David T. Doot
Secretary

December 30, 2020

VIA ELECTRONIC MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of January 7, 2021 NEPOOL Participants Committee Teleconference Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, initial notice is hereby given that the January meeting of the Participants Committee will be held **via teleconference on *Thursday*, January 7, 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, is **866-803-2146; Passcode: 7169224.**

For your information, the January 7 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.

Wishing you all a very safe, healthy and Happy New Year!

Respectfully yours,

/s/
David T. Doot, Secretary

FINAL AGENDA

1. To approve the draft minutes of the November 5 and December 3, 2020 Participants Committee meetings. The draft preliminary minutes of those meetings, marked to show changes from the drafts circulated with the initial notice, are included with this supplemental notice and posted with the meeting materials.

2. To adopt and approve all actions recommended by the Reliability Committee set forth on the Consent Agenda included with the initial notice and posted with the meeting materials.

3. To receive an ISO Chief Executive Officer report.

4. To receive an ISO Chief Operating Officer report.

5. To discuss the JNC process for the ISO New England Board nomination process for the 2021 slate. Background materials are included with this supplemental notice.

6. 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.

7. To receive reports from Committees, Subcommittees and other working groups:
    - Markets Committee
    - Reliability Committee
    - Transmission Committee
    - Budget & Finance Subcommittee
    - Others

8. To receive an update on the "Pathways to the Future Grid" process, including contemplated next steps. A copy of Dr. Frank Felder's report on various issues and tradeoffs associated with identified potential pathways/alternative market frameworks will be circulated and posted in advance of the meeting.

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, at 10:00 a.m. on Thursday, November 5, 2020. A quorum determined in accordance with the Second Restated NEPOOL Agreement was present and acting throughout the meeting. Attachment 1 identifies the members, alternates and temporary alternates who participated in the teleconference meeting.

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

APPROVAL OF OCTOBER 1, 2020 MEETING MINUTES

Ms. Chafetz referred the Committee to the preliminary minutes of the October 1, 2020 meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of the October 1, 2020 meeting were unanimously approved as circulated, with an abstention by Mr. Michael Kuser's alternate, Mr. Jason York, noted.

CONSENT AGENDA

Ms. Chafetz referred the Committee to the Consent Agenda that was circulated and posted in advance of the meeting. She noted that, because the first item on the Consent Agenda (changes to Market Rule 1 that would sunset the Forward Reserve Market (FRM)) had been contingent on the FERC's acceptance of the Energy Security Initiative (ESI) proposal, and the FERC had the week before rejected the ESI proposal, the ISO had agreed that the Participants Committee should forego a vote on the proposal to sunset the FRM. She indicated that, absent objection, the FRM sunset would be removed from the Consent Agenda. There were no objections. Then, following motion duly made and seconded, the Consent Agenda was approved with opposition noted by CSC and LIPA, and abstentions noted by Calpine and Mr. Kuser's alternate. The representatives for CSC and LIPA noted that their opposition related to Consent Agenda Items 3 and 4 (HQICC Values and ICR and Related Values for the 2021-22 3rd Annual Reconfiguration Auction (ARA), 2022-23 2nd ARA, and 2023-24 1st ARA) because of their previously conveyed positions that those values do not properly account for the reliability benefits and capacity import capability of the Cross-Sound Cable. The Calpine representative explained that the Calpine abstention was related to the HQICC values which did not require imports to be backed by non-recallable capacity committed to the region in order to be counted as capacity.

ISO COO REPORT

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), referred the Committee to his November report, which had been circulated and posted in advance of the meeting. He noted that the data in the report was through October 28. The report highlighted: (i) Energy Market value for October 2020 was $193 million, down $14 million from September 2020 and down $9 million from October 2019; (ii) October 2020 average natural gas prices were 5.5 percent higher than September average prices; (iii) the average Real-Time Hub Locational Marginal Prices (LMPs) for October ($25.06/MWh) were 26 percent higher than September averages; (iv) average October 2020 natural gas prices and Real-Time Hub LMPs over the period were down 8 percent and up 23 percent, respectively, from October 2019; (v) the average Day-Ahead cleared physical energy during peak hours as percent of forecasted load was 100.7 percent during October (up from 99.3 percent during September), with the minimum value for the month (95.6 percent) on October 8; and (vi) the Daily Net Commitment Period Compensation (NCPC) payments for October totaled $2.5 million, which was up $100,000 from September 2020 and down $200,000 from October 2019. October NCPC, which was 1.3 percent of total Energy Market value, was comprised of (a) $1.9 million in first contingency payments (up $300,000 from September); (b) $546,000 in second contingency payments (up $226,000 from September); (c) $43,000 in voltage payments (down $457,000 from September); and (d) $41,000 in distribution payments (up $35,000 from September).

Dr. Chadalavada noted that the November 19 Planning Advisory Committee (PAC) meeting would include discussion of capacity zone development and transmission planning for the clean energy transition. He also reported that, at the October 21 PAC meeting, the ISO had begun the Order 1000/Boston 2028 Request for Proposal lessons-learned process related to competitive transmission solutions, and expected that the lessons-learned process would continue through the end of 2020 and into 2021.

Looking ahead, Dr. Chadalavada reported that the lowest 50/50 and 90/10 Fall Operable Capacity Margins were projected for week beginning November 14, 2020; the lowest 50/50 and 90/10 Winter Operable Capacity Margins, 2,574 MW and 1,232 MW, respectively, were projected for week beginning January 2, 2021. The 50/50 and 90/10 winter peak demand forecasts were projected to be approximately 1.5% and 1.7% lower, respectively, than 2019. Dr. Chadalavada concluded his report by noting that preparations for Winter 2020-21 were well underway.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), referred the Committee to a presentation shared with members during the meeting entitled “Overview of Strategic Planning” (that presentation was posted following the meeting). He explained that the presentation summarized the strategic planning process that the ISO Board had undertaken previously. He noted that process was more extensive in 2019 and flagged that the output of those discussions, which had taken place last fall, had been reflected in prior presentations he had given to the Participants Committee. In particular, he said that the ~~Board~~Board's strategic planning had both informed his presentation earlier in the year on potential future pathways and the work plan that had been reviewed with the Committee at the October meeting. Following a brief summary of the business planning approach followed each year, he referred the Committee to the ISO's mission and ~~vision statement~~Vision Statement. He reminded the Committee that the ~~ISO~~ISO's mission was set forth in the Tariff and outlined the ISO's responsibilities to operate the system, conduct long-term planning, and administer the wholesale markets. He said the Board adopted last fall the following Vision Statement: "To harness the power of competition and advanced technologies to reliably plan and operate the grid as the region transitions to clean energy." He explained that the Vision Statement then informed five ~~Strategic Goals~~strategic goals that he read to the Committee. Elaborating on the first of those five goals, ~~Responsive Market Designs~~responsive market designs, he explained that the ISO did not consider itself to have the authority, given its mission, to define decarbonization objectives for the region. Rather, the ISO looked to the ~~states~~States individually and collectively to define their policy objectives. The strategic goal identified by the ISO was to adjust the market design in order to accommodate those objectives. He saw the ongoing future pathways discussion in the region as advancing this goal. He emphasized the importance that the ISO placed on ensuring that the market ~~attracted and retained~~attract and retain enough balancing resources to maintain reliability.

He went on to explain the remaining four ~~Strategic Goals~~strategic goals, including the following:

- Progress and innovation, with specific reference to improving grid modeling, incenting appropriate enhancements to the transmission infrastructure, and enhancing the information services from the ISO.
- Operational excellence.
- Stakeholder engagement, with emphasis on understanding and responding to the needs and desires of the FERC, the ~~states~~States and the NEPOOL members and nurturing positive relationships with all those entities.
- Attract, develop and retain talent for its workforce.

The Committee then discussed the Vision Statement and ~~Strategic Goals~~strategic goals, providing reaction and seeking clarification. Mr. van Welie was questioned on whether the first ISO goal was better characterized as working to align the markets with state objectives rather than to accommodate those objectives. He explained that accommodation better reflected the role the ISO could play within its mission. He also explained in response to questions the ISO's recognition that efforts to respond to the ~~state's~~States' desire for longer term system planning were necessarily constrained by the existing Tariff, which provided for planning on a ten-year horizon. He noted the ISO's willingness to work on economic studies, particularly in an effort to identify transmission needed to support increased renewables on the grid. He opined that Order 1000 public policy planning ~~does~~did not adapt well to this goal and ~~leaves~~left unresolved important cost-allocation questions. He acknowledged in response to a comment that decisions based on planning need to reflect the recognition of increasing potential inaccuracies of assumptions and projections the ~~further out in~~longer the planning ~~one looks~~horizon. Acknowledging the certainty that there ~~will~~would be ever-growing reliance on intermittent, renewable resources, he re-emphasized the importance to the ISO of ensuring that the markets preserve and attract balancing resources ~~that are~~ essential to maintaining reliability.

He noted ~~that~~ the ISO had previously expected to spend considerable time in 2021 defining details and implementing ESI. With the FERC's rejection of ESI, the ISO would be adjusting its 2021 work plan.

Many commenters expressed appreciation for the ISO laying out its Vision Statement and ~~Strategic Goals~~strategic goals and support for both. Those commenters included representatives of the MA DPU and of NESCOE, referencing a productive discussion that had occurred the prior day with state representatives and expressing appreciation for the ISO's efforts and engagement.

Following discussion of the ISO's Vision Statement and ~~Strategic Goals~~strategic goals, Mr. Van Welie discussed the FERC's order rejecting ESI. He explained that the ISO ~~remains~~remained interested in making the ancillary services improvements identified in ESI but wanted first to ensure full appreciation for, and understanding of, the FERC's reaction to that proposal. He noted that the order was unclear on whether compliance obligations remained under the FERC's July 2018 order requiring market changes to achieve fuel security. He explained that the ISO planned to pause ~~in~~ its efforts relating to ESI until it received more clarity from the FERC, which he expected ~~would~~could take at least six months. He said the ISO would consider separately adopting components of ESI, but not without first seeking further input from the FERC. He said the ISO would seek in the near term to confirm with the FERC that there was no longer *ex parte* limitations barring the ability of the ISO, the ~~states~~States and the Market Participants to discuss with FERC staff and Commissioners the issues that the region sought to address with ESI. He noted also that FERC guidance and priorities may be very different if there was a change in administration, which the ISO ~~must~~would consider in deciding how best to proceed. Concluding, he expressed the ISO's intent to promptly ~~to~~ request clarification from the FERC on these points.

In response to questions from members, the ISO General Counsel elaborated on the uncertainty over whether *ex parte* rules still apply, referencing the unlikelihood that the FERC on rehearing would change its unanimous conclusion to reject ESI. For that reason, the ISO ~~was~~did not ~~intending~~intend to seek rehearing and hoped others would also ~~would~~ forego seeking rehearing and potentially extending *ex parte* limitations while any rehearing request ~~is~~was pending. She explained that the earliest ~~that~~ the FERC might be approached outside of the planned request for clarification would be December 1, following expiration of the time for seeking rehearing of the ESI order. She also reminded members that rehearing requests remain pending on the underlying July 2018 order that prompted the ESI filing, which could also impact whether the FERC would still consider substantive discussions of market improvements to address fuel security to be prohibited *ex parte* discussions.

Numerous Market Participants urged the ISO to consider proceeding at least with implementation of a Day-Ahead reserve market, separate from the other advancements sought by ESI. The ISO responded that it intended first to seek the opportunity to interact informally with the FERC. If *ex parte* limitations persisted, the ISO indicated ~~that~~ it would also consider alternative means to provide and receive informal input from the FERC without violating those limitations.

"KNOW YOUR CUSTOMER" FAP CHANGES

Ms. Michelle Gardner, Budget & Finance Subcommittee (B&F) Chair, referred the Committee to the materials circulated and posted in advance of the meeting related to proposed changes to "Know Your Customer" disclosures required in the ISO New England Financial

Assurance Policy (FAP). She explained that the changes were proposed by the ISO as part of an industry-wide review of RTO disclosure requirements and were intended to improve the level of disclosure that Market Participants and applicants to become Market Participants would be required to make. She summarized the process undertaken by B&F to review the changes and reported that, at its October 5, 2020 meeting, there were no objections or comments on the version of the Know Your Customer FAP changes discussed.

Without discussion, the following motion was then duly made, seconded and unanimously approved, with an abstention noted by Mr. Kuser's alternate:

> RESOLVED, that the Participants Committee supports the Know Your Customer revisions to the ISO New England Financial Assurance Policy, as proposed by the ISO and as circulated to this Committee with the October 29, 2020 supplemental notice, together with such non-substantive changes as may be approved by the Chair of the Budget and Finance Subcommittee.

ISO-NE'S PROPOSED METHODOLOGY TO RECALCULATE THE DYNAMIC DE-LIST BID THRESHOLD (DDBT)

Ms. Chafetz began ~~this item~~ by referring the Committee to the materials circulated in advance of the meeting regarding Tariff revisions to reflect a new method to calculate the DDBT in the Forward Capacity Market (FCM), as proposed by the ISO (the ISO's DDBT Proposal). She then invited Ms. Mariah Winkler, ~~the~~ Chair of the Markets Committee, to summarize that Committee's deliberations on this item. Ms. Winkler did so, noting the four motions to amend the ISO's DDBT Proposal that had been voted at the Markets Committee, none of which passed. She reported on the specific voting results, noting that the Markets Committee motion to recommend Participants Committee support for the ISO's DDBT Proposal failed with a 44.53% Vote in favor.

Following this introduction, Ms. Chafetz explained that the ISO's DDBT Proposal would be the starting point for Committee deliberations. The following main motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports the revisions to Market Rule 1 to modify the Dynamic De-List Bid Threshold (DDBT) in the Forward Capacity Market, as proposed by ISO-NE and 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.

Calpine/NESCOE/Dynegy (Vistra) Amendment

Ms. Chafetz reported that, since the Markets Committee's actions, the proponents of many of the numerous amendments offered at the Markets Committee (representatives from Calpine, NESCOE, and Dynegy (Vistra)) had worked together to produce a single, consolidated amendment for Participants Committee consideration. She invited the proponents to present their consolidated amendment. They did so, referring to a presentation they had prepared and had been circulated to the Committee in advance of the meeting. As summarized in that presentation, they described their concerns with the ISO's DDBT Proposal, explaining how their joint amendment would address those concerns, offering a comparison for FCAs 9-14 of the ISO's DDBT against the DDBT that would have resulted were the joint amendment in place, and reviewing proposed Tariff language with the Committee.

A motion was then made and duly seconded to amend the main motion, consistent with these proponents' presentation, so as to lower the ISO DDBT upper bound to 75% of Net Cost of New Entry (Net CONE) and to set the DDBT at the ISO's estimated clearing price plus a margin adder calculated using 75% of Net CONE, as reflected in the materials circulated in advance of, and as just presented at, the meeting (the Calpine/NESCOE/Dynegy (Vistra) Amendment).

Following discussion, the Calpine/NESCOE/Dynegy (Vistra) Amendment was voted and passed unanimously, with abstentions noted by Acadia, BP, CLF, CSC, DTE, LIPA, Mercuria, NRDC, and Mr. Kuser's alternate.

Vote on the Amended Main Motion

The amended main motion was then discussed, considered, voted and passed, with all members in support except for the following: opposition by NRG and abstentions by Acadia, BP, CLF, CSC, DTE, LIPA, Mercuria, NRDC, Sunrun, and Mr. Kuser's alternate.

Vote on the ISO's Unamended DDBT Proposal

At the request of the ISO, the Committee then considered and did not approve the unamended DDBT Proposal. The vote on the ISO's ~~Unamended~~unamended DDBT Proposal failed to pass with none in favor and abstentions noted by BP, CSC, DTE, LIPA, Mercuria, the AR Sector Small Renewable Generation Group Seat, and Mr. Kuser's alternate.

LITIGATION REPORT

Mr. Doot referred the Committee to the November 4 Litigation Report that had been circulated and posted in advance of the meeting. He then highlighted the following items:

(1) ***ESI*** **–** As noted earlier in the meeting, the FERC had rejected as unjust and unreasonable both the ISO and NEPOOL ESI proposals. The ISO was expected to request clarification that, absent a request for rehearing of the ESI order, the ISO and others were able to engage in communications with the FERC and FERC staff about the ESI market design, reserve

market design, the option construct, and the voluntary nature of the markets, without violating *ex parte* restrictions.

(2) ***Carbon Pricing in RTO/ISO Markets*** **–** On October 15, the FERC had issued a Notice of Proposed Policy Statement to clarify the FERC'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 section 205 filings to establish such rules. Comments on the proposed policy statement had to be submitted on or before November 16, with reply comments due on or before December 1.

(3) ***Gross Load Forecast Reconstitution Revisions*** **–** On October 30, the FERC issued an order accepting changes to improve the methodology used by the ISO to reconstitute Passive Demand Resources in the long-term gross load forecast.

(4) ***Federal Court Appeals*** **–** In addition to noting the challenge by LS Power to the FERC's orders addressing the ISO's implementation of the Order 1000 exemptions for immediate-need reliability projects filed in mid-October, Mr. Doot encouraged members to review the increasing list of activities and matters on appeal to the federal courts. The extent of those mattes had increased noticeably since the DC Circuit's *Allegheny* decision effectively tightened the timeframes for FERC action on requests for rehearing.

COMMITTEE REPORTS

Markets Committee (MC). Mr. Bill Fowler, MC Vice-Chair, reported that the MC was scheduled to meet the following Monday and Tuesday, November 9-10, with key items to include a vote on updated Net CONE and ORTP values.

Joint MC/RC (Future Grid - Reliability Study). Mr. Fowler also reported that next joint meeting of the MC and RC was scheduled for November 12, where the Committees would work to achieve consensus on major study areas for analysis and a way to structure modelling for a phased study approach.

Transmission Committee (TC). Mr. José Rotger, TC Vice-Chair, reported that the November 24 TC meeting had been cancelled. The next TC meeting was scheduled for December 10.

B&F Subcommittee. Ms. Gardner noted that the next meeting of the Subcommittee was scheduled for November 20, with key items to include a review and recommendation regarding the 2021 NEPOOL Budget and an update on proposed trading Financial Assurance changes.

Joint Nominating Committee (JNC). Ms. Chafetz reported that work on the 2021 slate of ISO Board candidates would begin in November. The terms of three members would expire in October 2021, and expectations were that there would be at least two vacancies to fill (to replace the ISO Board members whose third consecutive terms were coming to an end).

ADMINISTRATIVE MATTERS

Ms. Heather Hunt, NESCOE Executive Director, thanked Mr. van Welie and the ISO for their efforts on the Vision Statement. She noted that meetings had been held between the States and the ISO the day before, and had been reported to be productive and well-received. Addressing the NESCOE Vision Statement, she clarified that the Vision Statement and related efforts were not intended to substitute for, or to interfere with, the future pathways discussions underway in the NEPOOL stakeholder process; rather, they were intended to facilitate and complement that process.

Mr. Doot reminded the Committee that the balloting process for the next Participants Committee Chair was underway and encouraged all members to vote before balloting concluded. He stated that the 2020 Annual Meeting of the Participants Committee would be held December 3, and reminded members that if a Participant wished to change its Sector membership, it needed to provide written notice to do so prior to the start of that meeting. He noted that each of the Sectors was scheduled to meet with the Board the next day, and referred members to the schedule for those meetings posted with the meeting materials. The schedule for meetings between the Sectors and State Officials was being finalized, with materials for those meetings to be submitted a week ahead of time. Finally, Mr. Doot announced that Ms. Kathryn Dube had come on board as the new NEPOOL Administrator. He reported that Ms. Dube came to the position with more than 16 years' association management experience, including in her current and continuing role as Executive Director of the Connecticut Power & Energy Society. He asked members to be on the look-out for e-mail distributions that would soon follow under her name.

POTENTIAL FUTURE MARKET FRAMEWORKS IN LIGHT OF EXPECTED CHANGES TO NEW ENGLAND'S GRID

After a brief recess, the meeting resumed via WebEx. Ms. Chafetz introduced this portion of the meeting by identifying the two topics to be covered: (1) Dr. Frank Felder's preliminary observations and discussion on the tradeoffs of two potential pathways explored at the last meeting (Energy Only Market (EOM) and Alternative Resource Adequacy Constructs (ARAC)); and (2) Dr. Frank Wolak's overview of a new potential pathway – "Energy-Contracting Resource Adequacy" construct.

Future Pathways - Round 2 Preliminary Observations: Focus on EOM and ARAC

Ms. Chafetz then introduced Dr. Frank Felder, who had presented at two prior meetings and who proceeded at this meeting to summarize and review slides, which had been circulated and posted in advance of the meeting, that reflected his preliminary observations on EOM and ARAC.

With respect to an EOM framework, he discussed the impacts and applicability of the Minimum Offer Price Rule (MOPR), the need for additional clarity regarding the definition, services and reliability requirements of balancing resources, whether an EOM would provide sufficient flexibility and ramping services, and how features of an EOM could be combined with carbon pricing, FCM and its variations (e.g., FCEM and ICCM), and ARACs. Discussing ARACs, he noted that a variety of ARACs could be structured to avoid the MOPR double payment issue, but they would do so by reducing the roles of a centralized regional capacity market linked to energy and ancillary services markets. He opined that ARACs would likely require additional mechanisms for balancing resources. After reviewing the high level tradeoffs of EOM and ARACs, Dr. Felder described a ~~newly identified~~newly-identified ARAC he referred to as the "FCM-Balancing Resources" (FCM-BR)" pathway, which was offered for consideration by a Publicly Owned Entity Sector member representative. Dr. Felder then offered an additional potential framework he termed "Net FCM" and reviewed suggested mechanics and advantages of such an ARAC.

During his presentation, members interjected with their observations and asked questions. One member explained how the treatment of reserves could impact the implementation and impact of an EOM pathway. Other members explored the impacts on, and applicability of, MOPR with these constructs, and they discussed their views on some of the practical and legal challenges that would require further exploration.

Dr. Felder expressed appreciation for the observations and suggestions. He concluded his presentation by again encouraging Participants to provide written feedback and comments on his presentations to date, asking that any such feedback be sent to Mr. Sebastian Lombardi, NEPOOL Counsel (slombardi@daypitney.com). He noted that he was planning for a final presentation at the December 3 Participants Committee meeting, and hoped to issue a final report, for Participant comment, by the end of the year.

A Standardized Energy Contracting Approach to Long-Term Resource Adequacy with Significant Intermittent Renewables

Ms. Chafetz then introduced Dr. Frank Wolak, Director, Program on Energy and Sustainable Development, Stanford University, who discussed the need for a long-term resource adequacy mechanism, at least in the absence of a willingness by regulators to commit to use the real-time price of energy to clear the market under all possible system conditions and subject customers to the full expected cost of a failure to procure adequate supply. In his presentation he walked those present through a power point presentation that had been circulated and posted with the meeting materials.

After providing some context and background, in part based on experiences in California and Canada, as to the shortcomings of capacity payments as a mechanism to achieve long-term resource adequacy in regions with significant intermittent generation resources, Dr. Wolak proceeded to describe an Energy-Contracting Resource Adequacy framework. He explained that, under this construct as he envisioned it, consumers would be provided with, and required to pay for, what they want -- system demand for electricity that will be met under all possible future scenarios. All entities that serve retail load would be subject to mandated standardized forward contract holdings for pre-specified fractions of system demand at various time horizons to delivery. The contracts would be shaped to actual hourly system demand within the delivery period (which could be multi-year, single year, quarterly or monthly) and total energy under the standardized contracts would be shaped to reflect realized patterns of system demand. Energy delivery on initial multi-year contracts would begin far enough in advance of the execution of the standard contract to allow new sources of supply to compete to provide that energy.

Dr. Wolak described benefits of the construct to include: a focus on securing adequate energy to serve demand in markets with significant amounts of renewable resources; the ability to employ a simple auction mechanism (e.g., a declining clock auction) to procure energy~~:~~; the ability of state regulators to impose the contracting mandates they desired; a level playing field for demand-side and supply-side solutions; the creation of operating reserve supplies that could also sell ancillary services; and the incentives for suppliers to meet system demand for energy and ancillary services in a way they identify as least cost. He explained that a forward procurement process could be used to address any concern that sufficient capacity to meet ancillary services requirements might not be constructed. He also explained how bilateral contracts could be used to hedge wholesale price and quantity risk, and how this proposed construct would allow for cross-hedging between dispatchable resources and intermittent resources in order- to ensure that demand is met under all possible future system conditions. He described how new entrants could compete, possible approaches to manage local long-term resource adequacy, and the timing required to transition to this construct.

Dr. Wolak then summarized the mechanics and results of an experimental energy trading game with which he had been involved that ultimately provided a comparison of capacity-based versus energy contracting-based long-term resource adequacy mechanisms. Comparing the outcomes of a series of these games, he reported that average wholesale revenues per MWh from the capacity payment mechanism were close to double that for the energy contracting approach. He reported also that the average cost to serve demand was slightly lower for the energy contracting approach.

Dr. Wolak concluded his presentation by stating that the energy contracting approach could be particularly attractive in regions where there were currently or were proposed to be significant renewable capacity resources. Such regions confront a potential reliability challenge with the availability of energy when needed (and not satisfied because of the intermittency of otherwise adequate capacity). He said that the forward contracting approach provides a very strong financial incentive for the market (both for supply and load) to ensure that system demand is met every hour of the day at the lowest possible cost.

There being no further business, the meeting adjourned at 3:05 p.m.

Respectfully submitted,

David Doot, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN NOVEMBER 5, 2020 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Able Grid Infrastructure Holdings, LLC	Provisional Group			Abby Krich
Acadia Center	End User	Deborah Donovan		Phelps Turner
Advanced Energy Economy	Fuels Industry Participant	Caitlin Marquis		
American Petroleum Institute	Fuels Industry Participant	Paul Powers		
AR Small Load Response (LR) Group Member	AR-LR	Doug Hurley	Brad Swalwell	
AR Small Renewable Generation (RG) Group Member	AR-RG	Erik Abend		
Ashburnham Municipal Light Plant	Publicly Owned Entity		Brian Thomson	
Associated Industries of Massachusetts (AIM)	End User			Roger Borghesani
AVANGRID: CMP/UI	Transmission		Alan Trotta	
Avangrid Renewables	Transmission	Kevin Kilgallen		
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	
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		
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	
Direct Energy Business, LLC	Supplier	Nancy Chafetz		
Dominion Energy Generation Marketing, Inc.	Generation		Weezie Nuara	
DTE Energy Trading, Inc.	Supplier			José Rotger
Dynegy Marketing and Trade, LLC	Supplier	Andy Weinstein	Arnie Quinn	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		
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	Jeff Iafrati	
Generation Group Member	Generation	Dennis Duffy	Abby Krich	Alex~~.~~ Worsley
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		Bob Stein	
Harvard Dedicated Energy Limited	End User		Joyceline Chow	
High Liner Foods (USA) Incorporated	End User		William P. Short III	

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN NOVEMBER 5, 2020 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Hingham Municipal Lighting Plant	Publicly Owned Entity		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	
Industrial Energy Consumer Group	End User	Alan Topalian		
Ipswich Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Jericho Power LLC (Jericho)	AR-RG	Mark Spencer		
KCE CT 1, LLC	Provisional Group	Rachel Goldwasser		
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			Erin Camp
Maine Skiing, Inc.	End User	Alan Topalian		
Mansfield Municipal Electric Department	Publicly Owned Entity		Brian Thomson	
Maple Energy LLC	AR-LR		Luke Fishback	Doug Hurley
Marble River, LLC	Supplier		John Brodbeck	
Marblehead Municipal Light Department	Publicly Owned Entity		Brian Thomson	
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 Brennan	Tim Martin	
Natural Resources Defense Council (NRDC)	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	
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity		Brian Thomson	
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	
Sunrun Inc.	AR-DG			Pete Fuller
Taunton Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	

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PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN NOVEMBER 5, 2020 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
The Energy Consortium	End User	Roger Borghesani		
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	
Vitol Inc.	Supplier	Joe Wadsworth		
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	

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PRELIMINARY

Pursuant to notice duly given, the annual meeting of the NEPOOL Participants Committee was held via teleconference, beginning in executive session at 9:30 a.m. on Thursday, December 3, 2020.

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

EXECUTIVE SESSION

The Committee began the meeting in executive session to afford Participants an opportunity to provide confidential feedback to the Participant members of the Joint Nominating Committee (JNC) on the one incumbent ISO Board Director whose term was scheduled to expire in 2021 and who had not yet served three full terms. Committee members provided that feedback. Prior to concluding the executive session, Mr. Doot explained that the Participant representatives on the JNC would consider the feedback received, along with any other feedback members might wish to separately share with those representatives, in the JNC deliberations over a recommended slate of three candidates for consideration by the Participants Committee in 2021.

GENERAL SESSION

Following a short recess, the NEPOOL Participants Committee reconvened, beginning at 10:00 a.m. A quorum determined in accordance with the Second Restated NEPOOL Agreement was present and acting throughout the meeting. Attachment 1 identifies the members, alternates and temporary alternates who participated in the teleconference meeting.

Ms. Chafetz began the general session by providing an update on the JNC process, which for the 2021 class year, was scheduled to begin later in the month. She noted expectations that there would be at least two vacancies to fill, given that Ms. Kathleen Abernathy and Mr. Phil Shapiro would be completing their third consecutive three-year terms, requiring them, absent an unexpected term limit waiver, to step off the ISO Board in 2021. Referring to recent discussions on potential changes to the selection process for new Board members, she noted that the NEPOOL representatives on the JNC planned to explore with the full JNC refinements to the selection process, and time would be set aside at a future meeting to continue those discussions with the benefit of preliminary feedback from the ISO Board and the new JNC.

CONSENT AGENDA

Ms. Chafetz referred the Committee to the Consent Agenda that was circulated and posted in advance of the meeting. Following motion duly made and seconded, the Consent Agenda was approved with opposition noted by Jericho Power and abstentions noted by Avangrid and the representative for Mr. Kuser. The Jericho Power and Avangrid representatives stated that their votes were each attributable to Consent Agenda Item 1 (Modifications to the ~~Qualification~~qualification of Energy Efficiency (EE) in the Forward Capacity Market (FCM)). The Jericho Power representative explained that, while Jericho Power supported the proposed changes, it objected to the ISO's plan to delay~~-~~ the changes until early 2022, which would retain for another year a flaw in the Market Rules. The Avangrid representative explained that he had abstained due to United Illuminating's concerns with the materially increased administrative requirements to implement the proposal.

REVISIONS TO APPENDIX K TO OP-23 AND REVISIONS TO OP-24

Ms. Chafetz referred the Committee to revisions to Appendix K to Operating Procedure (OP) 23 (Response Rate Auditing Calculation) (OP-23) and to ~~OP-~~OP 24 (Protection Outages, Settings and Coordination), including changes to each of its Appendices (together, OP-24), each as unanimously recommended by the Reliability Committee (RC) at its November 18, 2020 meeting and described in materials circulated in advance of the Participants Committee meeting. She said that the revisions to OP-23 and OP-24 would have been on the Consent Agenda but for the timing of the RC's consideration and vote.

The following motions were duly made, seconded and unanimously approved in a single vote without comment, with an abstention by Mr. Kuser's representative noted:

> RESOLVED, that the Participants Committee supports the revisions to Appendix K to OP-23, as recommended by the Reliability Committee at its November 18, 2020 meeting, together with such other non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.

> RESOLVED, that the Participants Committee supports the revisions to OP-24 (including changes to each of Appendices A, B, C, and D to OP-24), as recommended by the Reliability Committee at its November 18, 2020 meeting, together with such other non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.

ISO CEO REPORT

Mr. van Welie referred the Committee to the summaries of the ISO Board and Board Committee meetings that had occurred since the November 5 Participants Committee meeting, which had been circulated and posted in advance of the meeting. There were no questions or comments on the summaries.

ISO COO REPORT

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), reviewed highlights from the December COO report, which had been circulated and posted in advance of the meeting on the NEPOOL and ISO websites. He noted that the data in the report was through November 23.

The report highlighted: (i) Energy Market value for November 2020 was $197 million, down $42 million from October 2020 and down $134 million from November 2019; (ii) August 2020 average natural gas prices were 4.7 percent higher than October average prices; (iii) the average Real-Time Hub Locational Marginal Prices (LMPs) for November ($27.10/MWh) were 0.8 percent higher than October averages; (iv) average November 2020 natural gas prices and Real-Time Hub LMPs over the period were down 39 percent and 21 percent, respectively, from November 2019; (v) the average Day-Ahead cleared physical energy during peak hours as percent of forecasted load was 99.6 percent during November (down from 100.8 percent during October), with the minimum value for the month (95.3 percent) on November 14; and (vi) the Daily Net Commitment Period Compensation (NCPC) payments for November (data through November 22) totaled $1.6 million, which was down $1.2 million from October 2020 and down $2.1 million from November 2019. November NCPC, which was 0.8 percent of total Energy Market value, was comprised of (a) $1.4 million in first contingency payments (down $800,000 from October); (b) $233,000 in second contingency payments (down $313,000 from October); and (c) $9,000 in distribution payments (down $33,000 from October).

Dr. Chadalavada remarked that November had been relatively quiet, with peak load at 17,100 MW and temperatures across the region three degrees above normal. He highlighted continuing low levels of NCPC payments, stating that total annual payments for 2020, projected to be approximately $22 million, would be the lowest over the past 12 years. During that time, annual NCPC payments had averaged between $80 to $100 million, with the their highpoint at $160 million to $180 million in ~~in~~ 2013 and 2014.

Dr. Chadalavada reported that there would be a three-day transmission outage, from December 8 through December 10, on the Long Mountain to Cricket Valley 398 line, reducing transfers from New York to New England. Reductions in import and export capacity of 600 MW were expected with the total resulting anticipated import and export capacities of 800 MW and 400 MW, respectively.

Dr. Chadalavada then turned to load forecast expectations for winter 2020/21, indicating that the ISO would continue to monitor closely for any shifts between residential and commercial consumption. School and college closings could result in changes to consumption patterns, but were not expected to be as great as the changes experienced over the summer. Daily forecast volatility remained possible, but the ISO would continue to monitor and tune the forecast model as needed, reflecting continuing discussions with industry experts regarding and incorporating emerging technologies/trends and methods. The ISO would also closely monitor residential gas demand, particularly during prolonged cold periods, for its overall impact on the electric system.

Concluding his report, Dr. Chadalavada noted that the process for the development of the 2021 load forecast had begun, with discussions at the Load Forecast Committee, Energy Efficiency Forecast Working Group and Distributed Generation Forecast Working Group. Moody's macroeconomic forecast would be presented at the Planning Advisory Committee on December 16, followed by discussions in March and April about the preliminary 10-year forecast, which would then be finalized and published in the ISO's 2021 Forecast Report of Capacity, Energy, Loads, and Transmission (CELT Report).

In response to questions, Dr. Chadalavada confirmed that the transmission line outages discussed during the November report had resulted two ~~day~~days of second~~-~~ contingency commitments, with payments of about $50,000 - $60,000, and a few days of commitments in the east load zones. Addressing questions concerning the accuracy of the ISO's load forecasting, he explained that additional time was needed to identify the reasons for recent under forecasts relative to the back cast models being used by the ISO for weekly COVID-19 impact reports, and cautioned that, after several months of consistent forecasts, the region was likely entering a new period of uncertainty. Dr. Chadalavada indicated that the ISO still planned, but had not yet completed, the process to analyze and better understand changing consumption patterns as a result of the pandemic.

2020 NEPOOL ANNUAL REPORT

Ms. Chafetz referred the Committee to the 2020 NEPOOL Annual Report, "Moving Forward, Together", which was circulated to the Committee electronically and posted on the NEPOOL website. Ms. Chafetz thanked the Day Pitney team, and Messrs. Harold Blinderman and Pat Gerity particularly, for their efforts to assemble and complete the Annual Report. Ms. Chafetz highlighted the new NEPOOL logo, the refresh of the NEPOOL website, the inclusion of WebEx photos throughout the Report, and the last page which highlighted some of the things members miss most about in-person meetings. Mr. Doot noted that the Annual Report demonstrated that NEPOOL had achieved much in 2020 and could expect continued challenges in 2021. He encouraged Participant feedback on the format and substance of the Annual Report. Messrs. Blinderman and Gerity thanked Ms. Chafetz as the Report's editor-in-chief, the officers for their input, and members for all their contributions to the report. Printed copies would be made available upon request.

ELECTION OF 2021 PARTICIPANTS COMMITTEE OFFICERS

Ms. Chafetz referred the Committee to the proposed slate of 2021 NEPOOL Participants Committee Officers circulated and posted in advance of the meeting.

The following motion was duly made, seconded and unanimously approved, with an abstention noted by Mr. Kuser's representative:

WHEREAS, Section 4.6 of the Participants Committee Bylaws sets forth procedures for the nomination and election of a Chair and Vice-Chairs of the Participants Committee; and

WHEREAS, pursuant to those procedures the individuals identified in the following resolution were nominated and elected for 2021 to the offices of Chair and Vice-Chair, as set forth opposite their names; and

WHEREAS Section 7.1 of the Second Restated NEPOOL Agreement provides that officers be elected at the annual meeting of the Participants Committee.

NOW, THEREFORE, IT IS

RESOLVED, that the Participants Committee hereby adopts and ratifies the results of the election held in accordance with Section 4.6 of the Bylaws and elects the following individuals for 2021 to the offices set forth opposite their names to serve until their successors are elected and qualified:

Chair	David A. Cavanaugh
Vice-Chair	Christina H. Belew
Vice-Chair	Nancy P. Chafetz
Vice-Chair	Francis J. Ettori, Jr.
Vice-Chair	Michelle C. Gardner
Vice-Chair	Douglas Hurley
Secretary	David T. Doot
Assistant Secretary	Sebastian M. Lombardi

ESTIMATED BUDGET FOR 2021 NEPOOL EXPENSES

Mr. Thomas Kaslow, Budget & Finance Subcommittee (~~Subcommittee~~B&F) Chair, referred the Committee to the materials posted in advance of the meeting concerning the estimated budget for 2021 Participant Expenses (a copy of which is included as Attachment 3 to these minutes). He noted that the 2021 budget assumed virtual meetings through May 2021 and in-person meetings thereafter. He indicated ~~the Subcommittee~~that B&F had reviewed and discussed the proposed 2021 Budget and had recommended its adoption without objection.

The following motion was duly made, seconded and approved unanimously, with an abstention noted by Mr. Kuser's representative.

> RESOLVED, that the Participants Committee adopts the estimated budget for NEPOOL expenses for 2021 as presented at this meeting.

UPDATED (AS OF FCA16) FCM VALUES/PARAMETERS

Ms. Chafetz referred the Committee to the materials and draft resolution, circulated and posted in advance of the meeting, concerning proposed Tariff revisions to update the Cost of New Entry (CONE), Net CONE, and Payment Performance Rate (PPR) values, as well as the Offer Review Trigger Prices (ORTPs) to be used in the Forward Capacity Market ~~(FCM)~~. Ms. Mariah Winkler, Markets Committee Chair, then summarized the Market Rule changes and provided the procedural background for the Markets Committee's consideration of the changes. Following that summary, she explained that the ISO had revised certain FCM values after Markets Committee voting to correct an error in the dispatch model for the simple cycle technology and that this correction was applied both to the ISO-proposed FCM values and the relevant FCM values recommended by the Markets Committee. Ms. Chafetz proposed that, absent any objection, Participants Committee action on this matter would include the corrected values. There were no objections. The following motion was then duly made and seconded:

> RESOLVED, that the Participants Committee supports revisions to Market Rule 1 as recommended by the Markets Committee and as circulated to this Committee in advance of this meeting, together with the revised FCM parameter values to correct an error in the dispatch model used for calculating those values also as circulated to this Committee in advance of this meeting, and such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

Mr. Sebastian Lombardi, NEPOOL Counsel, noted that, for amendments that had been offered during Markets Committee consideration of these changes and had failed to gain the requisite support for inclusion in the changes recommended for Participants Committee support, neither NEPOOL nor the ISO would raise procedural objections at the FERC based on the failure to submit the amendment for a Participants Committee vote. This understanding would only apply if the party raising its concerns ~~does~~did not ask the FERC to order changes that had not otherwise been previously vetted and voted in the Participant Processes.

Jericho Power/NEPGA Amendment

Ms. Chafetz then invited a Jericho Power representative (on behalf of NEPGA) to describe its amendment to the main motion (Jericho Power/NEPGA Amendment). He summarized the materials circulated in advance of the meeting, explaining that the Jericho Power/NEPGA Amendment would account for the impact the Net CONE unit has on the Locational Forward Reserve Market (LFRM) clearing price by including the Net CONE unit in the LFRM supply stack at its opportunity costs (which would result in an increase to the Net CONE value). He argued that the exclusion of the Net CONE unit from the supply stack would overstate the LFRM revenue potential with a resulting understatement of Net CONE.

A number of members, primarily with supply resources in the region, expressed support for the Jericho Power/NEPGA Amendment and opposition to the ISO's proposal. Some opined that it would be inconsistent to presume a Net CONE reference unit on the system without also accounting for associated LFRM revenue opportunities for that unit, some citing how the Internal Market Monitor (IMM) accounts for resources when it sets unit-specific New Resource Offer Review Prices.

Responding, Mr. Mark Karl, ISO Vice President of Market Development & Settlements, recounted the reasons why the ISO did not support the amendment, describing how the ISO accounted for resources in the LFRM supply stack when updating Net CONE.

Another supporter of the Jericho Power/NEPGA Amendment argued that the Tariff required Net CONE updates ~~does~~did not support the ISO's incorporation of long-term equilibrium conditions in the calculation. Mr. Karl replied that the challenge to the ISOs application of the words "expected first year" was a new argument now being raised, and that the ISO had calculated Net CONE under long-term equilibrium conditions in the past. The supporter of the amendment disagreed and cited examples that, in his view, demonstrated that the ISO had changed its methodology for calculating Net CONE without first making the changes to the Tariff.

The Committee then considered and did not approve the Jericho Power/NEPGA motion to amend the main motion. That motion, which required a 60% Vote in favor to be approved by the Committee, failed to pass with a 32.97% Vote in favor (Generation Sector – 12.50%; Transmission Sector – 0%; Supplier Sector – 12.82%; AR Sector – 7.57%; Publicly Owned Entity Sector – 0%; End User Sector – 0%; and Provisional Members – 0.08%). (*See* Vote 1 on Attachment 2).

ORTP Treatment for Co-Located Assets Amendment

Next, a group of AR Sector and End User Sector members (representing Borrego Solar, ENEL X, ENGIE, and UCS on behalf of RENEW Northeast) proposed a second amendment to the main motion, which was duly made and seconded, to clarify how ORTPs should be assigned to co-located assets. Specifically, for co-located assets that register as a single FCM resource, the amendment would clarify that the IMM would assign an ORTP equal to the weighted average of the ORTPs applicable to the asset(s) comprising the resource, as prescribed in the Tariff. For co-located assets that register as separate FCM resources, the IMM would assign each FCM resource its own ORTP as applicable solely to the technology of the asset(s) underlying the resource. A spokesperson for the amendment walked the Committee through a presentation summarizing the background to and specifics of the amendment that had been circulated to the Committee in advance of the meeting and posted with the meeting materials.

In response, Mr. Jeffrey McDonald, ISO Vice President of Market Monitoring~~ (IMM)~~, offered his comments. First, he explained that his ability to respond fully was a challenge because the amendment had not been presented to the Markets Committee for feedback. He had concluded based on his review to date that the proposed amendment could undermine the purpose of the ORTPs. Accordingly, the IMM did not support the amendment and disagreed that any ambiguity existed in the Tariff.

The co-sponsors challenged the IMM. On process, they explained that the issues related to the amendment were raised prior to, and again at, the November Markets Committee ~~and then again at the November Markets Committee,~~meeting, and that there had been separate outreach directly to the IMM since the Markets Committee's consideration. They also expressed concern that the IMM took the position that the Tariff was unambiguous but was not able to explain how, without the proposed amendments, ORTPs would be determined for offers from co-located resources. They, along with other representatives of ~~alternative resources~~Alternative Resources, urged approval of the amendment.

NESCOE's representative explained that NESCOE had not taken a position on this amendment, but encouraged the ISO and the IMM to continue consideration of this issue and other ORTP-related issues, regardless of the vote outcome at this meeting.

Questioning the need for the amendment at all, another member expressed concern with restricting the IMM from looking specifically at offers from co-located resources to decide factually whether mitigation of such offers was needed.

Following further discussion, the Committee then considered and did not approve the amendment. The motion, which required a 60% Vote to pass, failed with a 59.76% Vote in favor (Generation Sector – 8.33%; Transmission Sector – 0%; Supplier Sector – 5.55%; AR Sector – 12.37%; Publicly Owned Entity Sector – 16.67%; End User Sector – 16.67%); and Provisional Members - 0.08%. (*See* Vote 2 on Attachment 2).

Vote on the Main Motion

Discussion continued on the unamended main motion. A Participant asked whether the ISO would consider updating the Net CONE value should there be a change in circumstances (e.g. elimination of the LFRM). Responding, Mr. Karl stated that the ISO would make changes, if and as necessary, were there a material change in circumstances. The NEPGA representative expressed various concerns with aspects of the main motion and agreement with the IMM's opinion on the various amendments that comprised the main motion. The NESCOE representative expressed NESCOE's support for both the ISO's proposal, as well as for the main motion, though NESCOE did not take a position on each and every input assumption on the ORTPs on which the ISO's proposal and the main motion ~~differ~~differed. Members of the Publicly Owned Entity Sector and the End User Sector expressed support for the main motion and stated that the CONE and Net CONE values were reasonable.

Offering final comments on behalf of the ISO, Mr. Karl stated that the ISO opposed the main motion for the reasons set forth in the ISO's memorandum circulated in advance of the meeting. Specifically, he expressed concern with the offshore wind ORTP calculation and noted that ORTPs ~~are~~were not meant to preclude resources from entering the market. Rather, ORTPs ~~are~~were thresholds for review that allow resources to justify offers below the relevant ORTP. The ISO representative pointed to the Killingly project as an example. Mr. McDonald reiterated his disagreement, described more fully in the IMM's memo to the Markets Committee on how capital costs would be calculated under the proposal for an offshore wind project, which he believed would, in part, produce an artificially low offshore wind ORTP.

The Committee then considered and approved the main motion with a 71.84% Vote in favor (Generation Sector – 4.17%; Transmission Sector – 16.67%; Supplier Sector – 5.12%; AR Sector – 12.37%; Publicly Owned Entity Sector – 16.67%; End User Sector – 16.67%; and Provisional Members - 0.17%). (*See* Vote 3 on Attachment 2).

Vote on the ISO's Unamended Proposal

The ISO sought a vote on its proposal without any of the Participant-proposed amendments (but with the revised FCM parameter values to correct the error in the dispatch model used for calculating those values), and a motion was duly made and seconded to approve the ISO's unamended proposal.

Various members expressed their views on the ISO's proposal, some abstaining even though they concluded that the value of energy and cost of contracts were nearer to the ORTP analysis supporting the main motion rather than to the ISO's analysis. The ISO was urged to continue assessing and refining its ORTP calculations based on updated information and more current experiences. Generator representatives, while expressing appreciation for the efforts of the ISO and stakeholders during the long and difficult discussions on these issues, expressed disappointment that the ISO failed to support their proposed amendments at the Markets Committee, which ~~it~~they argued were supported by consultant analysis and their own experiences.

Without further discussion, the motion to support the ISO's unamended proposal was voted and failed to pass with an 18.33% Vote in favor (Generation Sector – 0%; Transmission

Sector – 0%; Supplier Sector – 1.66%; AR Sector – 0%; Publicly Owned Entity Sector – 16.67%; End User Sector – 0%; and Provisional Members – 0%). (*See* Vote 4 on Attachment 2).

LITIGATION REPORT

After a brief recess, the meeting resumed via WebEx. Mr. Doot referred the Committee to the December 2, 2020 Litigation Report that had been circulated and posted in advance of the meeting. He then highlighted the following items:

(1) ***Order on Requests for Rehearing of CASPR Order*** **–** The FERC clarified on rehearing why it properly accepted the Competitive Auctions with Sponsored Policy Resources proposal.

(2) ***ESI Alternatives (ER20-1567)*** **–** As indicated at the last meeting, the ISO filed for clarification that it may engage in communications with the FERC and FERC staff about the ESI market design, reserve market design, the option construct, and the voluntary nature of the markets, unfettered by any *ex parte* restrictions.

(3) ***Two New Commissioners*** ~~-~~ – The Senate confirmed two new Commissioners, Mark Christie, the former Chair of the Virginia Commission and Allison Clements, a policy consultant for The Energy Foundation. He explained that, once the two were sworn in, the FERC would have five sitting Commissioners for the first time in nearly two years (at least until June 2021 when Commissioner Chatterjee's term ~~ends~~was scheduled to end).

(4) ***FCM Pricing Rules Complaints Remand (EL20-54***) **–** The FERC issued an order finding the 7-year price lock to be unjust and unreasonable. The FERC directed the ISO to submit a compliance filing, on or before February 1, 2021, eliminating the price lock and associated zero-price offer rule for new entrants starting in FCA16. The FERC order stated that

the "termination of the price lock will not impact price-lock agreements in effect prior to the issuance of the order".

COMMITTEE REPORTS

Markets Committee (MC). Mr. William Fowler, the MC Vice-Chair, reported that the next meeting of the Markets Committee was scheduled ~~for~~as a one-day, rather than a two-day, meeting, to be held on December 8, 2020.

Transmission Committee (TC). Mr. José Rotger, the TC Vice-Chair, reported that the next TC meeting would be held by teleconference on Thursday, December 10 and would include discussion on the PTOs' proposals to address the reconstitution of behind-the-meter generation in the Regional Network Load calculation.

Reliability Committee ~~***(RC)***~~. Mr. Robert Stein, the RC Vice-Chair, reported that the next RC meeting would be on December 15. He highlighted an expected presentation on an I.3.9 application for a 200 MW battery installation.

Joint MC/RC (Future Grid - Reliability Study). Mr. Stein also reported that next joint meeting of the MC and RC was scheduled for December 17, when the Committees would continue work on, and would consider input assumptions to be used in, the framework document to be used for all Future Grid scenarios.

Budget & Finance ~~***(B&F)***~~ ***Subcommittee***. Mr. Kaslow reported that the next B&F meeting was scheduled for January 28, 2021, when he expected discussion on trading Financial Assurance changes to continue. In addition, he highlighted for those interested an e-mail sent to Committee members and alternates providing instructions for accessing a copy of ISO New England's SOC 1 (Service Organization Controls Report) financial report.

ADMINISTRATIVE MATTERS

Mr. Doot reminded the Committee the next Participants Committee meeting was scheduled for January 7, 2021. He urged members to update their calendars with the scheduled 2021 meetings.

Before moving to the final agenda item, Ms. Chafetz noted that the meeting would be her last as Chair. She thanked Committee members for the opportunity to serve as Chair, and also thanked the ISO, NESCOE, NECPUC, NEPOOL officers, and the Day Pitney team for their support. She congratulated Mr. Cavanaugh on his election as Chair for 2021. Mr. Cavanaugh, in turn, expressed his thanks to all members for their support and confidence, and thanked Ms. Chafetz for her leadership. At his request, the Committee showed its appreciation to Ms. Chafetz by a warm round of virtual applause.

PATHWAYS TO THE FUTURE GRID

"Capacity as a Commodity"

Ms. Chafetz then referred the Committee to the materials that were circulated and posted in advance of the meeting and introduced Michael Borgatti, VP, Gabel Associates, for a presentation and discussion of an additional potential market framework for New England. Mr. Borgatti began his presentation with an overview of current market challenges, which he indicated were as follows: (1) undifferentiated capacity models do not value different resources' contributions to reliability; (2) consumer choice and willingness to pay were poorly reflected in market prices today; (3) there is no direct pathway to advance public policies within competitive markets; and (4) the markets are relying on mitigation to produce competitive results. Mr. Borgatti noted that FCM may not represent a durable, long-term solution despite historic success at maintaining reliability. Before reviewing the proposed framework, he explained that the Capacity as a Commodity concept could use the same general FCM timeline, parameters and CELT report, but would impose a new forecast capacity obligation on each load serving entity (LSE) in the ISO-NE footprint, a new ISO resource adequacy metric reflecting reliability needs based on resource fuel mix, a new "Market Specifications" describing available products and terms, and a new capacity trading platform with publicly available market data that LSEs would use to help satisfy their obligations.

In response to questions and discussions through the presentation, Mr. Borgatti clarified the contemplated capacity requirement estimates timeline, and further explained that the proposed framework would include two incremental residual reliability auctions (RRAs), which would provide two additional opportunities for buyers and sellers to transact. The ISO would then be the buyer of last resort in the final RRA. He further explained the resource adequacy metric as a way to define terms of reliability and allow the market to provide opportunity for consumer choice.

Mr. Borgatti clarified that the framework ~~can~~could be flexible on the time line and further indicated that current resources have shifted to shorter timelines and ~~are~~were now able to be built in much shorter timeframes than in the past. This framework ~~includes~~included the pre-auction along with the ISO-NE as the backstop.

Dr. Frank Felder: Standardized Fixed-Price Forward Contract (SFPFC) and Summary Report, Preliminary Observations and Request for Input

Ms. Chafetz then turned to Dr. Frank Felder for his presentation. Dr. Felder~~, who has been engaged to facilitate NEPOOL discussions of potential future pathways for New England,~~ provided an inventory of all potential pathways shared to date. He then reconfirmed the project goals along with certain functions that ~~are~~were presumed to be retained by the ISO under all of the potential pathways identified to date.

Dr. Felder reviewed his assessment of Dr. Frank Wolak's Standardized Fixed-Price Forward Contract (SFPFC) framework (which had been presented to the Committee on November 5, 2020) and provided the following overview: (1) regulators mandate that LSEs purchase and hold to delivery standardized forward contracts for energy for fractions of their annual energy demand at various horizons;~~-~~ (2) standardized contracts are shaped by hourly demands; (3) clearinghouse manages counterparty risk; and (4) no installed capacity requirement. Dr. Felder shared his preliminary observations that SFPFC ~~does~~did not explicitly address the procurement of clean energy resources to achieve States' energy policy objectives. He further indicated that for SFPFC to be considered a pathway that would help the States achieve certain energy policy goals, it would likely need to be augmented with decarbonization mechanisms. He also noted SFPFC may (or may not) be an improvement over the FCM.

Dr. Felder provided an overview of the final summary report. He indicated the report would include a review of the various pathways along with a summary of the each of the pathways, with cited references to materials that provide details and articulate the claimed advantages of each. ~~It will~~The report would also include high-level findings and identify gaps that would likely need to be addressed. He explained that throughout the process, he ~~has~~had sought to evaluate how each of the pathways ~~address~~addressed the following two questions: (1) ~~Whether~~whether and to what extent ~~does~~would the pathway ~~supports~~support the clean energy policies of States?; and (2) ~~To~~to what extent ~~does~~would the pathway garner efficiency of regional markets?

Dr. Felder then reviewed his general, overall observation that a broad agreement from stakeholders ~~is~~would be required in order to move forward~~. Successful~~; successful reconciliation ~~is~~was not likely to occur without broad agreement reached among the New England States, NEPOOL stakeholders and ISO-NE. Additionally, the ability to balance resources and services ~~does~~did not always line up with resource adequacy. Dr. Felder addressed questions about how each of the pathways explored to date may or may not meet all of the requirements necessary and the potential need for a portfolio approach.

Dr. Felder then reviewed his high-level findings. First, net carbon pricing ~~mitigates~~would mitigate, but ~~does~~would not necessarily solve, the double payment issue. Net carbon pricing would increase the revenues clean energy resources earn in the energy market, but ~~does~~would not specifically help the States tailor the timing and specific type of clean energy resources they desire to meet their individual policy objectives, as it sets prices not quantities. An advantage of the FCEM and ICCM frameworks is that they would procure the least-cost set of clean energy resources, but only if they reflect broad definitions of clean energy resources that allow a regional demand for these resources with regional competition among the resources. Achieving sufficient regional uniformity for demand ~~will~~would likely require the ~~states~~States to relinquish some control in order to garner the benefits of this model. Ultimately, there ~~is~~was a threshold question as to whether the ~~states can~~States could achieve agreement set forth in these proposed regional market frameworks.

Dr. Felder also discussed the need for a more precise definition of required balancing services needed to ensure reliability in the future. Without knowing these requirements, it ~~is~~was difficult to analyze each of the potential pathways to ensure the markets ~~will~~would continue to be successful in providing necessary resources to keep the lights on.

Dr. Felder next indicated that additional details ~~are~~were required to fully assess the tradeoffs.

