992) ("*Central Hudson*"). Factors that will generally support a waiver of prior notice include: (1) uncontested filings that do not change rates; (2) filings that reduce rates and charges; and (3) filings that increase rates as prescribed by a previously accepted contract or settlement on file with the FERC.

[106] "Indicated Generators" are Vistra, NRG, FirstLight, Cogentrix, and LS Power.

[107] "Joint Trade Associations" are AEE, AWEA, EEI, EPSA, INGAA, NGSA, NRECA and SEIA.

[108] *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 171 FERC ¶ 61,155 (May 21, 2020) ("*Natural Gas and Oil Pipeline ROE Policy Statement*").

[109] As previously reported, the FERC issued a notice of inquiry on March 21, 2019 seeking information and views to help the FERC explore whether, and if so how, it should modify its policies concerning the determination of ROE to be used in designing jurisdictional rates charged by public utilities.[109] The FERC also sought comment on whether any changes to its policies concerning public utility ROEs should be applied to interstate natural gas and oil pipelines. This NOI followed *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).

[110] The *Natural Gas and Oil Pipeline ROE Policy Statement* was published *Fed. Reg.* on May 27, 2020 (Vol. 85, No. 102) pp. 31,760-31,773.

[111] For this purpose, "Complainant-Aligned Parties" are: Connecticut Public Utilities Regulatory Authority, Connecticut Office of the Attorney General, Connecticut Department of Energy and Environmental Protection, Connecticut Office of Consumer Counsel, Massachusetts Office of the Attorney General, Massachusetts Department of Public Utilities, Massachusetts Municipal Wholesale Electric Company, and New Hampshire Electric Cooperative.

[112] "Joint Parties" are: AEP, Avista, Evergy Companies, Entergy Services, Exelon, FirstEnergy, Portland Gen. Elec., PG&E, Corporation, Puget Sound Energy, PacifiCorp, Idaho Power, PSEG, So. Cal. Edison, and San Diego Gas & Elec.

[113] "Six Cities" are the Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California.

previously proposed ROE models, including the Expected Earnings model, along with certain modifications, to ensure that ROEs attract capital investment in needed transmission infrastructure). On June 24, EEI and WIRES requested the FERC issue a NOI regarding the FERC's policy for determining base ROE applicable to the electric industry as a whole. Six Cities answered Joint Parties on June 30. APPA answered EEI and WIRES' June 24 motion.

- **NOI: Certification of New Interstate Natural Gas Facilities (PL18-1)**

Since the last Report, on February 18, 2021, the FERC issued a new notice of inquiry ("NOI") in which it seeks new information and additional stakeholder perspectives to help it explore whether it should revise its approach under the currently effective policy statement on the certification of new natural gas transportation facilities to determine whether a proposed natural gas project is or will be required by the public convenience and necessity, as that standard is established in section 7 of the Natural Gas Act.[114] The 2021 NOI is to provide an opportunity for stakeholders to refresh the record and provide updated information and additional viewpoints to help the FERC assess its policy.[115] The FERC strongly urged stakeholders to not resubmit previously filed comments, which remain in the record of this proceeding.[116] Comments on the 2021 NOI are due on or before April 26, 2021.[117] On March 15, 2021, Joint Associations[118] moved for a 45-day extension of time to submit comments in response to the NOI. That request is pending before the FERC.

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

- **Alliance NYGT (IN21-4)**

On February 8, 2021, the FERC approved a Stipulation and Consent Agreement ("Agreement") with Alliance NYGT LLC ("NYGT")[119] that resolved OE's investigation into whether NYGT violated the FERC's Unit Operation and Communications Market Behavior Rules[120] and several provisions of the NYISO Tariff, related to its submission of offers and information to NYISO. Specifically, Enforcement found that NYGT failed to timely notify NYISO that its generators, after completion of gas equipment upgrades in 2012, had the ability to operate on gas, a less expensive fuel than kerosene. As a result, NYGT received inflated make-whole payments. Under the Agreement, NYGT must ***disgorge $369,264.19 plus interest***, and pay a ***civil penalty of $420,000***. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

[114] *Certification of New Interstate Natural Gas Facilities*, 174 FERC ¶ 61,125 (Feb. 18, 2021) ("2021 NOI").

[115] *Id.* at P 3.

[116] The 2021 NOI follows an April 19, 2018 NOI that sought comments 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. Literally thousands of individual and mass-mailed comments were filed on the 2018 NOI.

[117] The 2021 NOI was published in the *Fed. Reg.* on Feb. 24, 2021 (Vol. 86, No. 35) pp. 11,268-11,274.