The identified pathways ~~are~~were high-level proposals that ~~do~~did not specifically identify how they ~~will~~would work along with transmission. The outcomes of the pathways would largely depend on how they interact with transmission~~, such as~~ (e.g. offshore wind). The intersection of pathways and transmission policy ~~is~~would be critical ~~in~~to achieving the least-cost deployment of generation and transmission resources.

Dr. Felder also noted that several proposed pathways ~~do~~did not define what ~~is~~was actually being delivered and he expressed the need for more thought on this ~~along with~~as well as on cost allocation.

Members responded with questions and observations. One member indicated that there ~~are~~were currently many types of projects that ~~have~~had large amounts of generation but ~~do~~did not have necessary transmission, creating a great disparity between discussion of ~~Frameworks~~frameworks and the ability of those frameworks to support the ~~state's~~States' decarbonization efforts. It was also noted that congestion ~~has~~had historically been ~~seen as~~viewed as a reliability issue. Dr. Felder indicated that if modeling was run for the different pathways the results might show how current transmission policies affect each pathway and how changes to transmission policies and the frameworks inter-relate. Another member expressed the need to evaluate each proposal through specific metrics. Dr. Felder hoped his review would provide the necessary clarity in identifying the next steps in the analytical process of meeting the intended goal. It was also suggested that the transmission needs of the region ~~be evaluated~~required evaluation before new resources ~~can~~could be intelligently located. Dr. Felder indicated both location and variability of intermittent resources should be known in order to advance the discussion.

Dr. Felder concluded his presentation by encouraging Participants to provide written feedback and comments. He intended to provide a draft report within the next few weeks. He would then take additional comments and provide his final report by the end of the year.

Mr. Gerity reminded members of the remaining Sector meetings with State Officials scheduled for the following week.

There being no further business, the meeting adjourned at 4:00 p.m.

Respectfully submitted,

David Doot, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN DECEMBER 3, 2020 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Able Grid Infrastructure Holdings, LLC	Provisional			Abby Krich
Acadia Center	End User	Deborah Donovan		Francis Pullaro
Advanced Energy Economy	Fuels Industry Part.	Caitlin Marquis		
American Petroleum Institute	Fuels Industry Part.	Paul Powers		
Anbaric Development Partners LLC	End User			Francis Pullaro
AR Large Renewable Generation (RG) Group Member	AR-RG	Alex Worsley		Francis Pullaro
AR Small Load Response (LR) Group Member	AR-LR	Doug Hurley	Brad Swalwell	
AR Small Renewable Generation Group Member	AR-RG	Erik Abend		
American PowerNet Management	Supplier			Joyceline Chow
Ashburnham Municipal Light Plant	Publicly Owned		Brian Thomson	
Associated Industries of Massachusetts	End User			Roger Borghesani
AVANGRID: CMP/UI	Transmission		Alan Trotta	
Belmont Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Block Island Utility District	Publicly Owned	Dave Cavanaugh		
Borrego Solar Systems, Inc.	AR-DG	Liz Delaney		
Boylston Municipal Light Department	Publicly Owned		Brian Thomson	
BP Energy Company	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned			Dave Cavanaugh
Brookfield Renewable Trading and Marketing	Supplier	Aleks Mitreski		
Calpine Energy Services, LP	Supplier	Brett Kruse		Bill Fowler
Cape Light Compact	End User			Erin Camp
Central Rivers Power	AR-RG		Dan Allegretti	
Chester Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned		Brian Thomson	
CLEAResult Consulting, Inc.	AR-DG	Tamara Oldfield		
Concord Municipal Light Plant	Publicly Owned		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned	Brian Forshaw		
Connecticut Office of Consumer Counsel	End User		Dave Thompson	
Conservation Law Foundation (CLF)	End User	Phelps Turner		
Consolidated Edison Energy, Inc. (ConEd)	Supplier	Norman Mah		
CPV Towantic, LLC	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned		Dave Cavanaugh	
DC Energy, LLC	Supplier	Bruce Bleiweis		
Deepwater Wind Block Island, LLC	Generation			Francis Pullaro
Direct Energy Business, LLC	Supplier	Nancy Chafetz		
Dominion Energy Generation Marketing, Inc.	Generation	Mike Purdie		
DTE Energy Trading, Inc.	Supplier			José Rotger
Dynegy Marketing and Trade, LLC	Supplier	Andy Weinstein		Bill Fowler
Enel X North America, Inc.	AR-LR	Michael Macrae		
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Environmental Defense Fund	End User	Jolette Westbrook		
Eversource Energy	Transmission	James Daly	Dave Burnham	Vandan Divatia
Excelerate Energy LP	Fuels Industry Part.			Gary Ritter
Exelon Generation Company	Supplier	Steve Kirk	Bill Fowler	
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Freepoint Commodities	Supplier			Abby Krich
Galt Power, Inc.	Supplier	José Rotger		
Generation Group Member	Generation	Dennis Duffy	Abby Krich	
Georgetown Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Great River Hydro	AR-RG			Bill Fowler
Groton Electric Light Department	Publicly Owned		Brian Thomson	

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN DECEMBER 3, 2020 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Groveland Electric Light Department	Publicly Owned		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc.	Supplier	Louis Guibault	Bob Stein	
Harvard Dedicated Energy Limited	End User	Mary Smith	Joyceline Chow	
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned		Brian Thomson	
Holyoke Gas & Electric Department	Publicly Owned		Brian Thomson	
Hull Municipal Lighting Plant	Publicly Owned		Brian Thomson	
Industrial Energy Consumer Group (IECG)	End User	Alan Topalian		
Ipswich Municipal Light Department	Publicly Owned		Brian Thomson	
Jericho Power LLC (Jericho)	AR-RG	Mark Spencer	Herb Healy	
KCE CT 1, LLC	Provisional			Pete Fuller
Littleton (MA) Electric Light and Water Department	Publicly Owned		Dave Cavanaugh	
Littleton (NH) Water & Light Department	Publicly Owned	Craig Kieny		
Long Island Power Authority (LIPA)	Supplier		Bill Killgoar	
Maine Public Advocate’s Office	End User	Andrew Landry		Erin Camp
Maine Skiing, Inc.	End User	Alan Topalian		
Mansfield Municipal Electric Department	Publicly Owned		Brian Thomson	
Maple Energy LLC	AR-LR			Doug Hurley
Marble River	Supplier		John Brodbeck	Abby Krich
Marblehead Municipal Light Department	Publicly Owned		Brian Thomson	
Mass. Attorney General’s Office (MA AG)	End User	Christina Belew		Rebecca Tepper
Mass. Bay Transportation Authority	Publicly Owned		Dave Cavanaugh	
Mass. Municipal Wholesale Electric Company	Publicly Owned	Brian Thomson		
Mercuria Energy America, Inc.	Supplier			José Rotger
Merrimac Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Michael Kuser	End User		Jason York	
Middleborough Gas & Electric Department	Publicly Owned		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned		Dave Cavanaugh	
National Grid	Transmission	Tim Brennan	Tim Martin	
Natural Resources Defense Council	End User	Bruce Ho		
Nautilus Power, LLC	Generation		Bill Fowler	
New Hampshire Electric Cooperative	Publicly Owned	Steve Kaminski		Brian Forshaw
New Hampshire Office of Consumer Advocate	End User	Pradip Chttopadhyay	Erin Camp	
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
North Attleborough Electric Department	Publicly Owned		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Novatus Energy (Blue Sky West, LLC)	AR-RG			Abby Krich
NRG Power Marketing LLC	Generation		Pete Fuller	
Pascoag Utility District	Publicly Owned		Dave Cavanaugh	
Paxton Municipal Light Department	Publicly Owned		Brian Thomson	
Peabody Municipal Light Department	Publicly Owned		Brian Thomson	
PowerOptions, Inc.	End User			Erin Camp
Princeton Municipal Light Department	Publicly Owned		Brian Thomson	
PSEG Energy Resources & Trade LLC	Supplier	Eric Stallings		
Reading Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Rowley Municipal Lighting Plant	Publicly Owned		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned		Brian Thomson	
Shell Energy North America (US), L.P.	Supplier	Matt Picardi		
Shrewsbury Electric & Cable Operations	Publicly Owned		Brian Thomson	
South Hadley Electric Light Department	Publicly Owned		Brian Thomson	
Sterling Municipal Electric Light Department	Publicly Owned		Brian Thomson	
Stowe Electric Department	Publicly Owned		Dave Cavanaugh	
Sunrun Inc.	AR-DG			Pete Fuller

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN DECEMBER 3, 2020 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Taunton Municipal Lighting Plant	Publicly Owned		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned		Brian Thomson	
The Energy Consortium	End User	Roger Borghesani	Mary Smith	
Transource	Provisional			Dylan Drugan
Union of Concerned Scientists	End User		Francis Pullaro	
Vermont Electric Coop.	Publicly Owned	Craig Kieny		
Vermont Electric Power Company	Transmission	Frank Ettori		
Vermont Energy Investment Corp (VEIC)	AR-LR		Doug Hurley	
Vermont Public Power Supply Authority	Publicly Owned			Brian Forshaw
Versant Power	Transmission	Lisa Martin	David Norman	
Verso Energy Services LLC	Generation	Glenn Poole		
Village of Hyde Park (VT) Electric Department	Publicly Owned		Dave Cavanaugh	
Vitol Inc.	Supplier	Joe Wadsworth		
Wakefield Municipal Gas & Light Department	Publicly Owned		Brian Thomson	
Wallingford DPU Electric Division	Publicly Owned		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned		Brian Thomson	
Westfield Gas & Electric Department	Publicly Owned		Dave Cavanaugh	
Wheelabrator North Andover, Inc.	AR-RG		Bill Fowler	

ATTACHMENT 2

VOTES TAKEN AT
DECEMBER 3, 2020 PARTICIPANTS COMMITTEE MEETING

TOTAL

Sector/Group	Vote 1	Vote 2	Vote 3	Vote 4
GENERATION	12.50	8.33	4.17	0.00
TRANSMISSION	0.00	0.00	16.67	0.00
SUPPLIER	12.82	5.55	5.12	1.66
ALTERNATIVE RESOURCES	7.57	12.37	12.37	0.00
PUBLICLY OWNED ENTITY	0.00	16.67	16.67	16.67
END USER	0.00	16.67	16.67	0.00
PROVISIONAL MEMBERS	0.08	0.17	0.17	0.00
% IN FAVOR	**32.97**	**59.76**	**71.84**	**18.33**

GENERATION SECTOR

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4
CPV Towantic, LLC	F	O	O	O
Deepwater Wind Block Island	O	F	F	O
Dominion Energy Generation Mktg	F	O	O	O
FirstLight Power Management, LLC	F	O	O	O
Generation Group Member	O	F	F	O
Nautilus Power, LLC	F	O	O	O
NextEra Energy Resources, LLC	F	F	O	O
NRG Power Marketing, LLC	F	F	O	O
IN FAVOR (F)	6	4	2	0
OPPOSED (O)	2	4	6	8
TOTAL VOTES	8	8	8	8
ABSTENTIONS (A)	0	0	0	0

ALTERNATIVE RESOURCES SECTOR

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4
Renewable Generation Sub-Sector				
Central Rivers Power	F	O	O	O
ENGIE Energy Marketing NA, Inc.	O	F	F	A
Great River Hydro, LLC	F	O	O	O
Jericho Power LLC	F	O	O	O
Novatus Energy	O	F	F	O
Wheelabrator/Macquarie	F	O	O	O
Large RG Group Member	A	F	F	O
Small RG Group Member	A	F	F	O
Distributed Gen. Sub-Sector				
Borrego Solar Systems Inc.	O	F	F	O
CLEAResult Consulting, Inc.	A	F	F	O
Sunrun Inc.	F	F	A	A
Load Response Sub-Sector				
Enel X North America, Inc.	O	F	F	O
Maple Energy	O	F	F	O
Vermont Energy Investment Corp.	O	F	F	O
Small LR Group Member	O	F	F	O
IN FAVOR (F)	5	11	10	- 0
OPPOSED	7	4	4	13
TOTAL VOTES	12	15	14	13
ABSTENTIONS (A)	3	0	1	2

TRANSMISSION SECTOR

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4
Avangrid (CMP/UI)	O	A	F	O
Eversource Energy	O	A	F	A
National Grid	O	A	A	A
VELCO	O	A	F	A
Versant Power	O	A	F	O
IN FAVOR (F)	0	0	4	0
OPPOSED	5	0	0	2
TOTAL VOTES	5	0	4	2
ABSTENTIONS (A)	0	5	1	3

SUPPLIER SECTOR

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4
American PowerNet Management, LP	O	F	F	O
BP Energy Company	A	A	A	A
Brookfield Renewable Trading & Mktg	F	--	O	O
Calpine Energy Services, LP	F	O	O	O
Castleton Comm. Merchant Trading	F	O	O	A
Consolidated Edison Energy, Inc.	F	A	A	A
Cross-Sound Cable Company	A	A	A	A
DC Energy, LLC	F	--	--	--
Direct Energy Business, LLC	A	O	O	A
DTE Energy Trading, Inc.	A	A	A	A
Dynegy Marketing and Trade, LLC	F	O	O	O
Emera Energy Companies	F	O	O	O
Exelon Generation Company	F	O	O	O
Freepoint Commodities, LLC	O	F	F	O
Galt Power, Inc.	A	A	A	A
H.Q. Energy Services (U.S.) Inc.	F	O	O	F
LIPA	A	A	A	A
Marble River, LLC	O	F	F	O
Mercuria Energy America, Inc	A	A	A	A
PSEG Energy Resources & Trade	F	O	O	O
Shell Energy North America (US) LP	A	F	F	A
Vitol Inc.	A	A	--	--
IN FAVOR (F)	10	4	4	1
OPPOSED	3	8	9	9
TOTAL VOTES	13	12	13	10
ABSTENTIONS (A)	9	8	7	10

END USER SECTOR

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4
Acadia Center	O	F	F	O
Associated Industries of Mass.	O	F	F	O

VOTES TAKEN AT
DECEMBER 3, 2020 PARTICIPANTS COMMITTEE MEETING

Conn. Office of Consumer Counsel	O	F	F	O
Conservation Law Foundation	O	F	F	O
Environmental Defense Fund	O	F	F	O
Harvard Dedicated Energy Limited	O	F	F	O
High Liner Foods (USA) Inc.	O	F	F	O
Industrial Energy Consumer Group	O	F	F	O
Michael Kuser	A	A	A	A
Maine Public Advocate Office	O	F	F	O
Maine Skiing, Inc.	O	F	F	O
Mass. Attorney General's Office	O	F	F	O
Natural Resources Defense Council	O	F	F	O
NH Office of Consumer Advocate	O	F	F	O
PowerOptions, Inc.	O	F	F	O
The Energy Consortium	O	F	F	O
IN FAVOR (F)	0	17	17	0
OPPOSED	17	0	0	17
TOTAL VOTES	17	17	17	17
ABSTENTIONS (A)	1	1	1	1

PUBLICLY OWNED ENTITY SECTOR

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4
Ashburnham Municipal Light Plant	O	F	F	A
Belmont Municipal Light Dept.	O	F	F	F
Block Island Utility District	O	F	F	F
Boylston Municipal Light Dept.	O	F	F	A
Braintree Electric Light Dept.	O	F	F	F
Chester Municipal Light Dept.	O	F	F	F
Chicopee Municipal Lighting Plant	O	F	F	A
Concord Municipal Light Plant	O	F	F	F
Conn. Mun. Electric Energy Coop.	O	F	F	F
Danvers Electric Division	O	F	F	F
Georgetown Municipal Light Dept.	O	F	F	F
Groton Electric Light Dept.	O	F	F	A
Groveland Electric Light Dept.	O	F	F	F
Hingham Municipal Lighting Plant	O	F	F	F
Holden Municipal Light Dept.	O	F	F	A
Holyoke Gas & Electric Dept.	O	F	F	A
Hull Municipal Lighting Plant	O	F	F	A
Ipswich Municipal Light Dept.	O	F	F	A
Littleton (MA) Electric Light Dept.	O	F	F	F
Littleton (NH) Water & Light Dept.	O	F	F	F
Mansfield Municipal Electric Dept.	O	F	F	A
Marblehead Municipal Light Dept.	O	F	F	A

PUBLICLY OWNED ENTITY SECTOR (cont.)

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4
Mass. Mun. Wholesale Electric Co.	O	F	F	A
Mass. Bay Transportation Authority	O	F	F	F
Merrimac Municipal Light Dept.	O	F	F	F

Middleborough Gas and Elec. Dept.	O	F	F	F
Middleton Municipal Electric Dept.	O	F	F	F
New Hampshire Electric Cooperative	O	F	F	A
North Attleborough Electric Dept.	O	F	F	F
Norwood Municipal Light Dept.	O	F	F	F
Pascoag Utility District	O	F	F	F
Paxton Municipal Light Dept.	O	F	F	A
Peabody Municipal Light Plant	O	F	F	A
Princeton Municipal Light Dept.	O	F	F	A
Reading Municipal Light Dept.	O	F	F	F
Rowley Municipal Lighting Plant	O	F	F	F
Russell Municipal Light Dept.	O	F	F	A
Shrewsbury's Elec. & Cable Ops.	O	F	F	A
South Hadley Electric Light Dept.	O	F	F	A
Sterling Municipal Electric Light Dept.	O	F	F	A
Stowe (VT) Electric Dept.	O	F	F	F
Taunton Municipal Lighting Plant	O	F	F	F
Templeton Municipal Lighting Plant	O	F	F	A
Vermont Electric Cooperative	O	F	F	F
VT Public Power Supply Authority	O	F	F	F
Village of Hyde Park (VT) Elec. Dept.	O	F	F	F
Wakefield Mun. Gas and Light Dept.	O	F	F	A
Wallingford, Town of	O	F	F	F
Wellesley Municipal Light Plant	O	F	F	F
West Boylston Mun. Lighting Plant	O	F	F	A
Westfield Gas & Electric Light Dept.	O	F	F	F
IN FAVOR (F)	0	51	51	29
OPPOSED	51	0	0	0
TOTAL VOTES	51	51	51	29
ABSTENTIONS (A)	0	0	0	22

PROVISIONAL MEMBERS

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4
Able Grid Infrastructure Holdings, LLC	O	F	F	O
Anbaric Development Partners, LLC	A	F	F	O
KCE CT 1 & 2	F	A	A	A
IN FAVOR (F)	1	2	2	0
OPPOSED	1	0	0	2
TOTAL VOTES	2	2	2	2
ABSTENTIONS (A)	1	1	1	1

**ESTIMATED 2021 NEPOOL BUDGET COMPARED TO
2020 NEPOOL BUDGET AND 2020 PROJECTED ACTUAL EXPENSES**

Line Items	2020 Approved Budget	2021 Proposed Budget	2020 Current Forecast
NEPOOL Counsel Fees (1)	$4,100,000	$4,100,000	$4,100,000
NEPOOL Counsel Disbursements (1)	$ 40,000	$ 20,000	$ 20,000
Independent Financial Advisor Fees and Disbursements (2)	$ 45,000	$ 45,000	$ 45,000
Committee Meeting Expenses (3)(4)	$ 725,000	$ 510,000	$ 210,000
Generation Information System (5)	$ 945,000	$ 1,070,600	$ 845,000
Credit Insurance Premium (3)	$ 510,000	$ 475,000	$ 434,000
NEPOOL Audit Management Subcommittee (NAMS) Consultant (6)	$ 0	$ 0	$ 0
SUBTOTAL EXPENSES	$6,365,000	$6,220,600	$5,654,000
Revenue			
NEPOOL Membership Fees (3) (7)	($2,070,000)	($2,110,000)	($2,238,000)
Generation Information System (5) (8)	($ 945,000)	($1,070,600)	($ 845,000)
Credit Insurance Premium (3) (9)	($ 510,000)	($ 475,000)	($ 434,000)
TOTAL REVENUE	($3,525,000)	($3,655,600)	($3,517,000)
TOTAL NEPOOL EXPENSES	**$2,840,000**	**$2,565,000**	**$2,137,000**

Notes

(1) 2021 proposed estimate provided by Day Pitney LLP, NEPOOL counsel.

(2) 2021 proposed estimate provided by Michael M. Mackles, NEPOOL's Independent Financial Advisor.

(3) 2021 proposed estimate provided by ISO New England Inc. (ISO).

(4) Committee meeting expense for 2020 includes amounts to be paid to consultants for assistance with Future Grid. The 2021 proposed budget assumes no in-person meetings for the first part of 2021.

(5) Based on new fee arrangement in Extension of and First Amendment to Amended and Restated Generation Information System Administration Agreement, pursuant to which the fixed fee for 2021 is projected to be $950,000, plus $120,600 projected expense related to changes associated with Massachusetts Clean Peak Energy Standard, which will be charged in 2021 when changes are completed.

(6) If NEPOOL determines that an audit should be performed in 2021, funding for that audit will be addressed separately.

(7) The 2021 proposed estimate is based on the 2020 actual receipts through October 2020, plus a forecast for new members for the remainder of the year. The breakdown for the proposed budget is approximately: 392 members at $5,000 each, 29 members at $1,000 each, 16 members at $500 each, 25 members at $1,500 each, and 31 members of large end users and MPEU's. This estimate takes into account the terminations throughout the year.

(8) GIS costs, other than those associated with accessing the GIS through the application programming interface (API) are paid by "GIS Participants" under Allocation of Costs Related to Generation Information System, which was approved by the NEPOOL Participants Committee on June 21, 2002. GIS costs associated with accessing the GIS through the API are paid by the GIS account holders using that API.

(9) Credit insurance premium is paid by Qualifying Market Participants according to methodology described in Section IX of the ISO Financial Assurance Policy. The 2021 premium is based on 2020 annual policy sales.

CONSENT AGENDA

Reliability Committee (RC)

From the previously-circulated notice of actions of the RC's December 15, 2020 meeting, dated December 15, 2020:[1]

1. **<u>Retirement of Appendix A to OP-12 and Conforming Revisions to OP-12</u>**

Support (i) the retirement of Appendix A (Voltage/Reactive Documents in the ISO New England ODMS) to ISO New England (ISO-NE) Operating Procedure (OP) No. 12 (Voltage and Reactive Control) (OP-12) and (ii) minor grammatical changes and conforming changes reflecting the retirement of Appendix A, all as recommended by the RC at its December 15, 2020 meeting, together with such other non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was approved unanimously.

2. **<u>Revisions to Planning Procedures 5-5, 5-1 and 5-0 (Changes to Align PPs with NERC RAS Definition and Reliability Standard PRC-012-2)</u>**

Support revisions to ISO-NE Planning Procedure (PP) 5-5 (Requirements and Guidelines for Application of Remedial Action Schemes (RAS) and Automatic Control Schemes), PP 5-1 (Section I.3.9 Applications: Requirements, Procedures, and Forms), and PP 5-0 (Proposed Plan Application Procedure) (together, the PPs), to conform the PPs to NERC's RAS definition and Reliability Standard PRC-012 (Remedial Action Schemes), as recommended by the RC at its December 15, 2020 meeting, together with such other non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was approved unanimously, with two abstentions recorded in the Supplier Sector.

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

NEPOOL Participants Committee Report

January 2021

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

- Highlights — Page 3
- System Operations — Page 14
- Market Operations — Page 27
- Back-Up Detail — Page 44
  - Demand Response — Page 45
  - New Generation — Page 47
  - Forward Capacity Market — Page 54
  - Reliability Costs - Net Commitment Period Compensation (NCPC) Operating Costs — Page 60
  - Regional System Plan (RSP) — Page 89
  - Operable Capacity Analysis – Winter 2021 Analysis — Page 115
  - Operable Capacity Analysis – Appendix — Page 122

Regular Operations Report - Highlights

Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Update: November 2020 Energy Market value totaled $245M
  - December 2020 Energy market value was $426M over the period, up $181M from November 2020 and down $42M from December 2019
    - December natural gas prices over the period were 120% higher than November average values
    - Average RT Hub Locational Marginal Prices ($42.04/MWh) over the period were 71% higher than November averages
      - DA Hub: $40.60/MWh
    - Average December 2020 natural gas prices and RT Hub LMPs over the period were down 7.5% and 1.7%, respectively, from December 2019 average
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 98.5% during December, down from 99.6% during November*
    - The minimum value for the month was 93.5% on Saturday, December 5th

Data through December 29th (RT NCPC through the 28th).

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

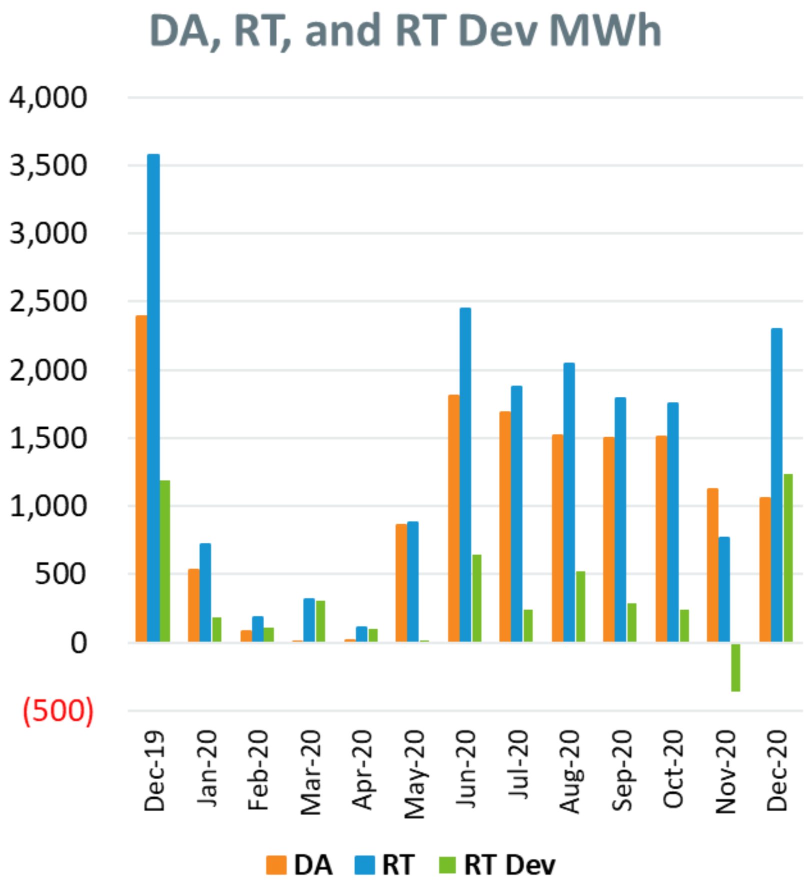
*DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market

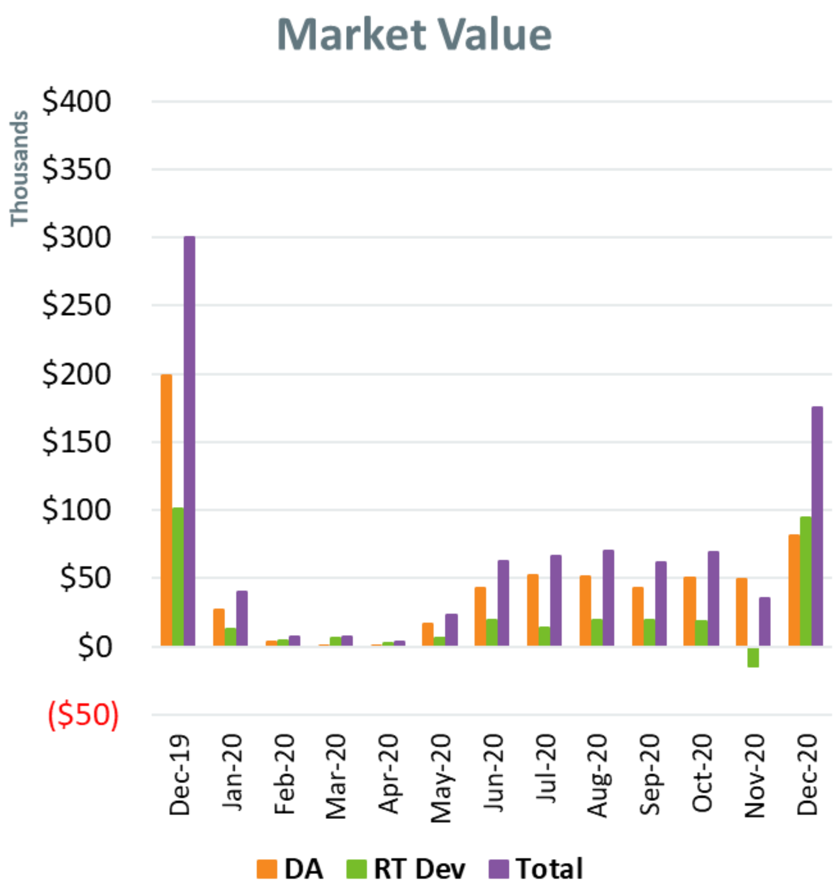
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - December NCPC payments totaled $3.4M over the period, up $1.4M from November 2020 and down $1.3M from December 2019
    - First Contingency payments totaled $1.8M, up $0.1M from November
      - $1.7M paid to internal resources, up $0.1M from November
        - » $631K charged to DALO, $483K to RT Deviations, $620K to RTLO*
      - $54K paid to resources at external locations, comparable to November
        - » Charged to RT Deviations
    - Second Contingency payments totaled $1.6M, up $1.3M from November
    - Distribution payments totaled $7K, down $1K from November
    - Voltage payments were zero
  - NCPC payments over the period as percent of Energy Market value were 0.8%

*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $280K; Rapid Response Pricing (RRP) Opportunity Cost - $207K; Posturing - $3K; Generator Performance Auditing (GPA) - $130K**

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) will be held on March 1-3, and results will be posted no later than March 31
  - ICR and related values for ARA3 were filed with FERC on November 25, 2020 and FERC has yet to rule
- 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
  - ICR and related values for ARA2 were filed with FERC on November 25, 2020 and FERC has yet to rule

CCP – Capacity Commitment Period
ICR – Installed Capacity Requirement

FCM Highlights, cont.

- 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
  - ICR and related values for ARA1 were filed with FERC on November 25, 2020 and FERC has yet to rule
- CCP 15 (2024-2025)
  - FCA 15 will model the same zones as FCA 14
    - Export-constrained zones: Maine nested inside Northern New England
    - Import-constrained zone: Southeast New England
  - Both the ICR and Informational (qualification) FERC filings were made on November 10, 2020 and FERC has yet to rule
  - Preparations are ongoing for the auction that will commence on February 8

FCM Highlights, cont.

- CCP 16 (2025-2026)
  - The qualification process has started, and training materials are under development
  - Topology certifications were sent to the TOs on October 1, 2020
    - Transmission Owners to identify in-service dates for new transmission projects and revisions to previously certified projects
    - Approved projects to be shared with the RC at their January 2021 meeting
  - Capacity zone development discussions began at the November 19, 2020 PAC meeting
    - All subsequent reconfiguration auctions model the same zones as the FCA
  - FCA 16 dynamic delist bid threshold price to be determined and posted to the ISO-NE website no later than early March

Highlights

- Transmission Planning for the Clean Energy Transition: Generation Dispatch Details will be discussed at the January 21 PAC meeting
- Additional production costs results for the National Grid 2020 economic study will be presented to PAC in both January and February; ancillary services results are expected to be presented to PAC in March
- Preparations are ongoing for the auction that will commence on February 8

Load Forecast

- Efforts continue to enhance load forecast models and tools to improve day-ahead and long-term load forecast performance
- The 2021 load forecast development process has commenced
  - Discussions will continue at the Load Forecast Committee, Energy-Efficiency Forecast Working Group, and Distributed Generation Forecast Working Group will continue in Q1 2021
  - In the March/April timeframe, PAC will discuss the preliminary ten-year forecast
  - Publication of the final ten-year forecast will be in the May 2021 CELT report

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
- Further discussion will occur at a Q1 2021 PAC meeting and will continue through much of 2021

Highlights

- The lowest 50/50 and 90/10 Winter Operable Capacity Margins are projected for week beginning January 9, 2021.

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (1.2°F) Max: 63°F, Min: 16°F Precipitation: 5.67" (1.90" Above Normal) Normal: 3.78" Snow: 13.0"	Hartford	Temperature: Above Normal (2.2°F) Max: 63°F, Min: 1°F Precipitation: 5.30" (1.90" Above Normal) Normal: 3.44" Snow: 13.3"

Peak Load:	18,756 MW	Dec 17, 2020	18:00 (ending)

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

Procedure	Declared	Cancelled	Note
None			

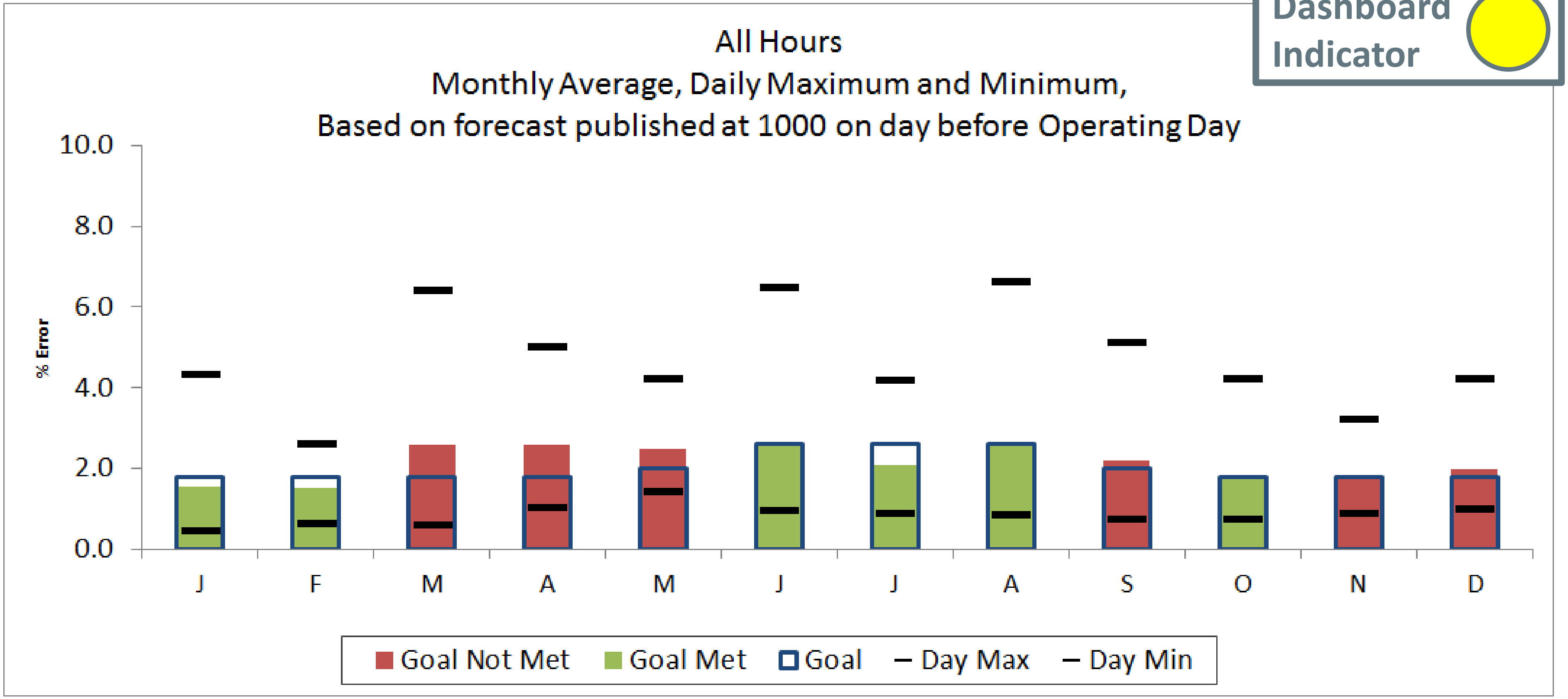
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
12/10	IESO	800
12/17	ISO-NE	700
12/29	IESO	880

2020 System Operations - Load Forecast Accuracy

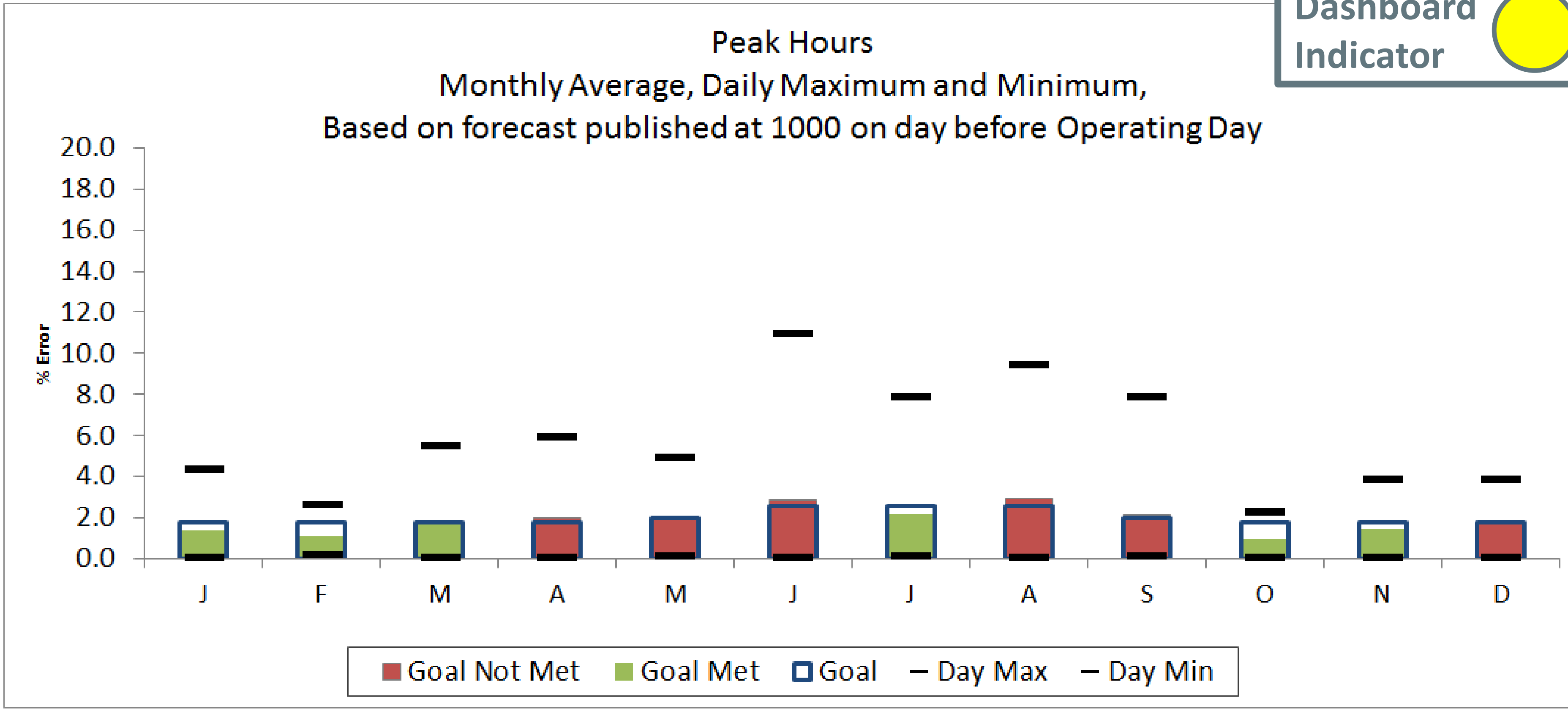
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.31	2.59	6.40	5.00	4.22	6.47	4.18	6.63	5.09	4.22	3.20	4.20	6.63
Day Min	0.46	0.61	0.58	1.03	1.42	0.96	0.88	0.84	0.72	0.75	0.89	0.98	0.46
MAPE	1.57	1.54	2.60	2.58	2.49	2.58	2.10	2.56	2.22	1.76	1.84	1.97	2.15
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80	1.80	1.80	

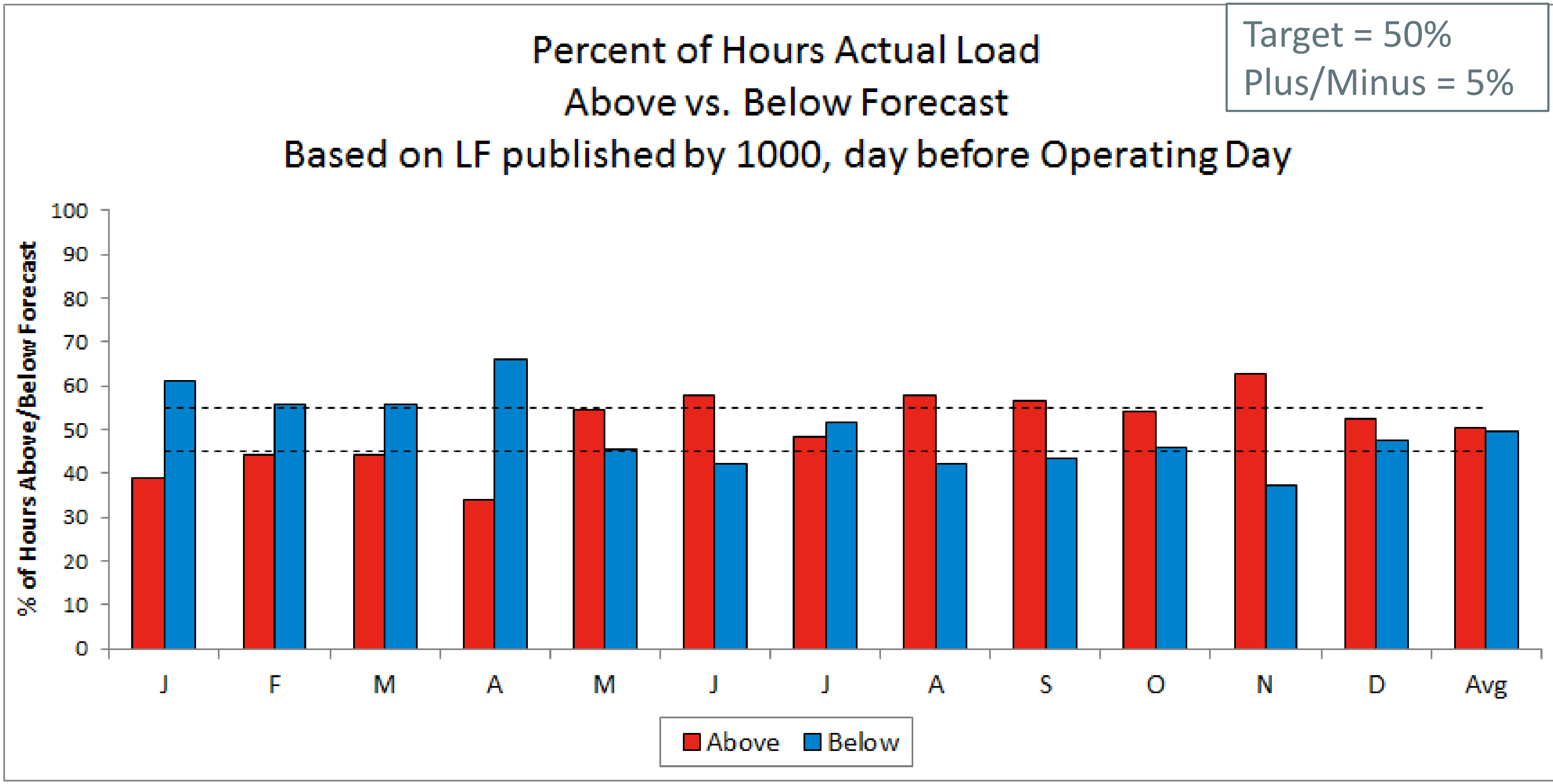
2020 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



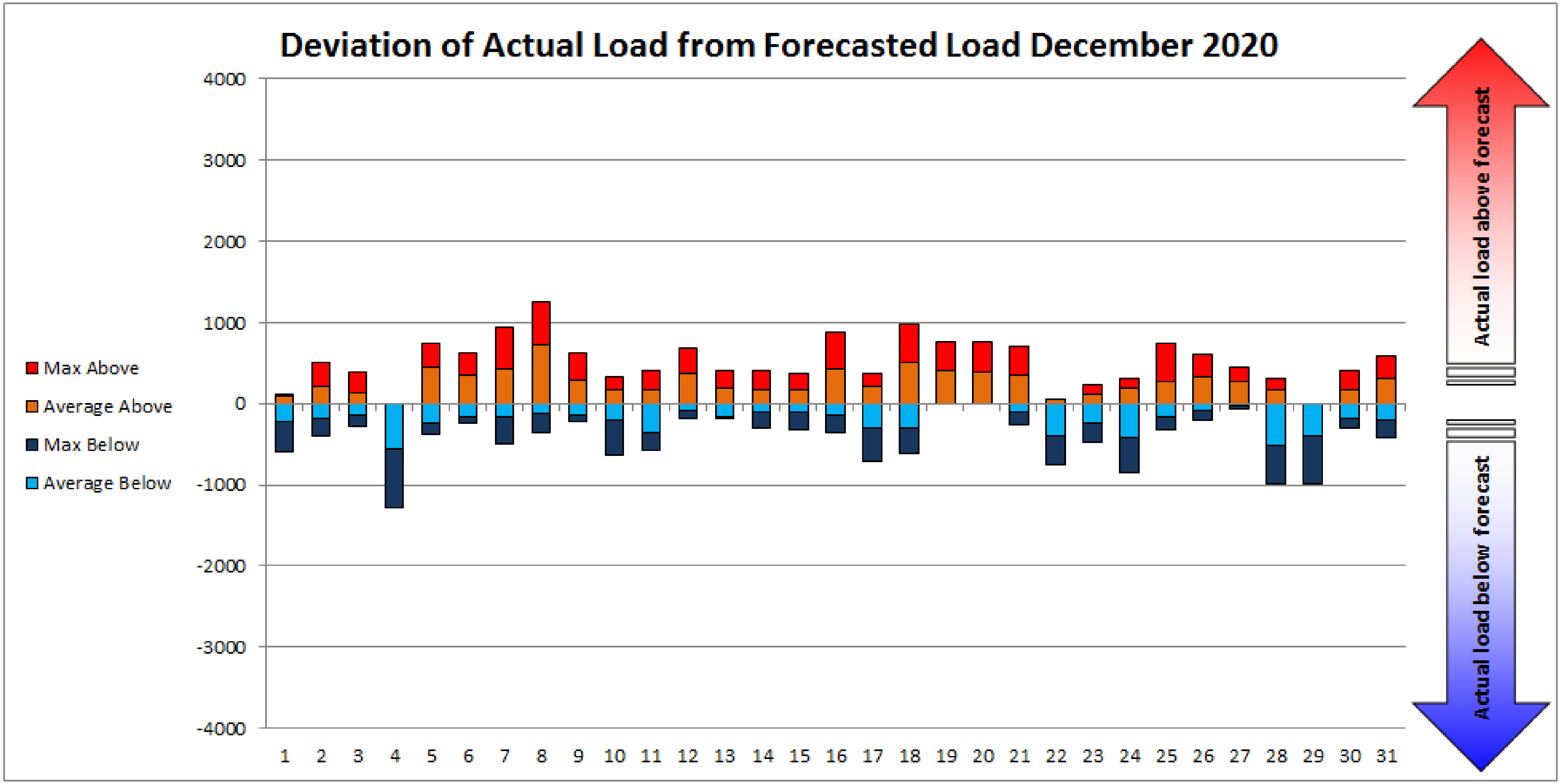
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.33	2.59	5.48	5.93	4.94	10.93	7.84	9.44	7.88	2.25	3.86	3.82	10.93
Day Min	0.07	0.19	0.01	0.00	0.13	0.05	0.14	0.07	0.10	0.00	0.05	0.06	0.00
MAPE	1.41	1.12	1.72	1.97	2.11	2.83	2.18	2.97	2.17	0.95	1.47	1.82	1.90
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80	1.80	1.80	

2020 System Operations - Load Forecast Accuracy cont.

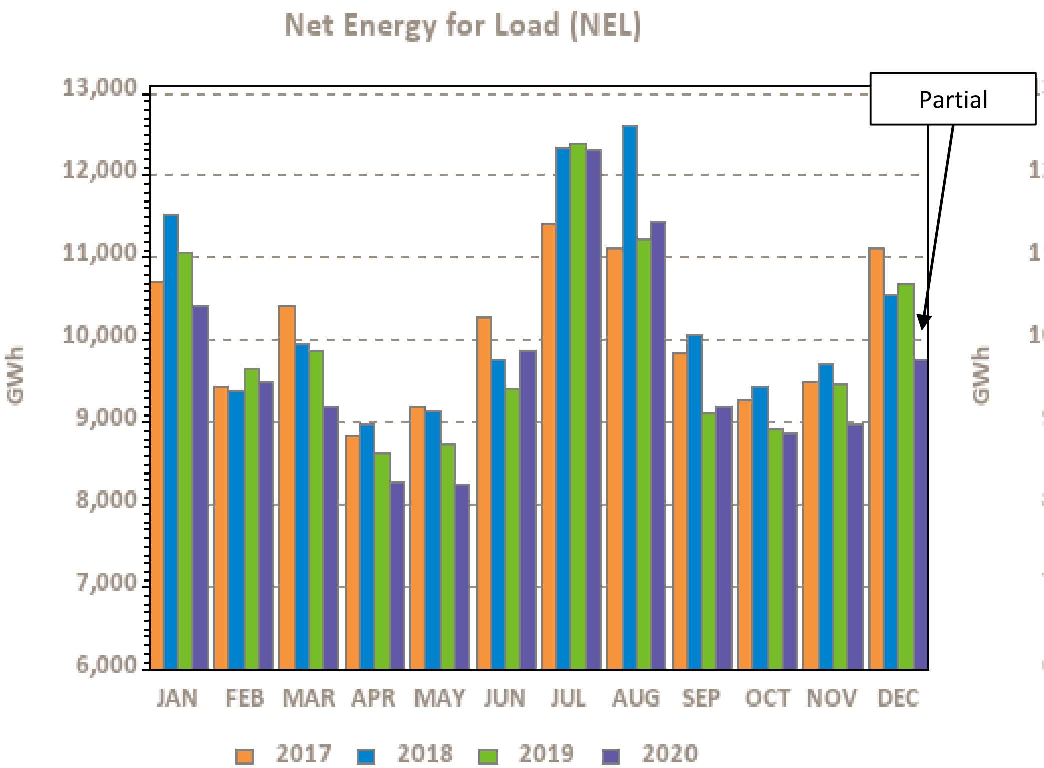


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	39	44.3	44.4	33.9	54.4	57.9	48.4	57.6	56.5	54.3	62.8	52.3	50
Below %	61	55.7	55.6	66.1	45.6	42.1	51.6	42.4	43.5	45.7	37.2	47.7	50
Avg Above	136.2	169.9	207	178.9	231.9	257.5	248.3	287.2	255.5	215.2	253.9	259.8	287
Avg Below	-192.4	-157.6	-263.9	-265.3	-196.3	-243.5	-281.7	-245.5	-166.6	-156.9	-150.5	-208.4	-282
Avg All	-65	-13	-56	-106	38	22	-26	73	89	52	96	30	11

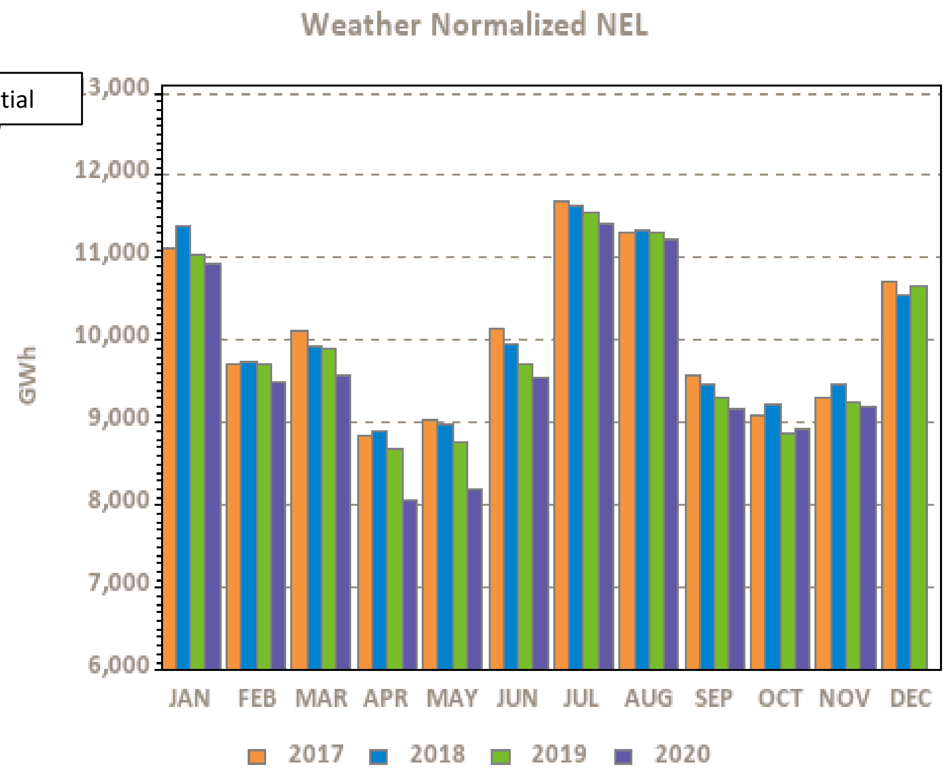
2020 System Operations - Load Forecast Accuracy cont.