[118] "Joint Associations" are: the American Forest & Paper Association ("AF&PA"), American Gas Association ("AGA"), the American Petroleum Institute ("API"), the American Public Gas Association ("APGA"), the Center for LNG ("CLNG"), the Energy Infrastructure Council ("EIC"), GPA Midstream Association ("GPA"), the Industrial Energy Consumers of America ("IECA"), Independent Petroleum Association of America ("IPAA"), Interstate Natural Gas Association of America ("INGAA"), the Natural Gas Supply Association ("NGSA"), and the Process Gas Consumers ("PGC").

[119] *Alliance NYGT LLC*, 174 FERC ¶ 61,086 (Feb. 8, 2021).

[120] 18 C.F.R. § 35.41(a)-(b) (2021).

Natural Gas-Related Enforcement Actions

- ***Rover Pipeline, LLC and Energy Transfer Partners, L.P. (IN19-4)***

On March 18, 2021, the FERC issued a show cause order[121] in which it directed Rover Pipeline, LLC ("Rover") and Energy Transfer Partners, L.P. ("ETP" and together with Rover, "Respondents") to show cause why they should not be found to have violated Section 157.5 of the FERC's regulations by misleading the FERC in its Application for Certificate of Public Convenience and Necessity under section 7(c) of the Natural Gas Act ("NGA").[122] The FERC directed Respondents to show cause why they should not be assessed civil penalties in the amount of ***$20.16 million***. On March 23, Respondents asked for a 60-day extension of time, to June 18, 2021, to file their answer. On March 29, FERC staff responded to Respondent's motion, not opposing the extension of time, but clarifying points made in Respondent's request.

- ***BP (IN13-15)***

On December 17, 2020, the FERC issued *Opinion 549-A*,[123] a 159-page decision addressing arguments raised on rehearing requested of *Opinion 549.*[124] *Opinion 549-A* modifies the discussion in *Opinion 549*, but reaches the same the result (ultimately requiring BP to pay a ***$20.16 million civil penalty (roughly $24.4 million with accrued interest) and disgorge $207,169***). Of note, *Opinion 549-A* denied BP's motion to dismiss this enforcement action as time barred (by the five-year statute of limitations set forth in 28 U.S.C. § 2462), finding BP waived any statute of limitations defense by failing to raise it earlier in this proceeding.[125] Opinion 549-A revised Ordering Paragraph (C) to direct the disgorged profits to non-profits that disburse the Low Income Home Energy Assistance Program of Texas funds, rather than to the Texas Department of Housing.[126]

On December 29, 2020, BP filed a notice that it intends to appeal *Opinion 549-A* to the Fifth Circuit Court of Appeals and paid the civil penalty amount on December 28, 2020, under protest and with full reservation of rights pending the outcome of judicial review of that Opinion. On January 19, BP filed a notice that it disgorged $250,295 ($207,169 principal plus interest), divided equally ($83,431.67) among the following 3 entities identified in the "2016 Comprehensive Energy Assistance Program Subrecipient List": Dallas County Dept. of Health and Human Services (serving Dallas); El Paso Community Action, Project Bravo (Serving El Paso); and Panhandle Community Services (serving Armstrong and numerous other counties), again under protest and with full reservation of rights pending the outcome of judicial review of *Opinion 549/549-A*.

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[121] *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.,* 174 FERC ¶ 61,208 (Mar. 18, 2021) ("*Rover/ETP Show Cause Order*").

[122] Specifically, Rover stated that it was "committed to a solution that results in no adverse effects" to the Stoneman House, an 1843 farmstead located near Rover's largest proposed compressor station. In truth, the OE Staff Report alleges, Rover was simultaneously planning to purchase the house with the intent to demolish it, if necessary, to complete its pipeline. The OE Staff Report alleges that Rover purchased the house in May 2015 and demolished the house in May 2016. The OE Staff Report further finds that despite taking these actions during the year and a half that Rover's application was pending before the FERC, Rover did not notify the FERC that it purchased the Stoneman House, intended to destroy the Stoneman House, and did destroy the Stoneman House. The OE Staff Report therefore concludes that Rover violated section 157.5's requirement for full, complete and forthright applications, through its misrepresentations and omissions, when it decided not to tell FERC that it had purchased the house and was considering demolishing it, and when Rover demolished it in May 2016 without notifying FERC.

[123] *BP America Inc. et al.,* Opinion No. 549-A, 173 FERC ¶ 61,239 (Dec. 17, 2020) ("*BP Penalties Allegheny Order*")

[124] *BP America Inc.*, Opinion No. 549, 156 FERC ¶ 61,031 (July 11, 2016) ("*BP Penalties Order*") (affirming Judge Cintron's Aug. 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 FERC's regulations ("Anti-Manipulation Rule") and NGA Section 4A (*BP America Inc.et al,* 152 FERC ¶ 63,016 (Aug. 13, 2015) ("*BP Initial Decision*")).

[125] *BP Penalties Allegheny Order* at P 1.

[126] *Id*. at P 319.

- ***Total Gas & Power North America, Inc. et al. (IN12-17)***

On April 28, 2016, the FERC issued a show cause order[127] 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.[128]

The FERC also directed TGPNA to show cause why it should not be required to disgorge unjust profits of ***$9.18 million***, plus interest; TGPNA, Tran and Hall to show cause why they should not be assessed civil penalties (TGPNA - ***$213.6 million***; Hall - ***$1 million*** (jointly and severally with TGPNA); and Tran - ***$2 million*** (jointly and severally with TGPNA)). In addition, the FERC directed TGPNA's parent company, Total, S.A. ("Total"), and TGPNA's affiliate, Total Gas & Power, Ltd. ("TGPL"), to show cause why they should not be held liable for TGPNA's, Hall's, and Tran's conduct, and be held jointly and severally liable for their disgorgement and civil penalties based on Total's and TGPL's significant control and authority over TGPNA's daily operations. Respondents filed their answer on July 12, 2016. OE Staff replied to Respondents' answer on September 23, 2016. Respondents answered OE's September 23 answer on January 17, 2017, and OE Staff responded to that answer on January 27, 2017. This matter remains pending before the FERC.

XIV. Natural Gas Proceedings

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

New England Pipeline Proceedings

The following New England pipeline projects are currently under construction or before the FERC:

- ***Iroquois ExC Project (CP20-48)***
  - 125,000 Dth/d of incremental firm transportation service to ConEd and KeySpan by building and operating new natural gas compression and cooling facilities at the sites of four existing Iroquois compressor stations in Connecticut (Brookfield and Milford) and New York (Athens and Dover)
  - Three-year construction project; service request by November 1, 2023
  - February 2, 2020 application for a certificate of public convenience and necessity pending; Iroquois requests on January 26, 2021 that the FERC act promptly and issue the certificate

- ***Atlantic Bridge Project (CP16-9)***
  - On February 24, 2020, the FERC authorized Algonquin Gas Transmission, LLC ("Algonquin") and Maritimes & Northeast Pipeline, LLC ("Maritimes") to place facilities associated with the Atlantic Bridge Project into service.[129] Rehearing of the Authorization Order was timely requested, but denied by operation of law.

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

[128] 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.

[129] *Algonquin Gas Transmission, LLC*, Docket No. CP16-9 at 1 (Sep. 24, 2020) (delegated order) ("*Authorization Order*").

- In a fairly unprecedented order issued February 18, 2021,[130] the FERC, expressing concerns regarding operation of the project, established briefing on the following matters:
  - In light of the concerns expressed regarding public safety, is it consistent with the FERC's responsibilities under the Natural Gas Act ("NGA") to allow the Weymouth Compressor Station to enter and remain in service?
  - Should the Commission reconsider the current operation of the Weymouth Compressor Station in light of any changed circumstances since the project was authorized? For example, are there changes in the Weymouth Compressor Station's projected air emissions impacts or public safety impacts the Commission should consider? We encourage parties to address how any such changes affect the surrounding communities, including environmental justice communities.
  - Are there any additional mitigation measures the Commission should impose in response to air emissions or public safety concerns?
  - What would the consequences be if the Commission were to stay or reverse the Authorization Order?
- Requests for rehearing of the Briefing Order were filed by Algonquin, NGSA and Center for Liquefied Natural Gas, and by America and Energy Infrastructure Council. Cheniere Energy submitted comments in support of the requests for rehearing. The requests for rehearing are pending, with FERC action required on or before April 19, 2021, or the requests will be deemed denied by operation of law.
- Initial briefs in response to the Briefing Order are due April 5, 2021; reply briefs, May 5, 2021. Comments have thus far been filed by Footprint Power, the Town of Weymouth, the Town of Weymouth Town Council, and 5 private citizens.
- The FERC noted that the facilities placed in service pursuant to the Authorization Order may remain in service while it considers the issues set for briefing.