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



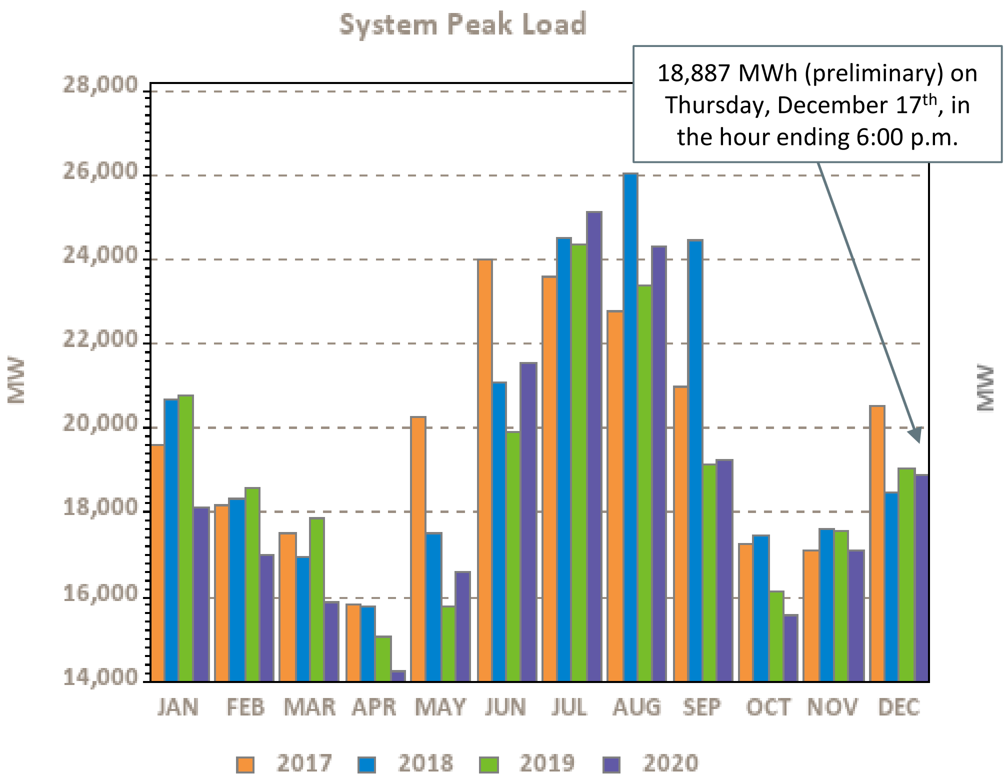
Ann Tot (TWh): 121.2 123.5 119.2 116.1



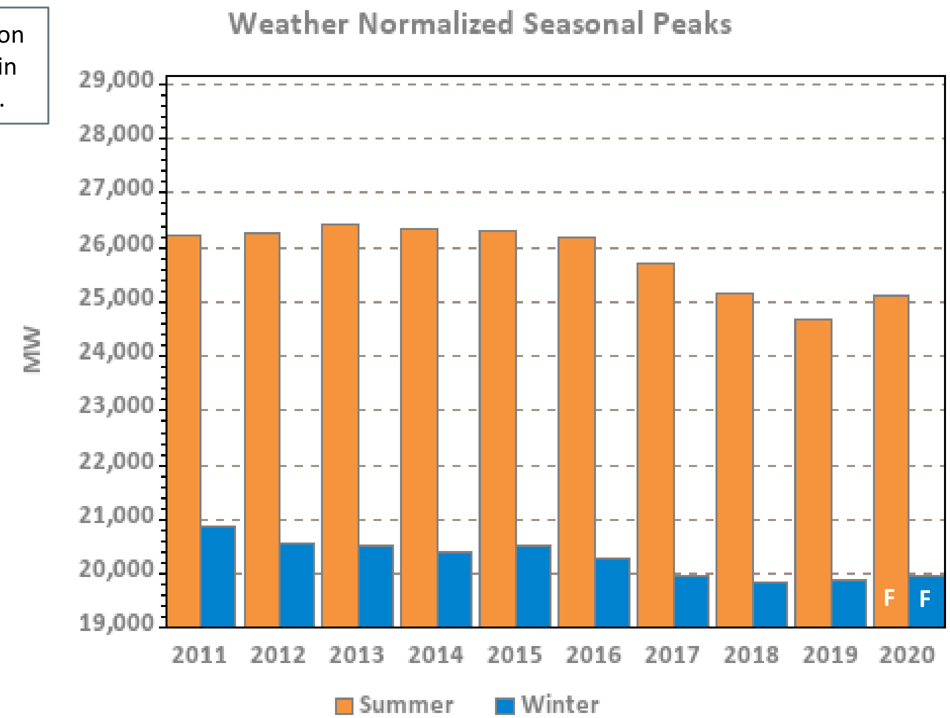
Ann Tot (TWh): 120.7 120.6 118.7 105.8

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

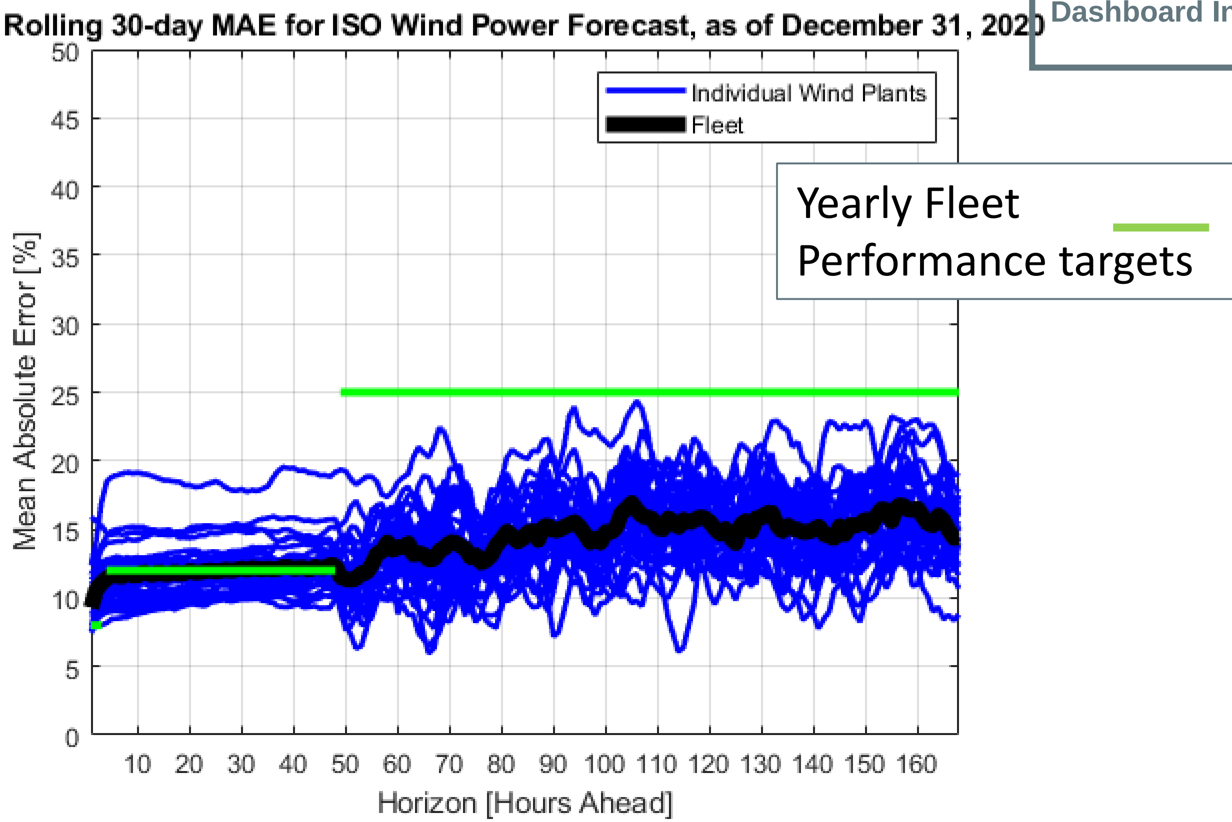


Winter beginning in year displayed

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

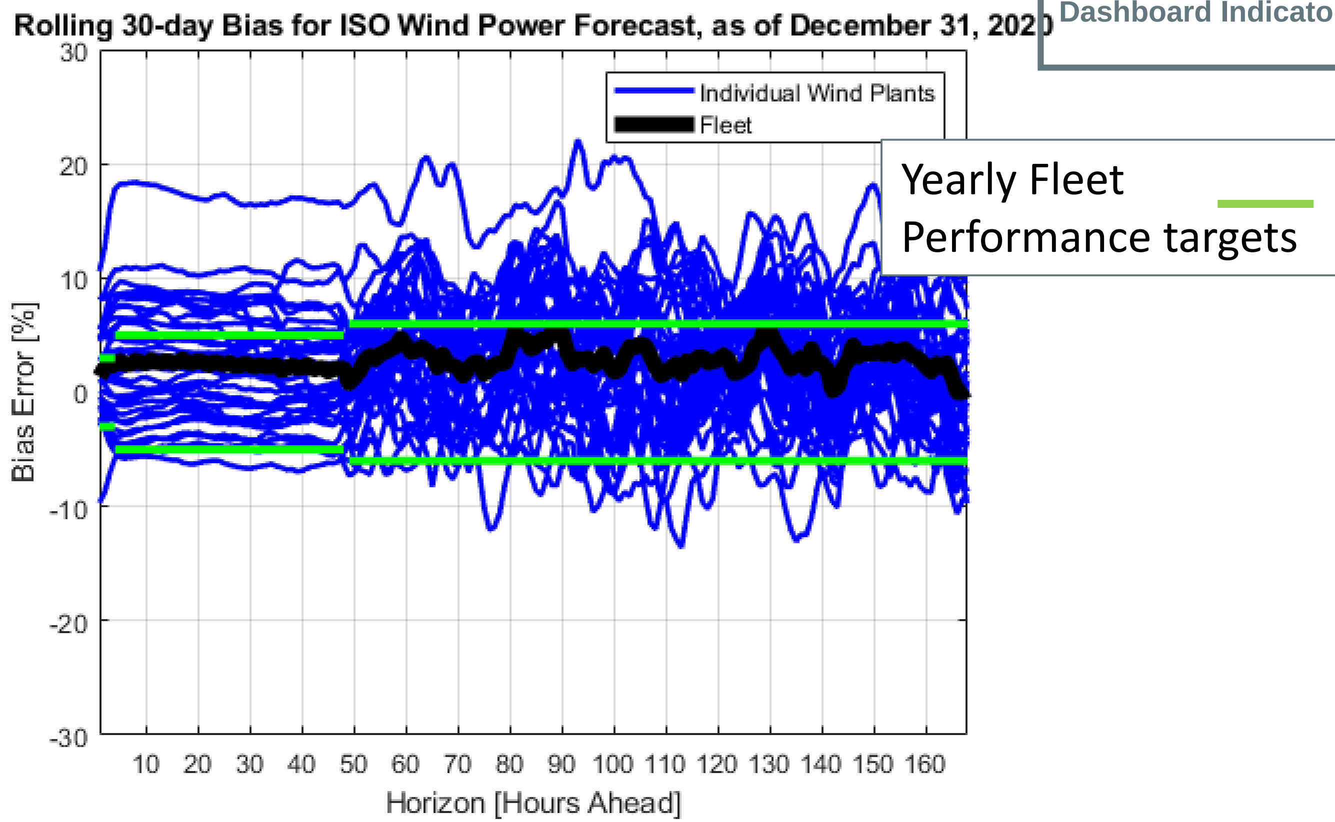
Dashboard Indicator



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

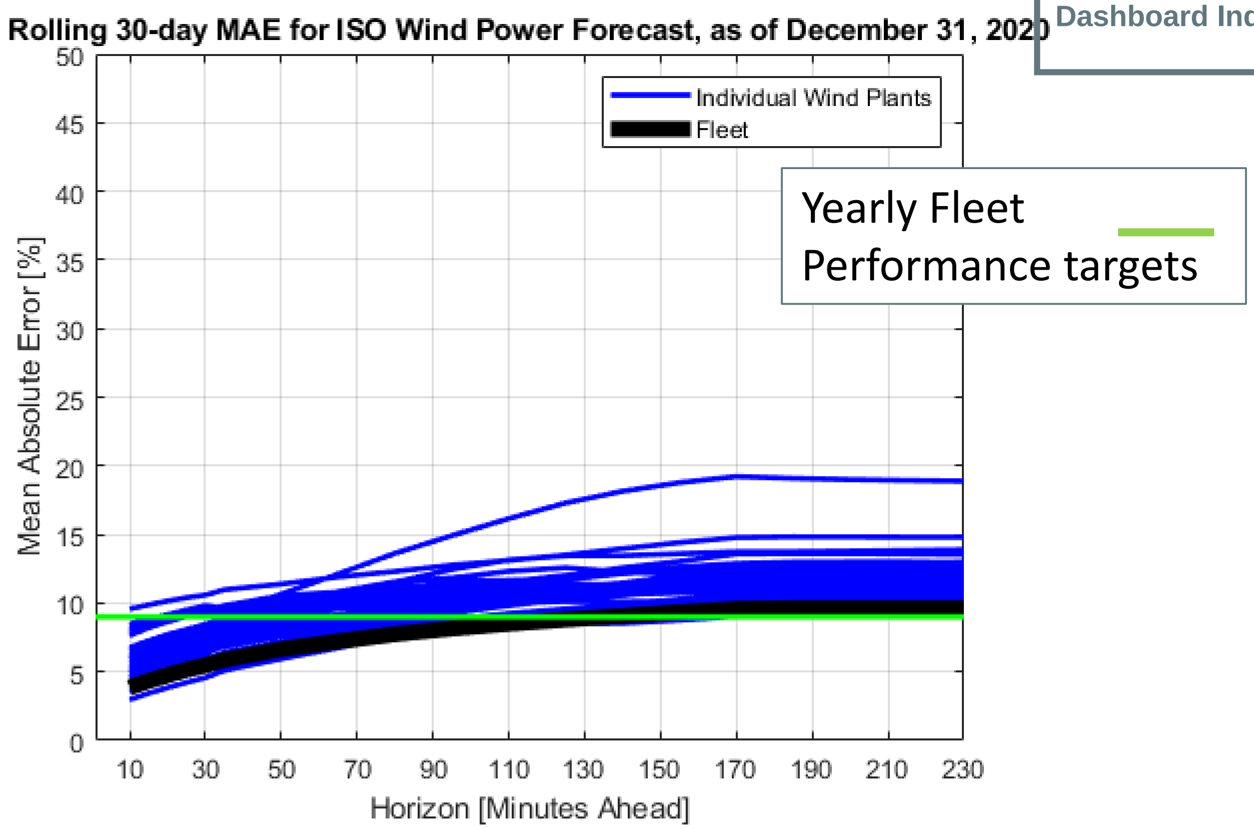
Dashboard Indicator



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

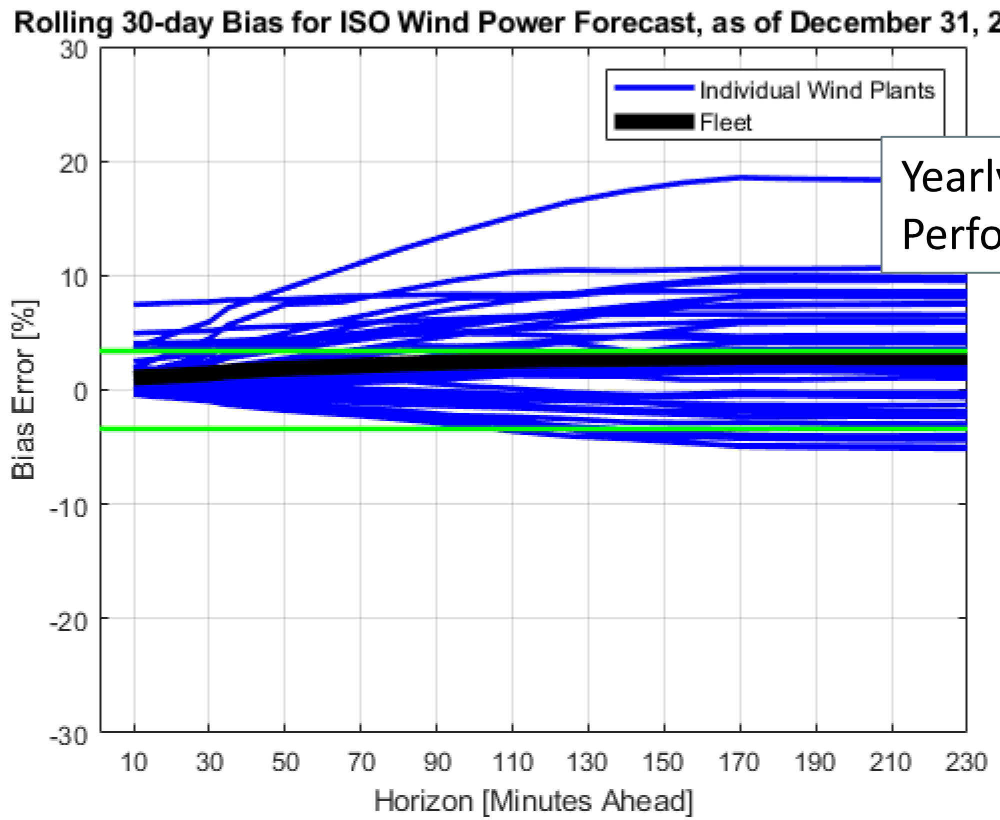
Dashboard Indicator



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 up to 170 minute look-ahead.

Wind Power Forecast Error Statistics: Short Term Forecast Bias

Dashboard Indicator

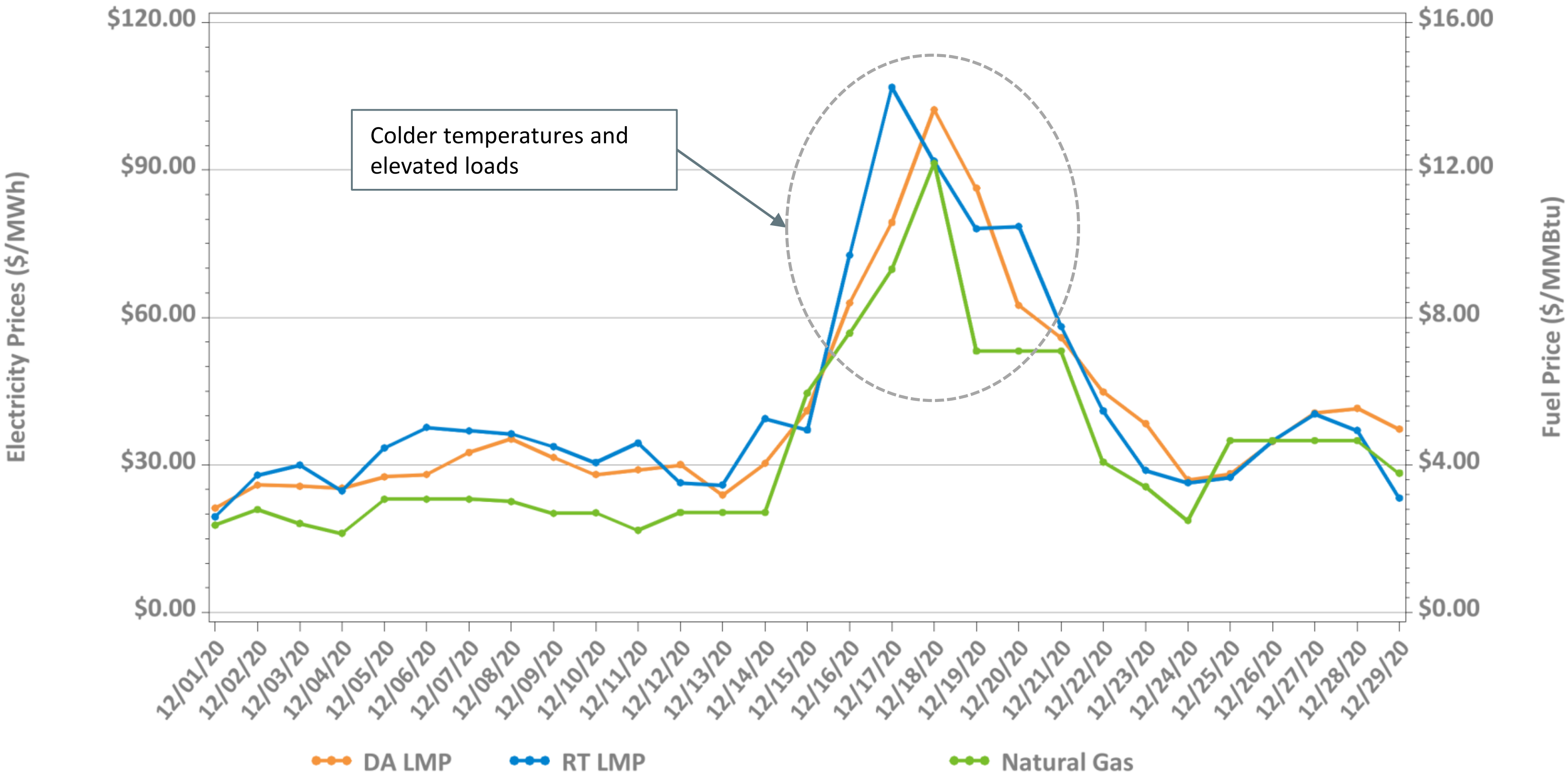


Yearly Fleet Performance targets

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

MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: December 1-29, 2020

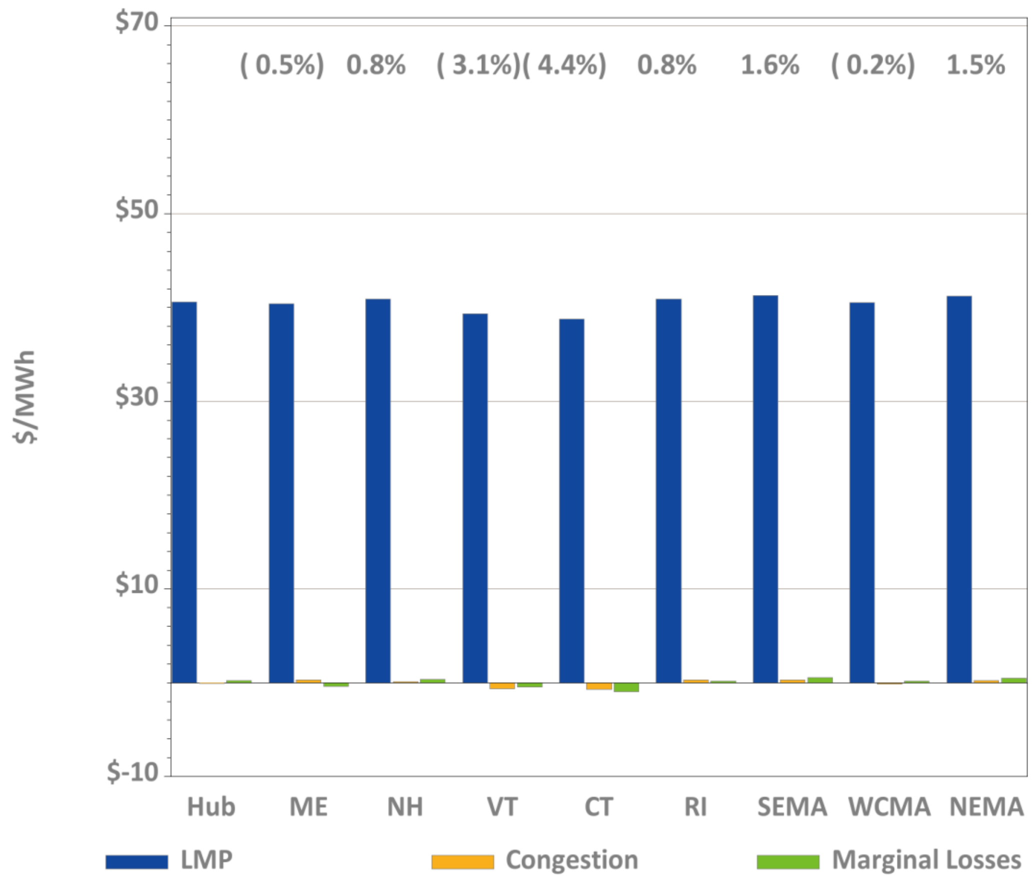


Underlying natural gas data furnished by:

ICE Global markets in clear view

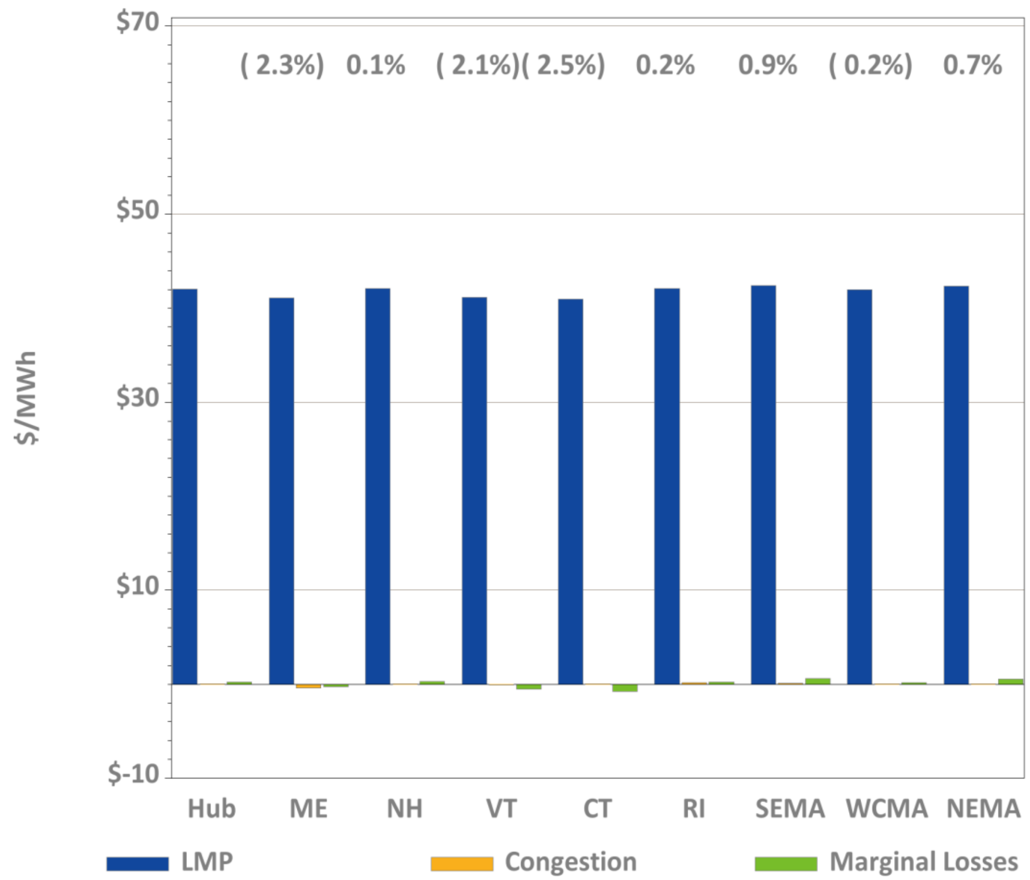
Average price difference over this period (DA-RT): $-1.44
Average price difference over this period ABS(DA-RT): $5.72
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 14%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, December 2020



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

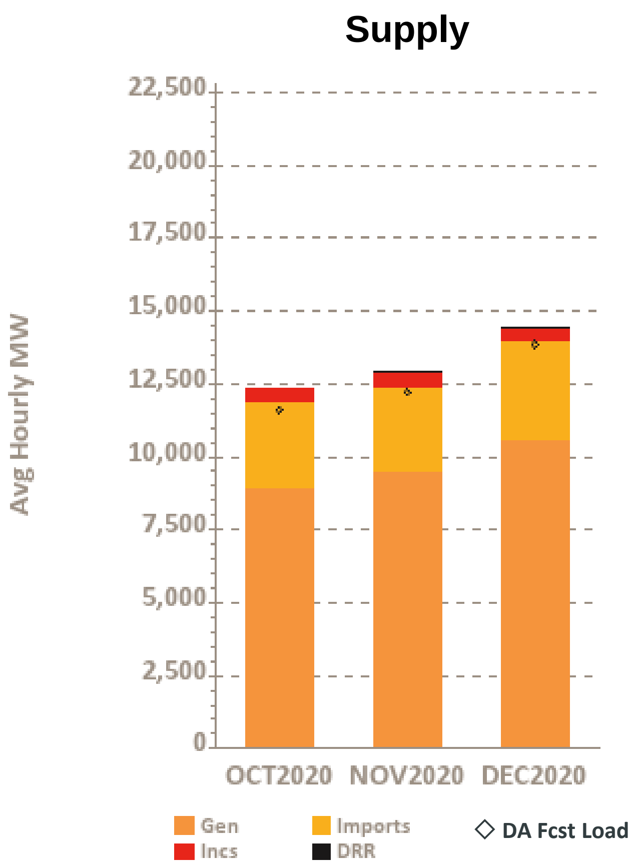
RT LMPs Average by Zone & Hub, December 2020

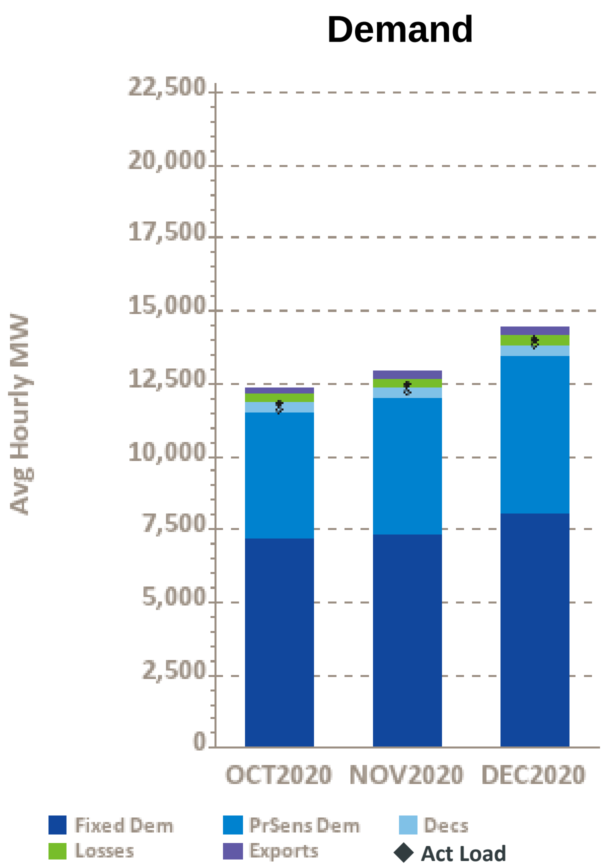


Definitions

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

Components of Cleared DA Supply and Demand – Last Three Months

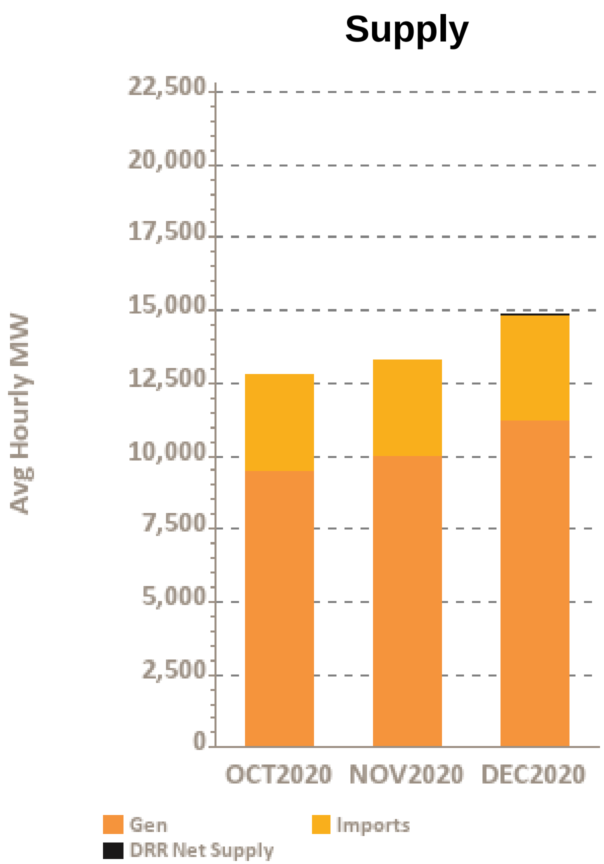


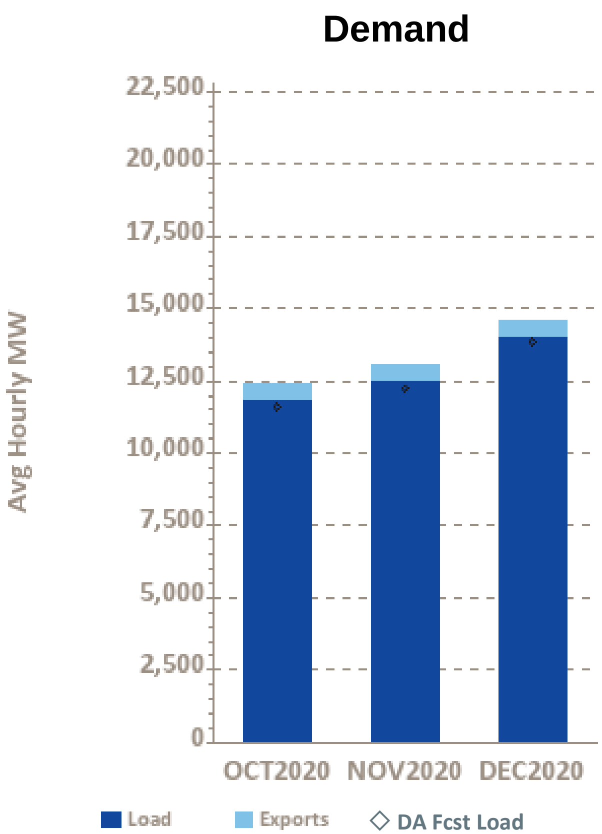


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load
DRR – Demand Response Resource

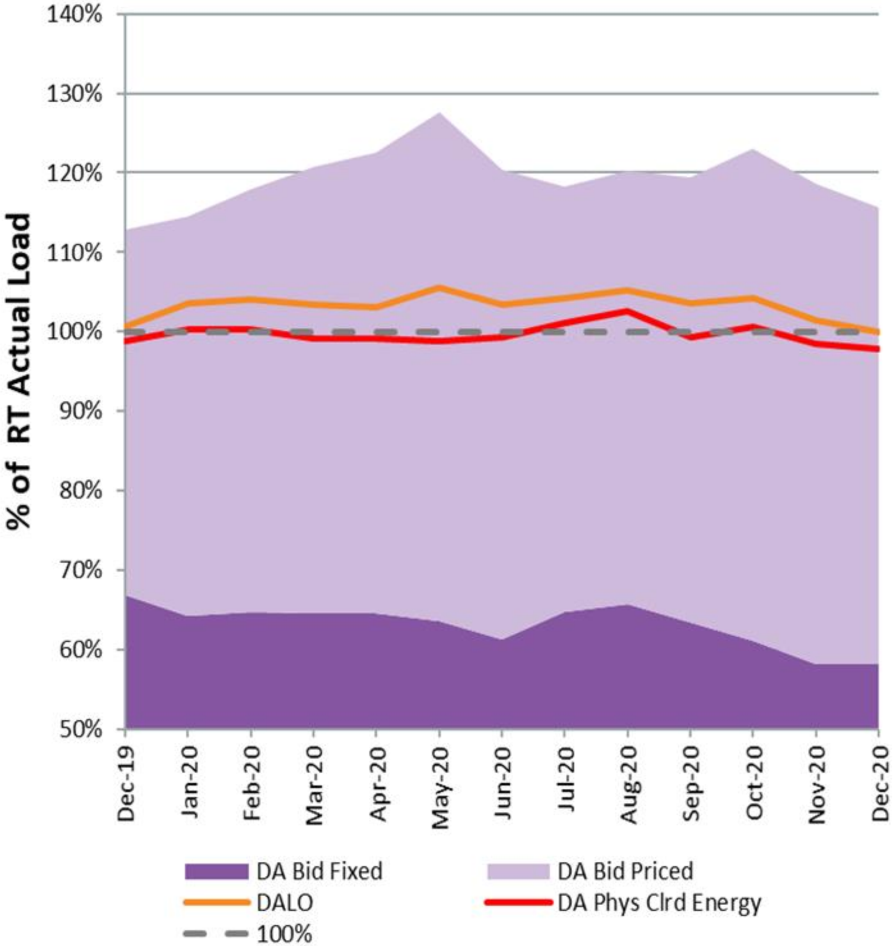
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

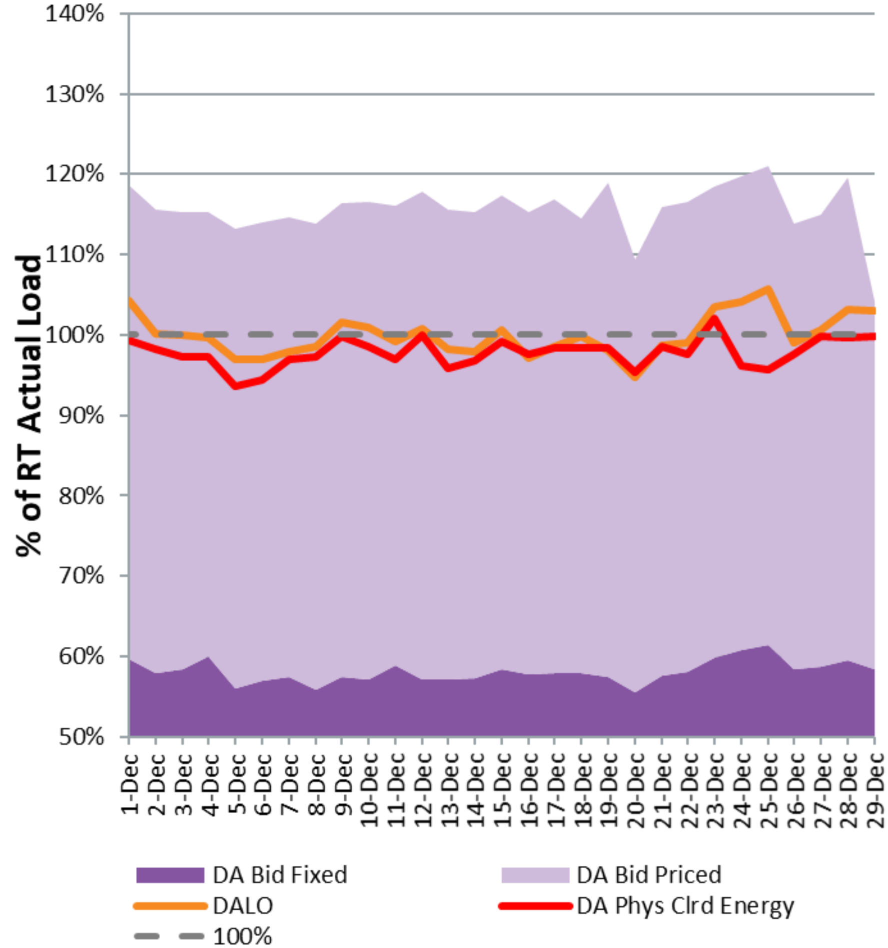
Components of RT Supply and Demand – Last Three Months





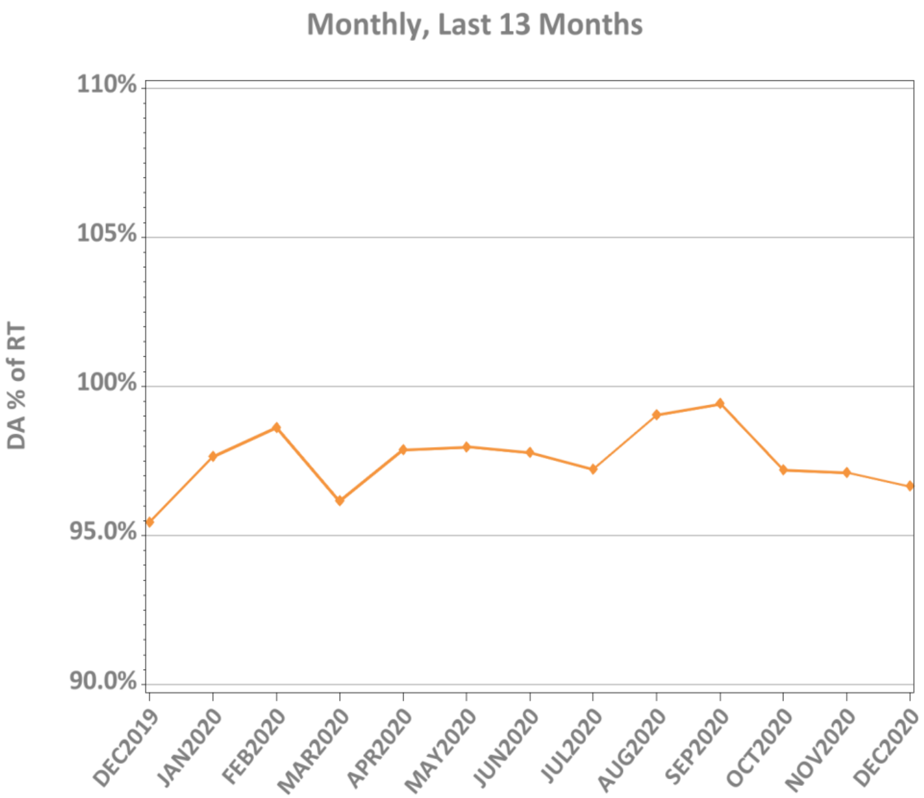
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

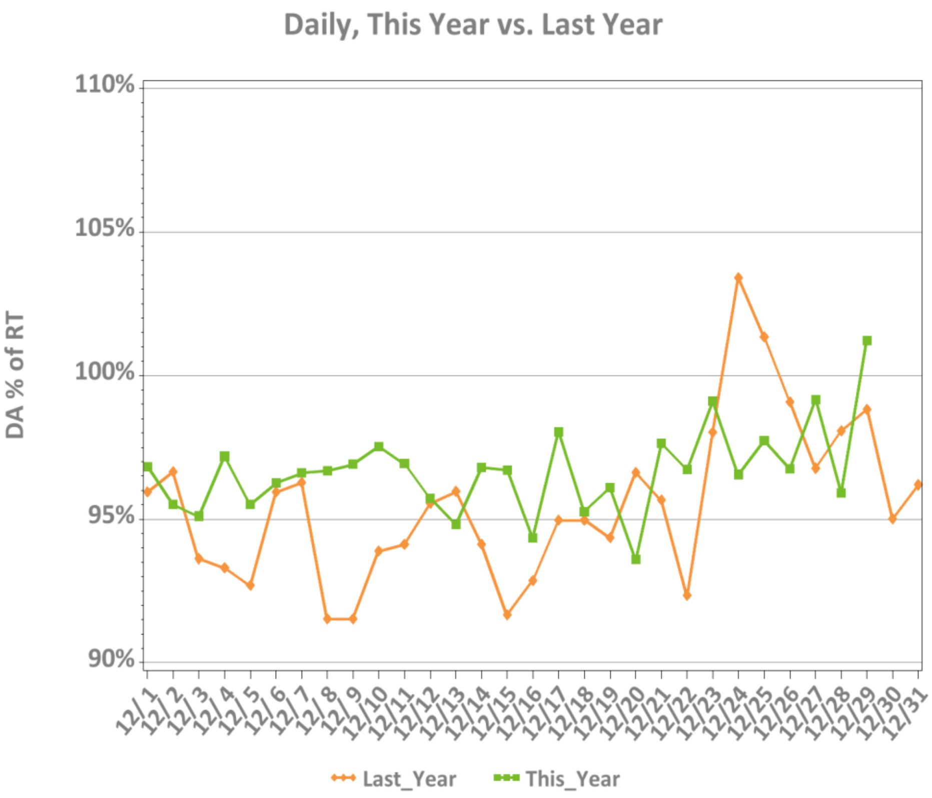




Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

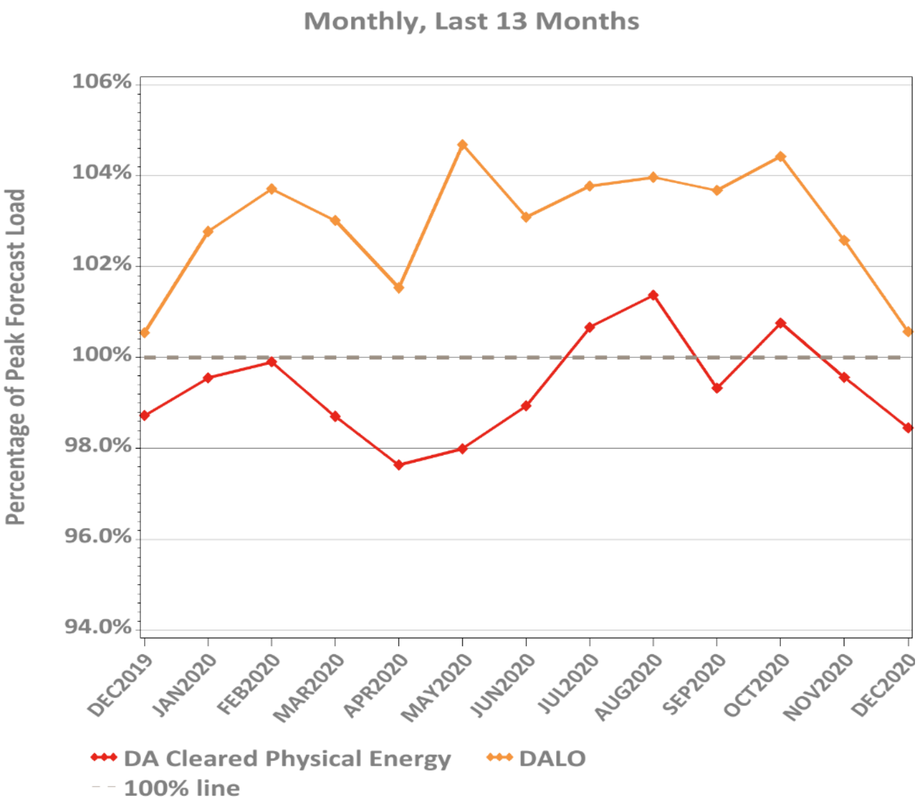
DA vs. RT Load Obligation: December, This Year vs. Last Year

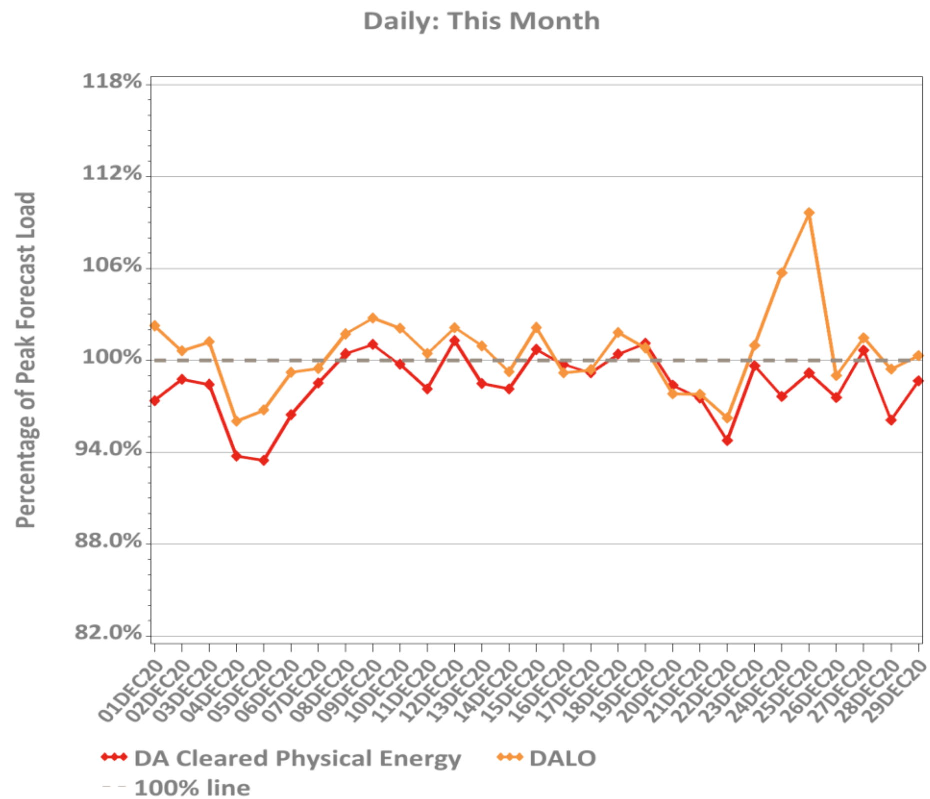




*Hourly average values

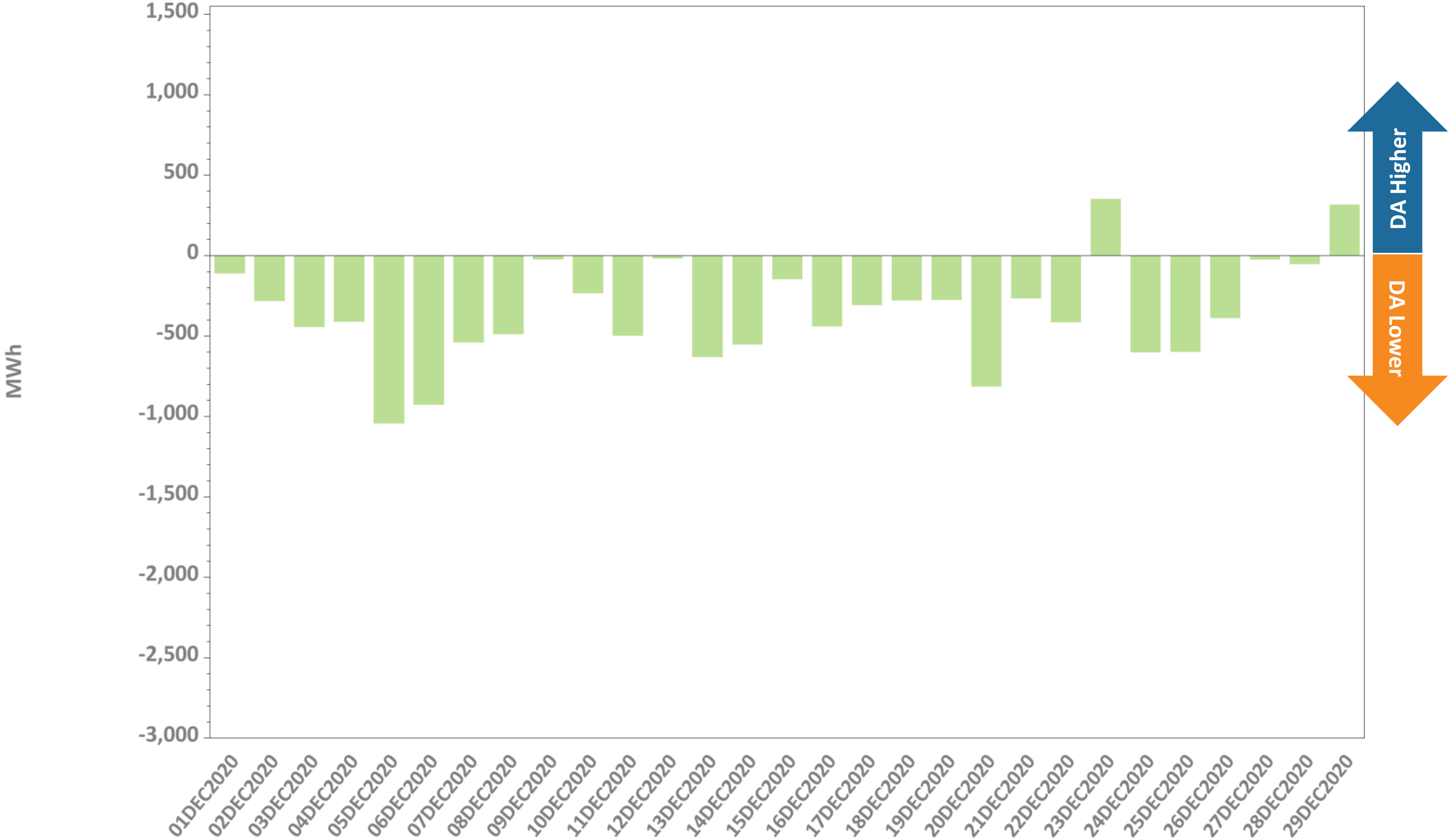
DA Volumes as % of Forecast in Peak Hour





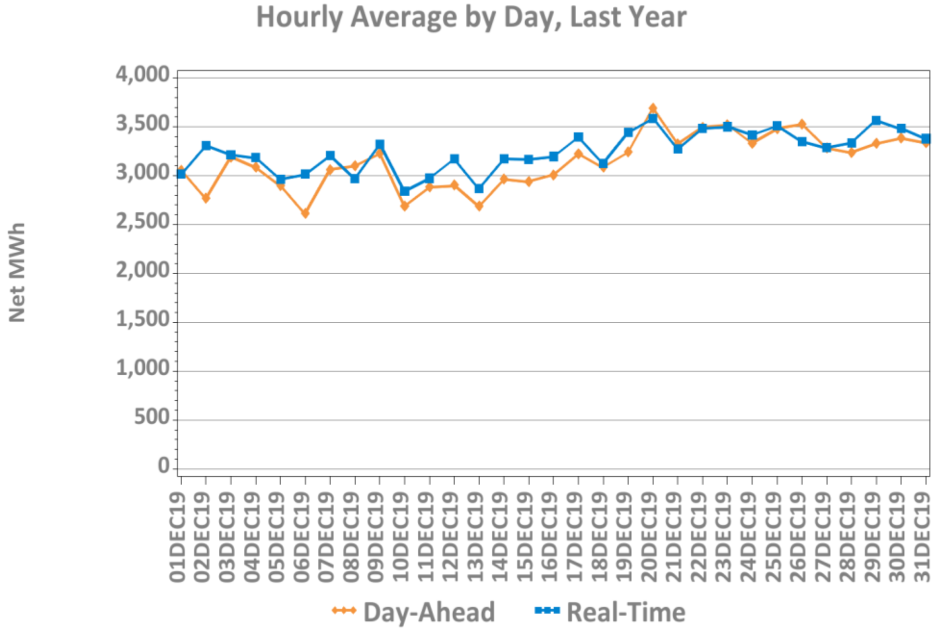
Note: There were two instances of system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) during December. The commitments were both fast start units.