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.[131] 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*.[132] Further, in an interesting twist, the FERC found that a December 5, 2017 "Renewed 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

[130] *Algonquin Gas Transmission, LLC and Maritimes & Northeast Pipeline, LLC*, 174 FERC ¶ 61,126 (Feb. 18, 2021) ("*Briefing Order*").

[131] *Nat'l Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 167 FERC ¶ 61,007 (Apr. 2, 2019).

[132] *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).

Northern Access Project, served as a motion requesting a waiver determination by the FERC,[133] 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.[134] 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.[135] 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,[136] provided a "more clearly articulate[d] basis for denial."
- On August 27, 2019, 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.[137]
- On October 16, 2020, Applicants requested, due to ongoing legal and regulatory delays, an additional 2-year extension of time, until December 1, 2024, to complete construction of the Project and enter service. More than 50 sets of comments on the requested extension were filed and on December1, 2020, the FERC dismissed, without prejudice, Applicants' request for an extension of time, [138] finding the request premature. The FERC reiterated its encouragement that pipeline applicants requesting extensions "file their requests no more than 120 days before the deadline to complete construction",

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[133] 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).

[134] *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*").

[135] *Nat'l Fuel Gas Supply Corp. v. NYSDEC et al*. (2d Cir., Case No. 17-1164).

[136] 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).

[137] *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).

[138] *National Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 173 FERC ¶ 61,197 (Dec. 1, 2020).

so that the FERC has the relevant information available to determine whether good cause exists to grant an extension of time and whether the FERC's prior findings remain valid.[139]

XV. State Proceedings & Federal Legislative Proceedings

- **New England States' Vision Statement**

In October 2020, the six New England states released their "Vision Statement", outlining their vision for "a clean, affordable, and reliable 21st century regional electric grid" and committing to engage in a collaborative and open process, supported by NESCOE, intended to advance the principles discussed in the Vision Statement. As part of that effort, the following series of online technical forums to discuss the issues presented in the Vision Statement were held:

Jan 13, 2021	Wholesale Market Reform
Jan 25, 2021	Wholesale Market Reform
Feb 2, 2021	Transmission Planning
Feb 25, 2021	Governance Reform
Mar 18, 2021	Equity and Environmental Justice

Written comments on the topics and discussions addressed in the on the equity and environmental justice topics and discussions are due by April 29, 2021 and may be submitted to were claire.sickinger@ct.gov. Comments will be publicly posted on **WholesaleEnergy@NewEnglandEnergyVision.com.**

Recordings of the technical forums, as well as draft notices, agendas, and additional information on these sessions, are available on the New England States' Vision Statement website (https://newenglandenergyvision.com/). Details on an evening forum related to environmental justice issues has yet to be announced.

XVI. 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 Implementation of Order 1000 Exemptions for Immediate Need Reliability Projects (20-1422)**
Underlying FERC Proceeding: EL19-90[140]
Petitioner: LS Power

On October 16, 2020, LSP Transmission Holdings II, LLC ("LS Power") petitioned the DC Circuit Court of Appeals for review of the FERC's orders addressing ISO-NE's implementation of the Order 1000 exemptions for

[139] *Id.* at P 10.

[140] *ISO New England Inc., 171 FERC ¶ 61,211 (June 18, 2020) ("Order Terminating Proceeding")* (finding (i) "insufficient evidence in the record to find under FPA section 206 that [ISO-NE's] implementation of the exemption for immediate need reliability projects is unjust, unreasonable, or unduly discriminatory or preferential; (ii) "insufficient evidence in the record to find that ISO-NE implemented the immediate need reliability project exemption in a manner that is inconsistent with or more expansive than [the FERC] directed"; and (iii) that ISO-NE complies with the five criteria established for the immediate need reliability project exemption); and *ISO New England Inc.,* 172

immediate need reliability projects. Since the last Report, and after the Clerk granted extensions of time to file procedural and dispositive motions, the FERC on December 10, 2020 requested at least 60 days between the filing of LS Power's opening brief and the FERC's brief in response, and on December 28, 2020, filed a certified index to the record. On December 29, 2020, the Court granted the motions to intervene by Avangrid and MMWEC.

On March 2, 2021, the Court at FERC's request, issued an amended briefing schedule to apply in this case, adding roughly one month to each deadline previously identified: Petitioner's Brief due April 5, 2021; Intervenors in Support of Petitioners Brief, April 1215, 2021; FERC's brief, June 11, 2021; Intervenors in Support of FERC, July 9, 2021; Petitioner's Reply Brief, July 9, 2021; Intervenors in Support of Petitioner Reply Brief, July 9, 2021; Deferred Appendix, July 16, 2021; and Final Briefs July 30, 2021.