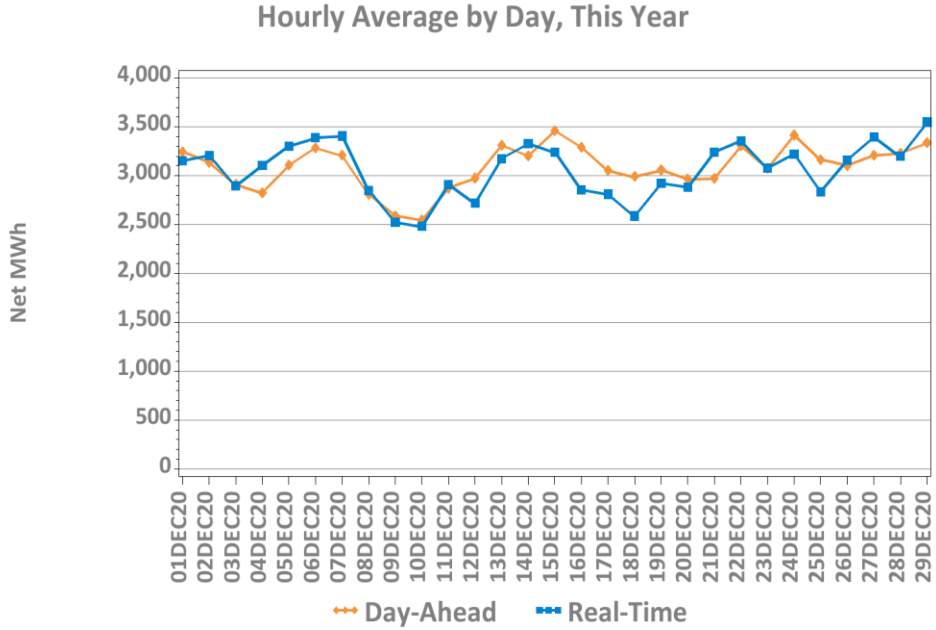
DA Cleared Physical Energy Difference from RT System Load at Peak Hour*



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

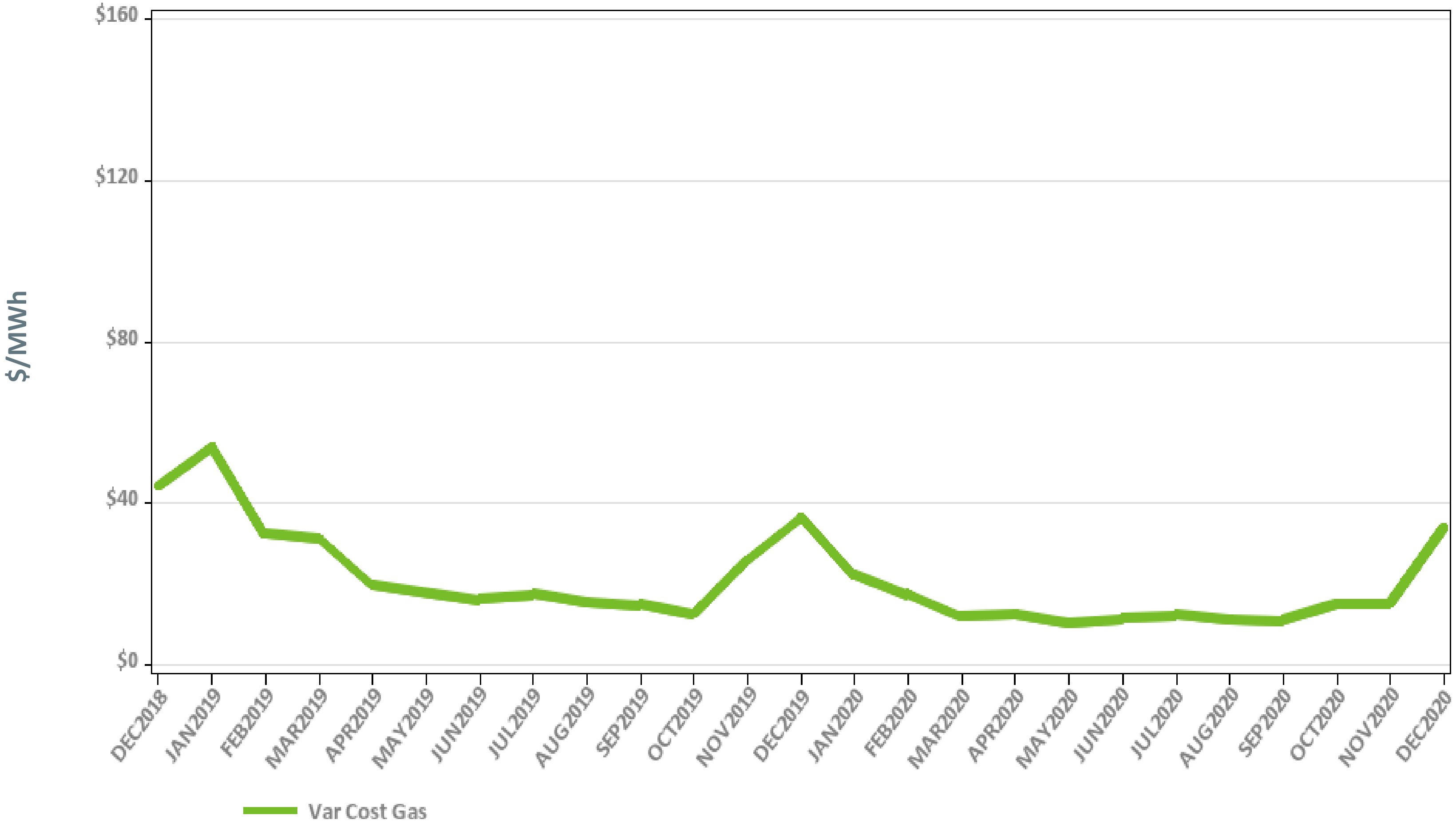
DA vs. RT Net Interchange December 2019 vs. December 2020





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

Variable Production Cost of Natural Gas: Monthly

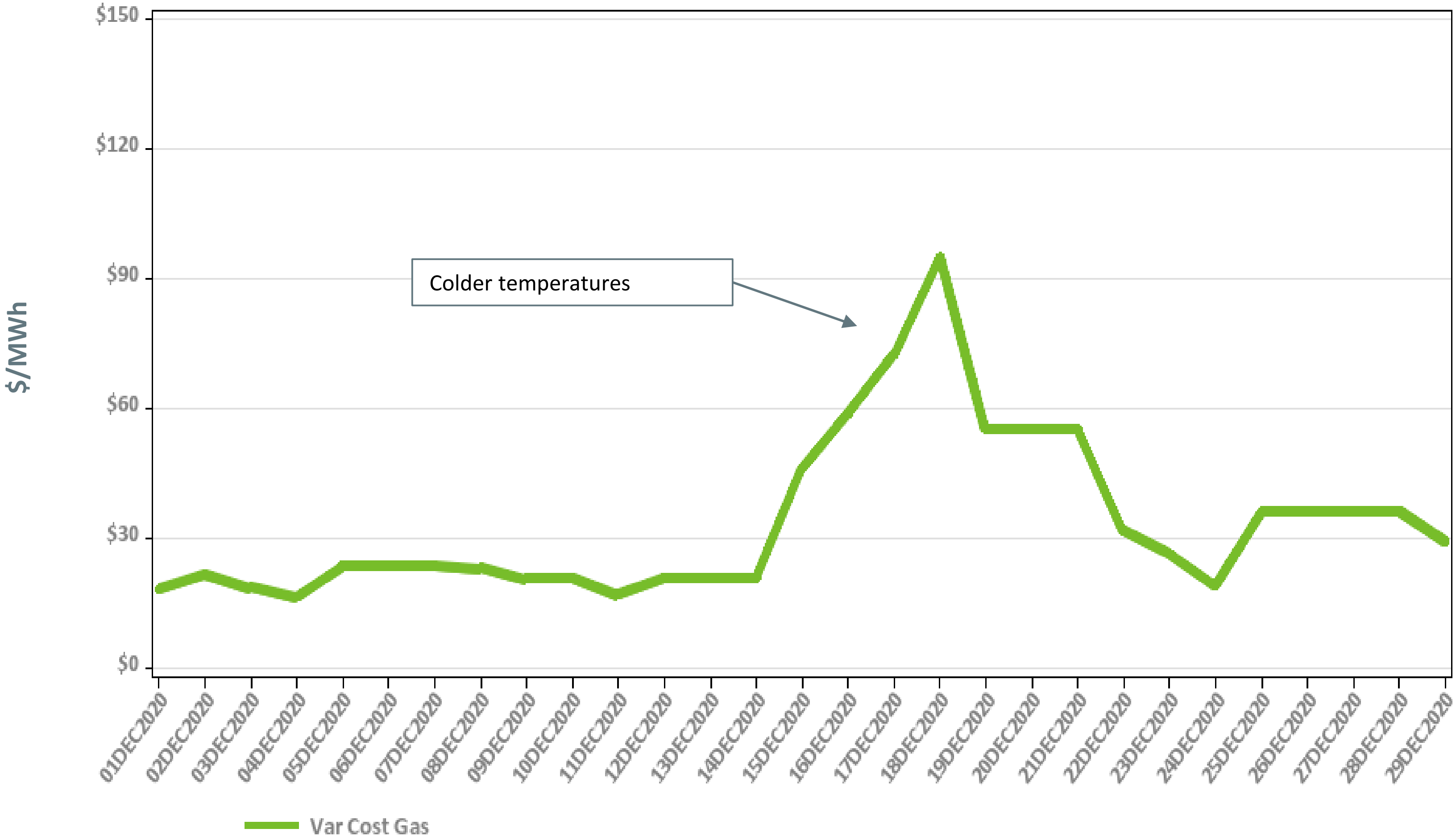


Underlying natural gas data furnished by:

ICE Global markets in clear view

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

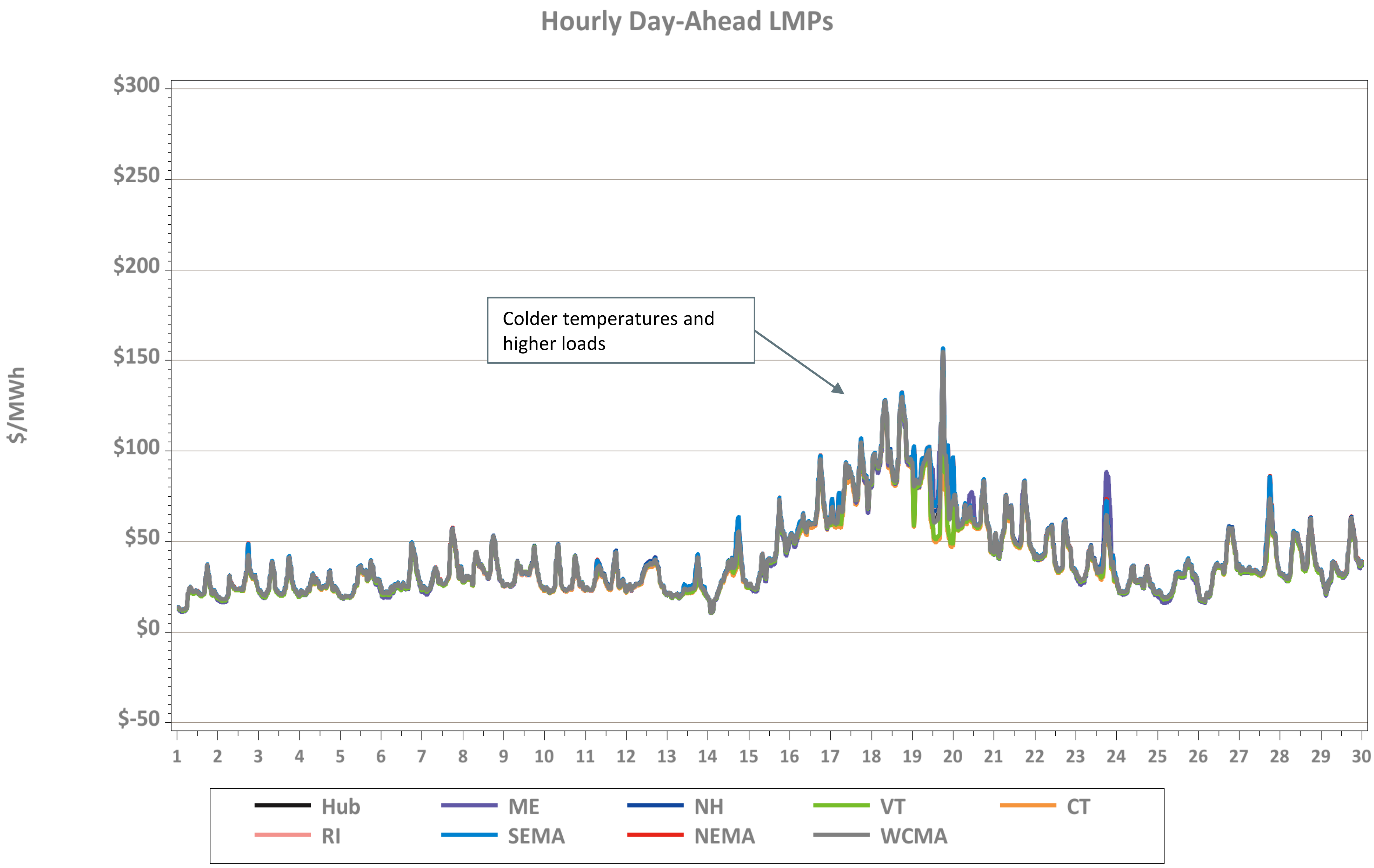
Variable Production Cost of Natural Gas: Daily



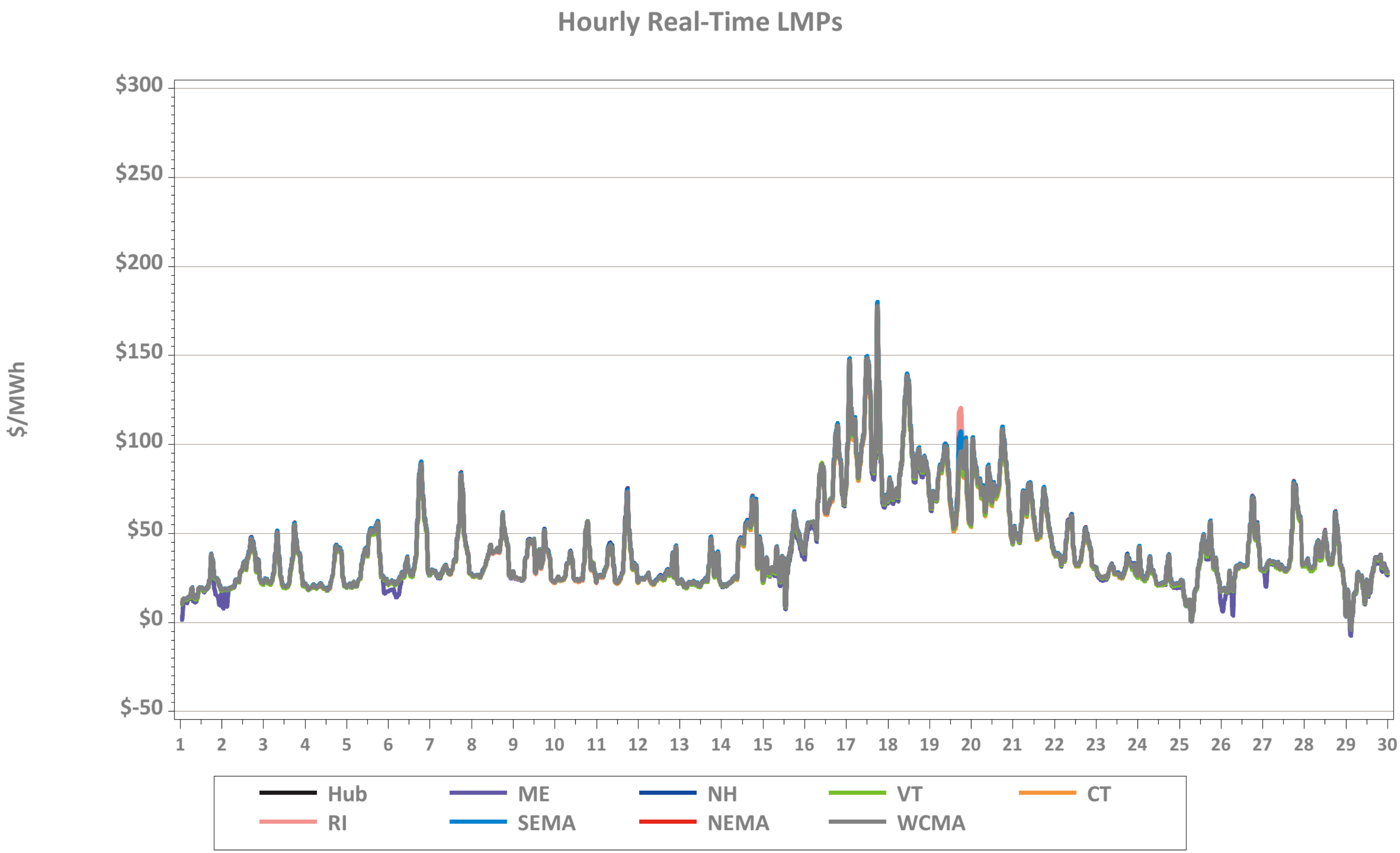
Underlying natural gas data furnished by: ICE Global markets in clear view

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

Hourly DA LMPs, December 1-29, 2020

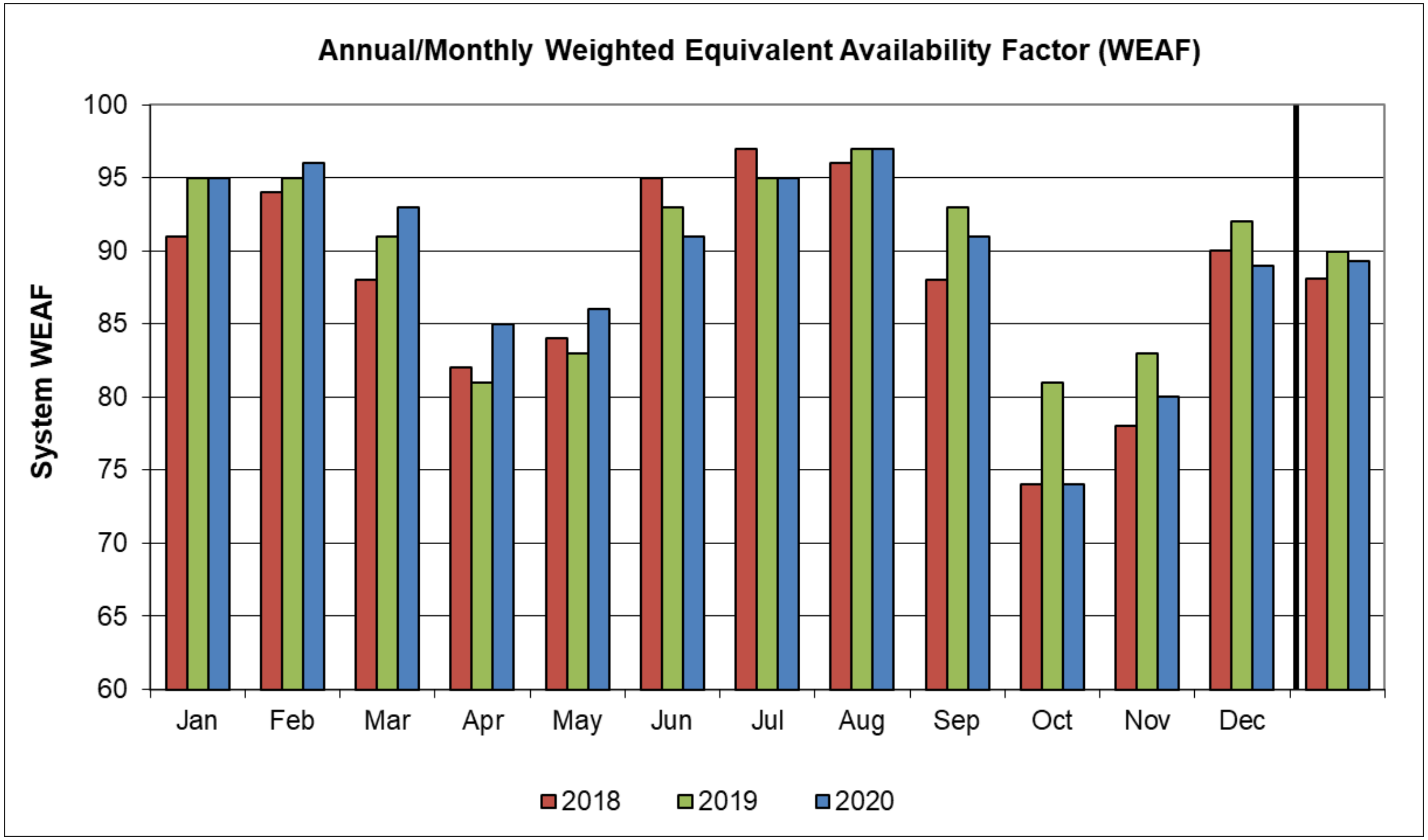


Hourly RT LMPs, December 1-29, 2020



- No Minimum Generation Emergencies were declared during December.

System Unit Availability



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

Data as of 12/28/2020

BACK-UP DETAIL

DEMAND RESPONSE

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

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	79.2	142.0	0.0	221.2
NH	42.0	126.4	0.0	168.3
VT	35.1	135.5	0.0	170.6
CT	107.5	100.8	567.2	775.5
RI	36.0	263.5	0.0	299.5
SEMA	42.4	415.2	0.0	457.6
WCMA	73.9	444.4	26.0	544.2
NEMA	60.2	762.6	0.0	822.8
Total	**476.2**	**2,390.4**	**593.2**	**3,459.8**

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

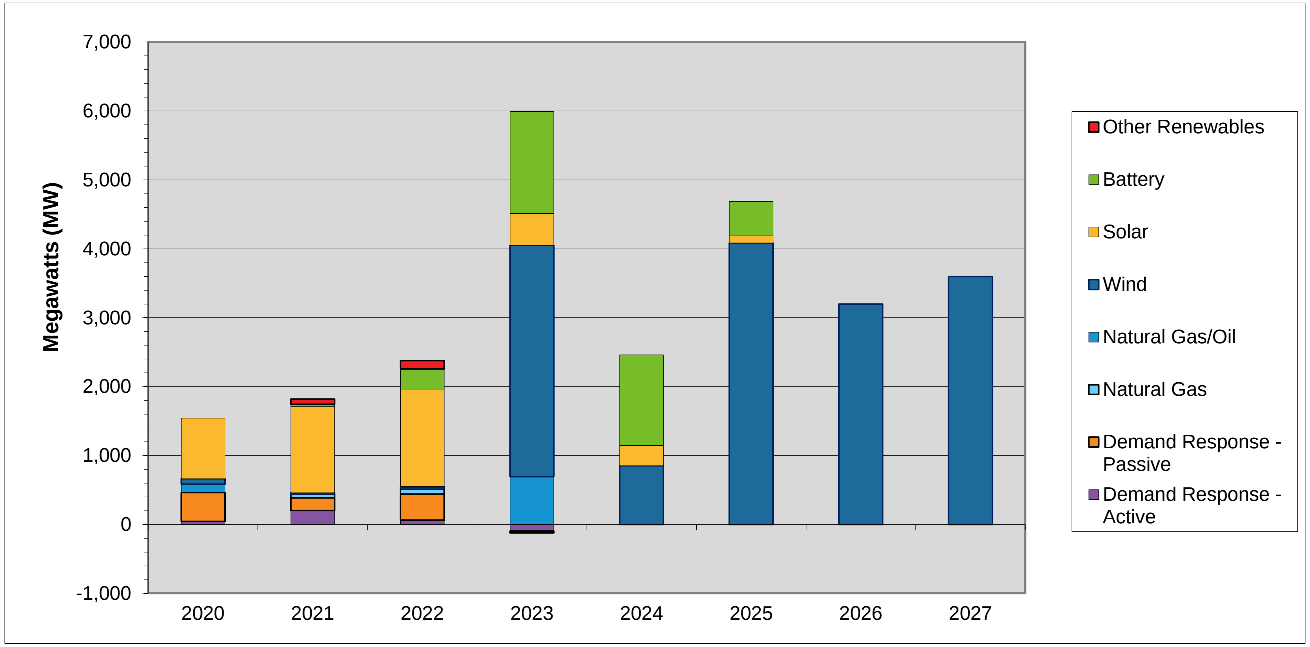
NEW GENERATION

New Generation Update
Based on Queue as of 12/31/20

- Three new projects totaling 130 MW applied for interconnection study since the last update
  - They consist of three new PV projects, with in-service dates ranging from 2021 to 2024
- Two projects went commercial and five were withdrawn, resulting in a net decrease in new generation projects of 795 MW
- In total, 261 generation projects are currently being tracked by the ISO, totaling approximately 24,100 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



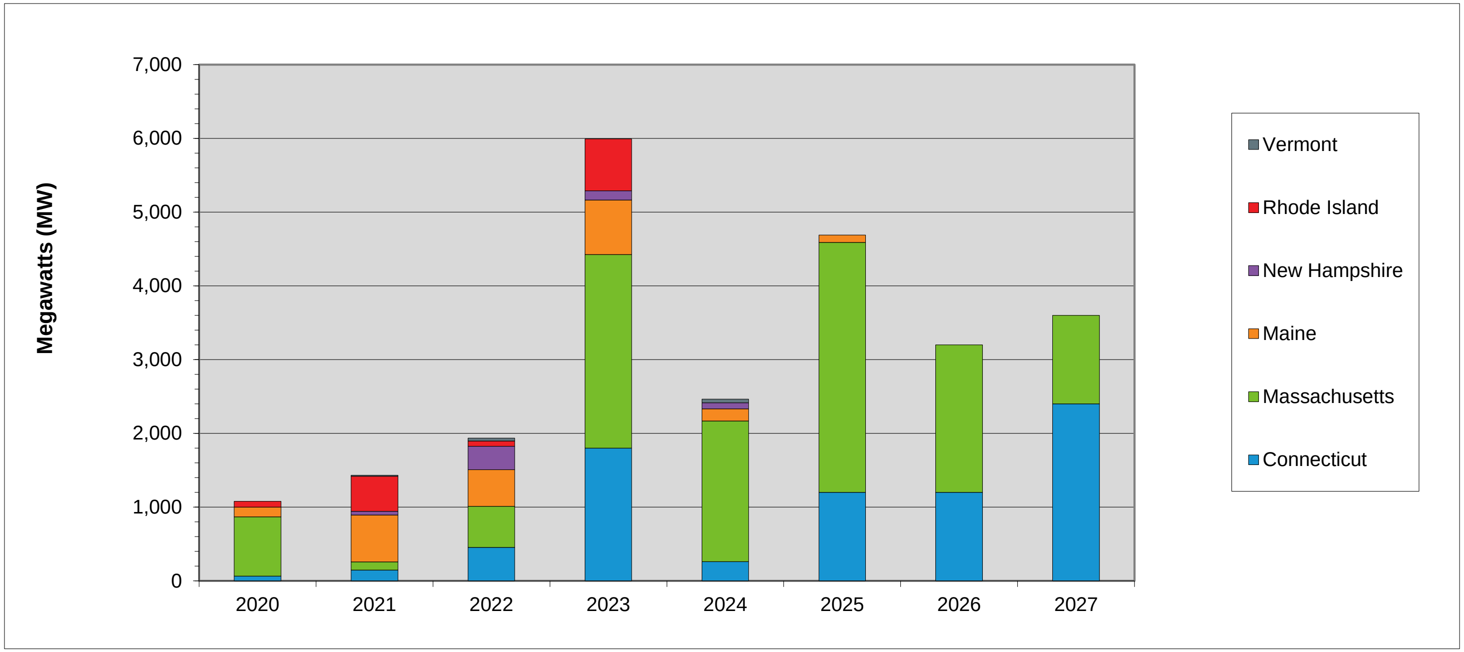
	2020	2021	2022	2023	2024	2025	2026	2027	Total MW	% of Total[1]
Other Renewables	0	76	122	0	0	0	0	0	198	0.8
Battery	0	34	304	1,481	1,316	500	0	0	3,635	14.2
Solar[2]	879	1,251	1,401	461	294	100	0	0	4,386	17.2
Wind	78	19	20	3,355	852	4,087	3,200	3,600	15,211	59.5
Natural Gas/Oil[3]	121	0	16	695	0	0	0	0	832	3.3
Natural Gas	0	53	73	0	0	0	0	0	126	0.5
Demand Response - Passive	422	184	380	-28	0	0	0	0	958	3.7
Demand Response - Active	42	204	62	-94	0	0	0	0	214	0.8
Totals	1,543	1,821	2,378	5,870	2,462	4,687	3,200	3,600	25,561	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

- 2020 values include the 259 MW of generation that went commercial in 2020
- DR reflects changes from the initial FCM Capacity Supply Obligations in 2010-11

Actual and Projected Annual Generator Capacity Additions

By State



	2020	2021	2022	2023	2024	2025	2026	2027	Total MW	% of Total[1]
Vermont	0	15	40	0	50	0	0	0	105	0.4
Rhode Island	78	476	73	704	0	0	0	0	1,331	5.5
New Hampshire	0	50	316	126	81	0	0	0	573	2.3
Maine	133	635	495	738	164	100	0	0	2,265	9.3
Massachusetts	802	110	560	2,624	1,907	3,387	2,000	1,200	12,590	51.6
Connecticut	65	147	452	1,800	260	1,200	1,200	2,400	7,524	30.9
Totals	**1,078**	**1,433**	**1,936**	**5,992**	**2,462**	**4,687**	**3,200**	**3,600**	**24,388**	**100.0**

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

- 2020 values include the 259 MW of generation that went commercial in 2020

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	20	3,635	0	0	20	3,635
Fuel Cell	4	54	1	10	3	44
Hydro	3	99	2	71	1	28
Natural Gas	7	126	0	0	7	126
Natural Gas/Oil	5	787	1	14	4	773
Nuclear	1	37	0	0	1	37
Solar	198	4,250	11	173	187	4,077
Wind	22	15,133	1	15	21	15,118
Total	261	24,129	17	291	244	23,838

- 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	222	8,042	12	239	210	7,803
Wind Turbine	22	15,133	1	15	21	15,118
Total	261	24,129	17	291	244	23,838

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

New Generation Projection

By Operating Type and Fuel Type

	Total		Baseload		Intermediate		Peaker		Wind Turbine	
Unit Type	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**
Biomass/Wood Waste	1	8	1	8	0	0	0	0	0	0
Battery Storage	20	3,635	0	0	0	0	20	3,635	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	7	126	0	0	6	120	1	6	0	0
Natural Gas/Oil	5	787	0	0	3	702	2	85	0	0
Nuclear	1	37	1	37	0	0	0	0	0	0
Solar	198	4,250	0	0	0	0	198	4,250	0	0
Wind	22	15,133	0	0	0	0	0	0	22	15,133
Total	261	24,129	8	132	9	822	222	8,042	22	15,133

- 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				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		
	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		
	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.

Active/Passive Demand Response

CSO Totals by Commitment Period

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

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

What are Daily NCPC Payments?

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

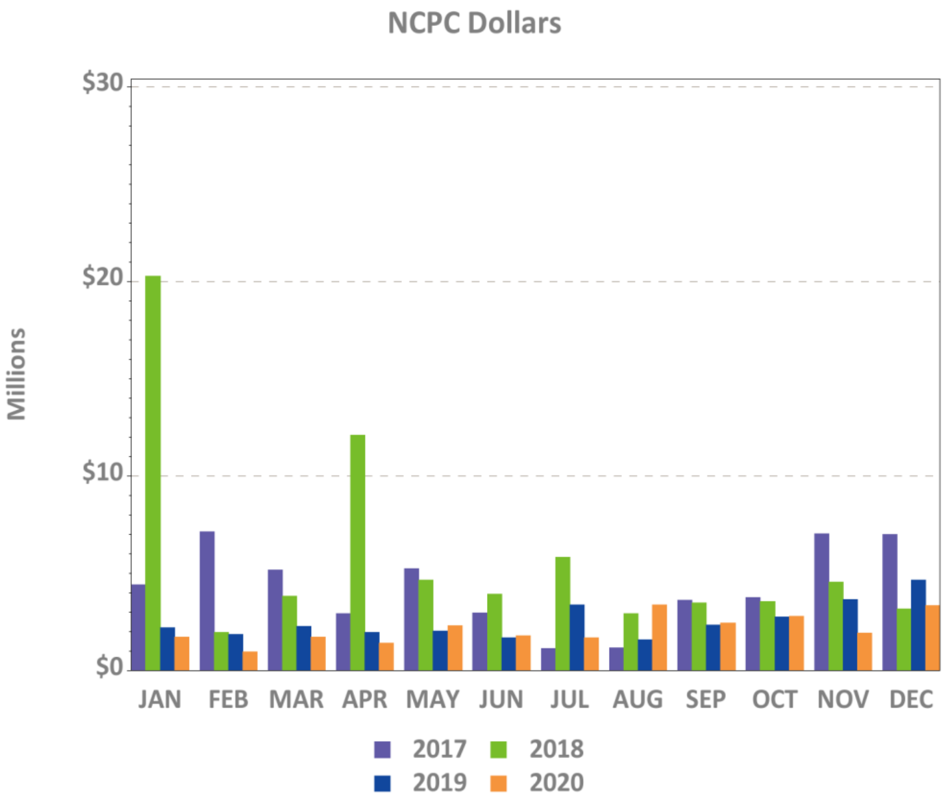
Definitions

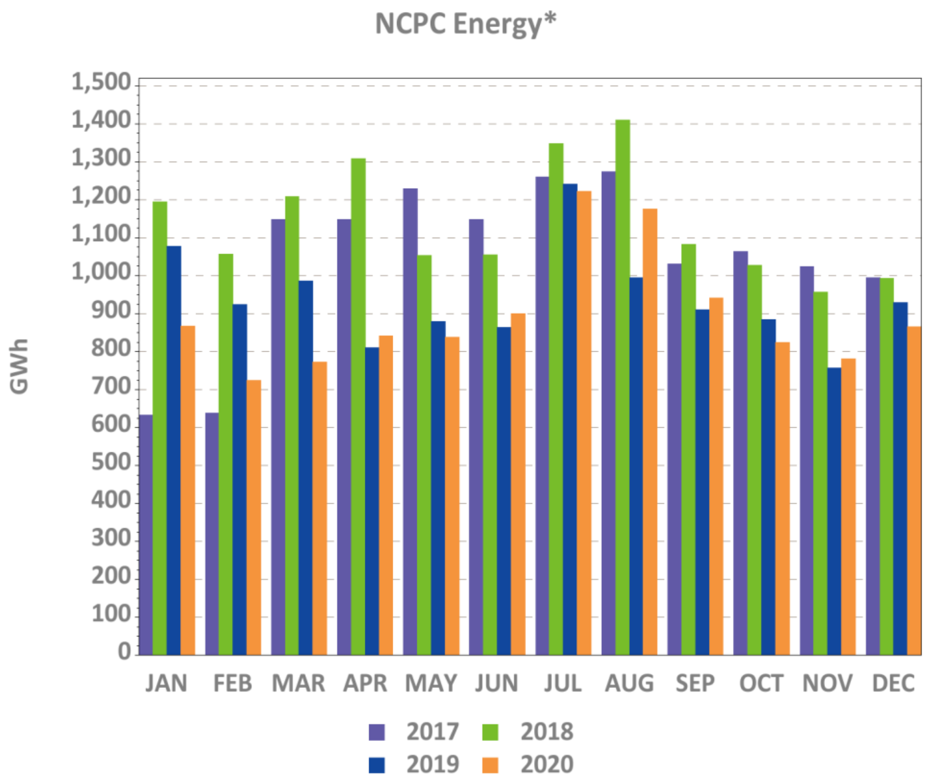
1^{st} Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2^{nd} Contingency NCPC Payments	Reliability costs paid to resources providing capacity in constrained areas to respond to a local second contingency. They are committed based on 2^{nd} 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).

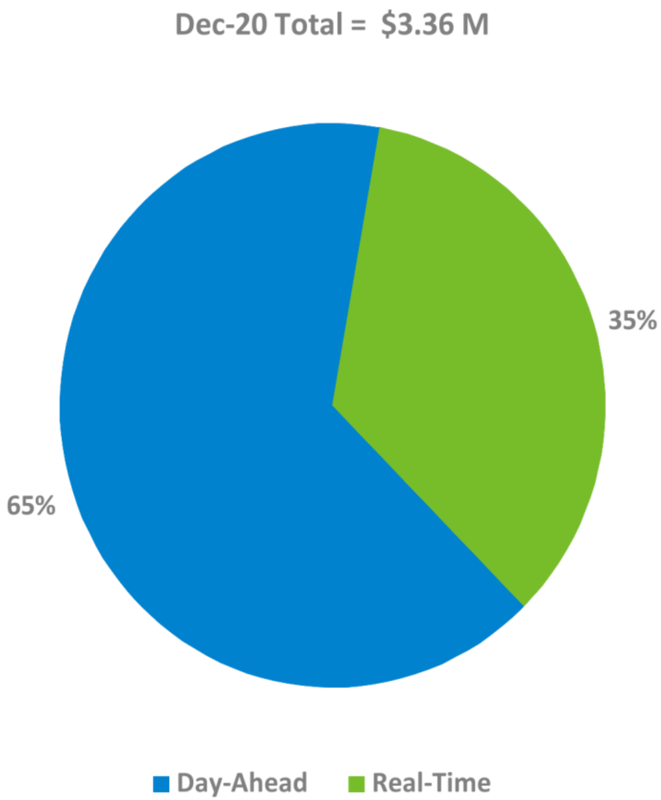
Year-Over-Year Total NCPC Dollars and Energy

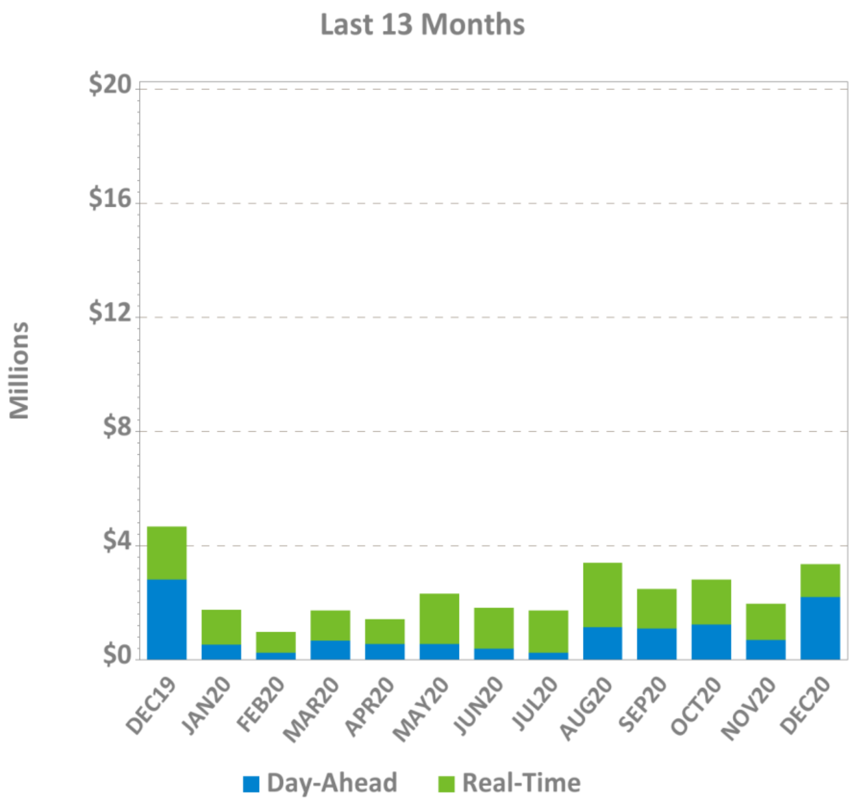




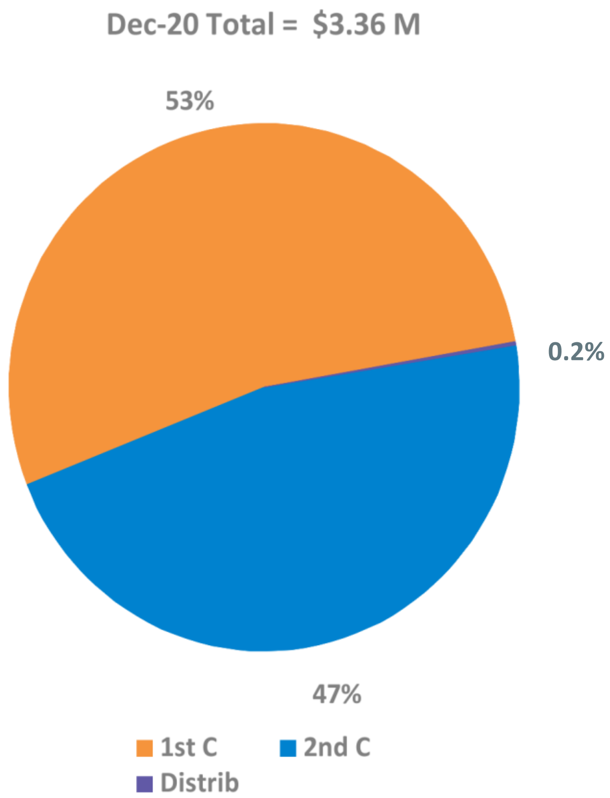
*** NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

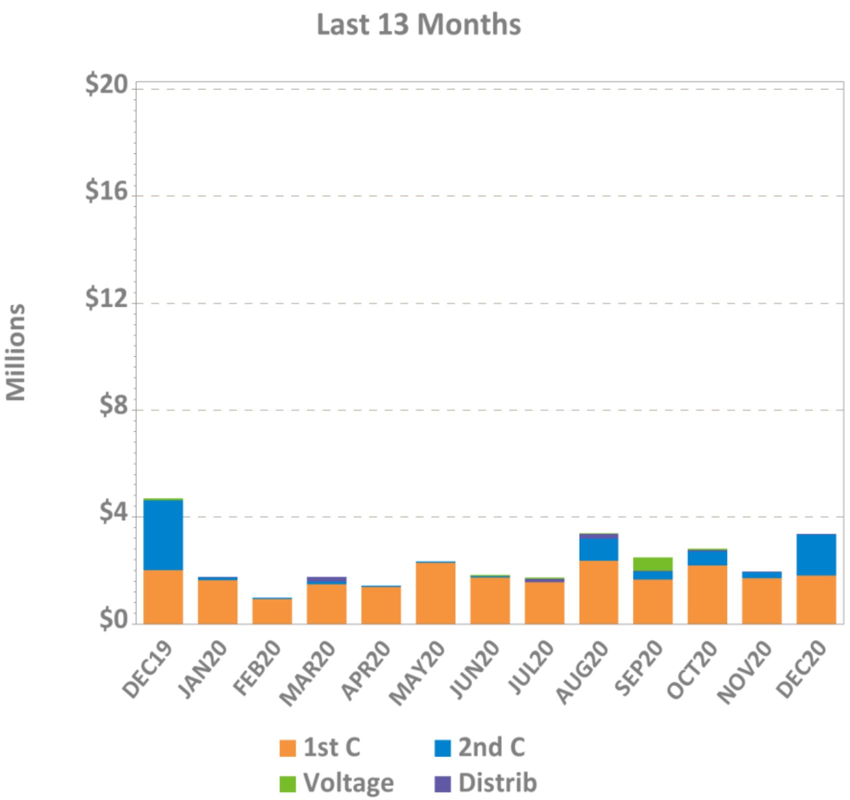
DA and RT NCPC Charges





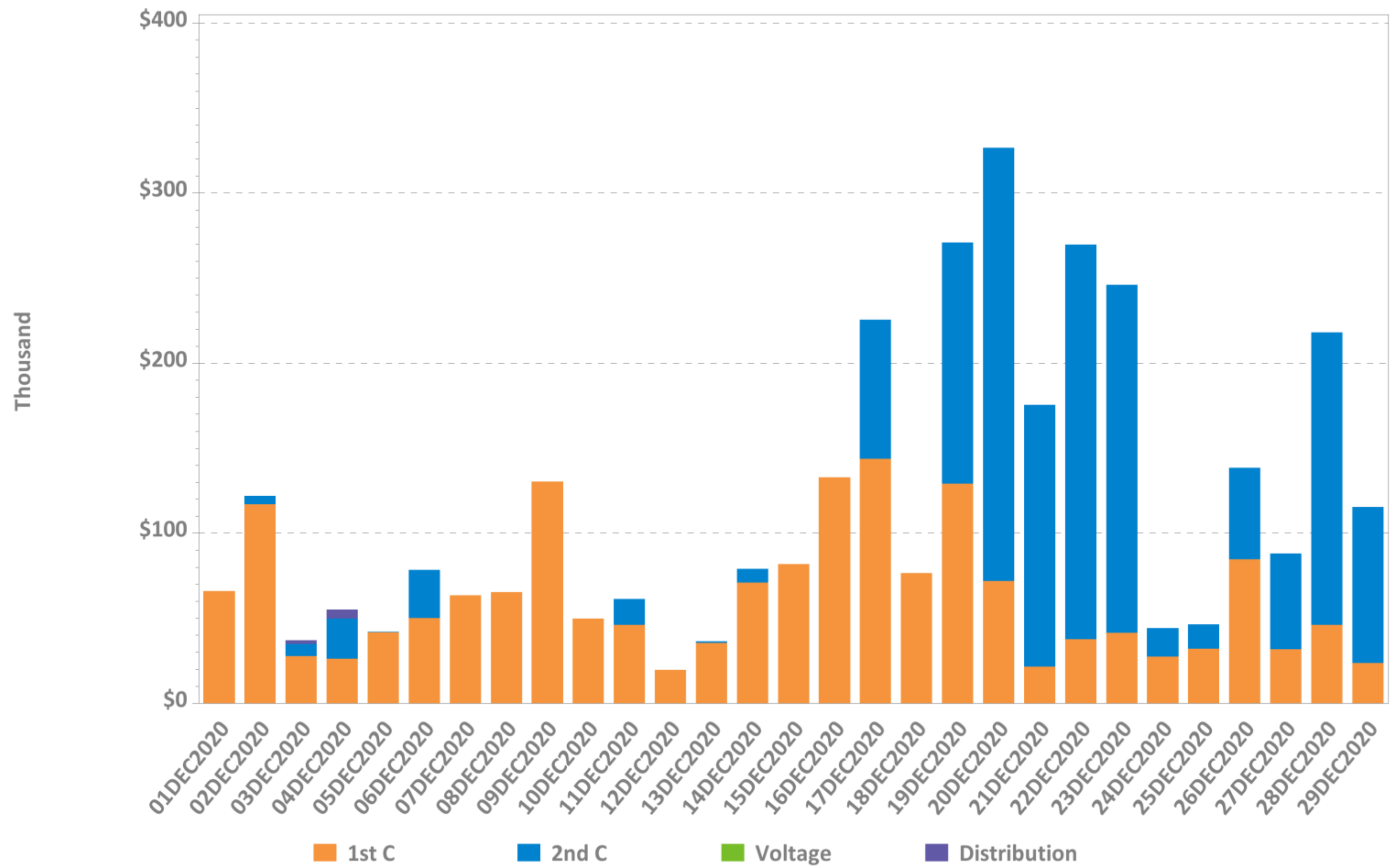
NCPC Charges by Type



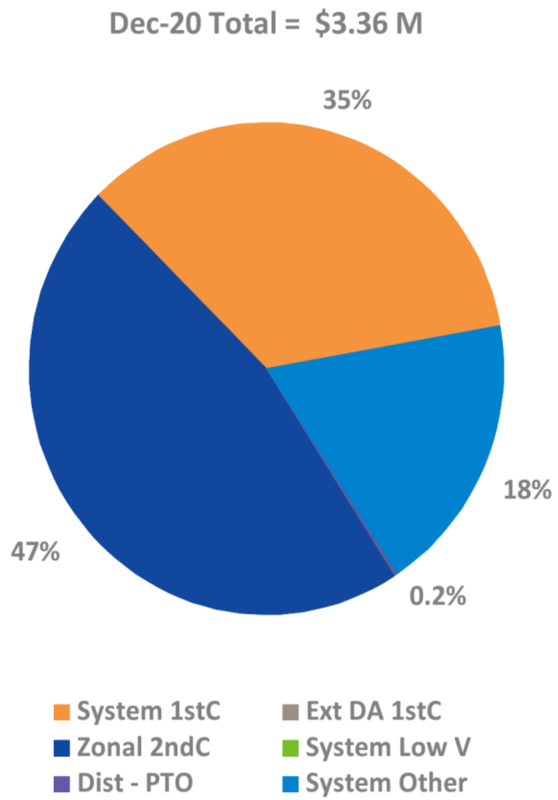


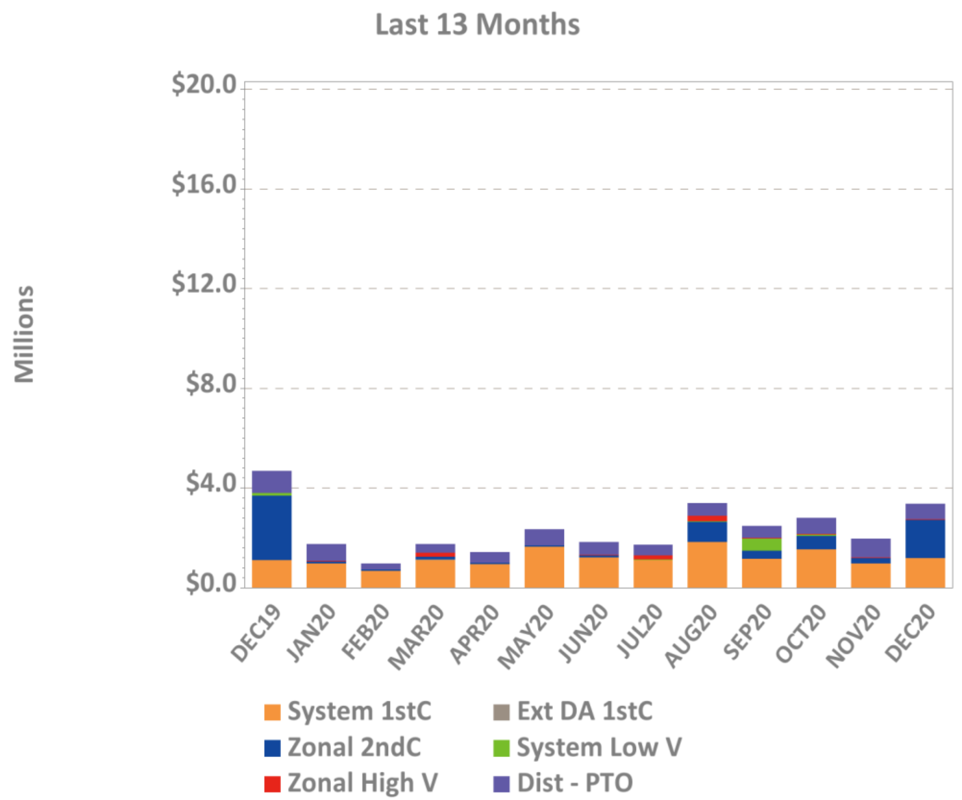
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



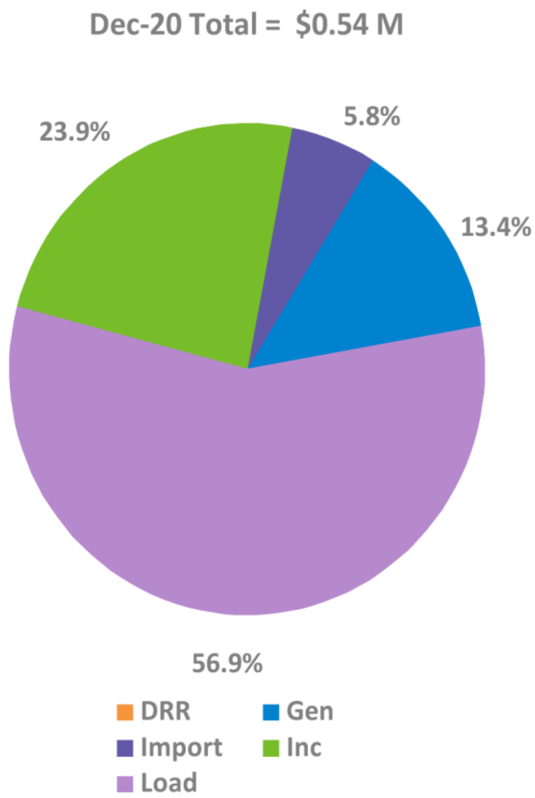
NCPC Charges by Allocation

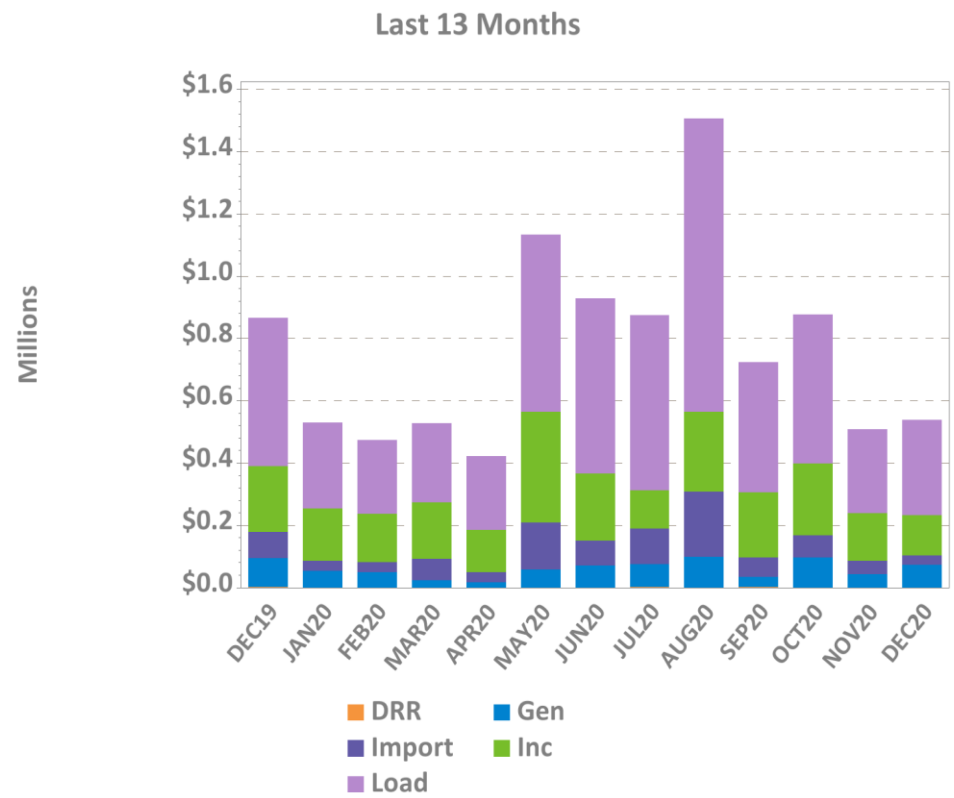




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

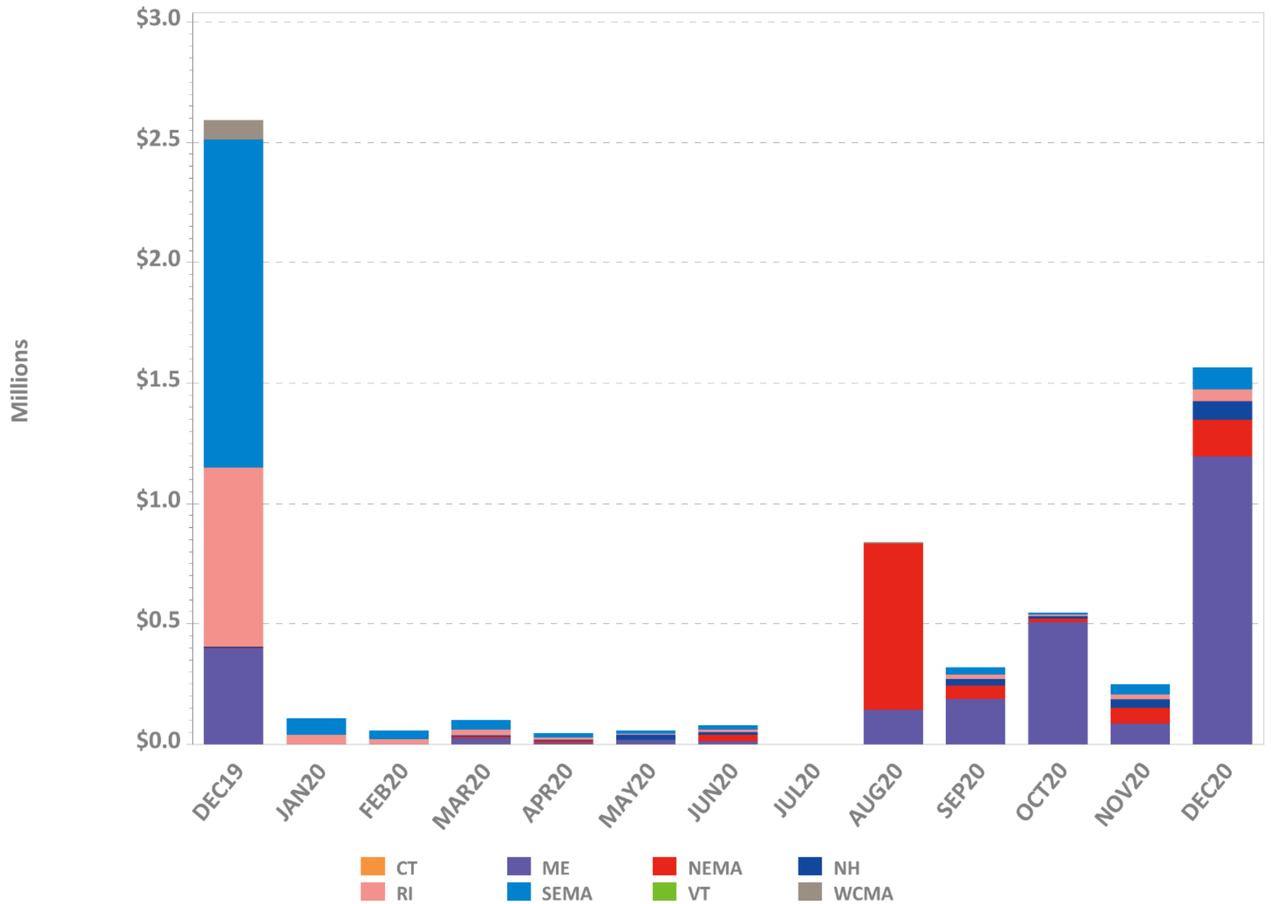
RT First Contingency Charges by Deviation Type





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

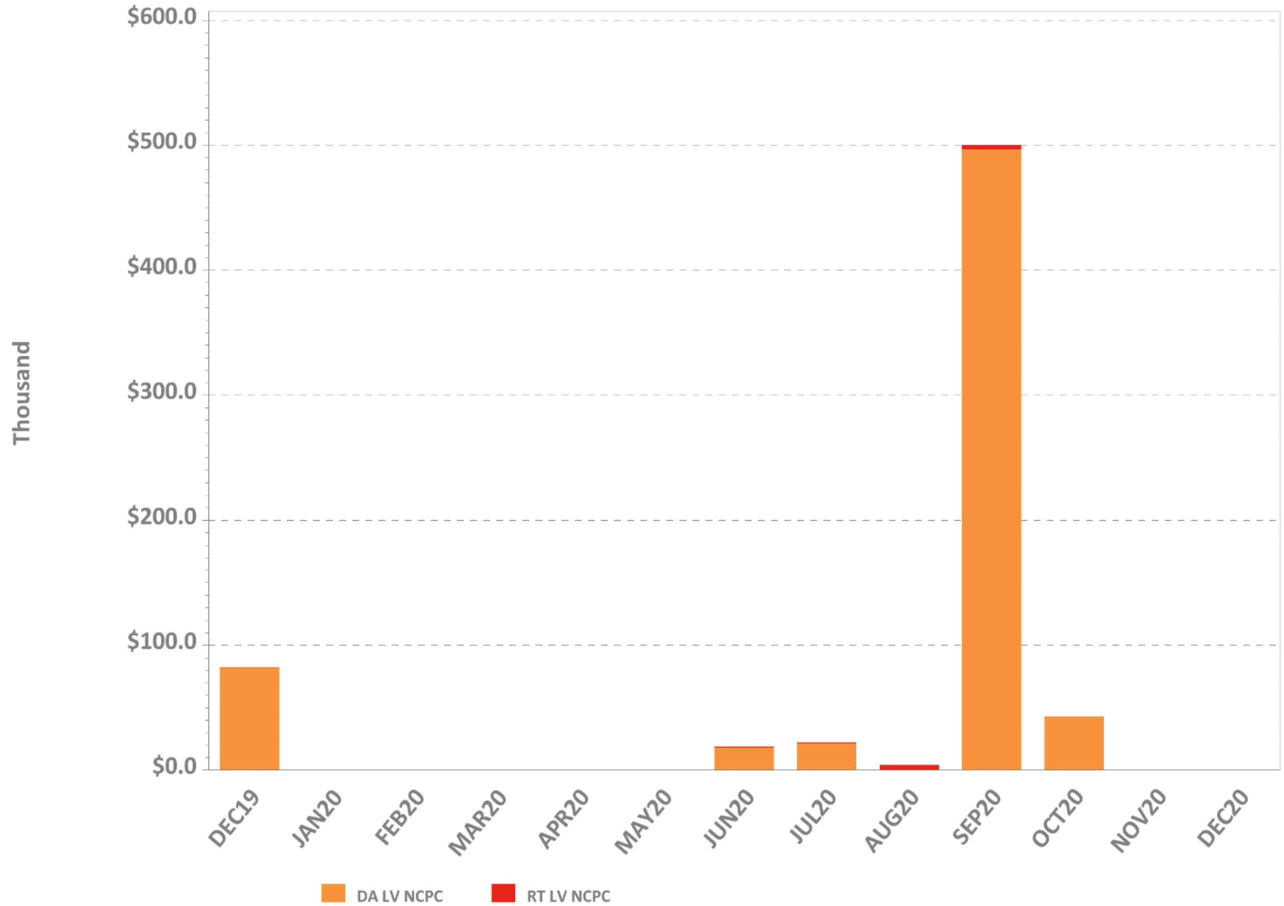
LSCPR Charges by Reliability Region



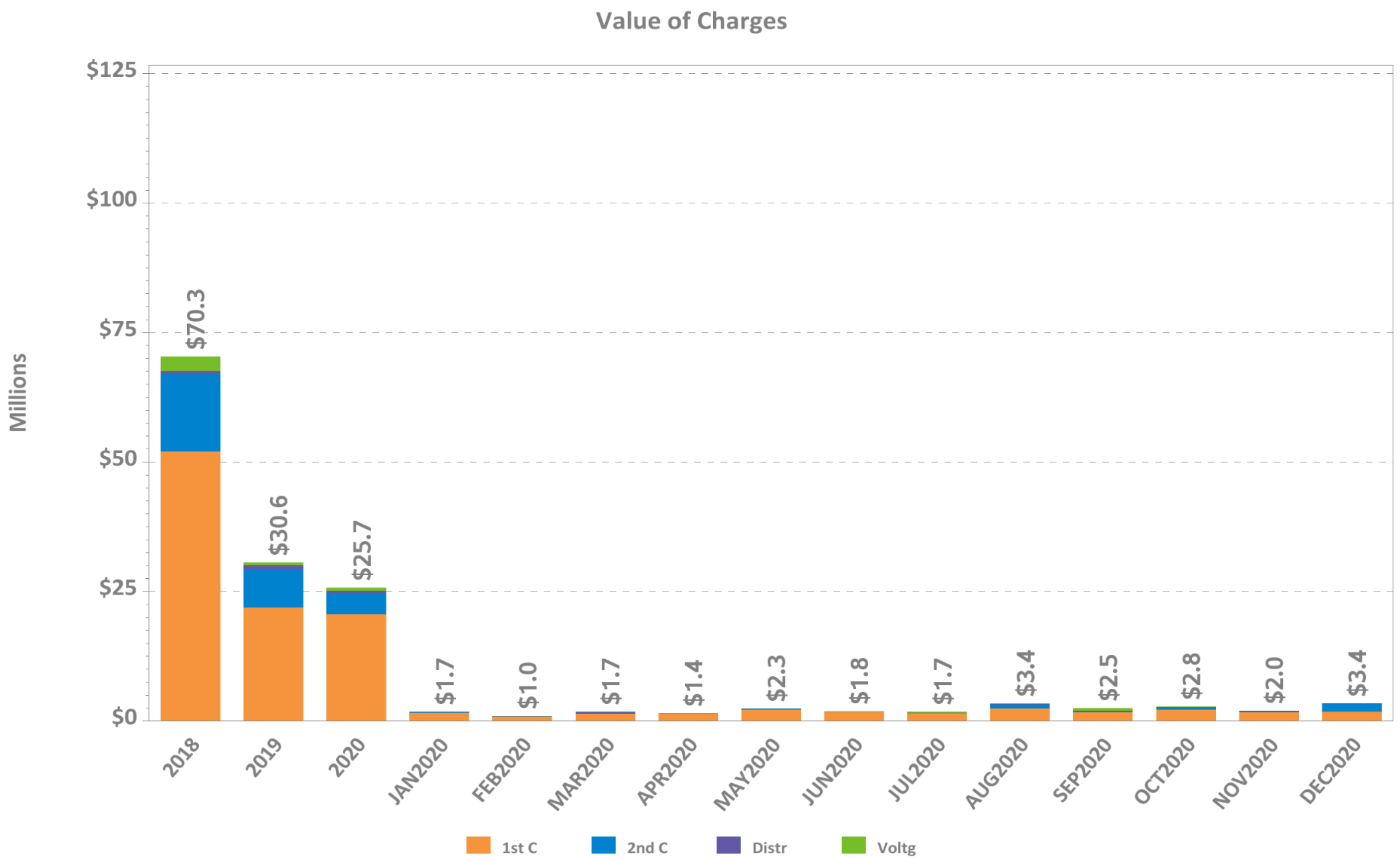
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

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

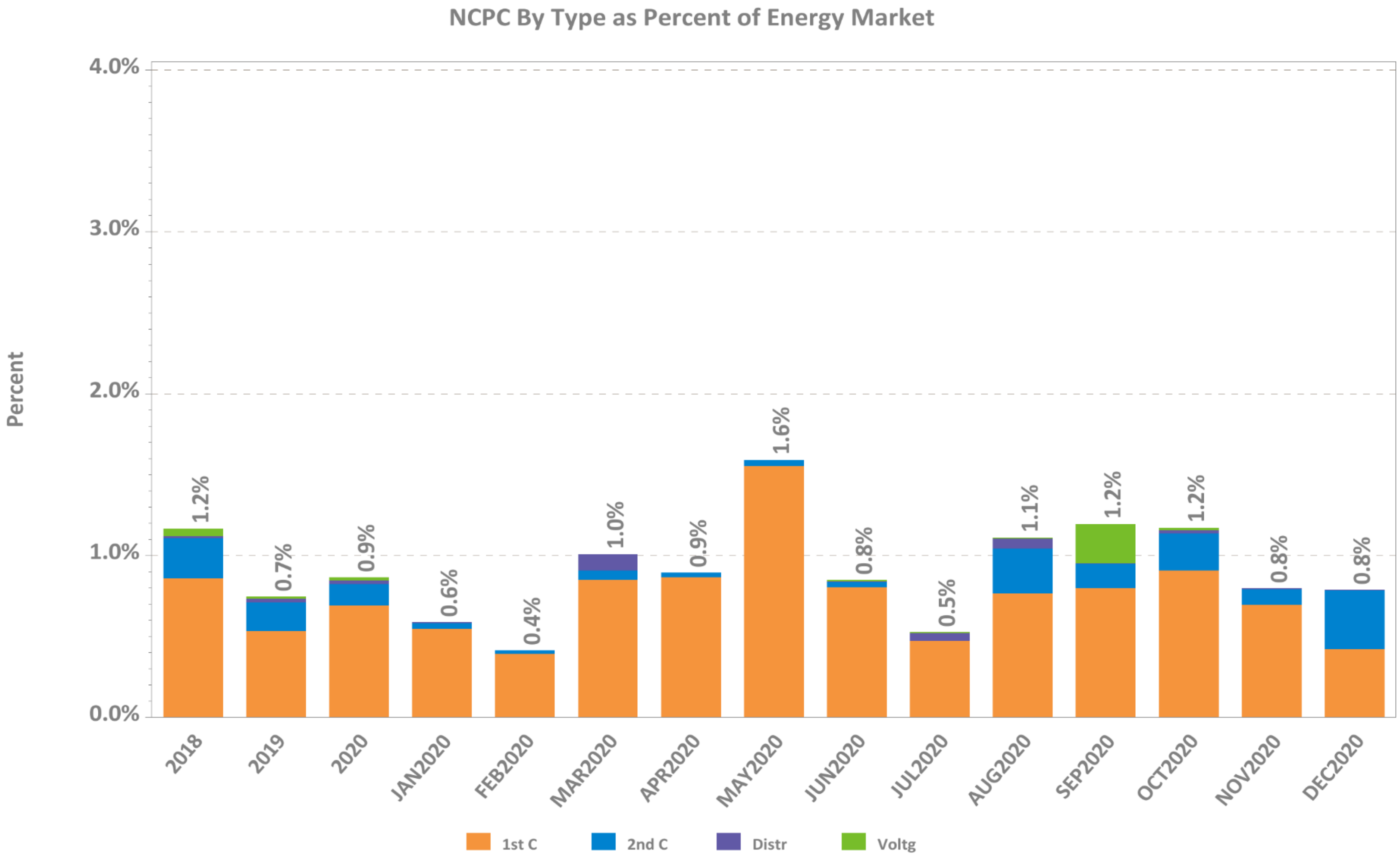
NCPC Charges for Voltage Support and High Voltage Control



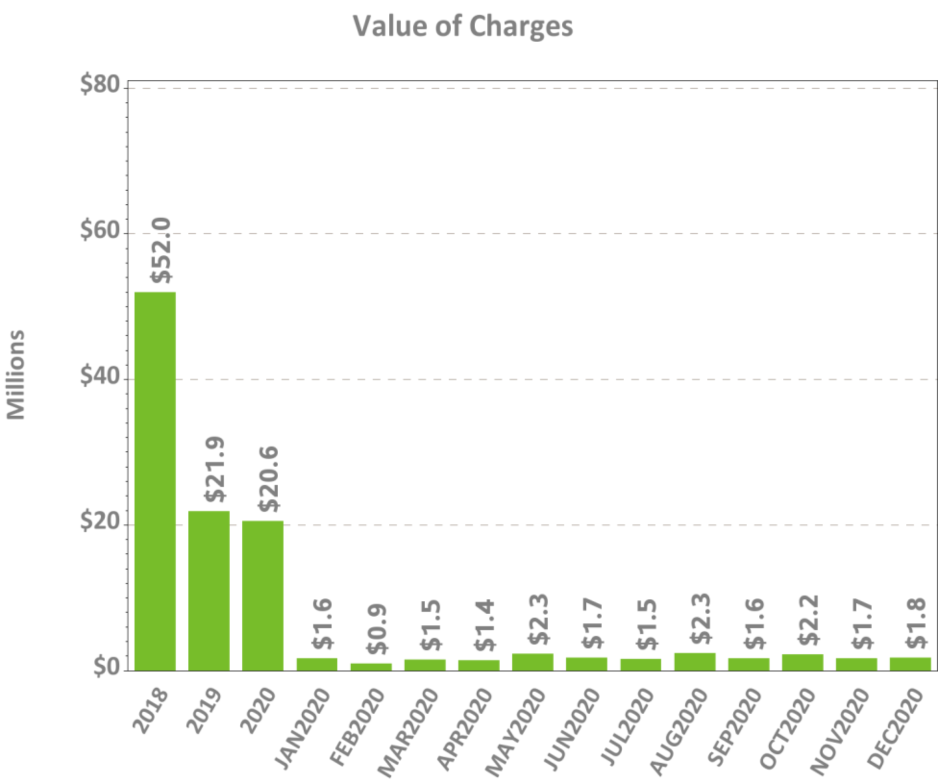
NCPC Charges by Type

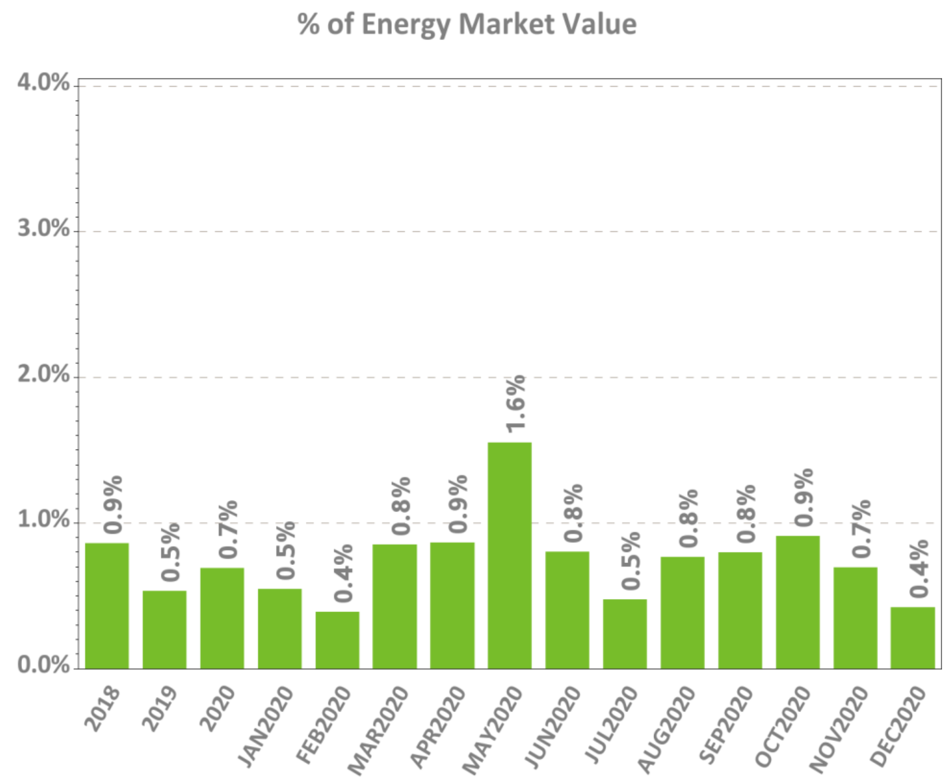


NCPC Charges as Percent of Energy Market



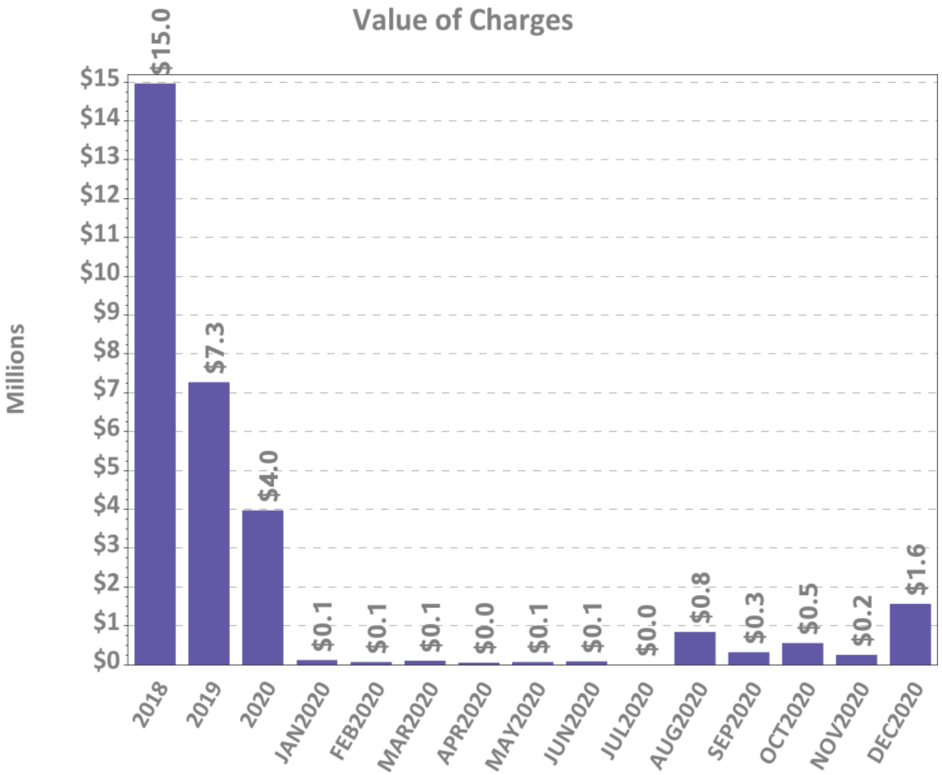
First Contingency NCPC Charges

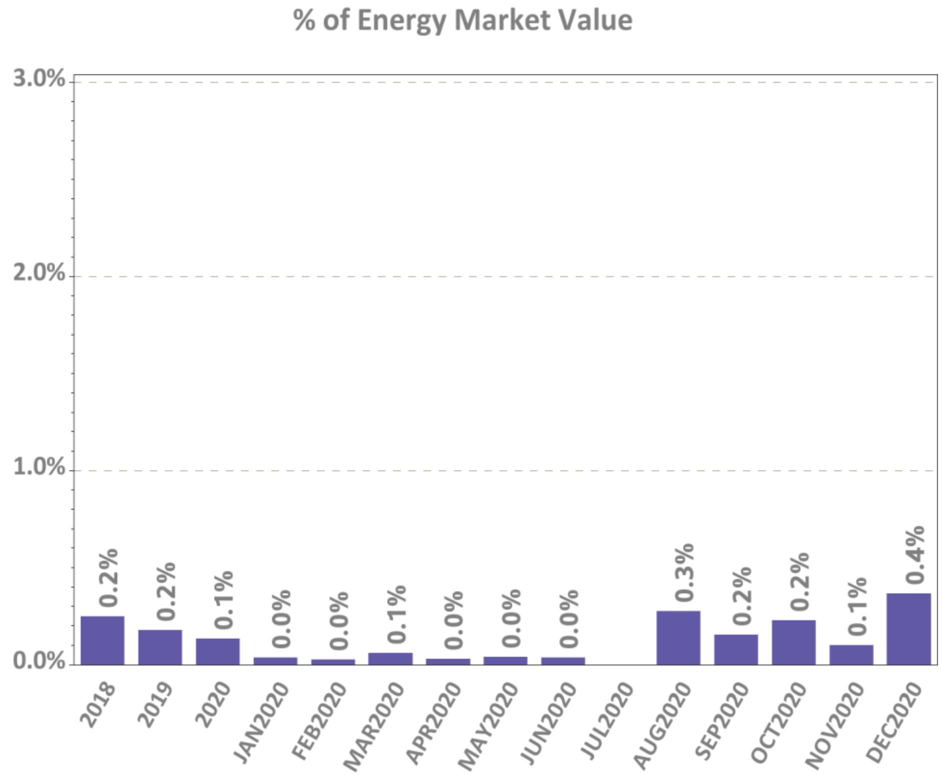




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

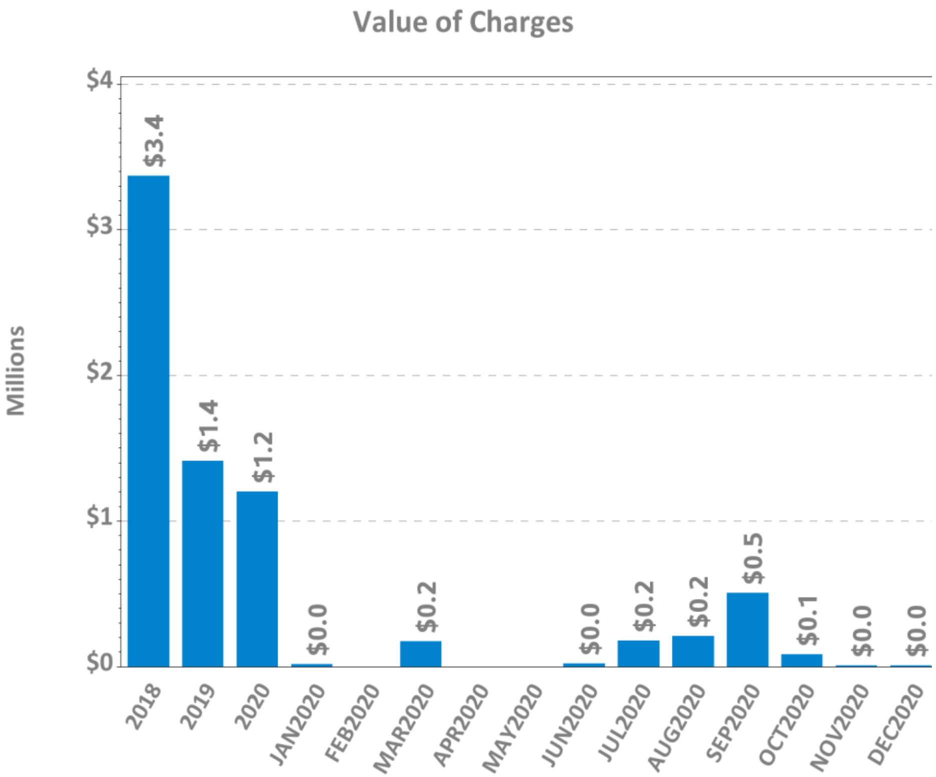
Second Contingency NCPC Charges

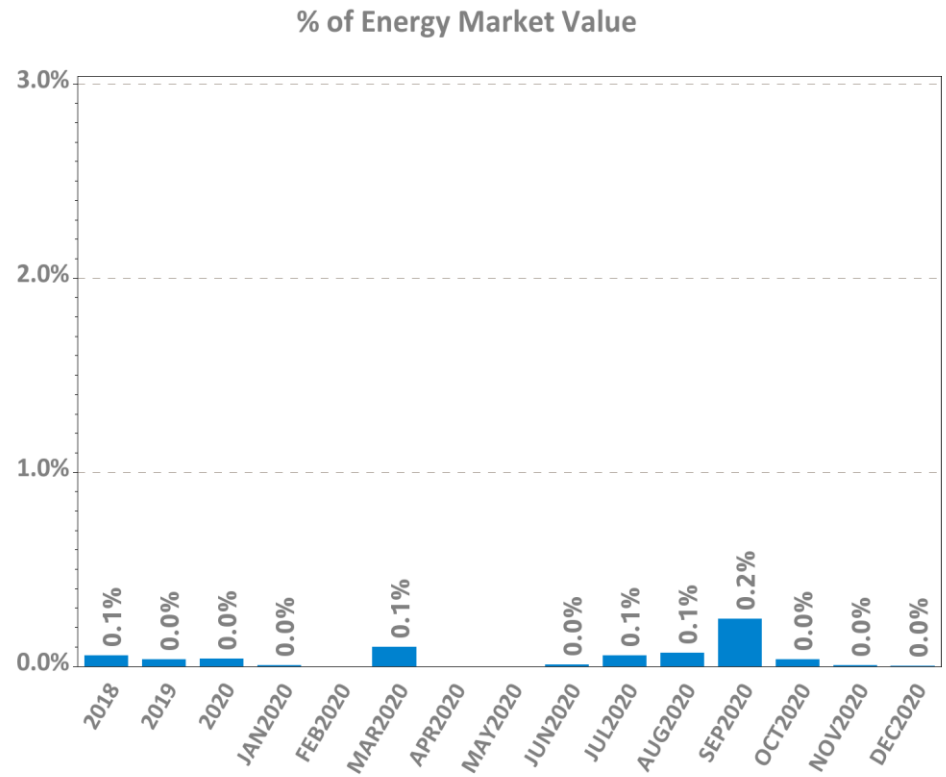




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

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

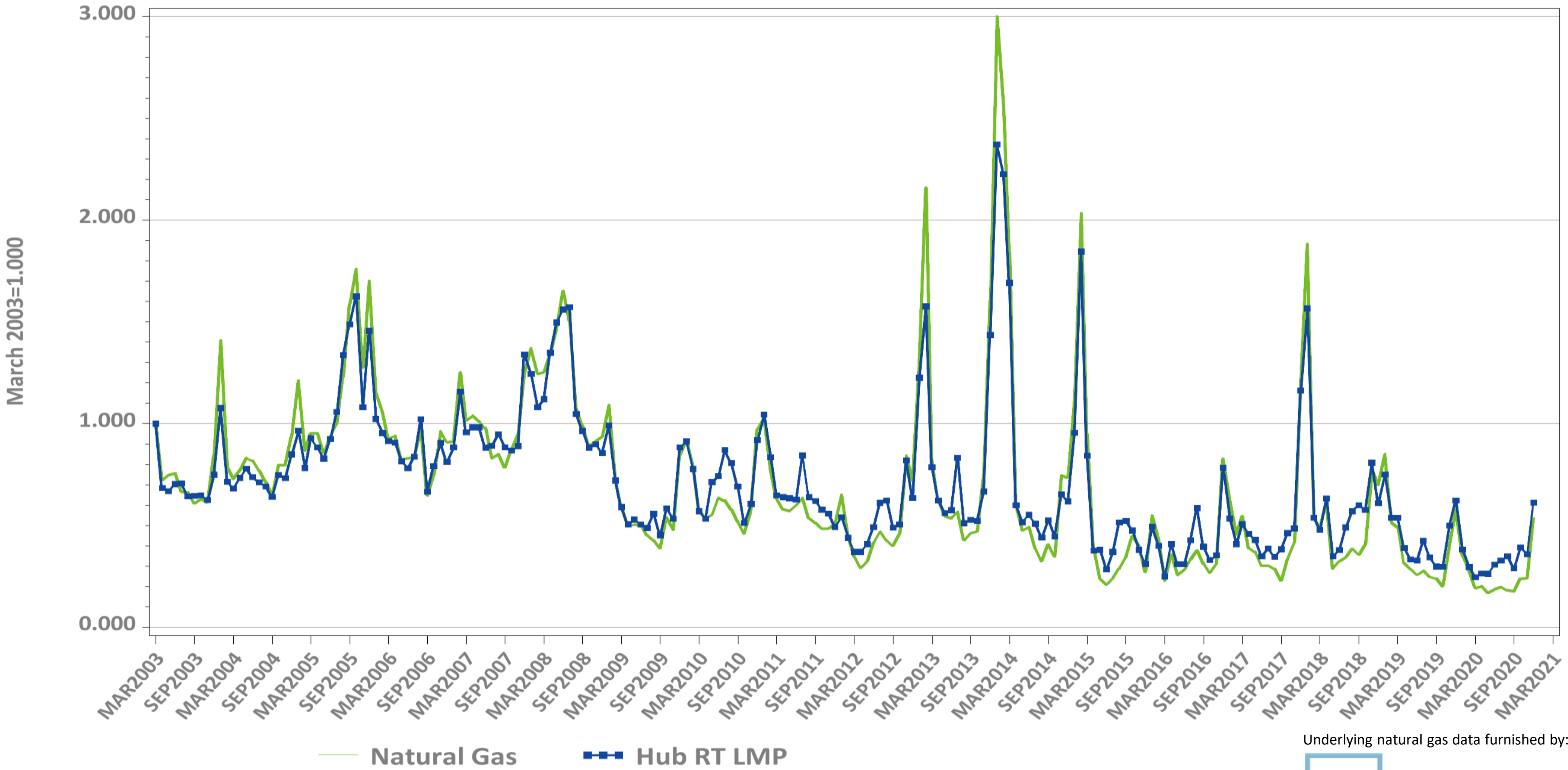
DA vs. RT LMPs ($/MWh)

Arithmetic Average

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

December-19	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$41.22	$39.99	$40.12	$40.80	$39.97	$41.21	$41.80	$40.98	$40.98
Real-Time	$42.98	$41.95	$41.38	$42.58	$41.51	$42.95	$43.20	$42.75	$42.77
RT Delta %	4.3%	4.9%	3.1%	4.4%	3.8%	4.2%	3.4%	4.3%	4.4%
December-20	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$41.20	$38.80	$40.41	$40.91	$39.36	$40.92	$41.27	$40.50	$40.60
Real-Time	$42.34	$40.98	$41.07	$42.08	$41.14	$42.13	$42.42	$41.97	$42.04
RT Delta %	2.8%	5.6%	1.6%	2.9%	4.5%	3.0%	2.8%	3.6%	3.5%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	-0.1%	-3.0%	0.7%	0.3%	-1.5%	-0.7%	-1.3%	-1.2%	-0.9%
Yr over Yr RT	-1.5%	-2.3%	-0.7%	-1.2%	-0.9%	-1.9%	-1.8%	-1.8%	-1.7%

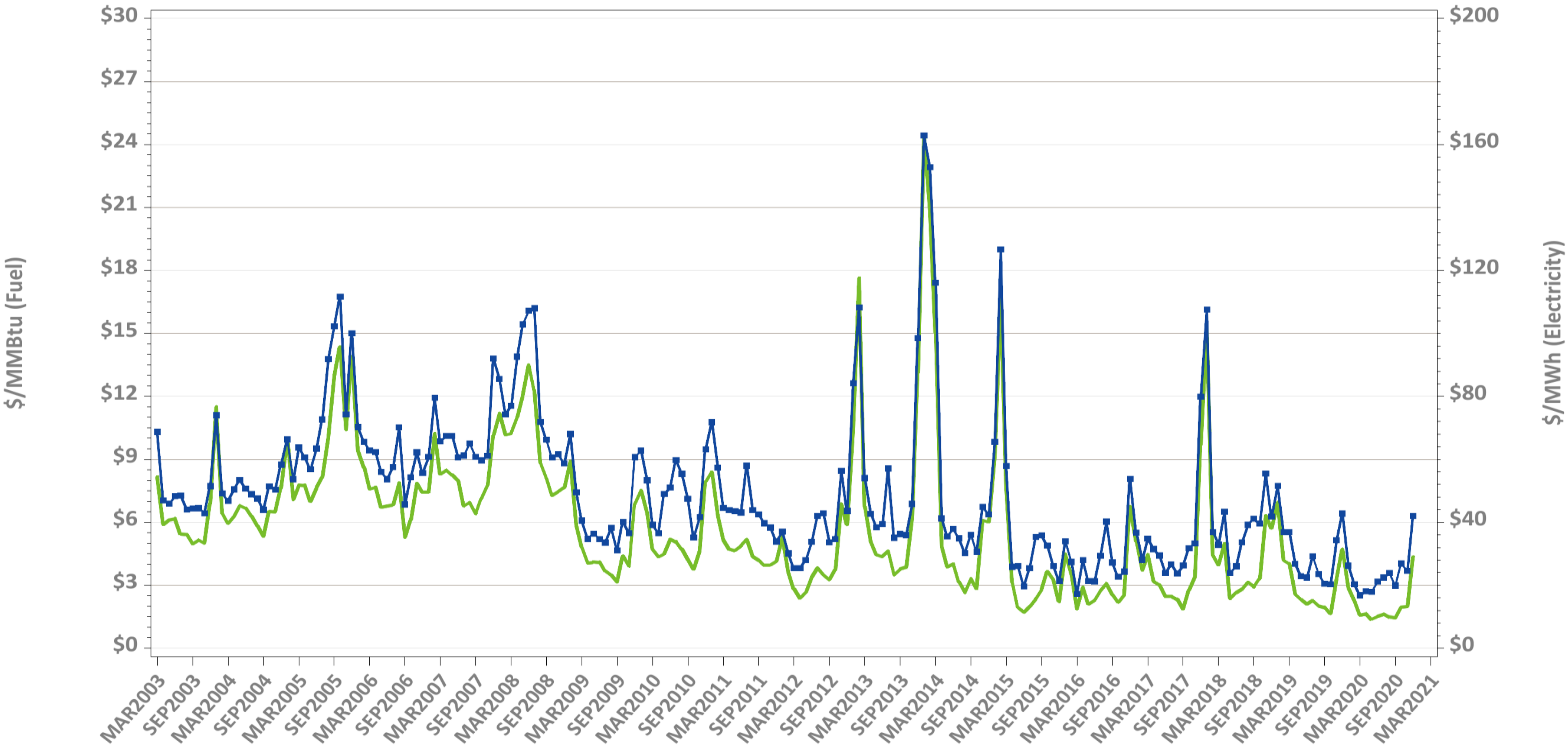
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ICE Global markets in clear view

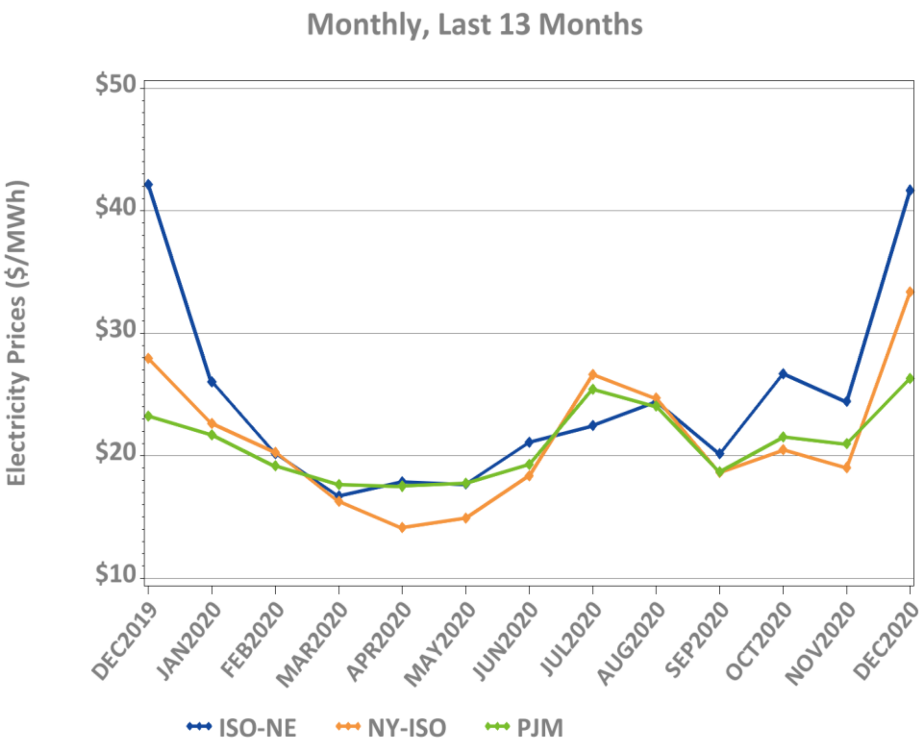
Monthly Average Fuel Price and RT Hub LMP



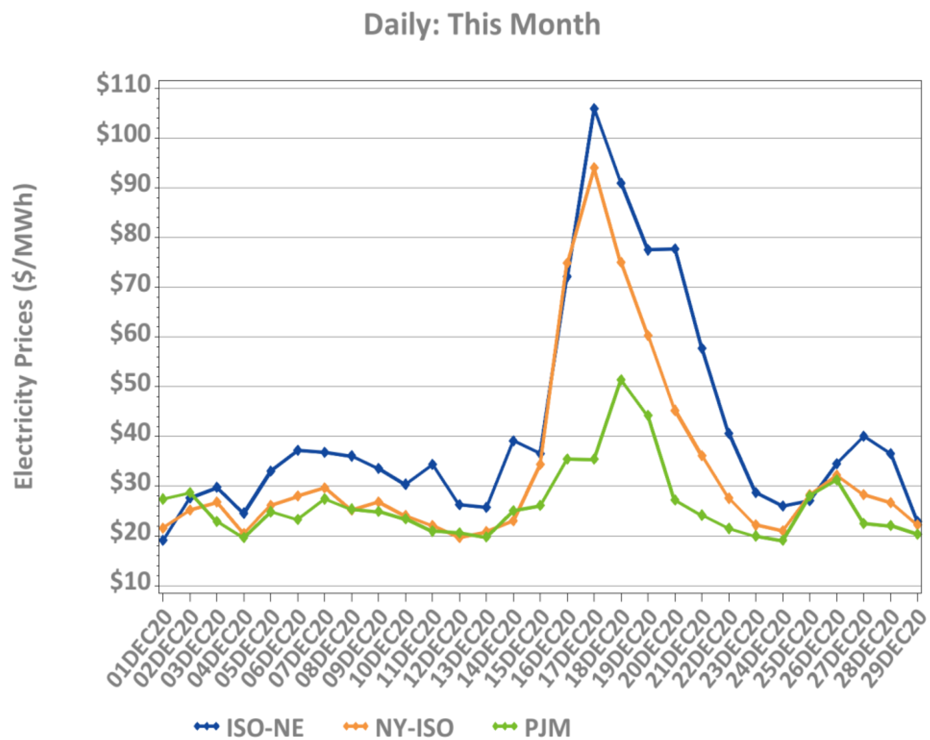
Underlying natural gas data furnished by:

ice Global markets in clear view

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

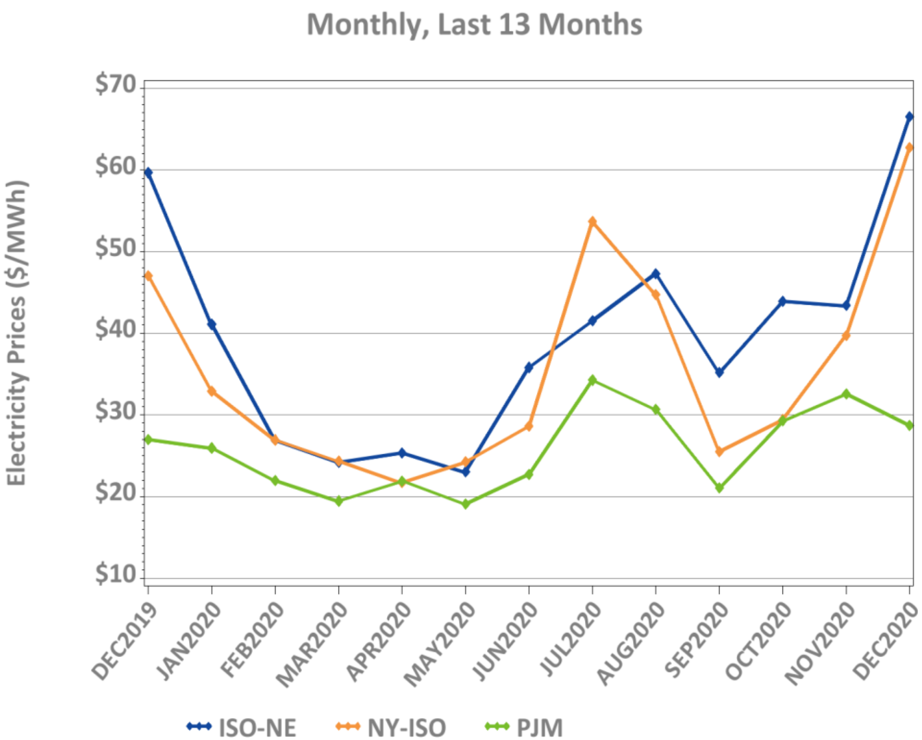


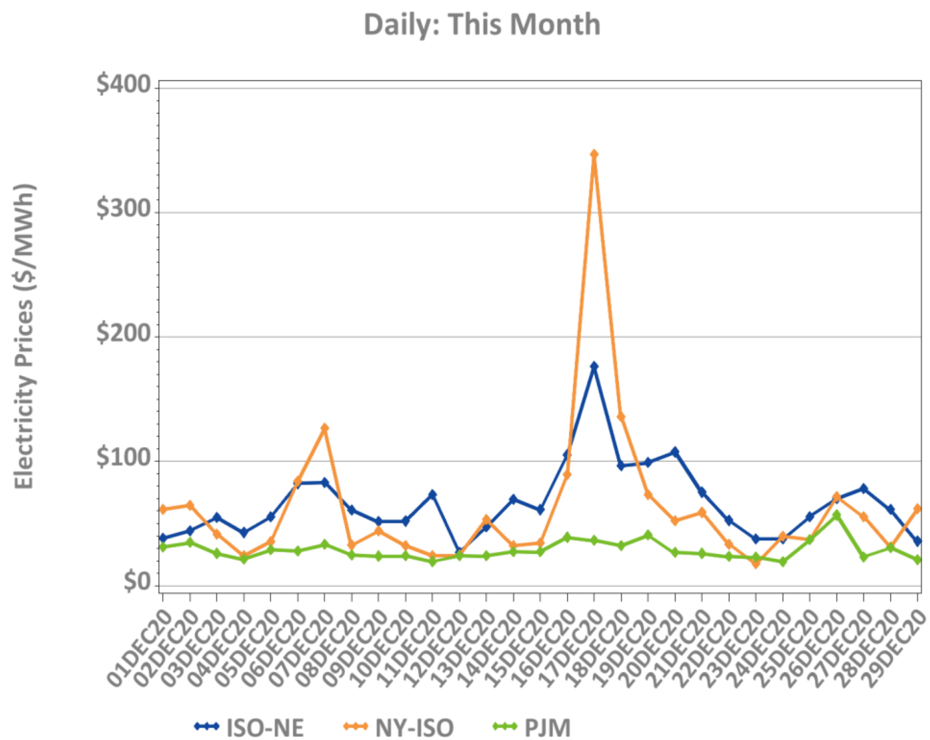
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





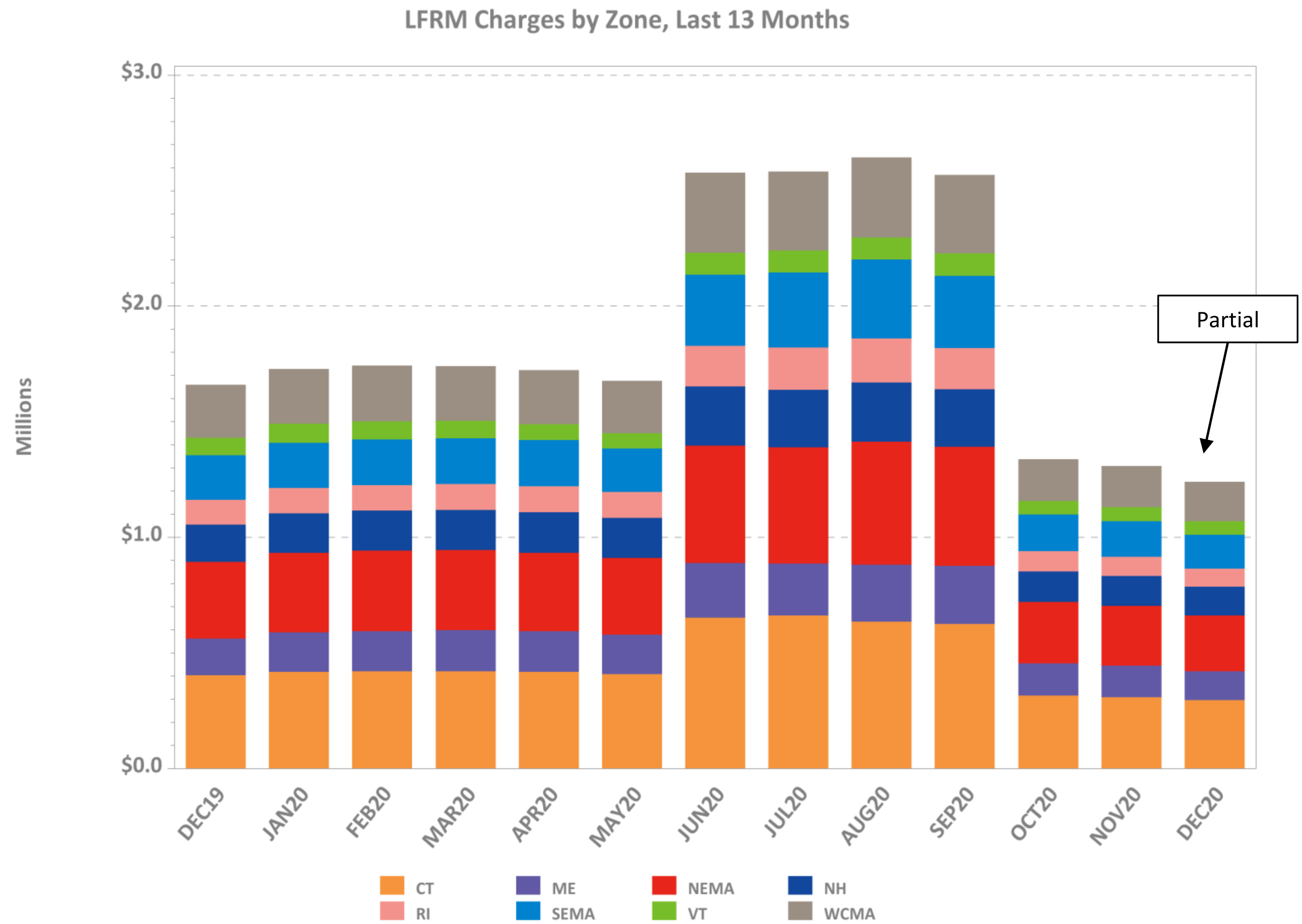
***Forecasted New England daily peak hours reflected**

Reserve Market Results – December 2020

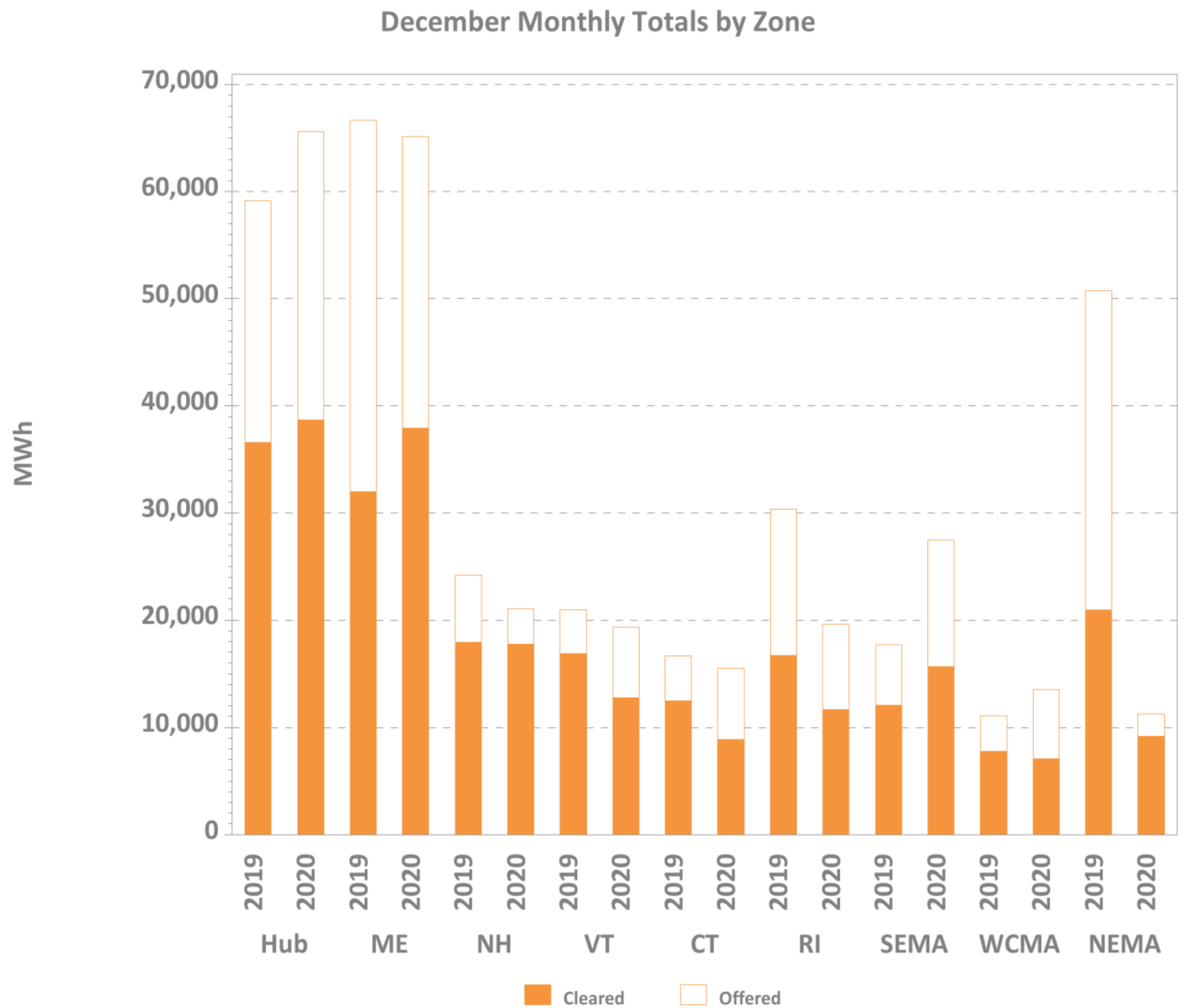
- Maximum potential Forward Reserve Market payments of $1.3M were reduced by credit reductions of $22K, failure-to-reserve penalties of $33K and no failure-to-activate penalties, resulting in a net payout of $1.2M or 96% of maximum
  - Rest of System: $0.95M/1.01M (95%)
  - Southwest Connecticut: $0.04M/0.04M (100%)
  - Connecticut: $0.25M/0.25M (100%)
- $795K total Real-Time credits were not reduced by any Forward Reserve Energy Obligation Charges for a net of $795K in Real-Time Reserve payments
  - Rest of System: 257 hours, $570K
  - Southwest Connecticut: 257 hours, $104K
  - Connecticut: 257 hours, $63K
  - NEMA: 257 hours, $57K

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.

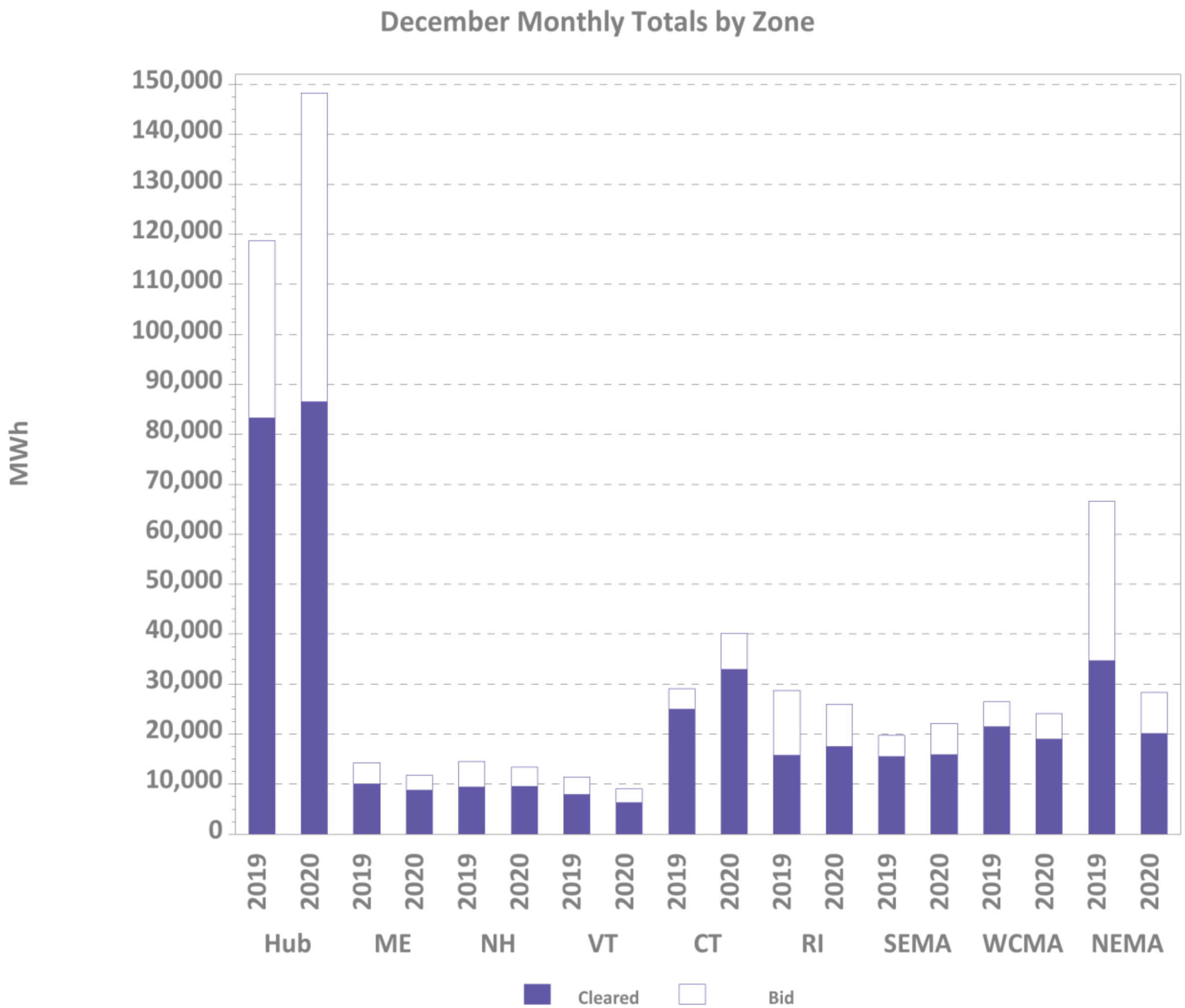
LFRM Charges to Load by Load Zone ($)



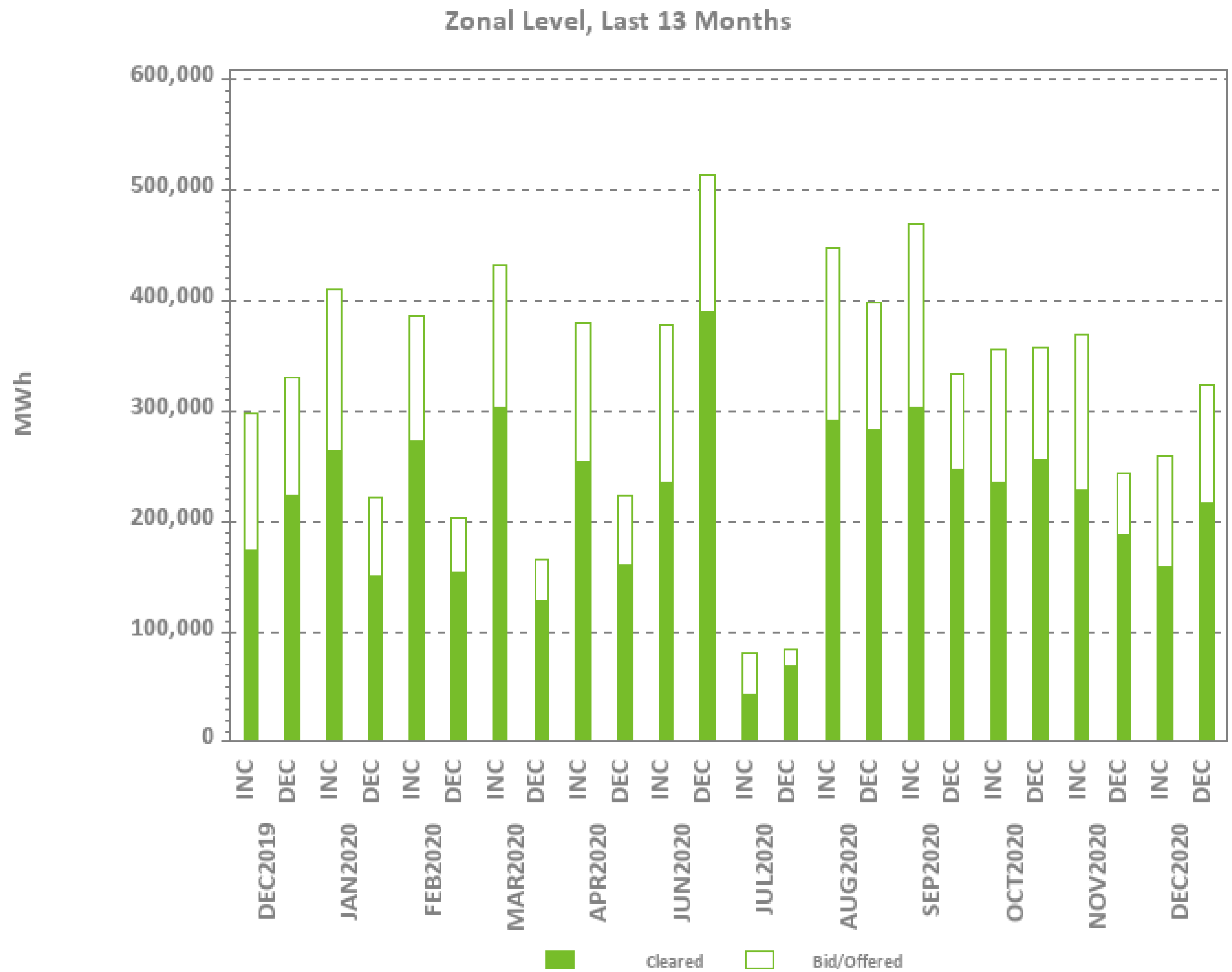
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

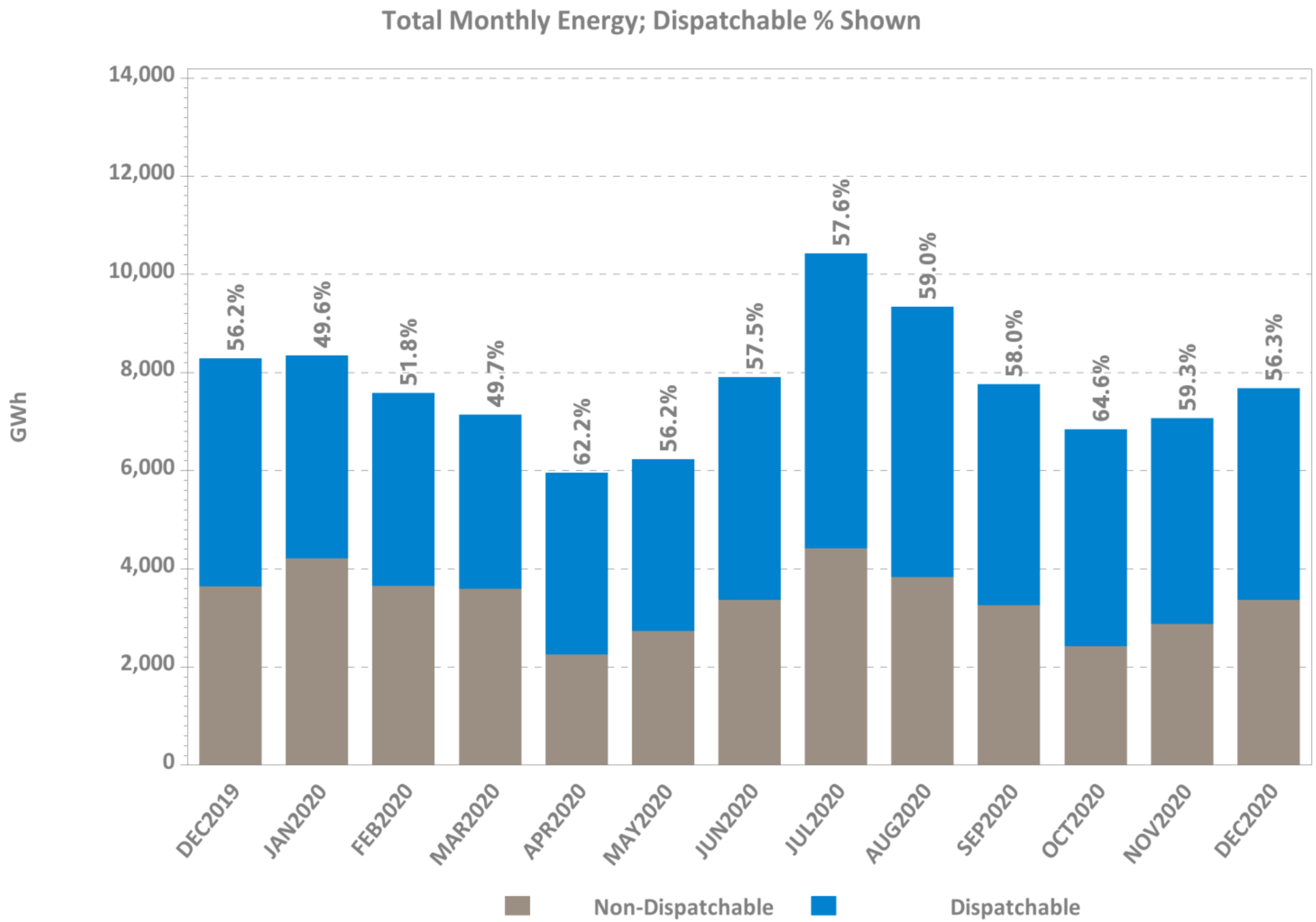


Total Increment Offers and Decrement Bids



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)

Planning Advisory Committee (PAC)

- January 21 PAC Meeting Agenda Topics*
  – Stochastic Time Series Modeling for ISO-NE: Results and Next Steps
  – Transmission Planning for the Clean Energy Transition: Generation Dispatch Details
  – Ludlow BPS and Asset Condition Project - Eversource
  – 345 kV Structure Replacements - Eversource
  – Copper Conductor Replacements - Eversource

* 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 September 24, 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 November 19 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 PAC meeting
  - The ISO expects to discuss further details at the 1/21/21 PAC meeting

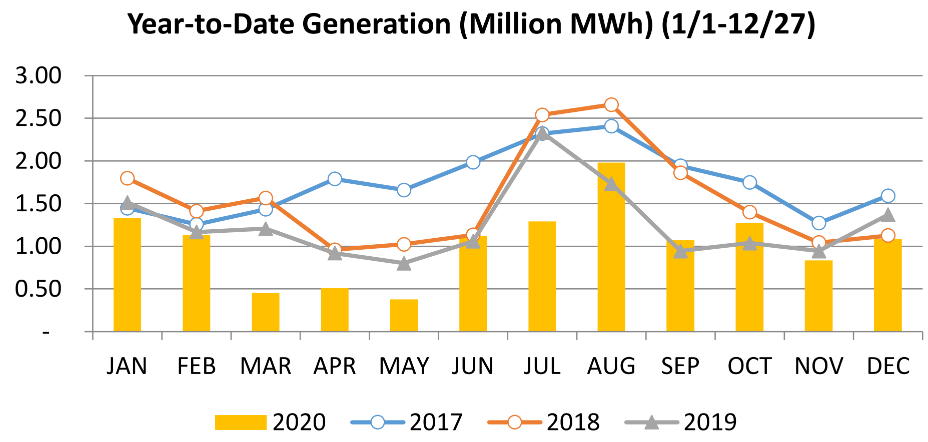
Economic Studies

- National Grid submitted a 2020 economic study request
  - Preliminary production cost results were shared at the November 19, 2020 PAC meeting, and additional scenarios/sensitivities will be presented in January and February
  - Ancillary Services study work to be presented to PAC in March
  - The goal is to complete all study work by Q2 2021
    - Study results expected to influence the NEPOOL Future Grid study

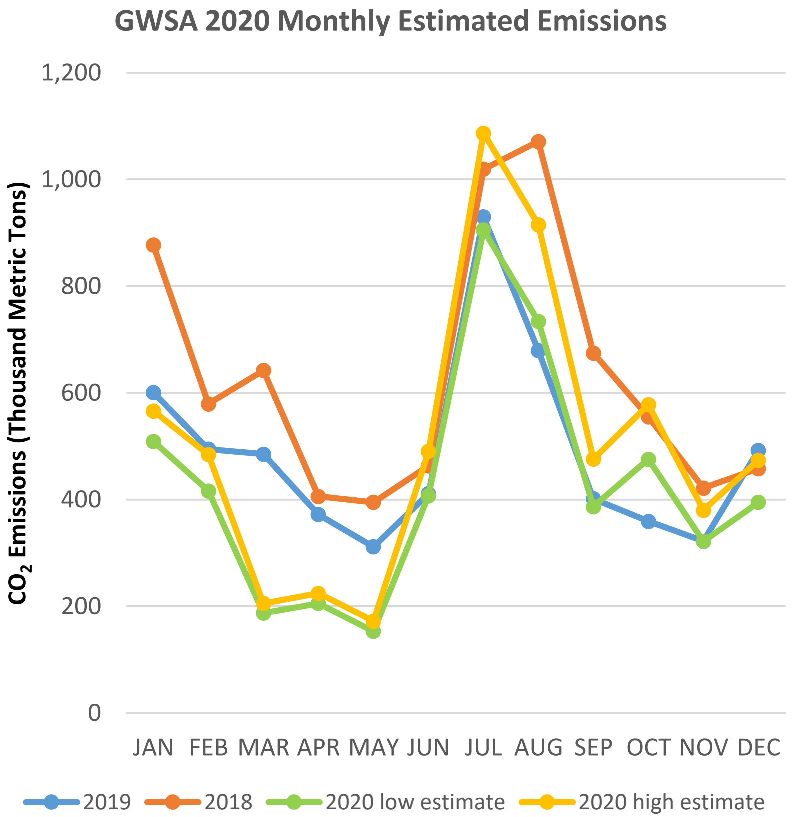
Environmental Matters – Massachusetts CO_2 Generator Emissions Cap

2020 CO_2 Emissions Trend Below 2019, Both Well Below Caps

- 2020 CO_2 emissions estimated between 5.1 – 6.0 million metric tons (MMT); 2020 cap is 8.5 MMT
  - GWSA allowance price: ~$7.25 per metric ton
- 2019 YTD emissions were 5.9 MMT



2018-2020 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 12/23/20

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

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

Southwest Connecticut Projects, cont.