- **CIP IROL Cost Recovery Rules (20-1389)**
  Underlying FERC Proceeding: ER20-739[141]
  Petitioner: Cogentrix, Vistra

On September 25, 2020, Cogentrix and Vistra petitioned the DC Circuit Court of Appeals for review of the FERC's orders allowing for recovery of expenditures to comply with the IROL-CIP requirements, but only those costs incurred on or after the effective date of the relevant individual FPA section 205 filing, including undepreciated costs of any such past capital expenditures to comply with the IROL-CIP requirements. On December 22, 2020, the Court adopted a proposed *revised* briefing schedule that added roughly 45 days to each procedural deadline previously established. On March 1, 2021, Cogentrix and Vistra filed Petitioners' Brief (which it corrected on March 8 to remove the use of the acronym "NERC" to identify the "North American Electric Reliability Corporation). Next up are FERC's Respondent Brief (April 30, 2021); Intervenor for Respondent Brief (June 1, 2021); Petitioners' Reply Briefs (June 28, 2021); Deferred Appendix (July 16, 2021); and Final Briefs (July 26, 2021).

- **Mystic 8/9 Cost of Service Agreement (20-1343; 20-1361, 20-1362; 20-1365, 20-1368; 21-1067; 21-1070)(consolidated)**
  Underlying FERC Proceeding: EL18-1639[142]
  Petitioners: Mystic (20-1343), NESCOE (20-1361, 21-1067), MA AG (20-1362), CT Parties (20-1365, 20-1368, 21-1070)

Mystic, NESCOE, MA AG, and CT Parties have separately petitioned the DC Circuit Court of Appeals for review of the FERC's orders addressing the COS Agreement among Mystic, ExGen and ISO-NE.143 The cases have been consolidated into Case No. 20-1343. Since the last Report, on February 17 and 24, 2021, the Court consolidated with 20-1343 the most recent appeals in cases 21-1067 (NESCOE) and 21-1070 (CT Parties), respectively. On March 25, 2021, the Court issued an order returning this case to its active docket. On March 26, the Court granted the interventions by MMWEC/NHEC, NESCOE, and ENECOS and its anticipation that it will file a proposed briefing schedule in this consolidated case.

FERC ¶ 61,293 (Sep. 29, 2020) *("Order 1000 Exemptions Allegheny Order")* (addressing arguments raised by request for rehearing denied by operation of law, modifying discussion in *Order Terminating Proceeding,* but reaching same result).

[141] *ISO New England Inc.*, 171 FERC ¶ 61,160 (May 26, 2020) ("*CIP IROL Cost Recovery Order*") and *ISO New England Inc.*, 172 FERC ¶ 61,251 (Sep. 17, 2020) ("*CIP IROL Allegheny Order*", and together with the CIP IROL Cost Recover Order, the "*CIP IROL Orders*").

[142] *July 2018 Order*; *July 2018 Rehearing Order*; *Dec 2018 Order*; *Dec 2018 Rehearing Order; Jul 17 Compliance Order*.

[143] The COS Agreement is to provide compensation for the continued operation of the Mystic 8 & 9 units from June 1, 2022 through May 31, 2024.

- ***CASPR* (20-1333, 20-1331) (consolidated)****
  Underlying FERC Proceeding: ER18-619[144]
  Petitioners: Sierra Club, NRDC, RENEW Northeast, and CLF

On August 31, 2020, the Sierra Club, NRDC, RENEW Northeast, and CLF petitioned the DC Circuit Court of Appeals for review of the FERC's order accepting ISO-NE's CASPR revisions (which, under *Allegheny*, is ripe for review). On October 2, 2020, appearances, docketing statements, a statement of issues to be raised, and a statement of intent to utilize deferred joint appendix were filed. On October 19, 2020, the FERC moved to dismiss the case for a lack of jurisdiction (arguing that Petitioners missed their opportunity to timely file their Petition for review in 2018, and filing within 60 days of *Allegheny* did not make their Petition timely). Alternatively, the FERC asked that the case be held in abeyance for 60 days pending issuance of a further FERC order on this matter. On October 29, Petitioners opposed the FERC's motion. On November 5, 2020, the FERC filed a reply, indicated that an order on rehearing would be issued imminently and suggested that, if the Court declines to dismiss the petition, it should be held in abeyance until the Commission issues an order on rehearing. As noted above, the FERC issued the *CASPR Allegheny Order* on November 19, modifying the discussion in the *CASPR Order*, but reaching the same the result. The Sierra Club, NRDC and CLF also requested rehearing of the November 19 order.