Status as of 12/23/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Add two 14.4 MVAR capacitor banks at the West Brookfield substation	Dec-17	4
Add a new 115 kV line from Plumtree to Brookfield Junction	Jun-18	4
Reconductor the 115 kV line between West Brookfield and Brookfield Junction (1887)	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 12/23/20

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

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

Southwest Connecticut Projects, cont.

Status as of 12/23/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Add 2 x 20 MVAR capacitor banks at the Hawthorne substation	Mar-16	4
Upgrade the 115 kV bus at the Baird substation	Mar-18	4
Upgrade the 115 kV bus system and 11 disconnect switches at the Pequonnock substation	Dec-14	4
Add a 345 kV breaker in series with the existing 11T breaker at the East Devon substation	Dec-15	4
Rebuild the 115 kV lines from Baird to Congress (8809A / 8909B)	Dec-18	4
Rebuild the 115 kV lines from Housatonic River Crossing (HRX) to Barnum to Baird (88006A / 89006B)	Feb-21	3

Southwest Connecticut Projects, cont.

Status as of 12/23/20

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

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

Greater Boston Projects

Status as of 12/23/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Install new 345 kV line from Scobie to Tewksbury	Dec-17	4
Reconductor the Y-151 115 kV line from Dracut Junction to Power Street	Apr-17	4
Reconductor the M-139 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
Reconductor the N-140 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
Reconductor the F-158N 115 kV line from Wakefield Junction to Maplewood and associated work at Maplewood	Dec-15	4
Reconductor the F-158S 115 kV line from Maplewood to Everett	Jun-19	4
Install new 345 kV cable from Woburn to Wakefield Junction, install two new 160 MVAR variable shunt reactors and associated work at Wakefield Junction and Woburn*	May-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 12/23/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Separate X-24 and E-157W DCT	Dec-18	4
Separate Q-169 and F-158N DCT	Dec-15	4
Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap	May-17	4
Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook	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 12/23/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Replace 345/115 kV autotransformer, 345 kV breakers, and 115 kV switchgear at Woburn	Dec-19	4
Install a 345 kV breaker in series with breaker 104 at Woburn	May-17	4
Reconfigure Waltham by relocating PARs, 282-507 line, and a breaker	Dec-17	4
Upgrade 533-508 115 kV line from Lexington to Hartwell and associated work at the stations	Aug-16	4
Install a new 115 kV 54 MVAR capacitor bank at Newton	Dec-16	4
Install a new 115 kV 36.7 MVAR capacitor bank at Sudbury	May-17	4
Install a second Mystic 345/115 kV autotransformer and reconfigure the bus	May-19	4
Install a 115 kV breaker on the East bus at K Street	Jun-16	4
Install 115 kV cable from Mystic to Chelsea and upgrade Chelsea 115 kV station to BPS standards	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	Mar-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 12/23/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Install a second 115 kV cable from Mystic to Woburn to create a bifurcated 211-514 line	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 12/23/20

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

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

SEMA/RI Reliability Projects

Status as of 12/23/20

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 12/23/20

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	Jun-24	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 12/23/20

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	2
Retire the Barnstable SPS	Dec-21	2
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 12/23/20

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	2
Loop the 201-502 line into the Medway substation to form the 201-502N and 201-502S lines	Jan-23	1
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 12/23/20

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	Dec-21	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	Oct-20	4

Eastern CT Reliability Projects

Status as of 12/23/20

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 12/23/20

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

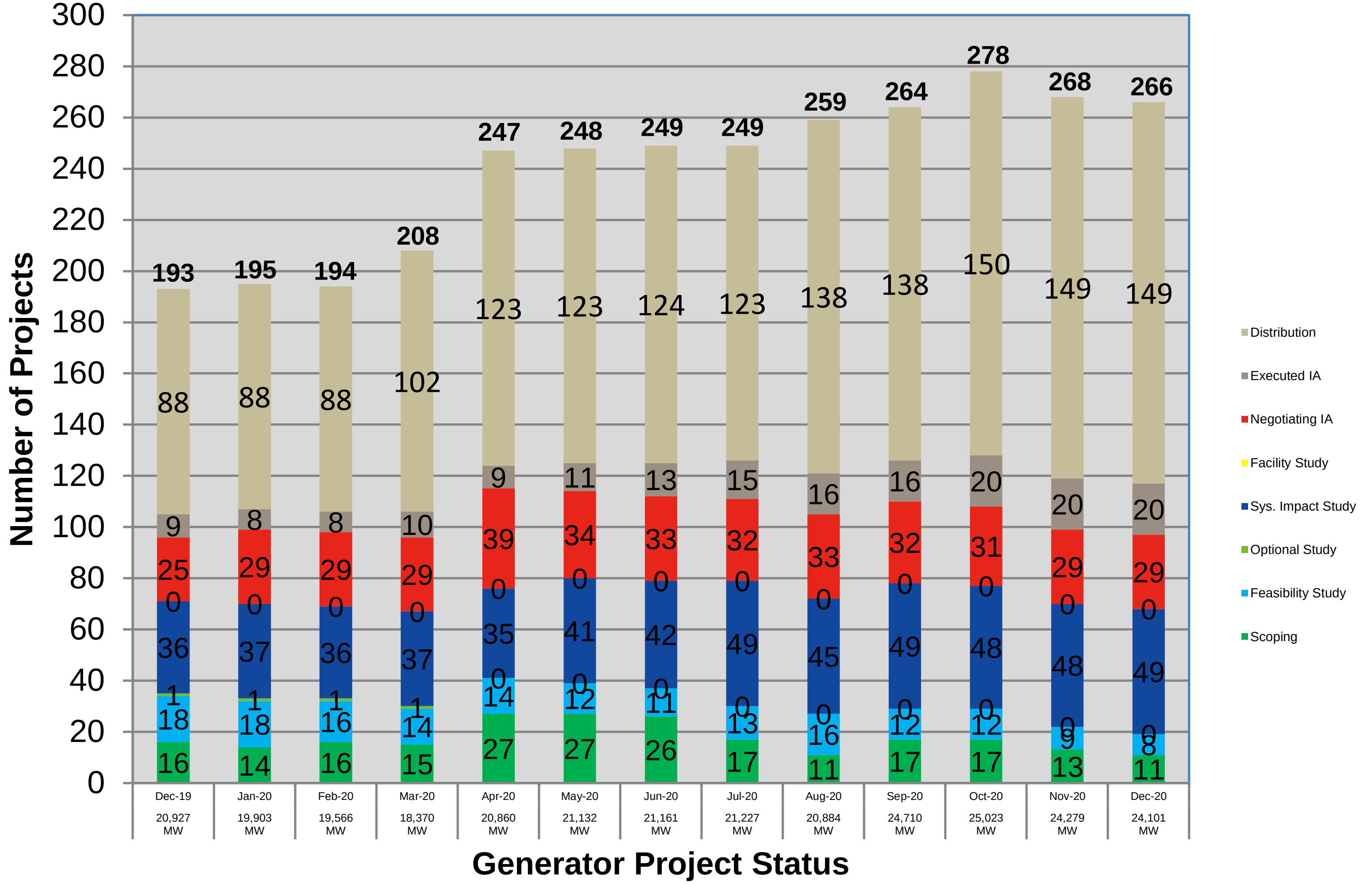
Eastern CT Reliability Projects, cont.

Status as of 12/23/20

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

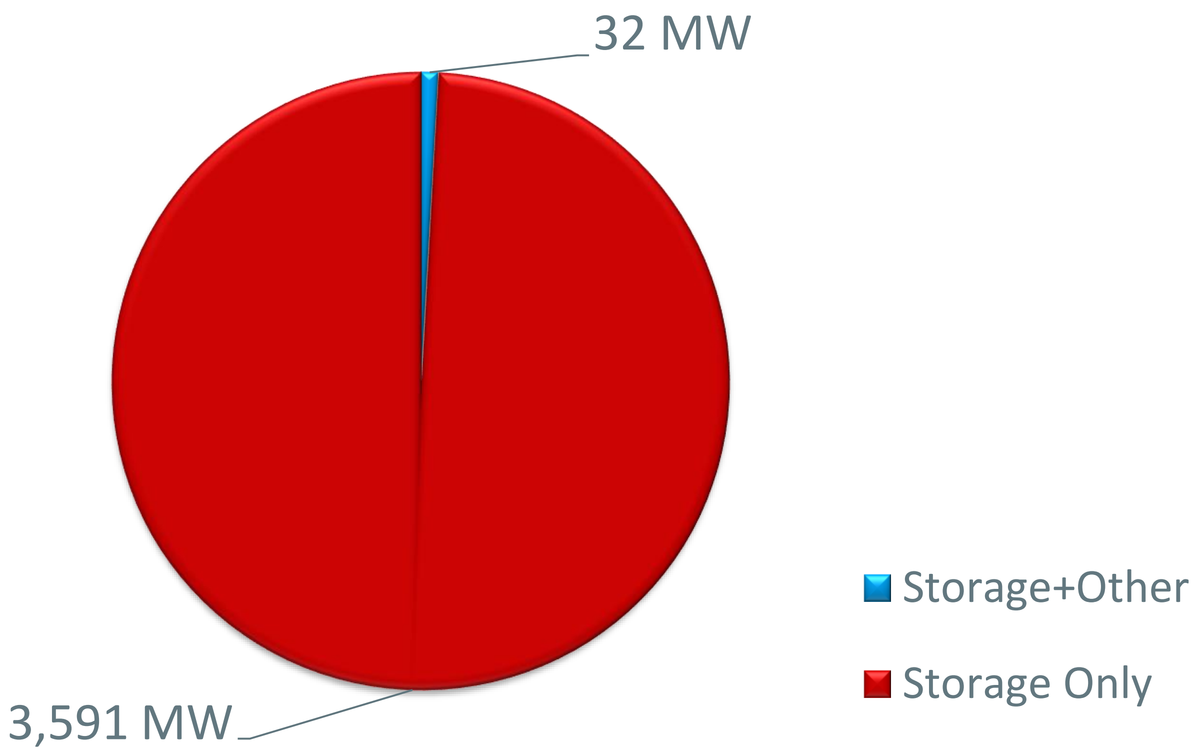
Status of Tariff Studies



Note: December 2020 is based on partial data.
As of December 2020, there are 0 ETU's 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 December 22, 2020)

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



OPERABLE CAPACITY ANALYSIS

Winter 2021 Analysis

Winter 2021 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Jan. - 2021[2] CSO (MW)	Jan. - 2021[2] SCC (MW)
Operable Capacity MW [1]	30,425	33,682
Active Demand Capacity Resource (+) [5]	441	408
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,130	1,130
Non Commercial Capacity (+)	19	19
Non Gas-fired Planned Outage MW (-)	322	426
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	3,887	4,439
Net Capacity (NET OPCAP SUPPLY MW)	25,006	27,574
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,166	20,166
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,471	22,471
Operable Capacity Margin	2,535	5,103

[1]Operable Capacity is based on data as of **December 29, 2020** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **December 29, 2020.**

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

Winter 2021 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	Jan. - 2021[2] CSO (MW)	Jan. - 2021[2] SCC (MW)
Operable Capacity MW [1]	30,425	33,682
Active Demand Capacity Resource (+) [5]	441	408
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,130	1,130
Non Commercial Capacity (+)	19	19
Non Gas-fired Planned Outage MW (-)	322	426
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	4,731	5,402
Net Capacity (NET OPCAP SUPPLY MW)	24,162	26,611
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,806	20,806
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,111	23,111
Operable Capacity Margin	1,051	3,500

[1]Operable Capacity is based on data as of **December 29, 2020** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **December 29, 2020.**

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

Winter 2021 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

January 1, 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]
1/9/2021	**30425**	**441**	**1130**	**19**	**322**	**0**	**2800**	**3887**	**25006**	**20166**	**2305**	**22471**	**2535**
1/16/2021	30425	441	1130	19	362	95	2800	3641	25117	20166	2305	22471	2646
1/23/2021	30425	441	1130	19	380	0	2800	3269	25566	19933	2305	22238	3328
2/27/2021	30459	533	1025	19	1224	55	2200	1502	27055	18308	2305	20613	6442
3/6/2021	30459	533	1025	19	1888	55	2200	1190	26703	17941	2305	20246	6457
3/13/2021	30459	533	1025	19	1904	305	2200	318	27309	17736	2305	20041	7268
3/20/2021	30459	533	1025	19	1475	262	2200	0	28099	17352	2305	19657	8442
3/27/2021	30446	537	1025	19	678	299	2700	0	28350	16759	2305	19064	9286

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)

Winter 2021 Operable Capacity Analysis

90/10 Forecast (Extreme)

ISO-NE OPERABLE CAPACITY ANALYSIS

January 1, 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]
1/9/2021	**30425**	**441**	**1130**	**19**	**322**	**0**	**2800**	**4731**	**24162**	**20806**	**2305**	**23111**	**1051**
1/16/2021	30425	441	1130	19	362	95	2800	4420	24338	20806	2305	23111	1227
1/23/2021	30425	441	1130	19	380	0	2800	4203	24632	20566	2305	22871	1761
2/27/2021	30459	533	1025	19	1224	55	2200	2280	26277	18897	2305	21202	5075
3/6/2021	30459	533	1025	19	1888	55	2200	2124	25769	18520	2305	20825	4944
3/13/2021	30459	533	1025	19	1904	305	2200	1252	26375	18309	2305	20614	5761
3/20/2021	30459	533	1025	19	1475	262	2200	828	27271	17915	2305	20220	7051
3/27/2021	30446	537	1025	19	678	299	2700	324	28026	17305	2305	19610	8416

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.
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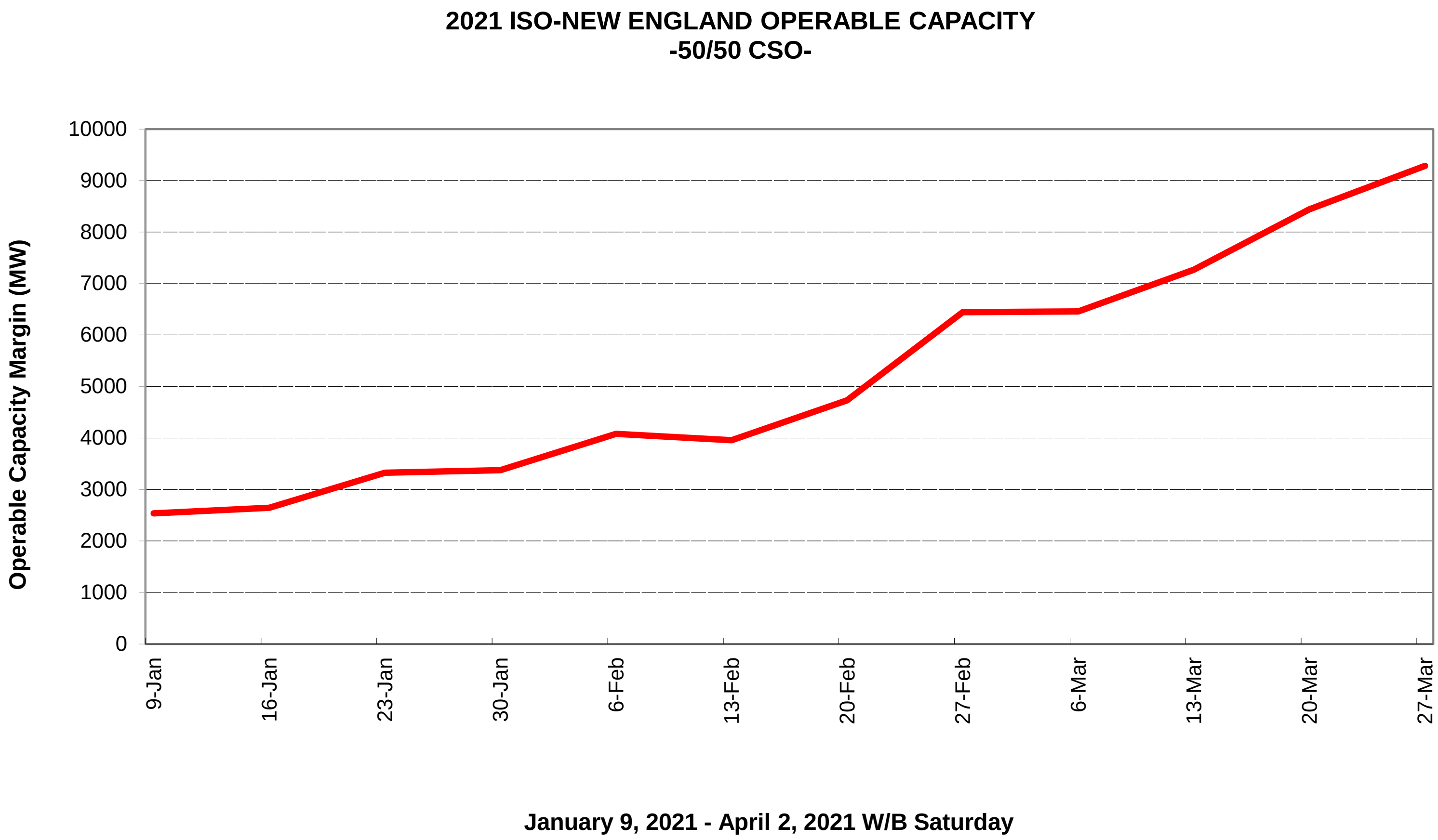
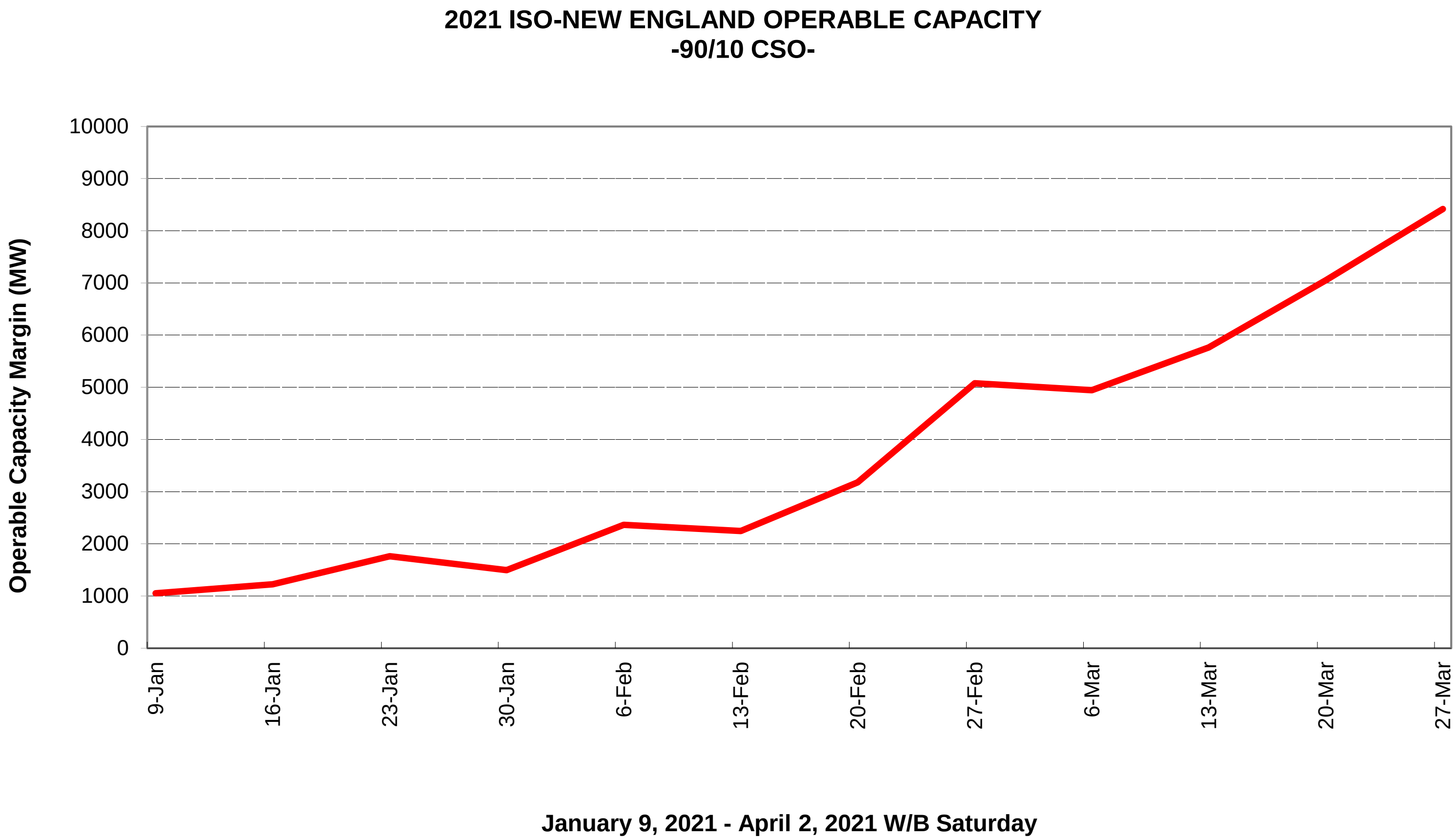
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 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**

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



Winter 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 resources <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 resources <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

Joint Nominating Committee
Notes from December 18, 2020 Meeting

1. The JNC reviewed a presentation from the ISO Board Chair entitled "2021 ISO New England Board Director Appointments" (attached). The presentation outlines factors that the Board would like the JNC to consider, including the ISO's strategic goals (including its diversity goals), upcoming Board retirements and resulting gaps in expertise and Committee leadership, and evolution of the power grid.
2. The JNC also considered a matrix depicting primary areas of technical expertise possessed by each of the directors (attached).
3. Members of the Board noted the criticality of replacing Mr. Rush's electricity markets expertise and Ms. VanZandt's bulk power transmission expertise, explaining that, due to their technical expertise, both serve as important liaisons with management and often help to educate the rest of the Board on technical matters.
4. Maria A. Gulluni, ISO New England Vice President and General Counsel, and David T. Doot, NEPOOL Counsel and Secretary, presented an "Overview of the JNC Process" (attached). That presentation describes the evolution of the JNC process, process mechanics, and the nondisclosure agreement that all Committee members are required to sign, which limits disclosure of the identify of candidates being considered for nomination. It notes that over the years, each of the JNC's search partners has stressed the importance of such agreements, as top candidates will not engage in the search process without a promise that their names will be held in confidence. Maria and Dave noted, however, that there was still a great deal of information that could be shared with the sectors under the NDA to describe the JNC's strategy and discussions, candidate specifications, and general characteristics of the candidates. Committee members agreed based on input received during consideration of the 2020 slate that it would be helpful to share more information with their constituents.

5. The market participant representatives of the JNC provided feedback that it would be beneficial to the process and NPC members to have greater insight into matters that the incumbent directors, who are up for reelection, have been engaged in during their tenure. It was recommended that the ISO look for opportunities to expose these directors to stakeholders.
6. Jennifer Rockwood of Russell Reynolds Associates, the Committee's selected search partner, spoke about the Evergreen Process designed to look for candidates for both current and future years. She indicated that there were some candidates surfaced in last year's search, who might be appropriate to revisit for 2021 and, that some who were conflicted last year, could be appropriate and conflict-free this coming year.
7. The next JNC meeting will be held in mid-January to finalize discussion of the search criteria and desired candidate attributes. Following that, Russell Reynolds will develop Position Specifications and generate a "Long List" of candidates for review by the JNC in mid-February.

DECEMBER 18, 2020 | JOINT NOMINATING COMMITTEE

2021 ISO New England Board Director Appointments

Roadmap for Acquiring Critical Skills, Experience, and Attributes

Kathleen Abernathy
ISO NEW ENGLAND BOARD CHAIR

New Directors Must Embrace ISO's Strategic Goals

- ISO Vision Statement: To harness the power of competition and advanced technologies to reliably plan and operate the grid as the region transitions to clean energy.
- Strategic Goals:
  - Responsive Market Designs
  - Progress and Innovation
  - Operational Excellence
  - Stakeholder Engagement
  - Attract Develop and Retain Talent

And, Must Embrace ISO's Diversity Goals

- Board diversity, according to many studies and as reflected in a recent NACD Blue Ribbon Commission on Board Diversity, improves diversity of thought and effectiveness due to different backgrounds and experiences. Diversity should be reflected with respect to gender, age, ethnicity and skill sets.

- Board diversity has been a core tenet of ISO New England and has been present since its inception. We are focused on ensuring we have the necessary range of technical and life skills to provide proper oversight as we address the issues of reliability and the clean-energy transition.

- Current Board Structure includes:
  - Three females
  - One Latino
  - One LGBTQ
  - One Veteran

Change Is Coming

- The ISO New England Board has turn-over every year but the next two years will see higher than usual retirements.
  - Two Board members retire in 2021 and two more retire in 2022.
- These retirements coincide with dramatic changes regarding how energy is produced, distributed, and consumed throughout our country.
- They leave expertise gaps on the Board that, if not replaced, will affect the quality of Board discussion, decisions and guidance to the ISO.
- Expertise gaps will also affect Committee leadership as one departing director is the Board Chair; three others are Committee Chairs; and all are valued Committee members.
- The retirements also result in the loss of two of the three female directors.

Technical Skill Sets Required

- Sections 9 and 13 of the Participants Agreement set forth requirements for Board composition, requiring a cross-section of skills and experiences ("such as, for purposes of illustration but not by way of mandate or limitation, experience in Commission electric regulatory affairs, energy industry management, corporate finance, bulk power systems, human resource administration, power pool operations, public policy, distributed generation or demand response technologies, renewable energy, consumer advocacy, environmental affairs, business management and information technologies").
  - At least three of the directors shall have prior relevant experience in the electric industry.
  - In addition, to ensure sensitivity to regional concerns, strong preference shall be given to electing members from New England to the extent qualified candidates are available and such representation can be accomplished consistent with ISO's Code of Conduct.

- As a reminder, we need expertise to populate the following six committees:

System Planning and Reliability (SPARC)	Markets
Audit and Finance	Human Resources and Compensation
IT and Cyber	Nominating and Governance

- All Committee Charters reside on the ISO's website (https://www.iso-ne.com/about/corporate-governance/board/?document-type=Board%20Committee%20Charters).

2021-2022 Upcoming Retirements & Areas of Expertise

Director (by retirement date)	(1) Electric Industry/ Transmission Experience	(2) Markets Expertise Financial Markets (F) Energy Markets (E)	(3) Top Corporate Officer Experience At least one CEO; as noted	(4) Public Service, Regulatory Experience (FERC, States)	(5) Audit Committee Financial Expert	(6) IT/Cyber Security Expertise
Kathleen Abernathy '21			X	X		
Phil Shapiro '21		X (F)	X	X	X	
Barney Rush '22	X	X (F,E)	X		X	
Vickie VanZandt '22	X		X			X
Roberto Denis '23	X		X			
Brook Colangelo '26			X			X
Mike Curran '27		X (F,E)	X (CEO)		X	X
Cheryl LaFleur '28	X	X (E)	X (CEO)	X		X
Mark Vannoy '29	X		X	X		
Gordon van Welie	X	X (E)	X (CEO)			X

Needed Experience

- As Chair of the Markets Committee and an expert in electricity markets, Barney Rush's 2022 retirement makes replacing this expertise, a top priority.
- This is particularly critical as the region's future grid priorities rely on designing (then operating) innovative, reliable, well functioning markets.
  - Ideally, the market expert that we hire will have expertise as a "practitioner" – someone with deep and broad experience working with electricity markets.
- The challenges facing the region also depend on having a robust transmission network across the region. Vickie VanZandt is a national transmission expert: someone who has planned, built and operated bulk power transmission systems. Her 2022 retirement will leave a significant void. Replacing her expertise is essential.
- Finally, in addition to the personal qualifications (e.g. ethics, integrity, etc.) that are sought each year, we need all of our Board members to be strategic assets to the ISO.

Revised: 12/18/20

CRITICAL AREAS OF EXPERTISE FOR ISO NEW ENGLAND BOARD OF DIRECTORS

September 2020

1 ELECTRIC INDUSTRY / TRANSMISSION EXPERIENCE (by retirement date)*	2 MARKETS EXPERTISE (F – Financial Markets E – Energy Markets) (by retirement date)*	3 TOP CORPORATE OFFICER EXPERIENCE At least one CEO (in bold) (by retirement date)*	4 PUBLIC SERVICE, REGULATORY EXPERIENCE (FERC, STATES) (by retirement date)*	5 AUDIT COMMITTEE FINANCIAL EXPERT (by retirement date)*	6 IT/CYBER SECURITY EXPERTISE (by retirement date)*
Barney Rush ’22	Phil Shapiro ’21 (F)	Phil Shapiro ‘21	Kathleen Abernathy ‘21	Phil Shapiro ‘21	Vickie VanZandt ‘22
Vickie VanZandt ‘22	Barney Rush ‘22 (F,E)	Kathleen Abernathy ‘21	Phil Shapiro ‘21	Barney Rush ‘22	Brook Colangelo ‘26
Roberto Denis ’23	Mike Curran ’27 (F,E)	Barney Rush ‘22	Cheryl LaFleur ‘28	Mike Curran ‘27	Mike Curran ‘27
Cheryl LaFleur ‘28	Cheryl LaFleur ’28 (E)	Vickie VanZandt ‘22	Mark Vannoy ‘29		Cheryl LaFleur ‘28
Mark Vannoy ‘29	Gordon van Welie (E)	Roberto Denis ‘23			Gordon van Welie
Gordon van Welie		Brook Colangelo ‘26			
		Mike Curran ‘27			
		Cheryl LaFleur ‘28			
		Mark Vannoy ‘29			
		Gordon van Welie			

* In each case, the date represents the latest possible retirement date given age and term limits, but does not account for potential waivers of either.

Revised: 12/18/20

Note 1: As of 3/18/10, a column was added to the Expertise Chart to address the A&F Committee's Charter, which states that "at all times at least one member of the Committee should be an audit committee financial expert within the meaning of Item 401(h) of Securities and Exchange Commission Regulation S-K."

Criteria:

(ii) For purposes of this Item, an audit committee financial expert means a person who has the following attributes:

(A) An understanding of generally accepted accounting principles and financial statements;

(B) The ability to assess the general application of such principles in connection with the accounting for estimates, accruals and reserves;

(C) Experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by the registrant's financial statements, or experience actively supervising one or more persons engaged in such activities;

(D) An understanding of internal control over financial reporting; and

(E) An understanding of audit committee functions.

(iii) A person shall have acquired such attributes through:

(A) Education and experience as a principal financial officer, principal accounting officer, controller, public accountant or auditor or experience in one or more positions that involve the performance of similar functions;

(B) Experience actively supervising a principal financial officer, principal accounting officer, controller, public accountant, auditor or person performing similar functions;

(C) Experience overseeing or assessing the performance of companies or public accountants with respect to the preparation, auditing or evaluation of financial statements; or

(D) Other relevant experience.

Revised: 12/18/20

CRITICAL AREAS OF EXPERTISE FOR ISO NEW ENGLAND BOARD OF DIRECTORS, BY DIRECTOR

Alternate View

DIRECTOR (by retirement date)*	1 ELECTRIC INDUSTRY / TRANSMISSION EXPERIENCE	2 MARKETS EXPERTISE (F – Financial Markets, E - Energy Markets)	3 TOP CORPORATE OFFICER EXPERIENCE At least one CEO (in bold)	4 PUBLIC SERVICE, REGULATORY EXPERIENCE (FERC, STATES)	5 AUDIT COMMITTEE FINANCIAL EXPERT	6 IT/CYBER SECURITY EXPERTISE
Kathleen Abernathy '21			X	X		
Phil Shapiro '21		X (F)	X	X	X	
Barney Rush '22	X	X (F/E)	X		X	
Vickie VanZandt '22	X		X			X
Roberto Denis '23	X		X			
Brook Colangelo '26			X			X
Mike Curran '27		X (F/E)	**X**		X	X
Cheryl LaFleur '28	X	X (E)	**X**	X		X
Mark Vannoy '29	X		X	X		
Gordon van Welie	X	X (E)	**X**			X

* In each case, the date represents the latest possible retirement date given age and term limits, but does not account for potential waivers of either.

Revised: 12/18/20

Note 1: As of 3/18/10, a column was added to the Expertise Chart to address the A&F Committee's Charter, which states that "at all times at least one member of the Committee should be an audit committee financial expert within the meaning of Item 401(h) of Securities and Exchange Commission Regulation S-K."

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(B) The ability to assess the general application of such principles in connection with the accounting for estimates, accruals and reserves;

(C) Experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by the registrant's financial statements, or experience actively supervising one or more persons engaged in such activities;

(D) An understanding of internal control over financial reporting; and

(E) An understanding of audit committee functions.

(iii) A person shall have acquired such attributes through:

(A) Education and experience as a principal financial officer, principal accounting officer, controller, public accountant or auditor or experience in one or more positions that involve the performance of similar functions;

(B) Experience actively supervising a principal financial officer, principal accounting officer, controller, public accountant, auditor or person performing similar functions;

(C) Experience overseeing or assessing the performance of companies or public accountants with respect to the preparation, auditing or evaluation of financial statements; or

(D) Other relevant experience.

DECEMBER 18, 2020

Overview of JNC Process

Maria Gulluni, ISO New England

David Doot, Day Pitney

Corporate Structure of ISO-NE

- ISO-NE is a non-profit Delaware non-stock corporation
- ISO-NE has a ten-member, independent Board of Directors
  - Directors include the CEO, who is non-voting
  - Directors' terms are staggered, so that three Directors' terms end each year

Evolution of the Director Election Process

- Per its governing documents, the Board is “self-perpetuating“ (i.e., directors selected and elected directors)
- The region modified the Board election process via contract as part of the transition to an RTO
  - The JNC arrangements are contained in the FERC-approved Participants Agreement
- The Participants Agreement also facilitates Board turnover
  - This was a stakeholder priority
  - The Participants Agreement includes a three term limit (each term is three years)
  - Directors are also subject to an age limit (must be 70 or less to be elected or re-elected)
  - The JNC can waive both limits

JNC Role and Composition

- See Section 13 of the Participants Agreement
- All director nominations occur through the JNC (13.1.1)
- The JNC consists of:
  - Up to 7 ISO directors (no incumbents standing for re-election)
  - Up to 6 NEPOOL representatives (NEPOOL officers or designees, no more than one per sector)
  - A representative of NECPUC
  - *See* Participants Agreement Section 13.1.2
- One of the Board members shall serve as the chair of the JNC (13.1.2)

JNC Mechanics

- The JNC identifies, with input from the ISO Board, the State representatives, and the market participants, the types of expertise needed to ensure that ISO has "sufficient knowledge and expertise to act as the RTO for New England" (13.1.3)
- The JNC engages a nationally recognized executive search firm to identify candidates; the JNC interviews candidates (13.1.4)
- The JNC develops a slate composed of each of the "incumbent ISO Board members whose term is expiring and who have been identified by the ISO Board for reelection" and candidates to fill vacancies (13.1.5)
- The JNC acts "by a consensus" (13.1.5)

Election of the Slate

- The slate is sent to the Participants Committee for vote (13.2.1)
  - 70% is required to endorse (the highest of any NEPOOL vote)
- If the Participants Committee endorses the slate, the slate is submitted to the Board (13.2.1)
- If the PC vote fails, the JNC takes feedback from stakeholders and repeats the process (13.2.2)
  - The JNC presents a new slate to the PC at its next meeting
  - There must be at least one change on the slate
  - If that slate is rejected, the JNC selects a slate to present to the Board
- If the Board rejects a slate, the process repeats before the next Board meeting with or without a change to the slate (13.2.3)
  - Note that the "deadline" for the PC to present an endorsed slate to the Board is the Board's annual meeting, which is held in September (13.1.1, 13.2.4)

Non-Disclosure Agreement (NDA)

- JNC members sign an NDA that prohibits sharing non-public information
- The NDA is primarily intended to protect the identity of unsuccessful candidates
  - Per feedback from candidates and search firms, this is a critical precondition to ensure that good candidates are willing to participate in the process

Non-Disclosure Agreement: Exclusions

- "Confidential Information" ***excludes:***
  - the existing board critical areas of expertise matrix
  - role description and profile of search criteria
  - board retirement schedule
- All of these can be shared publicly by JNC members
- The NDA also permits JNC members to share confidentially the final slate and resumes with constituents ahead of the NEPOOL vote, if it is useful (Section 2)

Potential Options to Enhance the JNC Process

- Improve transparency through more robust reporting to constituents regarding, for example, the following:
  - JNC meeting summaries
  - the existing board critical areas of expertise matrix
  - role description and profile of search criteria
  - board retirement schedule

  This reporting can be accomplished without a change to the Participants Agreement
- Other changes may require amendment of the Participants Agreement
  - Amendments require ISO-NE and NEPOOL approval (17.2.1)
  - NEPOOL approval requires a 70% vote (17.2.3)
  - FERC must review and approve any changes
  - Renegotiation of the Participants Agreement may open it to unrelated issues raised by participants, states or ISO

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of January 6, 2021

The following activity, as more fully described in the attached litigation report, has occurred since the report dated December 2, 2020 ("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	NEPGA Net CONE Complaint (EL21-26)	Dec 11	NEPGA files Complaint
			Dec 15-31	Avangrid, Calpine, Dominion, Eversource, FirstLight, LS Power, MA AG, MMWEC, National Grid, NHEC, NRG, MA DPU, RI PUC, Public Citizen, intervene
			Jan 4-5	BSW ProjectCo, CPV Towantic, Exelon intervene out-of-time
			Dec 31	Answers, comments and protests filed by ISO-NE, NEPOOL, NESCOE, NECOS/ENE, CT State Agencies, EPSA
	3	NECEC/Avangrid Complaint Against NextEra/Seabrook (EL21-6)	Dec 7	Avangrid answers NextEra's November 30 supplemental answer
	3	NextEra Energy Seabrook Declaratory Order Petition re: NECEC Elective Upgrade Costs Dispute (EL21-3)	Dec 4	Avangrid answers NextEra's Nov 19 answer
	5	RNS/LNS Rates and Rate Protocols Settlement Agreement II (ER20-2054)	Dec 28	FERC approves Settlement Agreement II; compliance filing due on or before Jan 27, 2021

II. Rate, ICR, FCA, Cost Recovery Filings

*	8	Dynegy CIP IROL (Schedule 17) Cost Recovery Filing (ER21-774)	Dec 30	Dynegy requests FERC acceptance of a proposed rate schedule to allow Dynegy to begin the recovery period for certain CIP-IROL Costs under Schedule 17 of the ISO-NE Tariff; comment date ***Jan 20, 2021***
			Jan 4	Calpine, NESCOE intervene
*	8	IRH Amended and Restated Support and Use Agreements (ER21-712)	Dec 18	IRH file amended and restated Support and Use Agreements; comment date ***Jan 8, 2021***
			Dec 28-29	Avangrid, ENE, NESCOE intervene
	9	ICR-Related Values and HQICCs – Annual Reconfiguration Auctions (ER21-496)	Dec 7-14	National Grid, NESCOE intervene
	9	FCA15 Qualification Informational Filing (ER21-372)	Dec 2, 3	Avangrid, EPSA intervene out-of-time
			Dec 10	ISO-NE answers NEPGA, Mystic limited protests; IMM answers Andro Hydro limited protest
	10	2021 NESCOE Budget (ER21-113)	Dec 18	FERC accepts 2021 NESCOE Budget, eff. Jan 1, 2021
	10	2021 ISO-NE Administrative Costs and Capital Budgets (ER21-106)	Dec 18	FERC accepts 2021 ISO-NE Budgets, eff. Jan 1, 2021

	11	Mystic 8/9 Cost of Service Agreement (ER18-1639)	Dec 21	FERC issues "Allegheny Order" modifying the discussion in the *July 17 Orders*, and setting aside in part both the *July 2018 Rehearing Order* and the *July 17 Compliance Order*
	13	MPD OATT 2019 Annual Informational Filing Settlement Agreement (ER15-1429-014)	Dec 28	Versant Power files Settlement Agreement; comment date ***Jan 18, 2021***; reply comments ***Jan 27, 2021***

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

*	13	Updated CONE, Net Cone and PPR Values (eff. FCA16) (ER21-787)	Dec 31 Jan 4-6	ISO-NE files updated values; comment date ***Jan 21, 2021*** Avangrid, Brookfield, Calpine, Dominion, LS Power, MA AG, NESCOE, NRG intervene
*	13	New DDBT Methodology (ER21-782)	Dec 31 Jan 4-6	ISO-NE and NEPOOL jointly file new methodology; comment date ***Jan 21, 2021*** Brookfield, Calpine, Dominion, LS Power, MA AG, NESCOE, NRG intervene
*	14	Energy Efficiency Resource FCM Qual. Modifications (ER21-640)	Dec 14 Dec 16-30	ISO-NE and NEPOOL jointly file modifications Calpine, Eversource, National Grid, NESCOE, MA DPU intervene
	14	ESI Alternatives (ER20-1567)	Dec 18	ISO-NE withdraws its Nov 13 request for clarification of the *Order Rejecting ESI Alternatives*
	15	*Order 841* Compliance Filings (Electric Storage in RTO/ISO Markets) (ER19-470)	Dec 7	ISO-NE and NEPOOL jointly file, in one comprehensive filing, Market Rule revisions in response to the requirements of the *Order 841 Compliance Filing II Order*
	16	Fuel Security Retention Proposal (ER18-2364)	Dec 3	FERC issues *Fuel Security Retention Proposal Allegheny Order*, modifying the *Fuel Security Retention Proposal Order*, in part (to be consistent with its clarification that the proposal was reviewed under FPA section 205), sustaining the results of the Fuel Security Retention Proposal Order and denying Verso's request for reconsideration
	16	ISO-NE Waiver Filing: Mystic 8 & 9 (ER18-1509; EL18-182)	Dec 3	FERC issues *Mystic Waiver Allegheny Order* modifying the discussion in the *Mystic Waiver Order,* reaching the same result and terminating the FPA section 206 proceeding instituted in EL18-182

V. OATT Amendments / TOAs / Coordination Agreements

No Activity to Report

V. Financial Assurance/Billing Policy Amendments

*	17	FAP Info Disclosure/KYC Requirements (ER21-816)	Jan 6 Jan 6	ISO-NE and NEPOOL jointly file changes; comment date ***Jan 27, 2021*** Brookfield intervenes

VI. Schedule 20/21/22/23 Changes

No Activity to Report

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

19	Capital Projects Report - 2020 Q3 (ER20-108)	Dec 15	FERC accepts Q3 Report, eff. Oct 1, 2020

IX. Membership Filings

*	19	January 2021 Membership Filing (ER21-769)	Dec 29	***Memberships:*** Cassadaga Wind LLC; Centrica Business Solutions Optimize, LLC; Pilot Power Group, LLC; and SmartestEnergy US LLC; ***Termination:*** Wheelabrator Bridgeport; comment date ***Jan 20, 2021***
	19	November 2020 Membership Filing (ER21-260)	Dec 17	FERC accepts Nautilus Solar Energy (AR Sector, RG Sub-Sector, Large AR RG Group Seat) as new member, eff. Dec 1, 2020

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

*	20	NERC Annual Report on FFT & Compliance Exception Programs (RC11-6-011)	Dec 30	NERC files annual report on FFT and compliance exception programs; comment date ***Jan 20, 2021***
*	20	Revised Rel. Standards: CIP-013-2, CIP-005-7, CIP-010-4 (RD21-2)	Dec 14	NERC files for approval proposed changes to CIP-013-2, CIP-005-7, and CIP-010-4 that address supply chain cybersecurity risk management
	20	CIP Standards Development: Info Filings on Virtualization & Cloud Computing Srvcs Projects (RD20-2)	Dec 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)
	21	Virtualization and Cloud Computing Services in BES Operations (RM20-8)	Dec 17	FERC issues order directing NERC to begin a formal process to assess, and to make an info. filing in a little over one year (Jan 1, 2022) that addresses, the feasibility of voluntarily conducting BES operations in the cloud in a secure manner

XI. Misc. - of Regional Interest

	23	203 Application: CPV Towantic (EC21-16)	Dec 17	FERC authorizes CPV Group LP to indirectly acquire all of the indirect voting securities owned by GIP II CPV in, among others, CPV Towantic
	23	203 Application: NRG/Direct (EC20-96)	Jan 5	NRG consummates transaction acquiring, among others, Direct Energy Business and Direct Energy Business Marketing
*	23	LGIA: NSTAR / MMWEC (Stony Brook) (ER21-777)	Dec 31	NSTAR files a LGIA to provide for the continued interconnection of Stony Brook Station; comment date ***Jan 21***
*	24	LGIA: CMP/ReEnergy Stratton (ER21-769)	Dec 30	CMP files a LGIA to renew and replace the terms of their existing but expiring interconnection agreement; comment date ***Jan 20***
*	24	Interim Distrib. Wheeling Agrm't: Unitil / Briar Hydro (ER21-759)	Dec 29	Unitil files interim agreement; comment date ***Jan 19***
*	24	D&E Agrm't Cancellation: NSTAR/ SEMASS (ER21-676)	Dec 17	NSTAR submits notice of cancellation of D&E Agreement; comment date ***Jan 7***
*	24	SGIA: CL&P / ECRRA (ER21-651)	Dec 15	CL&P files SGIA to provide for the continued interconnection of ECRRA's refuse-to-energy municipal solid waste facility
	25	VTransco Rate Schedule 2 Cancellation (ER21-256)	Dec 18	FERC accepts cancellation notice, eff. Dec 28, 2020
	25	NECEC TSAs: NECEC Transmission Notice of Succession and CMP Notice of Cancellation (ER21-12 et al.)	Dec 18	FERC accepts remaining notices addressing the transfer of TSAs with the participants that will fund the construction, operation and maintenance of the NECEC Transmission Line
*	26	FERC Enforcement Action: Algonquin Power Windsor Locks (IN21-2)	Jan 5	FERC approves Stipulation and Consent Agreement with Windsor Locks, requiring Windsor Locks to pay a ***$1,119,073 million civil penalty*** and to ***disgorge $1 million***, including interest, to resolve the FERC's investigation into violations, between Jul 2012 and Sep 2013, of the FERC's Anti-Manipulation Rules

XII. Misc. - Administrative & Rulemaking Proceedings

27	Offshore Wind Integration in RTOs/ISOs Tech Conf (AD20-18)	Dec 7	Transcript of Oct 27, 2020 tech conf posted in FERC's eLibrary
28	Hybrid Resources Technical Conference Tech Conf (AD20-9)	Dec 8	Transcript of Jul 23, 2020 tech conf posted in FERC's eLibrary

XIII. Natural Gas Proceedings

37	Enforcement Action: BP Initial Decision (IN13-15)	Dec 17	FERC issues *Opinion 549-A*, a 159-page decision addressing arguments raised on rehearing requested of *Opinion 549*, modifying the discussion in Opinion 549, but reaching 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***).

XIV. State Proceedings & Federal Legislative Proceedings

*	40	New England States' Vision Statement / On-Line Technical Forums	Dec-Jan	On-line tech forums announced by State Agencies include: Jan 13, 2021 (9:00am - 2:00pm) - Wholesale Market Reform Jan 25, 2021 (1:00pm - 6:00pm) - Wholesale Market Reform Feb 2, 2021 (1:00pm - 6:00pm) - Transmission Planning Feb 2021 (TBD) - Governance Reform

XV. Federal Courts

*	41	Exelon PP-10 Complaint (20-1509)	Dec 18	Exelon petitions DC Circuit Court of Appeals for review of the FERC's orders denying its PP-10 Complaint
			Dec 23	Court issues order requiring appearances, docketing statements and statement of issues by Jan 22, 2021; dispositive motions, if any, and a Certified Index to the Record, by Feb 8, 2021
	42	ISO-NE Implementation of Order 1000 Exemptions for Immediate Need Reliability Projects (20-1422)	Dec 7	Court extends deadlines for the filing of procedural and dispositive motions to Dec 10 and Dec 28, 2020, respectively
			Dec 10	FERC requests at least 60 days between the filing of LS Power's opening brief and the FERC's brief in response
			Dec 28	FERC files certified index to the record
			Dec 29	Court grants Avangrid, MMWEC interventions
	42	CIP IROL Cost Recovery Rules (20-1389)	Dec 18	FERC requests, with Petitioners' consent, a *revised* briefing schedule (adding 45 days to previous deadlines)
			Dec 22	Court issues order establishing *revised* briefing schedule, as requested
	42	Mystic 8/9 Cost of Service Agreement (20-1343; 20-1361, 20-1362; 20-1365, 20-1368) (consolidated)	Jan 5	FERC requests this proceeding be held in abeyance until Feb 26, 2021 (7 days after parties have an opportunity to appeal the *Dec 21 Order Addressing Arguments Raised on Rehearing*), when parties will file motions to govern further proceedings
	44	ISO-NE's Inventoried Energy Program (Chapter 2B) Proposal (19-1224)	Dec 11	Petitioners file opening briefs
	44	PennEast Project (18-1128)	Dec 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"
	45	Opinion 569/569-A: FERC's Base ROE Methodology (16-1325) (consol.)	Dec 3	FERC files certified Index to the Record
			Dec 23	Parties file joint unopposed briefing schedule
			Dec 23	First Energy moves to voluntarily dismiss cases 20-1227 & 20-1275
			Dec 29	Court consolidates 20-1513 with 16-1325
			Jan 5	Court grants FirstEnergy Dec 23 motion, dismissing 20-1227 & 20-1275

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: January 6, 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 January 6, 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 is 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

[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)**

The wavier of FERC regulations that require that filings with the FERC be notarized or supported by sworn declarations is ***in effect through January 29, 2021***.[5] The August 20 notice extended the waiver first noticed in May.[6] 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.[7]

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

The extension of the blanket waivers of ISO/RTO Tariff *in-person*[8] meeting and notarization requirements has similarly been ***extended through January 29, 2021***.[9] The August 20, 2020 order extended the blanket waivers first granted in the FERC's April 2, 2020 order.[10]

I. Complaints/Section 206 Proceedings

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

On December 11, 2020, NEPGA filed a complaint against ISO-NE alleging 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 seeks 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

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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 (Aug. 20, 2020).