On January 12, 2021, the Court dismissed as moot the FERC's October 19 motion to hold this proceeding in abeyance and ordered that the motion to dismiss be referred to the merits panel (Judges Pillard, Katsas and Walker) and addressed by the parties in their briefs. On January 25 and 26, CT Parties and MMWEC and NHEC filed statements of issues and notices that they intend to participate in support of Petitioners. On January 27, the Court ordered the parties to submit by February 26, 2021, proposed formats for the briefing of these cases.

Since the last Report, the Court granted NEPOOL's intervention and established a briefing schedule that calls for the following: Petitioners' Brief (May 3, 2021); Intervenor for Petitioners' Brief (May 10, 2021); Respondent's Brief (July 9, 2021); Intervenor for Respondent's Brief (July 16, 2021); Petitioners' Reply Brief (August 6, 2021); Intervenor for Petitioners' Reply Brief (August 6, 2021); Deferred Appendix (August 13, 2021); and Final Briefs (August 27, 2021). In addition, on March 26, Petitioners moved the Court to hold this matter in abeyance for 180 days (in light of the possibility that the FERC will act, following its March 23, 2021 technical conference on capacity issues, "to reform ISO New England's capacity market and change the rules at issue in this case"). Petitioners' request is pending before the FERC.

- ***Opinion 531-A* Compliance Filing Undo (20-1329)**
  Underlying FERC Proceeding: ER15-414[145]
  Petitioners: TOs' (CMP et al.)

On August 28, 2020, the TOs[146] petitioned the DC Circuit Court of Appeals for review of the FERC's October 6, 2017 order rejecting the TOs' filing that sought to reinstate their transmission rates to those in place prior to the FERC's orders later vacated by the DC Circuit's *Emera Maine*[147] decision. On September 22, 2020, the FERC submitted an unopposed motion to hold this proceeding in abeyance for four months to allow for the Commission to "a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the Commission." On October 2, 2020, the Court granted the FERC's motion, and directed the parties to file motions to govern future proceedings in this case by February 2, 2021. On January 25, 2021, the FERC requested that the Court continue to hold this petition for review in abeyance for an additional three months, with parties to file motions to govern future proceedings at the end of that period. The FERC requested continued abeyance because of its intention to issue a

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144 *ISO New England Inc.*, 162 FERC ¶ 61,205 (Mar. 9, 2018) ("*CASPR Order*").

145 *ISO New England Inc.*, 161 FERC ¶ 61,031 (Oct. 6, 2017) ("*Order Rejecting Filing*").

146 The "TOs" are CMP; Eversource Energy Service Co., on behalf of its affiliates CL&P, NSTAR and PSNH; National Grid; New Hampshire Transmission; UI; Unitil and Fitchburg; VTransco; and Versant Power.

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

future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the FERC. Petitioners consented to the requested abeyance. On February 11, 2021, the Court issued an order that that this case remain in abeyance pending further order of the court and directed the parties to file motions to govern future proceedings in this case by April 26, 2021.

- **2013/14 Winter Reliability Program Order on Compliance and Remand (20-1289, 20-1366) (consol.) Underlying FERC Proceeding: ER13-2266**[148]
  Petitioner: TransCanada

On July 30, 2020, TransCanada Power Marketing ("Petitioner" or "TransCanada") again petitioned the DC Circuit Court of Appeals for review of the FERC's action on the 2013/2014 Winter Reliability Program, this time in the FERC's April 1, 2020 *2013/14 Winter Reliability Program Order on Compliance and Remand*.[149] NEPGA intervened on October 15, 2020 (and its intervention granted on October 28). On October 16, TransCanada filed a docketing statement and statement of issues. On October 29, the FERC filed a certified index to the record and an unopposed motion for a 60-day briefing period. On December 2, 2020, the Court granted the FERC's October 29 motion On January 11, 2021, TransCanada submitted its initial brief. On March 12, FERC filed its Respondent Brief. Next up is Petitioner's Reply Brief due April 9, 2021. The Deferred Appendix and Final Briefs are due , April 16 and April 30, 2021, respectively.