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

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

[8] 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).

[9] *Temporary Action to Facilitate Social Distancing*, 172 FERC ¶ 61,151 (Aug. 20, 2020).

[10] *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).

NESCOE, ***NECOS/ENE***[11] and ***CT State Agencies***.[12] ***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. 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 October 13, 2020, NECEC Transmission LLC ("NECEC") and Avangrid Inc. (together, "Avangrid") filed a complaint against NextEra[13] requesting FERC action "to stop NextEra from unlawfully interfering with the interconnection of the New England Clean Energy Connect transmission project ("NECEC Project")." The Complaint seeks, among other things, an initial, expedited order that grants certain relief[14] and directs NextEra to immediately commence engineering, design, planning and procurement activities that are necessary 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 and 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, 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

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[11] "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").

[12] "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")

[13] 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").

[14] 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.

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 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)**

New England Generators[15] August 25, 2020 complaint against Exelon[16] remains pending. 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 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[17] and Connecticut Parties.[18] On September 28, NEPGA answer Exelon's answer. Interventions only were filed by Calpine, ENE, Eversource, Massachusetts Attorney General ("MA AG") National Grid, and Public Citizen. 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).

- **206 Proceeding: FCM Pricing Rules Complaints Remand (EL20-54)**

On December 2, 2020, the FERC issued an order[19] finding the price-lock mechanism and zero-price offer rule ("New Entrant Rules") no longer just and reasonable and directing ISO-NE to remove them from the Tariff.[20] Specifically, the FERC found that, "in light of changed circumstances, the New Entrant Rules are unjust and unreasonable because they result in unreasonable price distortion."[21] The FERC further found that the FCA price

[15] "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.

[16] 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.").

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

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

[19] *ISO New England Inc.*, 173 FERC ¶ 61,198 (Dec. 2, 2020) ("*December 2 Order*").

[20] *Id.* at PP 1, 77.

[21] *Id.* at P 68.

assurance that the FERC previously found necessary in approving these rules is no longer required to attract new entry, with the benefits provided by price certainty no longer outweighing their price suppressive effects. The FERC clarified that the "termination of the price lock will not impact price-lock agreements in effect prior to the issuance of the order".[22] The FERC directed ISO-NE to submit a compliance filing, on or before February 1, 2021, eliminating the price lock and associated zero-price offer rule for new entrants starting in FCA16.[23] The ISO-NE's proposed compliance changes will be reviewed at Markets Committee meetings in January (January 12-13 and 19).

As described in previous Reports, this proceeding was instituted when 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"),[24] found preliminarily that ISO-NE's new entrant rules may be unjust and unreasonable.[25] 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.[26]

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).

- **RNS/LNS Rates and Rate Protocols Settlement Agreement II (ER20-2054)**

On December 28, 2020, the FERC approved the uncontested Joint Offer of Settlement ("Settlement Agreement II") filed by the Transmission Owners to resolve all issues in this proceeding.[27] In approving Settlement Agreement II, the FERC suggested that it would be "legally authorized to impose a more rigorous application of the statutory "just and reasonable" standard of review" if it were required to determine the standard of review in a later challenge to Settlement II by a third party or by the Commission acting *sua sponte*.[28] The TOs were directed to make a compliance filing in this proceeding on or before January 27, 2021, with revised tariff records in eTariff format reflecting the FERC's action in the December 28 order. Challenges or requests for clarification, if any, would also be due on or before January 27, 2021. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

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

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[22] *Id.*

[23] *Id.*

[24] *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).

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

[26] 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.

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

[28] Id. at PP 3-4

- ***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,[29] 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*).[30] However, the FERC's orders were challenged, and in *Emera Maine,*[31] 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)[32] and third (EL14-86)[33] ROE complaint proceedings were consolidated for purposes of hearing and decision, though the parties were permitted to litigate a separate ROE for each refund period. After hearings were completed, ALJ Sterner issued a 939-paragraph, 371-page *Initial Decision*, which lowered the base ROEs for the EL13-33 and EL14-86 refund periods from 11.14% to 9.59% and 10.90%, respectively.[34] 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[35] also went to hearing before an ALJ, Judge Glazer, who issued his initial decision on March 27, 2017.[36] The *Base ROE IV Initial Decision* concluded that the currently-filed base ROE of 10.57%, which may reach a

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29 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*")).

30 *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*").

31 *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).

32 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%.

33 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.

34 *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*").

35 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.

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

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.[37] 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.[38] 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*[39] (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.[40]

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

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

The FERC provided preliminary analysis of how it would apply the proposed methodology in the Base ROE I Complaint, suggesting that it would affirm its holding that an 11.14% Base ROE is unjust and unreasonable. The FERC suggested that it would adopt a 10.41% Base ROE and cap any preexisting incentive-based total ROE at 13.08%.[41] 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

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

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

[39] *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*.

[40] *Id.* at P 19.

[41] *Id.* at P 59.

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[42] for an extension of time to submit briefs, the latest date for filing initial and reply briefs was extended to January 11 and March 8, 2019, respectively. On January 11, initial briefs were filed by EMCOS, Complainant-Aligned Parties, TOs, EEI, Louisiana PSC, Southern California Edison, and AEP. As part of their initial briefs, each of the Louisiana PSC, SEC and AEP also moved to intervene out-of-time. Those interventions were opposed by the TOs on January 24. The Louisiana PSC answered the TOs' January 24 motion on February 12. Reply briefs were due March 8, 2019 and were submitted by the TOs, Complainant-Aligned Parties, EMCOS, FERC Trial Staff.

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*[43] 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).

II. Rate, ICR, FCA, Cost Recovery Filings

- **Dynegy CIP IROL (Schedule 17) Cost Recovery Filing (ER21-774)**

On December 30, 2020, Dynegy Marketing & Trade, LLC ("Dynegy") requested FERC acceptance of a proposed rate schedule to allow Dynegy to begin the recovery period for certain Interconnection Reliability Operating Limits Critical Infrastructure Protection costs ("CIP-IROL Costs") under Schedule 17 of the ISO-NE Tariff. Dynegy stated that the rate schedule will provide interested parties notice of Dynegy'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 March 1, 2021 effective date was requested. Comments on this filing are due on or before January 21, 2021. Thus far, Calpine and NESCOE have filed doc-less interventions. If you have any questions concerning these 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

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

[43] *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).

("Use Agreement")[44] 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 are due on or before January 8, 2021. Thus far, Avangrid, ENE and NESCOE have filed doc-less interventions. If you have any questions concerning these matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **ICR-Related Values and HQICCs – Annual Reconfiguration Auctions (ER21-496)**

On November 25, 2020, ISO-NE and NEPOOL jointly filed materials that identify the Installed Capacity Requirement ("ICR"), Local Sourcing Requirements ("LSR"), Maximum Capacity Limits ("MCL"), Hydro Quebec Interconnection Capability Credits ("HQICCs"), and capacity requirement values for the System-Wide and Marginal Reliability Impact Capacity Demand Curves (collectively, the "ICR-Related Values") for the third annual reconfiguration auction ("ARA") for the 2021-22 Capability Year, the second ARA for the 2022-23 Capability Year, and the first ARA for the 2023-24 Capability Year. The ICR-Related Values were supported by the Participants Committee at its November 5, 2020 meeting (Consent Agenda Items 3 and 4). A January 24, 2021 effective date was requested. Comments on this filing were due December 15, 2020; none were filed. Dominion, NRG, NESCOE and National Grid filed doc-less interventions. This matter is pending before the FERC. If you have any questions concerning these matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **FCA15 Qualification Informational Filing (ER21-372)**

On November 10, 2020, ISO-NE submitted its informational filing (the "FCA15 Informational Filing") for qualification in FCA15. ISO-NE is required under Market Rule Section 13.8.1 to submit an informational filing with the FERC containing the determinations made by ISO-NE for the upcoming Forward Capacity Auction ("FCA") at least 90 days prior to each auction. FCA15 is scheduled to begin February 8, 2021. The Informational Filing contained ISO-NE's determinations that four Capacity Zones will be modelled for FCA15 -- Southeastern New England ("SENE"), Northern New England ("NNE"), the Maine Capacity Zone ("Maine"), and Rest of Pool. SENE will again be modeled as import-constrained; NNE will be modeled as export-constrained. The Maine Load Zone will be modeled as a separate nested export-constrained Capacity Zone within NNE. The Informational Filing reported that there will be 33,662 MW of existing capacity in FCA15 competing with 7,030 MW of new capacity under a Net ICR of 33,270 MW (ICR minus HQICCs). ISO-NE reported also that there were a total of 813 MW of Static De-List Bids. A summary of the De-List Bids accepted and those rejected for reliability purposes was included in a privileged Attachment E. ISO-NE qualified 13 demand bids, totaling 196 MW, and 116 supply offers, totaling 463 MW, to participate in the substitution auction.

Comments on the FCA15 Informational Filing were due November 25, 2020. Limited protests were filed by Andro Hydro, Mystic and NEPGA. ***Andro Hydro*** protested the basis for the IMM's mitigation of its resources. ***NEPGA***'s limited protest focused on the qualification of the Killingly Energy Center, requesting that the FERC require ISO-NE to submit additional confidential information regarding that qualification (related to the project's development progress) so that it can assess ISO-NE's determinations. ***Mystic***, for its part, asserted that the Informational Filing is based on a flawed transmission security analysis and the FERC should direct ISO-NE to re-run its transmission security analysis to reconsider its decision to assume completion of a

[44] 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 IMC.

now delayed and contentious NECEC transmission project when conducting that analysis. ISO-NE answered the NEPGA and Mystic protests on December 10, 2020; the IMM, Andro Hydro. Doc-less interventions were filed by NEPOOL, NEPOOL, Boston Energy Trading and Marketing, Calpine, Dominion, Eversource, National Grid, NESCOE, NRG, Avangrid (out-of-time) and EPSA (out-of-time). This matter is pending before the FERC. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **ICR-Related Values and HQICCs – FCA15 (2024-25) Capacity Commitment Period (ER21-371)**

On November 10, 2020, ISO-NE filed the ICR, LSR for SENE, MCL for the Maine and NNE Capacity Zones, HQICCs, and Marginal Reliability Impact ("MRI") Demand Curves (collectively, the "2024-25 ICR-Related Values") for the 2024-25 Capacity Commitment Period ("CCP"). The 2024-25 ICR will be 34,153 MW (reflecting tie benefits of 1,735 MW) and HQICCs of 883 MW/mo., the net amount of capacity to be purchased in FCA15 to meet the ICR will be 33,270 MW. The LSR for the SENE Capacity Zone is 10,305 MW. The MCL for the Maine Capacity Zone is 4,145 MW. The MCL for the NNE Capacity Zone is 8,680 MW. The Participants Committee supported the FAC15 ICR-Related Values at its October 1, 2020 virtual meeting. Comments on this filing were due December 1; none were filed. Doc-less interventions were filed by Calpine, Dominion, Eversource, MA DPU, National Grid, NESCOE, and NRG. This matter is still pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Sophia Browning (202-218-3904; sbrowning@daypitney.com).

- **2021 NESCOE Budget (ER21-113)**

On December 18, 2020, the FERC accepted ISO-NE's October 15, 2020 filing of the budget for funding NESCOE's 2021 operations.[45] As previously reported, the 2021 Operating Expense Budget for NESCOE is $2,428,300. The amount to be recovered reflects true-ups from 2019 (over-collections of $1,067,405). Accordingly, if accepted, the NESCOE budget will result in a charge of $0.00626 per kilowatt ("kW") of Monthly Network Load. Unless the NESCOE 2021 Budget Order is challenged, this proceeding will be concluded. If there are any questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **2021 ISO-NE Administrative Costs and Capital Budgets (ER21-106)**

Also on December 18, 2020, the FERC accepted ISO-NE's 2021 Budgets (its "2021 Revenue Requirement" and its "2021 Capital Budget").[46] As previously reported, the 2021 Revenue Requirement is $205.1 million (administrative costs (i.e., the 2021 Core Operating Budget) of $178.6 million; depreciation and amortization of regulatory assets, $26.3 million; and a $151,000 true-up for 2019 under-collections.); the 2021 Capital Budget, $28 million. The 2021 Capital Budget is comprised of the following (with 2021 projected costs and target completion dates, if available, in parentheses):

‣ nGem Market Clearing Engine Implementation (Mar 2023)	($5.3 million)	‣ Energy Security Improvements	($3.0 million)
‣ nGem Software Development Part II (Dec 2021)	($2.0 million)	‣ Forward Capacity Tracking System Infrastructure Conversation Part II (Dec 2020)	($2 million)
‣ 2021 Issue Resolution Projects (June 2021 and Dec 2021)	($1.5 million)	‣ 2020 Corrective Action Preventative Actions (Mar 2021)	($100,000)
‣ Enhanced Market Simulator	($1.5 million)	‣ CIP Electronic Security Perimeter Redesign	($1 million)

45 *ISO New England Inc.,* Docket No. ER21-113 (Dec. 18, 2021) (unpublished letter order) ("NESCOE 2021 Budget Order").

46 *ISO New England Inc.,* Docket No. ER21-106 (Dec. 18, 2021) (unpublished letter order) ("2021 ISO-NE Budgets Order").

- Forward Capacity Tracking System Infrastructure Conversation Part II (Jun 2021) ($1 million)
- Identity and Access Management – Phase II (May 2021) ($700,000)
- Data Governance, Risk Management & Compliance Software Phase I (Jun 2021) ($400,000)
- IMM Data Analysis Phase III (Nov 2021) ($500,000)
- Sub-accounts for FTR Market (Aug 2021) ($500,000)
- TranSMART Technical Architecture Update (Dec 2021) ($500,000)
- FERC Form 1, 3-Q, 714 (Oct 2021) ($200,000)
- Wireless Infrastructure Upgrade (Jun 2021) ($200,000)
- 2020 Issue Resolution Projects (Mar 2021) ($100,000)
- Cyber Security Improvements (Sep 2021) ($1 million)
- Enterprise Application Integration Phase III (Nov 2021) ($500,000)
- Data Governance, Risk Management & Compliance Software Phase II (Nov 2021) ($500,000)
- Human Resources Workflow & Document Management (Jun 2021) ($500,000)
- Security Information and Event Management Log Monitoring ($500,000)
- PI Historian for Short-term PMU Data Repository (Jun 2021) ($300,000)
- External Website Migration to Cloud (Mar 2021) ($100,000)
- Non-Project Capital Expenditures ($3.5 million)
- Other Emerging Work ($1.9 million)
- Capitalized Interest ($500,000)

Unless the 2021 ISO-NE Budgets Order is challenged, this proceeding will be concluded. If there are any questions on this proceeding, please contact Paul Belval (860-275-0381; pnbelval@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")[47] 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 17 Orders*[48] (and the earlier, underlying orders) have been appealed to the DC Circuit.

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,

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[47] 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.

[48] 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).

Connecticut Parties, ENECOS, 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,[49] 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, Mystic answered the CT Parties' and ENECOS' protests. The compliance filing is pending before the FERC.

Dec 21 Order Addressing Arguments Raised on Rehearing (-004; -005; -006). On December 21, 2020, the FERC issued an "Allegheny Order"[50] modifying the discussion in the *July 17 Orders*,[51] and setting aside in part both the *July 2018 Rehearing Order* and the *July 17 Compliance Order*. Changes to those orders included:

(i) a FERC finding that "a Tank Congestion Charge and a methodology for calculating tank congestion costs may be necessary for Mystic to demonstrate that ISO-NE ratepayers only pay the costs of tank congestion that are attributable to serving Mystic ... [t]o the extent the [*Dec 2018 Rehearing Order*] called into question ISO-NE's plans to develop this methodology with Exelon, we modify the [*Dec 2018 Rehearing Order*];"[52]

(ii) Persuaded by NESCOE's request for clarification, the FERC modified the *Dec 2018 Rehearing Order* to state that Tank Congestion Charges may be reviewed in the true-up process;[53] the FERC also agreed with Mystic and clarified that it did not intend to impose a heightened standard of review or *ex post* second-guessing of fuel supply practices, but rather its intent was limited to the expectation that ISO-NE will audit and ensure that the tank congestion charge is properly calculated;[54]

(iii) Persuaded by New England Generators arguments on rehearing, the FERC found the language "that were expensed" renders the clawback provision in section 2.4 of the Mystic Agreement unjust and unreasonable, and directed Mystic to remove that language;[55]

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

[50] *Constellation Mystic Power, LLC*, 173 FERC ¶ 61,261 (Dec. 21, 2020) ("*Dec 21 Order Addressing Arguments Raised on Rehearing*").

[51] 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).

[52] *Id.* at P 26.

[53] *Id.* at P 27.

[54] *Id.* at P 28.

[55] *Id.* at P 33.

(iv) As requested by NESCOE, the FERC clarified that "the third-party revenue crediting mechanism discussed in the July 2020 Orders refers to a specific type of third-party sales that were subject to the revenue crediting mechanism recommended by Trial Staff and adopted by the December 2018 Order (i.e., forward sales)."[56]

As noted above, the *July 17 Orders* have been appealed to the DC Circuit and further developments will be reported on in Section XV below. 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 ("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").[57] Initial comments and reply comments are due January 18 and 27, 2021, respectively. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

- **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 are due on or before January 21, 2021. Thus far, doc-less interventions have been filed by Avangrid, Brookfield, Calpine, Dominion, LS Power, MA AG, NRG, and NESCOE. 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).

- **New DDBT Methodology (ER21-782)**

On December 31, 2020, ISO-NE and NEPOOL jointly filed proposed Tariff revisions to implement a new methodology for calculating the FCM Dynamic De-List Bid Threshold ("DDBT"). Specifically, the new DDBT Methodology would replace the current triennial update methodology with an annual one, with the DDBT to be calculated annually for each FCA, using a new Tariff-based DDBT calculation methodology. That methodology,

[56] *Id.* at P 39.

[57] 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).

referred to as the "recalibration method," updates the DDBT value for each auction based on the most recently available supply conditions, as evidenced in the last FCA, and the most up-to-date projected demand conditions, using the estimated system-wide demand curve for the next FCA. The new DDBT methodology filed was the compromise DDBT proposal overwhelmingly approved by the Participants Committee in November, rather than the one that had been offered by ISO-NE. A March 2, 2021 effective date was requested. Comments on this filing are due on or before January 21, 2021. Thus far, doc-less interventions have been filed by Brookfield, Calpine, Dominion, LS Power, MA AG, NRG, and NESCOE. 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).

- **Energy Efficiency Resource FCM Qualification Modifications (ER21-640)**

On December 14, 2020, ISO-NE and NEPOOL jointly filed changes to the Market Rules to (i) produce Qualified Capacity values that better reflect performance capabilities of Energy Efficiency Resources ("EERs"); (ii) modify the rules that determine the quantity of Capacity Supply Obligation ("CSO") that a resource of any type may acquire in monthly reconfiguration auctions or CSO Bilateral transactions to increase trading opportunities; and (iii) reflect a number of conforming and clean-up changes ("EER FCM Qual. Modifications"). The EER FCM Qual. Modifications were approved by the Participants Committee at the December Annual meeting (Consent Agenda Item No. 1). A February 12, 2021 effective date was requested. Comments on this filing were due on or before January 4, 2021; none were filed. Calpine, Eversource, National Grid, NESCOE, and the MA DPU filed doc-less interventions. 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).

- **ESI Alternatives (ER20-1567)**

On October 30, 2020, the FERC rejected as unjust and unreasonable both the ISO-NE and NEPOOL "Energy Security Improvements" or "ESI" proposals.[58] Finding that ISO-NE failed to demonstrate that ESI will materially improve fuel security, and treating the filing as submitted under FPA section 205,[59] the FERC concluded that "ESI does not strike an appropriate balance between addressing fuel security in New England while protecting consumers from the significant cost of those fuel security benefits."[60] And, although the FERC noted that the NEPOOL Alternative would result in lower costs to consumers than ISO-NE's ESI proposal, they rejected the NEPOOL Alternative as unjust and unreasonable because it contained the "same deficiencies that render ISO-NE's proposal unjust and unreasonable."[61]

Because the FERC rejected both alternative ESI proposals, the FERC also rejected ISO-NE's associated proposal to sunset one year earlier than currently provided for in the Tariff the Fuel Security Retention Mechanism and the Inventoried Energy Program (the Interim Programs).[62]

The FERC made no finding on whether ISO-NE faces a fuel security or energy security issue,[63] but said ISO-NE may propose "other steps it believes are warranted to address fuel security, such as submitting a revised long-

[58] *ISO New England Inc.*, 173 FERC ¶ 61,106 (Oct. 30, 2020) ("*Order Rejecting ESI Alternatives*"), *clarif. requested*.

[59] *Id.* at n. 2. The April 15, 2020 ESI filing was submitted in response to the requirements of the *Mystic Waiver Order*, which directed ISO-NE, in part, to submit permanent Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns. *See ISO New England Inc.*, 164 FERC ¶ 61,003 (July 2, 2018), *reh'g requested* ("*Mystic Waiver Order*").

[60] *Id.* at P 55.

[61] *Id.* at P 56.

[62] *Id.* at P 63.

[63] *Id.* at P 57.

term fuel security proposal or seeking to extend one or more of the Interim Programs."[64] While the FERC did not direct ISO-NE to pursue any particular approach, if ISO-NE decides to pursue a solution to address their concerns, it encouraged ISO-NE:

> "to explore a market-based reserve product that provides resources sufficient lead time and ability to acquire fuel or take other steps necessary to be able to deliver energy when needed. We expect that such a market solution would be designed to (1) coordinate procurement of forward reserves with co-optimization of energy and reserves in the day-ahead and real-time markets; (2) incentivize resources to offer into the forward, day-ahead and real-time energy and reserves markets based on their actual costs; (3) prevent the exercise of market power, including through mitigation measures, if necessary; and (4) include financial obligations or incentives sufficient to ensure resources can deliver energy and/or reserves in real-time."[65]

The FERC noted that nothing in its order prohibits ISO-NE from proposing a Day-Ahead reserves market independent of any proposal to address the concerns at issue in the ESI proceeding.[66]

On November 13, 2020, ISO-NE requested clarification of the *Order Rejecting ESI Alternatives*. Specifically, ISO-NE asked the FERC to clarify that ISO-NE may engage in communications with the FERC and its staff about the ESI market design, the design of the reserve markets, the option construct, and the voluntary nature of the markets as of December 1, 2020, unfettered from any *ex parte* restrictions arising out of this or antecedent proceedings (e.g. ER18-1509 and EL18-182 (*see* ISO-NE Waiver Filing: Mystic 8 & 9 below)). On December 18, 2020, ISO-NE withdrew its November 13 request, citing (i) the passage of the deadline for parties to request (and no requests filed for) rehearing and/or clarifications of the *Order Rejecting ESI Alternatives* and (ii) the December 3, 2020 orders issued in Docket Nos. ER18-1509 and EL18-182.

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).

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

As previously reported, the FERC conditionally accepted both the November 22, 2019[67] and February 10, 2020[68] *Order 841*[69] compliance filings, each subject to additional compliance filing(s). On December 7, 2020, ISO-NE and NEPOOL filed, in one comprehensive filing, revisions to Market Rule 1 in response to the requirements of the *Order 841 Compliance Filing II Order*.[70] The revisions were supported by the Participants Committee at the December Annual Meeting (Consent Agenda Items 2 and 3). A March 1, 2021 effective date was requested for the majority of the revisions; a January 1, 2026 effective date was requested for the revisions specific to the Day-Ahead Energy Market. Comments on the December 7 filing were due on or before December 28, 2020; none were filed. No additional parties intervened in the proceeding. This matter

64 *Id.* at P 63.

65 *Id.* at P 57.

66 *Id.*

67 *ISO New England Inc.*, 169 FERC ¶ 61,140 (Nov. 22, 2019) ("*Order 841 Initial Compliance Filing Order*").

68 *ISO New England Inc.*, 172 FERC ¶ 61,125 (Aug. 4, 2020) ("*Order 841 Compliance Filing II Order*").

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

70 The compliance filing included revisions addressing (i) the application of transmission charges; (ii); ISO-NE Market participation (ensuring the Tariff cannot be read to create a barrier to entry); and (iii) how state of charge and duration characteristics will be accounted for in the Day-Ahead Energy Market.

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

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

On December 3, 2020, the FERC issued an "Allegheny Order"[71] addressing arguments raised in requests for rehearing and/or clarification of the *Fuel Security Retention Proposal Order*[72] by NEPGA, NRG, Verso, Vistra/Dynegy, MPUC, and PIOs.[73] While "[p]ursuant to *Allegheny Defense Project v. FERC*, the rehearing requests filed in this proceeding may be deemed denied by operation of law … as permitted by section 313(a) of the FPA, [the FERC modified] the discussion in the *Fuel Security Retention Proposal Order*,"[74] the FERC modified the order, in part, sustained the results of the *Fuel Security Retention Proposal Order* and denied Verso's request for reconsideration.[75] Specifically, the FERC clarified that it reviewed ISO-NE's Tariff revisions in this proceeding "as a new FPA section 205 filing" and to the extent that the FERC in the *Fuel Security Retention Proposal Order* "referred to ISO-NE's filing as a compliance filing, which built on how ISO-NE styled its filing,"[76] the FERC modified the *Fuel Security Retention Proposal Order* consistent with its clarification.

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

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

Also on December 3, 2020, the FERC issued an "Allegheny Order"[77] addressing arguments raised in requests for rehearing and/or clarification of the *Mystic Waiver Order*[78] by NEPGA, Connecticut Parties,[79] ENECOS, MA AG, MPUC, New England EDCs,[80] PIOs,[81] and AWEA/NGSA. The *Mystic Waiver Allegheny Order* modified the discussion in the *Mystic Waiver Order* and reached the same result.[82] The *Mystic Waiver Allegheny Order* also

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71 *ISO New England Inc.*, 173 FERC ¶ 61,204 (Dec. 3, 2020) ("*Fuel Security Retention Proposal Allegheny Order*").

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

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

74 *Fuel Security Retention Proposal Allegheny Order* at P 2.

75 *Id.* at Ordering Paragraphs (A) and (B).

76 *Id.* at P 34.

77 *ISO New England Inc.*, 173 FERC ¶ 61,205 (Dec. 3, 2020) ("*Mystic Waiver Allegheny Order*").

78 *ISO New England Inc.*, 164 FERC ¶ 61,003 (July 2, 2018) ("*Mystic Waiver Order*") (denying ISO-NE's request for waiver of certain Tariff provisions that would have permitted ISO-NE to retain Mystic 8 & 9 for fuel security purposes (ER18-1509); and (ii) instituting an FPA Section 206 proceeding (EL18-182), finding preliminarily that the ISO-NE Tariff may be unjust and unreasonable in that it fails to address specific regional fuel security concerns identified in the record that could result in reliability violations as soon as year 2022).

79 "Connecticut Parties" are CT PURA and CT DEEP.

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

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

82 *Mystic Waiver Allegheny Order* at P 2.

terminated the FPA section 206 proceeding instituted in Docket No. EL18-182.[83] Unless the *Mystic Waiver Orders* are challenged in Federal Court, this proceeding will be terminated. If you have any questions concerning this proceeding, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

IV. OATT Amendments / TOAs / Coordination Agreements

No Activities to Report

V. Financial Assurance/Billing Policy Amendments

- **FAP Info Disclosure/KYC Requirements (ER21-816)**

On January 6, 2021, ISO-NE and NEPOOL jointly filed revisions to the Financial Assurance Policy ("FAP") that (i) update FAP information disclosure requirements; (ii) update risk management disclosure requirements; and (iii) add a provision regarding prior uncured payment defaults and entry into the New England Markets (collectively, the "FAP Info Disclosure/KYC Requirements"). A March 9, 2021 effective date was requested. The changes were unanimously supported by the Participants Committee at its November 5 meeting (Agenda Item #5). Comments on this filing will be due on or before January 27, 2021. Thus far, Brookfield submitted a doc-less intervention. If you have any questions concerning this matter, please contact Paul Belval (pnbelval@daypitney.com; 860-275-0381).

VI. Schedule 20/21/22/23 Changes

- **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. 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*

[83] *Id.*

Order,[84] and certified by Settlement Judge Dring[85] to the Commission,[86] 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 have any questions concerning these matters, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

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

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

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

The TOs' November 2, 2015 refund report documenting resettlements of regional transmission charges by ISO-NE in compliance with *Opinions No. 531-A*[87] *and 531-B*[88] 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).

[84] *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.

[85] 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.

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

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

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

- **Capital Projects Report - 2020 Q3 (ER21-108)**

On December 15, 2020, the FERC accepted ISO-NE's Capital Projects Report and Unamortized Cost Schedule covering the third quarter ("Q3") of calendar year 2020 (the "Report").[89] ISO-NE was required to file the Report under Section 205 of the FPA pursuant to Section IV.B.6.2 of the Tariff. Report highlights included the following new projects: (i) nGEM Market Clearing Engine Implementation ($13,900,500); and (ii) CELT Report Automation Phase I ($155,500). The following four projects had significant changes: (i) ESI (2020 Budget decrease of $1 million); (ii) 2020 Issue Resolution Project Part II (2020 Budget decrease of $540,000); (iii) Energy Management Platform 3.2 Upgrade Part II (2020 Budget increase of $250,000); and (iv) Enterprise Application Integration Replacement Phase I (2020 Budget increase of $100,000). The Q3 Report was accepted effective as of October 1, 2020, as requested. Unless the December 15 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

IX. Membership Filings

- **January 2021 Membership Filing (ER21-769)**

On December 29, 2020, NEPOOL requested that the FERC accept: (i) the memberships of the following: Cassadaga Wind LLC (Supplier Sector); Centrica Business Solutions Optimize, LLC (Supplier Sector); Pilot Power Group, LLC (Supplier Sector); and SmartestEnergy US LLC (Supplier Sector); and the termination of the Participant status of Wheelabrator Bridgeport, LP. Comments on this filing are due on or before January 20, 2021.

- **December 2020 Membership Filing (ER21-499)**

On November 30, 2020, NEPOOL requested that the FERC accept the termination of the Participant status of the following: Eagle's View Partners, Ltd.; Goose River Hydro, Inc.; Patriot Partnership LLC; SFE Energy Connecticut, Inc., and Emera Energy Services Subsidiary No. 9 LLC. This filing is pending before the FERC.

- **November 2020 Membership Filing (ER21-260)**

On December 17, 2020, the FERC accepted the membership of Nautilus Solar Energy, LLC (AR Sector, RG Sub-Sector, Large AR RG Group Seat).[90] Unless the December 17 order is challenged, this proceeding will be concluded.

- **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 meeting. A doc-less intervention was submitted by Public Citizen. This informational filing is still pending before the FERC.

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).

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[89] *ISO New England Inc.*, Docket No. ER21-108 (Dec. 15, 2020).

[90] *New England Power Pool Participants Comm.*, Docket No. ER21-260 (Dec. 17, 2020).

- **Joint Staff White Papers on Notices of Penalty for Violations of CIP Standards (AD19-18)**

On September 23, 2020, following review of the comments submitted on their First White Paper,[91] FERC and NERC staff ("Joint Staffs") issued their second White Paper on Notices of Penalty Pertaining to Violations of Cortical Infrastructure Protection ("CIP") Reliability Standards ("Second White Paper"). Having determined based on those comments that the First White Paper proposal was insufficient to protect the security of the BPS, Joint Staffs modified the prior proposal. Going forward, CIP noncompliance submissions[92] will be filed or submitted by NERC with a request that the *entire* filing or submittal be designated as Critical Energy/Electric Infrastructure Information ("CEII") and FERC staff will designate the entire filing or submittal accordingly. Because of the risk associated with the disclosure of CIP noncompliance information, NERC will no longer publicly post redacted versions of CIP noncompliance filings and submittals.

- **NERC Annual Report on FFT & Compliance Exception Programs (RC11-6-011)**

On December 30, 2020, NERC filed its annual report on Find, Fix, and Track ("FFT") and Compliance Exception programs, in accordance with prior FERC Orders.[93] In the report, NERC stated that the ERO Enterprise appropriately handles noncompliance posing a minimal or moderate risk through these programs and that the results of the annual report show consistent improvement in program implementation. The report also demonstrates, NERC suggests, significant alignment across the ERO Enterprise, particularly in the processing and understanding of the risk associated with individual noncompliance. Comments on the annual report are due on or before January 21, 2021.

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

On December 14, 2020, NERC filed for approval proposed changes to Reliability Standards CIP-013-2, CIP-005-7, and CIP-010-4 (the "Supply Chain Standards"). 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. NERC asked that the Supply Chain Standards become effective (and the currently effective versions be retired) on the first day of the first calendar quarter that is 18 months following FERC approval. As of the date of this Report, a comment date has not yet been noticed.

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

On March 19, 2020, NERC submitted, as directed by the FERC,[94] an informational filing describing the activity of two NERC CIP standard drafting projects pertaining to virtualization and cloud computing services,

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[91] The first White Paper, prepared jointly by FERC and NERC staff, was issued on August 27, 2019. The First White Paper set out a proposed new format for NERC Notices of Penalty ("NOP") involving violations of CIP Reliability Standards. The First White Paper explained that the revised format was intended to improve the balance between security and transparency in the filing of NOPs. Specifically, NERC CIP NOP submissions would consist of a proposed public cover letter that discloses the name of the violator, the Reliability Standard(s) violated (but not the Requirement), and the penalty amount. NERC would submit the remainder of the CIP NOP filing containing details on the nature of the violation, mitigation activity, and potential vulnerabilities to cyber systems as a nonpublic attachment, along with a request for the designation of such information as CEII.

Few commenters supported the First Joint White Paper proposal without seeking modifications to either expand or reduce the amount of information that would be publicly disclosed. Comments submitted by private citizens, state representatives, and consumer advocate offices supported more disclosure of CIP noncompliance information. By contrast, most industry commenters and trade organizations raised concerns with at least some of the proposed disclosures because of the increased risk to the security of the Bulk-Power System ("BPS").

[92] Non-compliance submissions include Notices of Penalty ("NOPs"), Spreadsheet NOPs ("SNOPs"), Find, Fix and Track submissions ("FFTs") and Compliance Exceptions ("CEs")).

[93] *See N. Am. Elec. Rel. Corp.*, 138 FERC 61,193 (2012) ("March 2012 Order"); *N. Am. Elec. Rel. Corp.,* 143 FERC 61,253 (2013) ("June 2013 Order"); *N. Am. Elec. Rel. Corp.,* 148 FERC 61,214 (2014) ("September 2014 Order"); and *N. Am. Elec. Rel. Corp.*, Docket No. RC11-6-004 (Nov. 13, 2015) (unpublished letter order) ("November 2015 Order").

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

including a schedule for Project 2016-02 (Modifications to CIP Standards) and Project 2019-02 (BES Cyber System Information Access Management) (collectively, the "NERC Projects"). Comments were submitted by a private citizen (Barry Jones) and VMware, Inc. on April 21 and 27, 2020, respectively. The FERC took no action on the March 19 informational filing.

In addition, NERC is required to file on an information basis quarterly status updates, until such time as new or modified Reliability Standards are filed with the FERC. NERC filed its fourth informational filing on December 15, 2020, 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).

- **Revised Reliability Standard: CIP-002-6 (RM20-17)**

On June 12, 2020, NERC filed for approval a revised Reliability Standard -- CIP-002-6 (Cyber Security – BES Cyber System Categorization), and associated implementation plan, VRFs and VSLs (together, the "CIP-002 Changes"). NERC stated that the CIP-002 Changes improve upon the currently effective standard by clarifying the criterion for Transmission Owner Control Centers and tailoring the language to better reflect the risk posed by these Control Centers if unavailable or compromised. As of the date of this Report, the FERC has still not noticed a proposed rulemaking proceeding or otherwise invited public comment.

- **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, Solar Energy Industries Association ("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 ("BES") operations; and (ii) whether the CIP Reliability Standards impede the voluntary adoption of virtualization or cloud computing services.[95] On March 25, 2020, Joint Associations[96] 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.

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

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

In part in response the comments filed, the FERC in a December 17, 2020 order[97] 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,[98] 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."[99] 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.[100]

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*[101] (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 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).[102]

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

NERC's October 14, 2020 petition for FERC approval of its amended and restated Bylaws remains pending. 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. Comments, if any, on

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

[98] *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).

[99] *Order 873* at P 2.

[100] *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.

[101] *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.

[102] *Standards for Business Practices and Communication Protocols for Public Utilities*, 85 Fed. Reg. 55201 (September 4, 2020).

the Amended and Restated Bylaws were due on or before November 4, 2020; none were filed. This matter remains pending before the FERC.

- **Report of Comparisons of Budgeted to Actual Costs for 2019 for NERC and the Regional Entities (RR20-3)**

On November 24, 2020, the FERC accepted the NERC's comparisons of actual to budgeted costs for 2019 for NERC and the seven Regional Entities operating in 2019, including NPCC, filed by NERC on May 29, 2020.[103] The Report included comparisons of actual funding received and costs incurred, with explanations of significant actual cost-to-budget variances, audited financial statements, and tables showing metrics concerning NERC and Regional Entity administrative costs in their 2019 budgets and actual results. The November 24 order was not challenged and is final an unappealable.

XI. Misc. - of Regional Interest

- **203 Application: CPV Towantic (EC21-16)**

On December 17, 2020, the FERC authorized CPV Group LP to indirectly acquire all of the indirect voting securities owned by GIP II CPV Intermediate Holdings Partnership, L.P. ("GIP II CPV") in, among others, CPV Towantic, LLC ("CPV Towantic").[104] Upon consummation, Clearway Power Marketing and GenConn Energy will no longer be CPV Related Persons. Pursuant to the December 17 order, notice must be filed within 10 days of consummation of the transaction, which as of the date of this Report has not yet occurred.

- **203 Application: Millennium Power Partners (EC20-103)**

On November 18, 2020, the FERC authorized a transaction whereby Beal Bank USA, Beal Bank, SSB or their designee(s) ("Beal Bank") will acquire all of the membership interests in Millennium Power Partners, L.P. ("Millennium") and New Athens Generating Company, LLC (which owns facilities in New York) from Talen. Pursuant to the November 18 order, notice must be filed within 10 days of consummation of the transaction, which as of the date of this Report has not yet occurred.

- **203 Application: NRG/Direct (EC20-96)**

On November 24, 2020, the FERC authorized NRG's acquisition of, among others, Direct Energy Business and Direct Energy Business Marketing (together, "Direct").[105] The transaction was consummated on January 5, 2021. Pursuant to the November 24 order, notice must be filed within 10 days of consummation of the transaction (of January 15, 2021), which as of the date of this Report has not yet occurred.

- **203 Application: CMP/NECEC (EC20-24)**

On March 13, 2020, the FERC authorized CMP to transfer to NECEC Transmission LLC 7 TSAs, executed on June 13, 2018, that provide the rates, terms, and conditions under which transmission service will be provided over the New England Clean Energy Connect ("NECEC") Transmission Line to the participants that are funding construction of the Line.[106] Pursuant to the March 13 order, notice must be filed within 10 days of consummation of the transaction, which as of the date of this Report has not yet occurred.

- **LGIA: NSTAR / MMWEC (Stony Brook) (ER21-777)**

On December 31, 2020, NSTAR filed an LGIA with MMWEC for the continued interconnection of MMWEC'S Stony Brook Generating Station located in Ludlow, Massachusetts to NSTAR's transmission system. The LGIA replaces the original 1992 Stony Brook interconnection agreement which, as previously reported,

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103 *N. Amer. Elec. Rel. Corp.*, Docket No. RR20-3 (Nov. 24, 2020) (unpublished letter order).

104 *CPV Fairview, LLC et al.,* 173 FERC ¶ 62,149 (Dec. 17, 2020).

105 *NRG Energy, Inc. et al.*, 173 FERC ¶ 62,103 (Nov. 24, 2020).

106 *Central Maine Power Co.*, 170 FERC 62,145 (Mar. 13, 2020).

had been extended three times[107] and expired on December 31, 2020. Since the LGIA covers an existing, interconnected facility, and does not set forth any terms or conditions that would otherwise modify the interconnection services provided under the original IA, NSTAR states that a new three-party interconnection agreement (that would include ISO-NE) was not required. A December 31, 2020 effective date was requested. Comments on this filing are due on or before January 21, 2021. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **LGIA: CMP / ReEnergy Stratton (ER21-769)**

On December 30, 2020, CMP filed an LGIA to renew and replace the terms of the original interconnection agreement entered into between CMP and ReEnergy Stratton's predecessor in interest (Stratton Energy Associates). Since the LGIA covers an existing, interconnected facility, and does not set forth any terms or conditions that would otherwise modify the interconnection services provided under the original IA, CMP states that a new *three*-party LGIA (that would include ISO-NE) was not required. A December 21, 2020 effective date was requested, and includes a discussion of how charges for service provided from the expiration of the original IA (August 31, 2019) to the requested effective date have been and are to be administered. Comments on this filing are due on or before January 20, 2021. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Interim Distribution Wheeling Agreement: Unitil / Briar Hydro (ER21-759)**

On December 29, 2020, Unitil filed an Interim Distribution Wheeling Service Agreement between Unitil Energy Systems ("UES") and Briar Hydro Associates ("Briar") to provide for Briar's ongoing receipt of distribution wheeling services for the Penacook Lower Falls Resource[108] (pending UES' filing of a distribution wheeling rate in early 2021). Briar intends to sell the output of the facility into the New England Market. A December 28, 2020 effective date was requested. Comments on this filing are due on or before January 19, 2021. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement Cancellation: NSTAR / SEMASS (ER21-676)**

On December 17, 2020, NSTAR filed a notice of cancellation of a Design and Engineering Agreement ("D&E Agreement") with SEMASS Partnership ("SEMASS"). The D&E Agreement set forth the terms and conditions under which NSTAR undertook preliminary engineering, design and construction activities on its interconnection facilities to accommodate SEMASS's planned construction activity at its switchyards within its generation station. The D&E Agreement terminated by its terms on July 1, 2020 and all billing reconciliations under the D&E Agreement have been completed. A December 17, 2020 effective was requested. Comments on this filing are due on or before January 7, 2021. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **SGIA: CL&P / ECRRA (ER21-651)**

On December 15, 2020, CL&P filed a Small Generator Interconnection Agreement ("SGIA") between the itself and Eastern Connecticut Resource Recovery Authority ("ECRRA") to allow for the continued interconnection of ECRRA's refuse-to-energy municipal solid waste facility. ECCRA, through Wheelabrator North Andover, intends to sell the output of the facility into the New England Market. Since the SGIA covers an existing, interconnected facility, and does not set forth any terms or conditions that would otherwise modify the interconnection services provided under the original IA, CL&P states that a new three-party SGIA (that would include ISO-NE) was not required. A December 15, 2020 effective date was requested. Comments

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[107] *See NSTAR Elec. Co.*, Docket No. ER19-2303 (Feb. 22, 2019) (unpublished letter order) (1st extension); *NSTAR Elec. Co.*, Docket No. ER19-2303 (Aug. 22, 2019) (unpublished letter order) (2nd extension); *NSTAR Electric Co.,* Docket No. ER19-2897 (Nov. 5, 2019) (unpublished letter order) (3rd extension).

[108] The Penacook Lower Falls Resource is a 4.5 MW hydro unit located in Boscawen, New Hampshire on the southern bank of the Contoocook River.

on this filing were due on or before January 5, 2021; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **VTransco Rate Schedule 2 Cancellation (ER21-256)**

On December 18, 2020, the FERC accepted the notice of cancellation of the Vermont Yankee Transmission Agreement, which is no longer in use, filed by Vermont Transco.[109] The cancellation notice was accepted effective December 28, 2020, as requested. Unless the December 18 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).

- **D&E Agreement: NSTAR/Ocean State Power (ER21-192)**

On December 11, 2020, the FERC accepted a Preliminary Agreement for Design, Engineering and Construction services (the "D&E Agreement") between NSTAR and Ocean State Power, effective October 23, 2020.[110] The D&E Agreement sets forth the terms and conditions under which NSTAR will undertake preliminary design and engineering activities to increase the real power capacity of Ocean State Power's large generating facility. Unless the December 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).

- **NECEC TSAs: NECEC Transmission Notices of Succession and CMP Notice of Cancellation (ER21-12 et al.)**

On November 30, 2020 and December 18, 2020, the FERC accepted notices addressing the transfer of the 7 transmission service agreements ("TSAs") with the participants that will fund the construction, operation and maintenance of the NECEC Transmission Line.[111] Once the transfer of the TSAs from CMP to NECEC Transmission is consummated (see EC20-24 above), NECEC will succeed to CMP's position in the TSAs and CMP will no longer be a party to the TSAs. As a result, NECEC filed notices of succession to the TSAs[112] and CMP filed a notice cancelling the TSAs as CMP Rate Schedules in the FERC's eTariff database.[113] The notices are to be effective as of the date the transaction is consummated. If you have any questions concerning these matters, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

[109] *Vermont Transco LLC*, Docket No. ER21-256 (Dec. 18, 2020) (unpublished letter order).

[110] *NSTAR Electric Co.*, Docket No. ER21-192 (Dec. 11, 2020) (unpublished letter order).

[111] *NECEC Transmission LLC*, Docket No. ER21-12-000 (Nov. 30, 2020).

[112] The NECEC Transmission succession notices to the 7 TSAs were separately docketed as follows: Eversource (ER21-12); National Grid (ER20-13); Unitil (ER21-14); HQ US/Eversource (ER21-15); HQ US/National Grid (ER21-17); HQ US/Unitil (ER21-18); and HQ US Additional (ER21-19).

[113] *See Central Maine Power Co.*, Docket No. ER21-20 (Dec. 18, 2020) (accepting CMP notice of cancellations; effective date to be identified in a subsequent compliance filing).

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

In accordance with *Order 864*[114] and *Order 864-A,*[115] 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
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	New England TOs	pending
Jul 15, 2020	ER20-2429	CMP	pending
Jun 29, 2020	ER20-2219	New England Power	pending
Jun 23, 2020	ER20-2133	Versant Power	pending
May 18, 2020	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

- **FERC Enforcement Action: Algonquin Power Windsor Locks (IN21-2)**

On January 5, 2021, the FERC approved a Stipulation and Consent Agreement with Algonquin Power Windsor Locks LLC[116] ("Windsor Locks") that resolved OE's investigation into whether Windsor Locks complied with its ISO-NE Tariff offer obligations during the period July 1, 2012 through September 24, 2013. Enforcement determined that Windsor Locks' failure to make required offers into the ISO-NE energy markets violated provisions of the ISO-NE Tariff related to the Forward Capacity and Forward Reserve Markets and section 35.41(a) of the Commission's regulations. Under the Settlement, in which Windsor Locks neither admits nor denies the alleged violations, Windsor Locks must ***disgorge $1,119,073.15*** (which includes interest) to ISO-NE, to be allocated by ISO-NE in its discretion for the benefit of load and upon approval by Enforcement of ISO-NE's plan for doing so, and ***pay a $1 million civil penalty*** to the United States Treasury. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

[114] *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.

[115] *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*").

[116] *Algonquin Power Windsor Locks LLC*, 174 FERC ¶ 61,001 (Jan. 5, 2021).

XII. Misc. - Administrative & Rulemaking Proceedings

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

On November 4, 2020, the FERC issued a notice that staff will convene a February 25-26, 2021 technical conference to discuss principles and best practices for credit risk management in ISO/RTOs. The conference may address the following aspects of credit policy: ISO/RTO credit and risk management infrastructure; best practices and principles underlying capitalization requirements, financial security requirements, and unsecured credit allowances; the applicability of Know Your Customer ("KTC") protocols and other counterparty risk management tools; considerations for implementing FTR-specific credit policies, such as a mark-to-auction mechanism; and the relationship between credit policy and wholesale electric market design. Commissioners may participate in the technical conference. The conference will be open for the public to attend. Supplemental notice(s) will be issued prior to the technical conference with further details regarding the agenda and organization of the conference.

Recall that, as previously reported, Energy Trading Institute[117] requested that the FERC hold a technical conference and conduct a rulemaking to update the requirements adopted in *Order 741*[118] 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 is responsive to that request. Reporting on developments in this proceeding will continue under AD21-6 in future reports.

- **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.

- **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,[119] 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" 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,

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[117] 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."

[118] *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.

[119] "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.

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.[120] 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."[121] 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 NY PSC. This matter is pending before the FERC.

- **Hybrid Resources Technical Conference Tech Conf (Jul 23, 2020) (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.

On August 10, 2020, the FERC invited interested persons to file post-technical conference comments to address issues raised during the technical conference and identified in the Supplemental Notice of Technical Conference issued July 13, 2020. Post-technical conference comments were filed by ISO-NE, CAISO, MISO, NYISO,

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

[121] *Id.* at P 15.

PJM, Enel, American Council on Renewable Energy, AWEA, EEI, EPRI, R Street institute, Savion, and SEIA. This matter is pending before the FERC.

- **RTO/ISOs Common Performance Metrics (AD19-16)**

With Office of Management and Budget ("OMB") approval, FERC staff has reinstated and revised its information collection form, FERC-922, on the Performance Metrics for ISOs, RTOs, and Regions Outside ISOs and RTOs. FERC staff expects to collect Common Metrics information every two years. The revised data collection, after additions and deletions, consists of twenty-nine Common Metrics.[122] RTO/ISOs were encouraged to submit responsive information by October 30, 2020. ISO-NE submitted its information on October 30, 2020. The ISO-NE submittal will not be noticed for public comment.

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

On January 8, 2018, the FERC initiated a Grid Resilience in RTO/ISOs proceeding (AD18-7)[123] and terminated the DOE NOPR rulemaking proceeding (RM18-1).[124] In terminating the DOE NOPR proceeding, the FERC concluded that the Proposed Rule and comments received did not support FERC action under Section 206 of the FPA, but did suggest the need for further examination by the FERC and market participants of the risks that the bulk power system faces and possible ways to address those risks in the changing electric markets. On February 7, Foundation for Resilient Societies ("FRS") requested rehearing of the January 8 order terminating the DOE NOPR proceeding. The FERC issued a tolling order on March 8, 2018 to afford it additional time to consider the FRS request for rehearing, which remains pending.

Grid Resilience Administrative Proceeding (AD18-7). AD18-7 was initiated to evaluate the resilience of the bulk power system in RTO/ISO regions. The FERC directed each RTO/ISO to submit information on certain resilience issues and concerns, and committed to use the information submitted to evaluate whether additional FERC action regarding resilience is appropriate. RTO submissions were due on or before March 9, 2018.

ISO-NE Response. In its response, ISO-NE identified fuel security[125] as the most significant resilience challenge facing the New England region. ISO-NE reported that it has established a process to discuss market-based solutions to address this risk, and indicated that it believed it will need through the second quarter of 2019

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[122] There are seven ***Group 1 metrics***: Reserve Margins, Average Heat Rates, Fuel Diversity, Capacity Factor by Technology Type, Energy Emergency Alerts (("EEA") Level 1 or Higher), Performance by Technology Type during EEA Level 1 or Higher, and Resource Availability (Equivalent Forced Outage Rate Demand ("EFORd")). There are 12 ***Group 2 metrics***: Number and Capacity of Reliability Must-Run Units, Reliability Must-Run Contract Usage, Demand Response Capability, Unit Hours Mitigated, Wholesale Power Costs by Charge Type, Price Cost Markup, Fuel Adjusted Wholesale Energy Price, Energy Market Price Convergence, Congestion Management, Administrative Costs, New Entrant Net Revenues, and Order No. 825 Shortage Intervals and Reserve Price Impacts; There are 10 ***Group 3 metrics***: Net Cost of New Entry ("Net CONE") Value, Resource Deliverability, New Capacity (Entry), Capacity Retirement (Exit), Forecasted Demand, Capacity Market Procurement and Prices, Capacity Obligations and Performance Assessment Events, Capacity Over-Performance, Capacity Under-Performance, and Total Capacity Bonus Payments and Penalties. The update metrics eliminate previously-collected metrics on reliability, RTO/ISO billing controls and customer satisfaction, interconnection and transmission processes, and system lambda.

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

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

[125] ISO-NE defined fuel security as "the assurance that power plants will have or be able to obtain the fuel they need to run, particularly in winter – especially against the backdrop of coal, oil, and nuclear unit retirements, constrained fuel infrastructure, and the difficulty in permitting and operating dual-fuel generating capability."

to develop a solution and test its robustness through the stakeholder process. In the meantime, ISO-NE indicated that it would continue to independently assess the level of fuel-security risk to reliable system operation and, if circumstances dictate, would take, with FERC approval when required, actions it determines to be necessary to address near-term reliability risks. ISO-NE's response was broken into three parts: (i) an introduction to fuel-security risk; (ii) background on how ISO-NE's work in transmission planning, markets, and operations support the New England bulk power system's resilience; and (iii) answers to the specific questions posed in the January 8 order.

Industry Comments. Following a 30-day extension issued on March 20, 2018, reply comments were due on or before May 9, 2018. NEPOOL's comments, which were approved at the May 4 meeting, were filed May 7, and were among over 100 sets of initial comments filed. A summary of the comments that seemed most relevant to New England and NEPOOL was circulated to the Participants Committee on May 15 and is posted on the NEPOOL website. On May 23, NEPOOL submitted a limited response to four sets of comments, opposing the suggestions made in those pleadings to the extent that the suggestions would not permit full use of the Participant Processes. Supplemental comments and answers were also filed by FirstEnergy, MISO South Regulators, NEI, and EDF. Exelon and American Petroleum Institute filed reply comments. FirstEnergy included in this proceeding its motion for emergency action also filed in ER18-1509 (ISO-NE Waiver Filing: Mystic 8 & 9), which Eversource answered (in both proceedings). Reply comments were filed by APPA and AMP and the Nuclear Energy Institute ("NEI") moved to lodge presentations by the National Infrastructure Advisory Council. On December 6, the Harvard Electricity Law Initiative filed a comment suggesting that, as a matter of law, "Commission McNamee cannot be an impartial adjudicator in these proceedings" and "any proceeding about rates for 'fuel-secure' generators" and should recuse himself. Similarly, on December 18, "Clean Energy Advocates"[126] requested Commissioner McNamee recuse himself from these proceedings. These matters remain pending before the FERC.

FirstEnergy DOE Application for Section 202(c) Order. In a related but separate matter, FirstEnergy Solutions ("FirstEnergy") asked the Department of Energy ("DOE") in late March to issue an emergency order to provide cost recovery to coal and nuclear plants in PJM, saying market conditions there are a "threat to energy security and reliability". FirstEnergy made the appeal under Section 202(c) of the FPA, which allows the DOE to issue emergency orders to keep plants operating, but has previously been exercised only in response to natural disasters. Action on that 2018 request is pending.

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

On November 19, 2020, the FERC issued a NOPR[127] 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* are due [60 days after the publication date of the *Managing Transmission Line Ratings NOPR* in the *Federal Register*].[128]

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[126] For purposes of these proceedings, "Clean Energy Advocates" are NRDC, Sierra Club and UCS.

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

[128] As of the date of this Report, the *Managing Transmission Line Ratings NOPR* still has not been published in the *Federal Register*.

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

Still pending is the FERC's March 20,2020 NOPR[129] proposing to revise its existing transmission incentives policy and corresponding regulations.[130] 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 and 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.
- ***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[131] 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 872-A*: Pricing and Eligibility Changes to PURPA Regulations (RM19-15)**

As previously reported, the FERC issued on July 16, 2020 its final rule[132] approving pricing and eligibility revisions to its long-standing regulations implementing sections 201 and 210 of the Public Utility Regulatory

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

[130] 18 CFR 35.35 (2020).