- **ISO-NE's Inventoried Energy Program (Chapter 2B) Proposal (19-1224***; 19-1247; 19-1252; 19-1253)(consolidated); Underlying FERC Proceeding: ER19-1428**[150]
  Petitioners: ENECOS (Belmont et al.) (19-1224); MA AG (19-1247); NH PUC/NH OCA (19-1252); Sierra Club/UCS (19-1253)

As previously reported, at the unopposed request of the FERC, the Court issued an order suspending the previous briefing schedule and remanding the record back to the FERC. Subsequently, the FERC issued its *IEP Remand Order* (June 18, 2020) and its Notice of Denial by Operation of Law of the requests for rehearing of its *IEP Remand Order* (August 20, 2020). As previously reported, each of the Petitioners filed amended petitions for review in the consolidated proceeding in order to bring the FERC's *IEP Remand Order* and the post-remand FERC record before the DC Circuit. On November 10, 2020, the Court ordered that the cases be removed from abeyance. Opening Briefs from Petitioners were filed on December 11, 2020. The FERC filed its Respondent Brief on February 9. Intervenor for Respondent Briefs were filed on February 16 by ISO-NE and NEPGA. On February 24, the FERC filed an amended certified index to the record. Petitioners' Reply Brief was filed on March 30, 2021. The Deferred Appendix will be filed on April 20, 2021; Final Briefs are due on or before May 4, 2021.

[148] 171 FERC ¶ 61,003 (Apr. 1, 2020) ("*2013/14 Winter Reliability Program Order on Compliance and Remand*") (accepting ISO-NE's January 23, 2017 compliance filing, finding that the bid results from the 2013/14 Winter Reliability Program were just and reasonable, and providing for this finding the further reasoning requested by the DC Circuit in *TransCanada Power Mktg. Ltd. v. FERC*, 811 F.3d 1 (DC Cir. 2015) ("*TransCanada*").)

[149] In TransCanada, the DC Circuit granted TransCanada's prior petition in part, and directed the FERC to either better justify its determination or revise its disposition to ensure that the rates under the Program are just and reasonable. *TransCanada* at 1.

[150] 162 FERC ¶ 61,127 (Feb. 15, 2018) ("*Order 841*"); 167 FERC ¶ 61,154 (May 16, 2019) ("*Order 841-A*").

Other Federal Court Activity of Interest

- ***Order 872* (20-72788,* 21-70113; 20-73375, 21-70113) (consol.) (9th Cir.)**
  Underlying FERC Proceeding: RM19-15[151]
  Petitioners: SEIA et al.

On September 17, 2020, SEIA petitioned the 9th Circuit Court of Appeals for review of *Order 872*.[152] On October 9, the FERC filed an unopposed motion for the Court to hold this appeal in abeyance, suspend filing of the certified index to the record, and issue a new briefing schedule after January 4, 2021. The abeyance will permit the FERC to address the pending rehearing requests in a future order. On October 26, 2020, the Court granted the FERC's motion. On January 29, 2021, SEIA requested that this case be consolidated with the others, and that the abeyance period be extended to give the parties additional time to coordinate and develop a unified, efficient briefing schedule.

Since the last Report, on March 25, 2021, the Court granted SEIA's unopposed March 5, 2021 motion to lift the stay in this proceeding. Briefing will resume as follows: Petitioners' briefs (May 27, 2021); joint brief of petitioner-intervenors (June 28, 2021); motions and associated briefs by amici curiae in support of petitioners (June 28, 2021); Respondent's brief (September 27, 2021); joint brief of respondent-intervenors (October 27, 2021); motions and associated briefs by amici curiae in support of respondent (October 27, 2021); and any optional reply briefs (December 13, 2021).

- **PennEast Project (18-1128)**
  Underlying FERC Proceeding: CP15-558[153]
  Petitioners: NJ DEP, DE and Raritan Canal Commission, NJ Div. of Rate Counsel

Abeyance continues of the appeal before the DC Circuit of the FERC's orders granting certificates of public convenience and necessity to PennEast Pipeline Company, LLC ("PennEast")[154] 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"). The cases are being held in abeyance "pending final disposition of any post-dispositional 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, which is in the midst of proceedings before the Supreme Court, the DC Circuit will not take up this case. The last Joint Status Report was filed on March 23, 2021, noting developments since the December 23, 2020 Status Report, and reporting that none of the events "constitute any of the conditions that [the DC Circuit] enumerated in its October 1, 2019 Order as triggering an obligation to file a motion governing future proceedings."

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[151] *Transcontinental Gas Pipe Line Co., LLC*, 159 FERC ¶ 62,181 (Feb. 3, 2017); *Transcontinental Gas Pipe Line Co., LLC*, 161 FERC ¶ 61,250 (Dec. 6, 2017).

[152] *Order 872* approved pricing and eligibility revisions to the FERC's long-standing regulations implementing sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA"), including: state flexibility in setting QF rates; a decrease (to 5 MW) to the threshold for a rebuttable presumption of access to nondiscriminatory, competitive markets; updates to the "One-Mile Rule"; clarifications to when a QF establishes its entitlement to a purchase obligation; and provision for certification challenges.

[153] *PennEa*st *Pipeline Co., LLC*, 162 FERC ¶ 61,053 (Jan. 19, 2018), *reh'g denied*, 163 FERC ¶ 61,159 (May 30, 2018).

[154] 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.

- **Opinion 569/569-A: FERC's Base ROE Methodology (16-1325, 20-1182, 20-1240, 20-1241, 20-1248, 20-1251, 20-1267, 20-1513)**
  Underlying FERC Proceeding: EL14-12; EL15-45[155]
  Petitioners: MISO TOs, Transource Energy, Dec 23 Petitioners et al.

The MISO Transmission Owners (TOs), Transource and "Dec 23 Petitioners",[156] among others, have appealed *Opinion 569/569-A*. The MISO TOs' case has been consolidated with previous appeals that had been held in abeyance, with the lead case number assigned as 16-1325. The FERC filed a certified Index to the Record on December 3, 2020, the Parties filed a joint unopposed briefing schedule on December 23, 2020. Statements of issues were filed on February 8, 2021. Since the last Report, Petitioners' Briefs were filed on March 10. On March 17, 2021, a motion to participate as amicus curiae was jointly filed by NEP, CPM, Eversource, Fitchburg and Unitil, NHT, VTransco, Versant Power, and UI ("New England Parities"). On March 18, New England Parties submitted an amicus brief in support of Transmission Owning Petitioners. On March 24, 2021, Intervenors in Support of Petitioners[157] filed their Brief. The following deadlines remain: FERC's brief, June 8, 2021; Intervenors in Support of FERC, June 22, 2021; Petitioners Reply Briefs, July 8, 2021; Intervenors in Support of Petitioners Reply Briefs, July 22, 2021; Joint Deferred Appendix, August 6, 2021; and Final Briefs, August 19, 2021.

[155] *Transcontinental Gas Pipe Line Co., LLC*, 159 FERC ¶ 62,181 (Feb. 3, 2017); *Transcontinental Gas Pipe Line Co., LLC*, 161 FERC ¶ 61,250 (Dec. 6, 2017).

[156] "Dec 23 Petitioners" are: Assoc. of Bus. Advocating Tariff Equity; Coalition of MISO Transmission Customers: IL Industrial Energy Consumers; IN Industrial Energy Consumers, Inc.; MN Large Industrial Group; WI Industrial Energy Group; AMP; Cooperative Energy; Hoosier Energy Rural Elec. Coop.; MS Public Service Comm.; MO Public Service Comm.; MO Joint Municipal Electric Utility Comm.; Organization of MISO States, Inc.; Southwestern Elec. Coop., Inc.; and Wabash Valley Power Assoc.

[157] The Intervenors for Petitioners Brief was filed by Citizens Utility Board of Wisconsin, Illinois Citizens Utility Board, Indiana Office of Utility Consumer Counselor, Iowa Office of Consumer Advocate, Louisiana Public Service Commission, Michigan Citizens Against Rate Excess, Minnesota Department of Commerce, and Missouri Office of Public Council.

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Summary of March 25-26, 2021 Joint Nominating Committee Meetings

- On March 25-26, Jennifer Rockwood of Russell Reynolds Associates, presented the JNC with a "Long List" of candidates for the two upcoming ISO Board Director openings. Based on the Position Specifications, Jennifer presented candidates with technical electric markets and transmission expertise and also included "best athlete" candidates whose experiences touched more generally on these fields, with the thought that some could be considered for openings in future years. Ms. Rockwood stressed her firm's focus on building a slate with strong diversity candidates.

- Ms. Rockwood reviewed the twenty-three candidates, describing the backgrounds of each. Committee members shared their direct knowledge of candidates, when applicable, and asked numerous clarifying questions about each.

- Committee members discussed the two candidates who would require age-based waivers to enable them to serve, in one case for more than one term, and agreed that at this point in the process they were reluctant to seek any waivers, particularly as twenty-one of the candidates were unconstrained.

- The Committee ranked the candidates and selected nine for first round interviews to take place April 8, 9, and 16. Candidates' backgrounds include electric markets and transmission experience, customer service and transformation, emergency preparedness and disaster recovery. The Committee selected two alternates as well, in the event that any of the primary candidates withdrew from the process.

- Over the next week, in advance of the interviews, Committee members will be reviewing and finalizing interview questions.