[131] 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.

[132] *Qualifying Facility Rates and Requirements; Implementation Issues Under the Public Utility Regulatory Policies Act of 1978*, Order No. 872, 172 FERC ¶ 61,041 (July 16, 2020) ("*Order 872*").

Policies Act of 1978 ("PURPA").[133] Requests for rehearing and/or clarification of *Order 872* were filed by California Utilities, EPSA, Northwest Coalition, One Energy Enterprises, Public Interest Organizations, SEIA, and Thomas Mattson. On September 17, 2020, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[134] The Notice confirmed that the 60-day period during which a petition for review of *Order 872* can be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing of *Order 872*. 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."

Consistent with its September 17, 2020 notice, the FERC issued on November 19, 2020 an order addressing arguments raised on rehearing.[135] *Order 872-A* modified the discussion in *Order 872*, reached the same result, but clarified, in part, *Order 872*. Specifically, *Order 872-A* provided clarification on (1) states' use of tiered avoided cost pricing; (2) states' use of variable energy rates in QF contracts and availability of utility avoided cost data; (3) the role of independent entities overseeing competitive solicitations; (4) the circumstances under which a small power production QF needs to recertify; (5) application of the rebuttable presumption of separate sites for the purpose of determining the power production capacity of small power production facilities; and (6) the PURPA section 210(m) rebuttable presumption of nondiscriminatory access to markets and accompanying regulatory text.

Thus far, petitions for the review of *Order 872* have been filed with the 9th Circuit Court of Appeals by SEIA and Montana Environmental Information Center (*see* Section XV below). If you have any questions, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

On September 17, 2020, the FERC issued a final rule ("*Order 2222*")[136] adopting reforms to remove what it found were barriers to the participation of distributed energy resource ("DER")[137] 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 distributed energy resource aggregations must:

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

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

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

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133 16 U.S.C. § 2601 et seq. (2018). PURPA was enacted to help lessen the dependence on fossil fuels and promote the development of power generation from non-utility power producers.

134 *Qualifying Facility Rates and Requirements; Implementation Issues Under the Public Utility Regulatory Policies Act of 1978*, Order No. 872, 172 FERC ¶ 62,154 (Sep. 11, 2020), *clarif. granted in part*, 173 FERC ¶ 61,158 (Nov. 19, 2020).

135 *Qualifying Facility Rates and Requirements; Implementation Issues Under the Public Utility Regulatory Policies Act of 1978*, Order 872-A, 173 FERC ¶ 61,158 (Nov. 19, 2020) ("*Order 872-A*").

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

137 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 distributed energy resource aggregations;

(5) address distribution factors and bidding parameters for distributed energy resource aggregations;

(6) address information and data requirements for distributed energy resource aggregations;

(7) address metering and telemetry requirements for distributed energy resource aggregations;

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

(9) address modifications to the list of resources in a distributed energy resource aggregation;

(10) address market participation agreements for distributed energy resource 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.[138] 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 distributed energy resources, it must demonstrate on compliance that its existing approach meets *Order 2222*'s requirements.

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.[139] On November 19, 2020, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[140] 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 860/860-A*: Data Collection for Analytics & Surveillance and MBR Purposes (RM16-17)**

As previously reported, *Order 860,*[141] issued three years after the FERC's *Data Collection NOPR,*[142] (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

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

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

[140] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Indep. Sys. Operators*, 173 FERC ¶ 62,090 (Nov. 19, 2020).

[141] *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).

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

Order 816 that MBR Sellers submit corporate organization charts. In addition, the FERC stated that it will *not* adopt the *Data Collection NOPR* proposal to collect Connected Entity data from MBR Sellers and entities trading virtuals or holding FTRs. The FERC will post on its website high-level instructions that describe the mechanics of the relational database submission process and how to prepare filings that incorporate information that is submitted to the relational database. As recently extended (*see* below), *Order 860* will become effective April 1, 2021, and submitters will have until close of business on August 2, 2021 to make their initial baseline submissions. Submitters will be required to obtain in Spring 2021 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,[143] 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,[144] 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.

Effective Date Extended by 6 Months. On May 6, 2020, EEI requested a four-month extension of implementation of *Order 860*. EPSA supported that request on May 13, 2020. On May 20, the FERC issued a notice extending the effective and associated implementation dates of *Order 860* by *six* months. The new *Order 860* effective date will be April 1, 2021, and the deadline for baseline submissions to and including August 2, 2021. First change in status filings under these new timelines will be due August 31, 2021.

- **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").[145] 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."[146] Comments on the *NAESB WEQ v. 003.3 Standards NOPR* were due on or before November 3, 2020[147] 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.

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[143] 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.

[144] *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*").

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

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

[147] 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.

- **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.[148] 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 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[149] 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

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

[149] 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.

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 waivers,[150] 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,[151] 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,[152] 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*.[153] 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").[154] 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.[155] 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.

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[150] *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.

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

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

[153] *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*").

[154] 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.[154] 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).

[155] 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.

Complainant-Aligned Parties[156] answered the New England TO's May 10 supplemental comments. On June 15, 2020, Joint Parties[157] 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.[158] 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 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)**

On April 19, 2018, the FERC announced its intention to revisit its approach under its 1999 Certificate Policy Statement to determine whether a proposed jurisdictional natural gas project is or will be required by the present or future public convenience and necessity, as that standard is established in NGA Section 7. Specifically, the NOI[159] seeks comments from interested parties on four broad issue categories: (1) project need, including whether precedent agreements are still the best demonstration of need; (2) exercise of eminent domain; (3) environmental impact evaluation (including climate change and upstream and downstream greenhouse gas emissions); and (4) the efficiency and effectiveness of the FERC certificate process. Pursuant to a May 23 order extending the comment deadline by 30 days,[160] comments were due on or before July 25, 2018. Literally thousands of individual and mass-mailed comments were filed. This matter remains pending before the FERC.

XIII. Natural Gas Proceedings

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

- **Natural Gas-Related Enforcement Actions**

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

BP (IN13-15). On December 17, 2020, the FERC issued *Opinion 549-A*,[161] a 159-page decision addressing arguments raised on rehearing requested of *Opinion 549.*[162] *Opinion 549-A* modifies the discussion in *Opinion 549*,

[156] 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.

[157] "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.

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

[159] The NOI was published in the *Fed. Reg.* on Apr. 26, 2018 (Vol. 83, No. 80) pp. 18,020-18,032.

[160] *Certification of New Interstate Natural Gas Facilities*, 163 FERC ¶ 61,138 (May 23, 2018).

[161] *BP America Inc. et al.,* Opinion No. 549-A, 173 FERC ¶ 61,239 (Dec. 17, 2020) ("*BP Penalties Allegheny Order*")

[162] *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

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.[163] 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.[164] On December 29, 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.

Total Gas & Power North America, Inc. et al. (IN12-17). On April 28, 2016, the FERC issued a show cause order[165] 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.[166]

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.

- **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
    - Application for a certificate of public convenience and necessity pending.

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*")).

163 *BP Penalties Allegheny Order* at P 1.

164 *Id*. at P 319.

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

166 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.

- **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.[167] 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*.[168] 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 Northern Access Project, served as a motion requesting a waiver determination by the FERC,[169] 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.[170] 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.[171] 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

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[167] *Nat'l Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 167 FERC ¶ 61,007 (Apr. 2, 2019).

[168] *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).

[169] 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).

[170] *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*").

[171] *Nat'l Fuel Gas Supply Corp. v. NYSDEC et al*. (2d Cir., Case No. 17-1164).

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,[172] 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.[173]
- 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, [174] 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", 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.[175]

XIV. 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, a series of online technical forums to discuss the issues presented in the Vision Statement have been announced by certain State Agencies.[176] Thus far, the following on-line technical sessions have been announced:

Jan 13, 2021	9:00 am - 2:00 pm	Wholesale Market Reform
Jan 25, 2021	1:00 pm - 6:00 pm	Wholesale Market Reform
Feb 2, 2021	1:00 pm - 6:00 pm	Transmission Planning
Feb TBD, 2021	TBD	Governance Reform

Draft notices, proposed agendas, and additional information on these sessions are available on the New England States' Vision Statement website (https://newenglandenergyvision.com/). Specific details are supposed to follow in subsequent announcements.

[172] 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).

[173] *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).

[174] *National Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 173 FERC ¶ 61,197 (Dec. 1, 2020).

[175] *Id.* at P 10.

[176] "State Agencies" jointly announcing the technical forums are identified as: CT DEEP, ME Governor's Energy Office, MA Executive Office of Energy and Environmental Affairs, NH PUC, RI Office of Energy Resources, and VT DPS.

- **Executive Order on Securing the United States Bulk-Power System**

On May 1, 2020, President Trump signed an Executive Order that authorizes U.S. Secretary of Energy Dan Brouillette to work with the Cabinet and energy industry to secure America's BPS. The Executive Order prohibits Federal agencies and U.S. persons from "acquiring, transferring, or installing BPS equipment in which any foreign country or foreign national has any interest and the transaction poses an unacceptable risk to national security or the security and safety of American citizens. Evolving threats facing our critical infrastructure have only served to highlight the supply chain risks faced by all sectors, including energy, and the need to ensure the availability of secure components from American companies and other trusted sources." The Secretary of Energy is accordingly authorized to (i) establish and publish criteria for recognizing particular equipment and vendors as "pre-qualified" (pre-qualified vendor list); (ii) identify any now-prohibited equipment already in use, allowing the government to develop strategies and work with asset owners to identify, isolate, monitor, and replace this equipment as appropriate; and (iii) work closely with the Departments of Commerce, Defense, Homeland Security, Interior; the Director of National Intelligence; and other appropriate Federal agencies to carry out the authorities and responsibilities outlined in the Executive Order. A Task Force led by Secretary Brouillette will develop energy infrastructure procurement policies to ensure national security considerations are fully integrated into government energy security and cybersecurity policymaking. The Task Force will consult with the energy industry through the Electricity and Oil and Natural Gas Subsector Coordinating Councils to further its efforts on securing the BPS. A copy of the Executive Order may be accessed here.

XV. Federal Courts

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

- **Exelon PP-10 Complaint (20-1509)**
Underlying FERC Proceeding: EL20-52[177]
Petitioner: Exelon

On December 18, 2020, Constellation Mystic Power, LLC ("Exelon") petitioned the DC Circuit Court of Appeals for review of the FERC's orders denying Exelon's PP-10 Complaint and the denial of its request for rehearing of the *Order Denying PP-10 Complaint*.[178] Appearances are due January 22, 2021. Parties must file docketing statements and statement of issues to be raised also by January 22. Dispositive motions, if any, and a Certified Index to the Record must be filed by February 8, 2021.

[177] *Constellation Mystic Power, LLC v. ISO New England Inc.*, 173 FERC ¶ 62,034 (Oct. 19, 2020); *Constellation Mystic Power, LLC v. ISO New England Inc*., 172 FERC ¶ 61,144 (Aug. 17, 2020) *("Order Denying PP-10 Complaint"), reh'g denied by operation of law*, 173 FERC ¶ 62,034 (Oct. 19, 2020).

[178] The PP-10 Complaint requested that ISO-NE be prohibited from (i) implementing changes to the Planning Procedure to Support the Forward Capacity Market ("PP-10"), which Exelon asserted would significantly affect the rates, terms and conditions of jurisdictional services by dramatically changing the way in which ISO-NE conducts its annual transmission security review of capacity auction retirement bids and the Network Model upon which the capacity auction is based, and (ii) violating the requirements of its Tariff for *Order 1000* competitive transmission procurements.

- **ISO-NE Implementation of Order 1000 Exemptions for Immediate Need Reliability Projects (20-1422)**
  Underlying FERC Proceeding: EL19-90[179]
  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 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. A schedule for the filing of briefs will be established by future order.

- **CIP IROL Cost Recovery Rules (20-1389)**
  Underlying FERC Proceeding: ER20-739[180]
  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 adds roughly 45 days to each procedural deadline previously established. Revised deadlines now include the following re: Petitioners' Brief (March 1, 2021); Respondent Brief of FERC (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)(consolidated)**
  Underlying FERC Proceeding: EL18-1639[181]
  Petitioners: Mystic (1343), NESCOE (1361), MA AG (1362), CT Parties (1365, 1368)

Mystic, NESCOE, MA AG, and CT Parties 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.182 The cases have been consolidated into Case No. 20-1343. Appearances were filed October 8, 2020. On October 8 (in the case of Mystic) and October 16 (in the case of the remaining Petitioners), statements of issues and docketing statements were filed. Also on October 16, the FERC filed an unopposed motion to hold this appeal in abeyance until the earlier of December 15, 2020 (60 days) or the date of the issuance by the FERC of a further order on rehearing. In addition, the FERC asked for 21 days from that day for the parties to file motions to govern further proceedings. On November 4, 2020, the Court granted the FERC's motion and ordered that the consolidated cases be held in abeyance pending further order of the Court and that he parties file motions to govern further proceedings in these cases within 21 days of the FERC's decision on rehearing or by January 5, 2021, whichever occurs earlier.

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[179] *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 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).

[180] *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*").

[181] *July 2018 Order*; *July 2018 Rehearing Order*; *Dec 2018 Order*; *Dec 2018 Rehearing Order; Jul 17 Compliance Order*.

[182] 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)**
  Underlying FERC Proceeding: ER18-619[183]
  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. The FERC's October 19 motion is still pending before the Court.

- ***Opinion 531-A* Compliance Filing Undo (20-1329)**
  Underlying FERC Proceeding: ER15-414[184]
  Petitioners: TOs' (CMP et al.)

On August 28, 2020, the TOs[185] 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*[186] 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.

- **2013/14 Winter Reliability Program Order on Compliance and Remand (20-1289, 20-1366) (consol.)**
  Underlying FERC Proceeding: ER13-2266[187]
  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*.[188] 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

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[183] *ISO New England Inc.*, 162 FERC ¶ 61,205 (Mar. 9, 2018) ("*CASPR Order*").

[184] *ISO New England Inc.*, 161 FERC ¶ 61,031 (Oct. 6, 2017) ("*Order Rejecting Filing*").

[185] 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.

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

[187] 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*").)

[188] 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.

motion and set the briefing schedule, including the following: Petitioners' Brief (January 11, 2021); Respondent Brief of FERC (Mach 12, 2021); Intervenors' Joint Brief in Support of Respondent (March 19, 2021); Petitioners' Reply Briefs (April 9, 2021); Deferred Appendix (April 16, 2021); and Final Briefs (April 30, 2021).

- **ISO-NE's Inventoried Energy Program (Chapter 2B) Proposal (19-1224***; 19-1247; 19-1252; 19-1253)(consolidated); Underlying FERC Proceeding: ER19-1428**[189]
  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, the Court ordered that the cases be removed from abeyance and set a revised briefing schedule that called for the following: Petitioners' Opening Briefs (December 11, 2020); Respondent Brief of FERC (February 9, 2021); Intervenors' Joint Brief in Support of Respondent (February 16, 2021); Petitioners' Reply Briefs (March 30, 2021); Deferred Appendix (April 20, 2021); and Final Briefs (May 4, 2021). Since the last Report, Opening Briefs from Petitioners were filed on December 11, 2020. Next up will be briefs from FERC and intervenors in support of FERC.

Other Federal Court Activity of Interest

- ***Order 872* (20-72788) (9th Cir.)**
  Underlying FERC Proceeding: RM19-15[190]
  Petitioner: SEIA

On September 17, 2020, SEIA petitioned the 9th Circuit Court of Appeals for review of *Order 872*.[191] 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, suspended briefing, and directed the FERC to file a status report, or a motion for appropriate relief on or before that date, with a failure to timely do so potentially resulting in the termination of the stay of proceedings.

- **PennEast Project (18-1128)**
  Underlying FERC Proceeding: CP15-558[192]
  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")[193] 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

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[189] 162 FERC ¶ 61,127 (Feb. 15, 2018) ("*Order 841*"); 167 FERC ¶ 61,154 (May 16, 2019) ("*Order 841-A*").

[190] *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).

[191] *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.

[192] *PennEast Pipeline Co., LLC*, 162 FERC ¶ 61,053 (Jan. 19, 2018), *reh'g denied*, 163 FERC ¶ 61,159 (May 30, 2018).

[193] 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.

("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 December 23, 2020, noting developments since the September 28, 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."

- **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[194]
  Petitioners: MISO TOs, Transource Energy, Dec 23 Petitioners et al.

The MISO Transmission Owners (TOs), Transource and "Dec 23 Petitioners",[195] 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. Since the last Report, the FERC filed a certified Index to the Record (December 3), the Parties filed a joint unopposed briefing schedule (December 23) and First Energy moved to voluntarily dismiss the cases it initiated (20-1227 & 20-1275), which the Court granted on January 5, 2021. The Court also consolidated case no. 20-1513 (filed by Dec 23 Petitioners) with the lead case (16-1325). The proposed briefing schedule calls for the following: Statement of issues, procedural motions and dispositive motions (January 25, 2021); Petitioners' Briefs (February 24, 2021); Intervenors in Support of Petitioners Briefs and Amici Curiae Briefs (March 10, 2021); Intervenors in Support of FERC (June 8, 2021); Petitioners Reply Briefs (June 24, 2021); Intervenors in Support of Petitioners Reply Briefs (July 8, 2021); Joint Deferred Appendix (July 22, 2021); and Final Briefs (August 5, 2021).

[194] *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).

[195] "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.

INDEX
Status Report of Current Regulatory and Legal Proceedings as of January 6, 2021

COVID-19

Blanket Waiver of ISO/RTO Tariff In-Person Meeting & Notarization Requirements .... (EL20-37) 2
Extension of Filing Deadlines .... (AD20-11) 2
Jul 8-9 Tech Conf: Impacts of COVID-19 on the Energy Industry .... (AD20-17) 1
Remote ALJ Hearings .... (AD20-12) 1

I. Complaints/Section 206 Proceedings

206 Proceeding: FCM Pricing Rules Complaints Remand .... (EL20-54) 4
Base ROE Complaints I-IV .... (EL11-66, EL13-33; EL14-86; EL16-64) 5
New England Generators' Exelon Complaint .... (EL20-67) 4
NECEC/Avangrid Complaint Against NextEra/Seabrook .... (EL21-6) 3
NEPGA Net CONE Complaint .... (EL21-26) 2
NECEC Elective Upgrade Costs Dispute: NextEra Energy Seabrook Declar. Order Petition . (EL21-3) 3
RNS/LNS Rates and Rate Protocols Settlement Agreement II .... (ER20-2054; EL16-19-002) 5

II. Rate, ICR, FCA, Cost Recovery Filings

2021 ISO-NE Administrative Costs and Capital Budgets .... (ER21-106) 10
2021 NESCOE Budget .... (ER21-113) 10
Amended and Restated IRH Support and Use Agreements .... (ER21-712) 8
Dynegy CIP IROL (Schedule 17) Cost Recovery Filing .... (ER21-774) 8
FCA15 Qualification Informational Filing .... (ER21-372) 9
ICR-Related Values and HQICCs – Annual Reconfiguration Auctions .... (ER21-496) 9
ICR-Related Values and HQICCs – FCA1 (2024-25) Capacity Commitment Period .... (ER21-371) 10
MPD OATT 2019 Annual Informational Filing Settlement Agreement .... (ER15-1429-014) 13
Mystic 8/9 Cost of Service Agreement .... (ER18-1639) 11
RNS/LNS Rates and Rate Protocols Settlement Agreement II .... (ER20-2054; EL16-19-002) 5

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

ESI Alternatives .... (ER20-1567) 14
Energy Efficiency Resource FCM Qualification Modifications .... (ER21-640) 14
Fuel Security Retention Proposal .... (ER18-2364) 16
ISO-NE Waiver Filing: Mystic 8 & 9 .... (ER18-1509; EL18-182) 16
New DDBT Methodology .... (ER21-782) 13
Order 841 Compliance Filings (Electric Storage in RTO/ISO Markets) .... (ER19-470) 15
Orders 864/864-A (Public Util. Trans. ADIT Rate Changes): New England Compliance Filings (various) 26
Updated CONE, Net Cone and PPR Values (eff. FCA16) .... (ER21-787) 13

IV. OATT Amendments/Coordination Agreements

CIP IROL Cost Recovery Rules .... (ER20-739) 17
RNS/LNS Rates and Rate Protocols Settlement Agreement II .... (ER20-2054; EL16-19-002) 5

V. Financial Assurance/Billing Policy Amendments

FAP Info Disclosure/KYC Requirements .... (ER21-816) 17

VI. Schedule 20/21/22/23 Updates

Schedule 21-VP: 2019 Annual Update Settlement Agreement .... (ER15-1434-004) 17
Schedule 21-VP: Bangor Hydro/Maine Public Service Merger-Related Costs Recovery ...... (ER15-1434-001 et al.) 17

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

Capital Projects Report - 2020 Q3 .... (ER21-108) 19
Opinion 531-A Local Refund Report: FG&E .... (EL11-66) 18
Opinions 531-A/531-B Local Refund Reports .... (EL11-66) 18
Opinions 531-A/531-B Regional Refund Reports .... (EL11-66) 18

IX. Membership Filings

December 2020 Membership Filing .... (ER21-499) 19
Invenia Additional Conditions Informational Filing .... (ER20-2001) 19
January 2021 Membership Filing .... (ER21-769) 19
November 2020 Membership Filing .... (ER21-260) 19

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

Amended and Restated NERC Bylaws .... (RR21-1) 22
CIP Standards Development: Informational Filings on Virtualization and Cloud Computing Services Projects .... (RD20-2) 20
Joint Staff White Papers on Notices of Penalty for Violations of CIP Standards .... (AD19-18) 20
NERC Annual Report on FFT & Compliance Exception Programs .... (RC11-6-011) 20
NOI: Enhancements to CIP Standards .... (RM20-12) 21
NOI: Virtualization and Cloud Computing Services in BES Operations .... (RM20-8) 21
Order 873 - Retirement of Rel. Standard Reqs. (Standards Efficiency Review) .... (RM19-17; RM19-16) 22
Report of Comparisons: 2019 Budgeted to Actual Costs for NERC and its Regional Entities (RR20-3) 23
Revised Reliability Standard: CIP-002-6 .... (RM20-17) 21
Revised Reliability Standards: CIP-013-2, CIP-005-7, CIP-010-4 .... (RD21-2) 20

XI. Misc. Regional Interest

203 Application: CMP/NECEC .... (EC20-24) 23
203 Application: CPV Towantic .... (EC21-16) 23
203 Application: Millennium Power Partners .... (EC20-103) 23
203 Application: NRG/Direct .... (EC20-96) 23
D&E Agreement: NSTAR/Ocean State Power .... (ER21-192) 25
D&E Agreement Cancellation: NSTAR / SEMASS .... (ER21-676) 24
FERC Enforcement Action: Algonquin Power Windsor Locks .... (IN21-2) 26
Interim Distribution Wheeling Agreement: Unitil / Briar Hydro .... (ER21-759) 24
LGIA: CMP/ReEnergy Stratton .... (ER21-769) 24
LGIA: NSTAR / MMWEC (Stony Brook) .... (ER21-777) 23
NECEC TSAs: NECEC Transmission Notice of Succession and CMP Notice of Cancellation .. (ER21-12 et al.) 25
Orders 864/864-A (Public Util. Trans. ADIT Rate Changes): New England Compliance Filings (various) 26
SGIA: CL&P / ECRRA .... (ER21-651) 24

VTransco Rate Schedule 2 Cancellation .... (ER21-256) 24

XII. Misc: Administrative & Rulemaking Proceedings

Carbon Pricing in RTO/ISO Markets .... (AD20-14) 27
FERC Enforcement Action: High Desert .... (IN20-6) 26
FERC's ROE Policy for Natural Gas and Oil Pipelines .... (PL19-4) 36
FirstEnergy DOE Application for Section 202(c) Order 29
Grid Resilience in RTO/ISOs; DOE NOPR .... (AD18-7) 29
Hybrid Resources Technical Conference .... (AD20-9) 28
ISO/RTO Credit Principles and Practices .... (AD21-6) 27
NOI: Certification of New Interstate Natural Gas Facilities .... (PL18-1) 37
NOPR: Electric Transmission Incentives Policy .... (RM20-10) 31
NOPR: Managing Transmission Line Ratings .... (RM20-16) 30
NOPR: NAESB WEQ Standards v. 003.3 - Incorporation by Reference into FERC Regs .... (RM05-5-029, -030) 34
Offshore Wind Integration in RTOs/ISOs Tech Conf (Oct 27, 2020) .... (AD20-18) 27
Order 860/860-A: Data Collection for Analytics & Surveillance and MBR Purposes .... (RM16-17) 33
Order 872: Pricing and Eligibility Changes to PURPA Regulations .... (RM19-15) 31
Order 2222: DER Participation in RTO/ISOs .... (RM18-9) 32
RTO/ISOs Common Performance Metrics .... (AD19-16) 29
Waiver of Tariff Requirements .... (PL20-7) 35

XIII. Natural Gas Proceedings

Enforcement Action: BP Initial Decision .... (IN13-15) 37
Enforcement Action: Total Gas & Power North America, Inc. .... (IN12-17) 37
Iroquois ExC Project .... (CP20-48) 38
New England Pipeline Proceedings 38
Non-New England Pipeline Proceedings 39

XIV. State Proceedings & Federal Legislative Proceedings

Executive Order on Securing the United States Bulk-Power System 41
New England States' Vision Statement / On-Line Technical Forums 40

XV. Federal Courts

2013/14 Winter Reliability Program Order on Compliance and Remand .... 20-1289 ..... (DC Cir.) 43
CASPR .... 20-1333 ..... (DC Cir.) 42
CIP IROL Cost Recovery Rules .... 20-1389 ..... (DC Cir.) 42
ISO-NE Implementation of Order 1000 Exemptions for Immed. Need Rel. Projects .... 20-1422 ..... (DC Cir.) 42
ISO-NE's Inventoried Energy Program (Chapter 2B) Proposal .... 19-1224 ..... (DC Cir.) 44
Mystic 8/9 Cost of Service Agreement .... 20-1343 ..... (DC Cir.) 42
Opinion 531-A Compliance Filing Undo .... 20-1329 ..... (DC Cir.) 43
Opinion 569/569-A: FERC's Base ROE Methodology .... 16-1325 ..... (DC Cir.) 45
Order 872 .... (20-72788) (9th Cir.) 44
PennEast Project .... 18-1128 ..... (DC Cir.) 44

NEPOOL's Pathways to the Future Grid Process

Project Report

January 6, 2021

Frank A. Felder, Ph.D.

I. Preface

As part of New England's Future Grid Initiative[1], NEPOOL commenced stakeholder discussions in 2020 focused on identifying and exploring potential alternative pathways/market frameworks that may help advance the region's clean energy transition. To support these explorative discussions among Participants, State officials and ISO-NE, NEPOOL engaged Independent Electricity Consultants, LLC to provide technical support from September to December 2020 to the NEPOOL Participants Committee (NPC).[2] This support consisted of reviewing a multitude of potential pathways and identifying and assessing their tradeoffs between achieving the clean energy policy objectives of the New England States and maximizing the benefit of efficient, regional wholesale markets. I have also worked to identify additional decision areas on details and design that would need to be made in order to more fully assess and compare the various potential pathways/frameworks.

The intended purpose of the explorative effort to date has been to develop a common understanding among a diverse group of stakeholders and State officials by clarifying issues, discussing pathway elements and their implications, and facilitating constructive exchanges on the relative merits of each identified pathway. As I explain further herein, my assessment of the various pathways has focused in particular on the following two questions: 1) whether and to what extent pathways support (or help to advance) the clean energy policies of States and 2) whether and to what extent pathways garner efficiency of regional markets? This final draft report summarizes my higher-level qualitative observations and assessment and is being distributed for review and written comment. More specific observations are documented in the series of presentations that I made before the NPC and posted on NEPOOL's website.

II. Background

State energy policies in New England (and elsewhere in the country) are generally devised to meet certain economic, environmental and/or political objectives at low costs whereas efficient markets are designed to maximize social surplus, the difference between the economic

[1] As stated in the 2020 NEPOOL Annual Report (https://nepool.com/uploads/Annual_Report_2020.pdf), NEPOOL leadership, working closely with NESCOE and ISO-NE representatives, launched New England's Future Grid Initiative in two parallel processes. (1) to define and assess the future state of New England's regional power system ("Future Grid Reliability Study") and (2) to explore and evaluate potential market frameworks that could be pursued to help support New England's clean energy transition ("Pathways to the Future Grid").

[2] Technical support is being provided by Frank A. Felder, Ph.D., Independent Electricity Consultants, LLC. The work product provided herein reflects my views and opinions and not necessarily those of NEPOOL, ISO-NE, individual NEPOOL participants, or State officials.

benefits of consuming electricity and the costs of producing it.[3] In other words, States would like to achieve their specific policy objectives cost effectively, whereas wholesale electricity markets are designed to maximize economic efficiency. Although there is some substantial overlap between the States' objectives of decarbonization and environmental enhancements, economic development, and political acceptability, and the objective of efficient, regional wholesale electricity markets, these objectives are not necessarily reconcilable.

New England States are pursuing the decarbonization of the electric power sector by employing a slate of policies to accomplish their clean energy policy objectives, including turning to out-of-market, state-sponsored support for certain generation. These policies envision replacing most if not all of the existing generation fleet with variable renewable energy resources (VRER) whose output is intermittent, and many of these new resources, such as offshore wind, are likely to be at different locations than existing power plants. Because decarbonization will result in major changes in the types and locations of generation, it raises the fundamental question of how to achieve the least cost deployment of generation and transmission to meet demand within the context of wholesale electricity markets and State policies.

Further adding to the challenge, under the direction of the FERC, the eastern RTOs/ISOs (including New England) has adopted minimum offer prices for new resources bidding into its capacity markets (i.e., the "MOPR"). Although the MOPR has been employed to address the potential adverse impact of out-of-market, state-sponsored contracts on price formation in the wholesale competitive markets, the MOPR has also resulted in state-sponsored resources[4] not clearing in the FCM and not being counted to help satisfy ISO-NE's resource adequacy requirements. As observed herein, resolving this tension through any one pathway or combination of pathways remains a challenge.

Within NEPOOL's "Pathways to the Future Grid" process, four major categories of pathways were discussed and are listed in Table 1. These identified pathways varied regarding their number of alternatives, level of detail, and expressions of support. For instance, the Forward Clean Energy Market (FCEM) contains several major design variables that substantially change the characteristics and outcomes of specific FCEM alternatives as well as the associated tradeoffs that would occur. Some elements within the identified pathways are potential stand-alone market improvements that could be considered separately from the broader pathway discussions but are discussed in this report as part of a pathway category. For example, an Energy Only Market (EOM) can be a stand-alone reform or be part of a larger future pathway to

[3] A socially efficient market would include the costs of negative externalities as part of production costs.

[4] State-subsidized resources are those that obtain at least some of their compensation via a State-sanction policy such as a renewable portfolio or energy standard. *See, e.g.*, FERC's December 2019 PJM Capacity Market Order, where the Commission defined State Subsidy as "[a] direct or indirect payment, concession, rebate, subsidy, non-bypassable consumer charge, or other financial benefit that is (1) a result of any action, mandated process, or sponsored process of a state government, a political subdivision or agency of a state, or an electric cooperative formed pursuant to state law, and that (2) is derived from or connected to the procurement of (a) electricity or electric generation capacity sold at wholesale in interstate commerce, or (b) an attribute of the generation process for electricity or electric generation capacity sold at wholesale in interstate commerce, or (3) will support the construction, development, or operation of a new or existing capacity resource, or (4) could have the effect of allowing a resource to clear in any PJM capacity auction." December 2019 Order, 169 FERC ¶ 61,239 at p. 67, cited in 173 FERC ¶ 61,061, p. 6.

help support regional decarbonization. Pathway related references are provided in the Reference section at the end of this paper.

Table 1: Inventory of Pathway Categories

No.	Pathway Name and Abbreviation
1	Forward Clean Energy Market (FCEM), with potential inclusion of a Balancing Resource Constraint (BRC) and/or Integrated Clean Capacity Market (ICCM)
2	Carbon Pricing
3	Energy Only Market (EOM)
4	Alternative Resource Adequacy Constructs (ARAC)

To kick off discussions on various identified pathway, invited speakers presented to the NPC describing different concepts/market frameworks followed by presentations I delivered comparing the tradeoffs among the pathways and their alternatives. Stakeholders provided oral feedback during the question-and-answer portion of each presentation and have also submitted written comments, which are posted on the NEPOOL website.[5]

[5] http://nepool.com/Fut_Grid_Poten_Pathways.php

Table 2: Presentations on Clean Energy Transitions and Potential Future Pathways[6]

Date	Presentation Title	Presenter and Affiliation
Jun. 24, 2020	Challenges Associated with Deep Decarbonization and Evolving Grid Systems	Melanie Kenderdine, Energy Futures Initiative
Jun. 24, 2020	BPS Reliability, Perspectives for 2050	Jim Robb, NERC
Jun. 24, 2020	What Pathways Have Others Chosen or Are Considering	Frank Felder, IEC
Aug. 6, 2020	Forward Clean Energy Market: A Market-based Option for States to Achieve Their Clean Electricity Goals	Kathleen Spees, The Brattle Group
Aug. 6, 2020	Carbon Pricing for New England	Joseph Cavicchi, Analysis Group
Sep. 3, 2020	ERCOT's Energy Only Market	Beth Garza, R Street
Sep. 3, 2020	Resource Adequacy: Panel Introduction, Dimensions & Options, and Resource Adequacy Models and Low Carbon Power Markets	Sharon Reishus, Reishus Consulting Steve Corneli Rob Gramlich, Grid Strategies, LLC
Oct. 1, 2020	The Integrated Clean Capacity Market: A Design Option for New England's Grid Transition	Kathleen Spees, The Brattle Group
Oct. 1, 2020	Round 1: Focus on FCEM and Carbon Pricing: Preliminary Observations and Request for Input	Frank Felder, IEC, LLC.
Nov. 5, 2020	Round 2: Focus on Energy Only Market and Alternative Resource Adequacy Constructs: Preliminary Observations and Request for Input	Frank Felder, IEC, LLC.
Nov. 5, 2020	Long-Term Resource Adequacy with Significant Intermittent Renewables	Frank Wolak, Stanford University
Dec. 3, 2020	Capacity as a Commodity	Michael Borgatti, Gabel Associates
Dec. 3, 2020	Round 3: Focus on SFPFC and Draft Report	Frank Felder, IEC, LLC

The pathway discussions spawned a long list of abbreviations, which are listed in Table 3 to aid in reading this report and reviewing the associated presentations and references.

[6] Available at https://nepool.com/future-grid-initiative/potential-pathways/

Table 3: Abbreviations Related to Clean Energy Transition and Future Pathways

ACP: Alternative Compliance Payment
ARAC: Alterative Resource Adequacy Constructs
BRC: Balancing Resource Constraint
CCS: Carbon Capture and Sequestration
CEAC: Clean Energy Attribute Credit
CONE: Cost of New Entry
CP: Carbon Pricing
EOM: Energy Only Market
ERCOT: Electricity Reliability Council of Texas
FCEM: Forward Clean Energy Market
FCM: Forward Capacity Market
FRR: Fixed Resource Requirement
ICCM: Integrated Clean Capacity Market
IRP: Integrated Resource Planning
LOLP: Loss of Load Probability
LSE: Load Serving Entities
MOPR: Minimum Offer Pricing Rule
ORDC: Operating Reserve Demand Curve
PPA: Power Purchase Agreement
RDPA: Reliability Deployment Price Adder
REC: Renewable Energy Credit
RES: Renewable Energy Standard
RGGI: Regional Greenhouse Gas Initiative
RPS: Renewable Portfolio Standard
SCED: Security Constrained Economic Dispatch
SFPFC: Standardized Fixed-Price Forward Contract
VOLL: Value of Lost Load
VRER: Variable Resource Energy Resources

II. Potential Pathways/Market Frameworks to Support New England's Clean Energy Transition

Across the different pathways discussed, there are some common presumptions regarding how the region is to achieve its clean energy transition and the role of the ISO-NE. Markets would be used to procure energy, capacity (as applicable), ancillary services, although the type, structure and administration of these markets may differ across pathways. As I understand the frameworks presented at the NPC, ISO-NE would continue to conduct energy dispatch, unit commitment, maintenance scheduling, transmission planning, market monitoring and mitigation, and market administration and settlement.

From the review and discussion of pathways, I have observed three key issues that have emerged that I believe need to be addressed in order for New England to proceed with a new pathway/market framework to support the region's clean energy transition. First, the effort underway to reconcile conflicting objectives of wholesale electricity markets and States' clean energy policies is clearly an ambitious and challenging undertaking. Any successful reconciliation is not likely to occur without broad agreement being reached among the New England States and NEPOOL stakeholders. The importance of agreement among New England States is particularly important for two of the pathways that have garnered substantial interest, Forward Clean Energy Market (FCEM) and Integrated Clean Capacity Market (ICCM), because both depend upon a regional auction of inter-State tradeable clean energy and/or capacity products.

Second, the required types, amounts and timing of balancing services needed to accommodate increasing levels of VRER has not been defined or articulated. Without knowing these requirements, analyzing whether proposed pathways will be successful in providing the resources needed for reliability to support decarbonization let alone cost effectively cannot be performed. The reliability criteria and metrics should be specified in order to establish the balancing services needed to plan and reliably operate the bulk power system given increasing penetration of VRERs, perhaps as part of the NEPOOL's ongoing Future Grid Reliability Study effort.[7] Specifically, with large amounts of renewables, resource adequacy requirements may need to be set based upon meeting demand with sufficient resources over multiple cloudy, non-wind days, and additional changes to the ancillary services markets may need to occur to ensure sufficient flexibility to balance supply and demand over various time steps from cycles to seconds to weeks. Whether employment of an FCM-like mechanism is the preferred means to procure the required balancing services is an open question given that such a mechanism is designed primarily to procure new resources to maintain resource adequacy as opposed to maintain existing resources to provide balancing services.

Third, the proposed pathways that the region decides to continue to be discussed need more development and specificity before a complete analysis of their implications and impacts can be conducted. At this stage, the pathways are really collections of similar high-level proposals that vary, in some cases substantially, within each pathway category. Furthermore, the outcomes of pathways depend on how they interact with energy dispatch and curtailment, unit commitment, ancillary service definition and opportunity costs, imports and exports of power, bid and offer incentives, transmission planning and cost allocation, deployment of smart grid technologies, dynamic retail pricing, market monitoring and mitigation, wholesale and retail credit policies, and regional and State energy policies. One major example of the need for more development is the intersection of the proposed pathways and transmission expansion and cost allocation, and the region's push for extensive expansion of offshore wind is a prime example. Evaluating impact on generation and transmission investments due to the intersection of a particular pathway and regional transmission planning will be necessary in order to ensure that these investment decisions are aligned to achieve the least cost joint deployment of generation and transmission.

[7] Further information on NEPOOL's Future Grid Reliability Study effort can be accessed at https://nepool.com/meetings/future-grid-reliability-study/.

III. High-level Description of Pathways and Open Issues

This section describes the criteria that pathways are being evaluated against followed by a brief description of each of the pathways. Pathway descriptions, motivations, and claimed benefits are provided in the cited references. In addition, the subsequent section discusses more detailed findings related to potential pathways and many of their alternatives and variations.

Recall that the thrust of this high-level qualitative assessment is how each of the pathways answer the following two questions: 1) whether and to what extent pathways support the clean energy policies of States; and 2) whether and to what extent pathways garner efficiency of regional markets?

To help answer these two questions, four criteria are suggestions to be used to evaluate potential pathways.

The first criterion is the achievement of *States' energy objectives*. As noted above, States would like to set the timing, quantity and type of clean energy resources to meet their particular objectives. In general, there is a tradeoff between achieving States' specific clean energy objectives that use quantity mandates via, for example, renewable portfolio or energy standards, to incentivize clean energy resources versus using regional markets that rely on price signals. The more specific the clean energy requirements are, the more difficult it is to implement a regional, technology neutral mechanism in which clean energy resources compete based upon price and performance.

The second criterion is addressing the so-called *double capacity payment* issue. If state-subsidized clean energy resources do not clear the Forward Capacity Market due to the MOPR, then States will have advanced certain clean energy resource objectives but without necessarily garnering the financial value of resource adequacy that those resources provide. Retail electricity consumers could be paying twice for the capacity value that the state-sponsored clean energy resources provide to the system.

The third issue is ensuring sufficient price integrity in the markets (i.e., addressing *price suppression*). If without the MOPR, State-subsidized clean energy resources clear the FCM because the subsidy provides these resources with additional revenue that would not have occurred but for the subsidy, then capacity and energy prices would be lower, i.e., suppressed, than without the State subsidy.[8] Price suppression is an identified concern for both economic efficiency and reliability reasons (which is discussed below regarding balancing resources). It is an economic efficiency concern because the social welfare benefits of out-of-market subsidizes of clean energy resources depend both on the relative benefits of reducing greenhouse gas and other emissions with the relative costs including the price suppression and distortions of the subsidizing mechanism. Whether the net impact of increasing the amount of clean energy resources and suppressing prices is positive or negative is an open question and depends on the particular setting.

[8] This could occur if the FERC reversed itself and eliminated the MOPR.

The tradeoff between "double payment" and price suppression is unavoidable and caused by the divergence between individual State's clean energy policy objectives and the pursuit of regional markets to maximize social surplus. Reducing the magnitude of the double payment may increase the amount of price suppression and vice-versa.

The fourth issue is the increasing need for *balancing resources* in a future state. Pathways may not procure sufficient amounts and types of balancing resources that the region needs to operate the grid reliably or if they do, it is not clear that they do so in the most cost-effective manner. Having sufficient balancing resources is partially connected to the price suppression issue. If a pathway results in substantially added price suppression in the organized markets, premature retirements of resources that may be needed for balancing could result due to the reduction in wholesale market prices. And if there is not another means of compensating the needed balancing resources, then reliability may be adversely affected. If a pathway avoids or minimizes the double capacity payment issue, that does not, however, mean that the pathway necessarily efficiently procures and/or retains the necessary balancing resources that are needed for reliability.

With these four criteria in mind, each pathway is considered. In the following discussion, pathways are grouped for ease of explanation and the order is not indicative of anything else. More detail on each of the identified pathways is provided in presentation and other background materials on NEPOOL's dedicated Future Grid Initiative webpages.

A. Forward Clean Energy Market and Integrated Clean Capacity Market

The Forward Clean Energy Market (FCEM) framework would use an auction mechanism to procure the quantity and amount of clean energy resources based upon demand curves constructed by each participating New England State and then combined into a regional demand curve (Brattle, Sep. 2019). As presented by Dr. Kathleen Spees of The Brattle Group, the FCEM would be conducted before the forward capacity market (FCM). Although there are many design components to the FCEM, the key elements are a downward sloping demand curve for clean energy resources, a forward auction, e.g., 3 years, with a possible multi-year commitment period for new resources (e.g., 3-7 years), an unbundled Clean Energy Attribute Credit (CEAC) that is tradeable via bilateral and spot markets, and associate market administration policies regarding tracking, credit, and market power monitoring and mitigation policies.

The Integrated Clean Capacity Market (ICCM) integrates the FCEM and the FCM into one auction in which resources offer in to provide both clean energy and capacity (Brattle, Oct. 2020). Resources that clear the joint procurement auction sell unbundled capacity and CEAC products. The motivation for the ICCM is to obtain the benefits of jointly optimizing the procurement of capacity and clean energy as opposed to running the FCEM and the FCM sequentially. One open question is whether it is possible to design and implement such a joint auction that is feasible and practical (ISO-NE, Jan. 2017).

Given their similarities, the FCEM and ICCM are analyzed together against the four criteria. States may need to relinquish some control of their more targeted policy objectives or preferences in order to obtain sufficient agreement with other States so that the FCEM or ICCM have sufficient uniformity in the definition of clean energy resources to garner the regional efficiency benefits of these auction mechanisms. The major claimed advantage of the FCEM and ICCM is that they procure the least cost set of clean energy resources, but they do so by having broad definitions of clean energy resources and setting a regional demand for these resources to foster regional competition.

Whether the FCEM and ICCM avoid the double capacity payment issue by procuring resources that are not considered receiving States' subsidies for the purposes of the MOPR is not clear. If the FCEM or ICCM were part of a FERC approved tariff, then the claim could be made that resources that clear these markets are not State-subsidized and do not have an additional revenue stream that advantages them over other resources participating in the wholesale market. If this were to occur, then any resulting or remaining price suppression issues would have to be addressed. On the other hand, if the clean energy resources that the FCEM or the ICCM procure are defined too narrowly and State specific, then there may be a higher potential of FERC either not accepting the FCEM or ICCM as part of a FERC tariff or possibly insisting on continued imposition of some form of MOPR, which could result in continued tensions associated with the double capacity payment issue. Finally, neither the FCEM nor the ICCM explicitly address the balancing resource issue.

B. Alternatives to the Forward Capacity Market

The FCM with a minimum balancing resource constraint (BRC) is intended to address the balancing resource issue (and therefore the reliability concerns associated with price suppression) by incorporating into the FCM requirements the balancing resources necessary to reliably operate the grid (Energy Market Advisors, 2020) but appears to have the same limitations as do the FCEM and ICCM with respect to achieving States' energy objectives and double capacity payment. The BRC presumably would be established to provide the types and amounts of balancing services determined to meet reliability requirements as discussed in the prior section.

Two options propose changes/reforms to the FCM: Capacity as a Commodity (Gabel Associates, 2020) and Always on Capacity Exchange ("AOCE") (Reliable Energy Analytics, 2019). As currently formulated, however, both options have not explicitly made clear how they would help to advance or achieve States' clean energy objectives, address the double payment/price suppression tradeoff, or ensure sufficient balancing resources. If either of these options are pursued in future pathway discussions, it would be useful to understand how they would specifically help to facilitate the resolution of one or more of these issues.

The FCM could be replaced with a standardized fixed-price forward contract (SFPFC) (Wolak Oct. 2020 and Nov. 2020). SFPFC would mandate load serving entities (LSEs) to purchase and hold for delivery standardized forward energy contracts with increasing percentages of their load in the near delivery years that are shaped to hourly system demand and backed by sufficient credit requirements to ensure delivery. In and of itself, SFPFC alone does not achieve decarbonization or other States' clean energy policy objectives. As presented, it presumes that additional renewable resources are being incentivized and then develops a mechanism in which these VRERs are combined with other resources to meet resource adequacy requirements, although formulated using energy obligations instead of capacity ones. How the SFPFC would facilitate addressing decarbonization and related objectives requires more development of this possible pathway taking into account more fully the particular context and characteristics of the New England region.

Similarly, the FCM could be replaced with energy scarcity pricing, for example with an operating reserve demand curve (ORDC) model used in the Electric Reliability Council of Texas (ERCOT) (i.e., "Energy Only Market" or "EOM"), but again, this market construct in and of itself would not achieve States' clean energy objectives or alone address the balancing resource challenges.

Eliminating the FCM, either by adopting the SFPFC or EOM, as first glance would seem to resolve the double payment problem. Without a capacity market, the MOPR would also be eliminated because there would not be capacity offers for the MOPR to restrict. The result would be resolving the double payment issue but possibly at the expense of price suppression. The States' subsidies would continue to provide revenue streams to clean energy resources that would enable them to recover some or much of their costs outside of the region's wholesale electricity markets. This would possibly affect the efficiency and reliability concerns discussed in the prior section.[9] The SFPFC or EOM pathways do not explicitly have a mechanism to ensure the sufficient procurement of needed balancing services.

C. Carbon Pricing

Instead of using a FCEM or ICCM to acquire clean energy resources via a regional market mechanism, another approach is to supplement the current Regional Greenhouse Gas Initiative price on carbon dioxide (CO_2) with an additional regional CO_2 price. One approach is net carbon pricing (NYISO, Jun. 20, 2019). In short, this pathway would require an agreement upon a social cost of carbon (SCC), subtract out the RGGI CO_2 price, have ISO-NE charge emitting generators this additional cost of carbon, and net out (i.e., rebate) back to load serving entities (LSEs) the additional CO_2 revenue. Net carbon pricing mitigates, but not necessarily solves, the double payment issue by raising the revenues clean energy resources would earn in the energy markets but would reduce the States' ability to tailor specific timing and type of clean energy resources to meet their individual policy objectives. Net carbon pricing does not explicitly address the balancing resource issue.

IV. Specific Findings Regarding Pathways and Their Variations

The presentations and associated discussions on the identified pathways raised numerous insights that are documented below and that may inform future discussions.

[9] Given that the FERC's historical concerns regarding price suppression (as reflected in its establishment of the MOPR), it is at least conceivable that the FERC could adopt an analogous mitigation construuct with respect to energy offers if the FCM was eliminated. Whether the FERC would do so and how it would go about crafting such a rule may need to be considered if discussions about eliminating the FCM proceed.

A. Overall Findings Comparing Pathways

In general, the four categories of pathways vary among two major sets of dimensions: regional vs. State specific and planning vs. markets. Carbon Pricing and EOM are regional and market based. Planning refers to States setting the types, quantities and timing of clean energy investments, whether through specific mandates or market mechanisms such as RPS/RES. The FCEM, ICCM and ARACs are more planning based than Carbon Pricing and EOM and, depending on their variations, can be regional or State specific. Some variations of ARACs are intended to further State-specific clean energy objectives. These ARAC alternatives, such as the alternatives that involve regional or state-level integrated resource planning, were not extensively discussed as part of this effort. Of the pathways identified, FCEM, ICCM and CP are primarily directed at reducing greenhouse gas emissions, whereas the other two categories (EOM and ARACs) are different ways to provide resource adequacy, although some ARACs are directed at advancing/supporting States' clean energy objectives. Figure 1 provides a conceptual orientation of the four core pathways across these two dimensions, including variations within each identified pathway category.

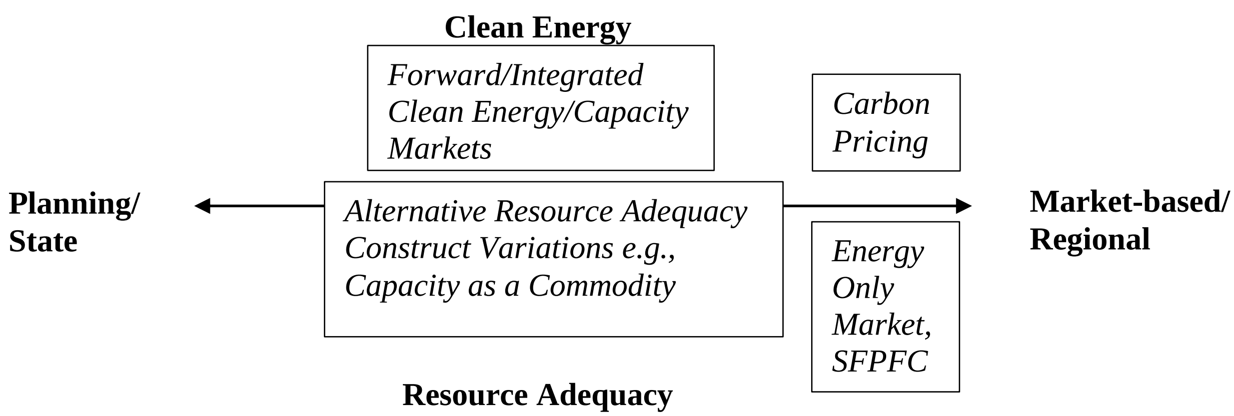

Figure 1: Conceptual Comparison of Pathways along Planning-Market-based and State-Regional Dimensions

When States set the type, quantity and timing of clean energy investments (i.e., planning), they have more control of outcomes and financing costs may be lower with longer and more certain guarantees than with other market mechanisms. Ratepayers, however, would ultimately bear the risk of such state-imposed requirements, whereas developers/investors take on the risks in the competitive markets. Regional market-based approaches/pathways may also result in lower costs than state integrated resource planning due to technology flexibility and decreasing costs of clean energy resources over time (although would still need to address potential market power and manipulation issues).

Each of the identified pathways has variations, some of which substantially alter the pathway's characteristics and outcomes. Moreover, many pathways could be combined with each other with varying degrees of merit, although EOM and ARACs are by definition mutually exclusive. Table 3 summarizes each pathway's objectives, whether they are regional or State specific, their major variations and design variables, and their organizational structure.

Table 3: High-level Comparison of Four Pathways and Major Variations

Major Components	**Forward Clean Energy Market/Integrated Clean Capacity Market**		**Carbon Pricing**	**Energy Only Market**	**Alternative Resource Adequacy Constructs**	
	Regional	**State Specific**	**Regional**	**Regional**	**Regional**	**State Specific**
Primary Objective	Clean Energy via regional coordination	Clean Energy by accommodating different States' objectives and procurement strategies	Reducing regional CO_2 emissions in the power sector and extending to other sectors	Resource adequacy via scarcity pricing	Resource adequacy	Resource adequacy and State Clean Energy objectives
Major Design Questions, Components and/or Alternatives	Forward auction of unbundled Clean Energy Attribute Credit (CEAC) Integrated with FCM or not Explicit BR requirements Definition of Credit CEAC; static or Dynamic CEAC? Downward sloping demand curve of aggregated State or individual State clean energy goals? Demand curve reference price set to SCC or Clean Net CONE Multiple-year commitment period for new resources or not? Technology specific carve-outs or not? Grandfathering of existing contracts or not? Banking of CEAC restrictions if any Compliance via spot market and demand curve (to replace alternative compliance penalties)		Social cost of carbon equivalent to regional emission caps How to allocate the revenues from the sale of emission allowances or revenues from pricing CO_2? Use RGGI framework or pursue an alternative approach, e.g., via ISO-NE? How to extend to other non-power sectors?	VOLL that sets the ORDC cap Minimum quantity of reserves needed for system security Shape of the ORDC based upon LOLP*VOLL LOLP calculation Additional reliability adders to offset price suppression impacts of reliability actions Whether ORDC is co-optimized with SCED? Multiple reserve products and adders? Zonal/locational reliability adders Policies regarding reliability unit commitment	Definition of resource adequacy? Centralized or decentralized capacity market, standardized fixed-price forward contract (SFPFC), Capacity as a Commodity, Always on Capacity Exchange (AOCE) Regional or State Specific resource adequacy requirements? Fixed Resource Requirement option allowing for States/Load Serving Entities (LSE) to self-supply Regional Integrated Resource Planning (IRP) State IRPs that determine the combination of energy resources that meet the State's clean energy policy and resource adequacy requirements using long-term financial arrangements	
Contemplated Organizational Structure	ISO-NE market or RGGI-like organization?	Individual State sanctioned organizations	ISO-NE (net carbon pricing or RGGI or something else	ISO-NE	ISO-NE	Individual State structures

Both Carbon Pricing and EOM pathways fundamentally rely upon short-term, wholesale energy prices and their expectations (augmented by longer-term forward bilateral markets) to drive major capital investment decisions, whereas the FCEM and certain ARACs provide longer-term commitments as part of their constructs.[10] Some of the variations of the ARACs are modifications to the existing ISO-NE forward capacity markets and therefore fit within the current wholesale market structure whereas other variations likely require a substantially different structure or institutional framework.

B. Forward Clean Energy Market and Integrated Clean Capacity Market Related Findings

In theory, co-optimizing the forward procurement of clean energy resources with capacity needed for adequacy would maximize the social surplus of meeting States' clean energy objectives and regions' resource adequacy requirements, but as noted above, it is not clear if this can be implemented in practice. If ICCM has multiple products, then co-optimization becomes more difficult, if at all, to implement because the co-optimization problem becomes more complicated as the types of products and requirements increase. Without co-optimization, resources offering into the FCEM would have to estimate their expected revenues in the FCM and if those estimates are incorrect, inefficient outcomes may result.

The value of co-optimizing the FCEM with the FCM, i.e., an ICCM, depends in part on the extent that resources have both clean energy and capacity attributes. The less they overlap, i.e., if clean energy attributes provide little capacity value or vice-versa, then co-optimization provides less benefits because there is little to co-optimize. If FCEM has multiple and individually targeted resources, then the value that a regional market provides is less than with fewer targeted resources because there is less flexibility across resources to optimize than without targeted resources. In other words, an FCEM design that limits eligibility to a more narrow or targeted set of resources or technology types would garner less efficiency benefits than an FCEM with a broader (more inclusive) definition of "clean energy" because the more types of clean energy resources that compete in the FCEM, the more cost-effective it will be.

C. Carbon Pricing Related Findings

Carbon Pricing alternatives are at the regional market end of the spectrum as indicated in Figure 3 and do not necessarily result in desired State outcomes, whether levels of CO_2 reductions or deployment of specific technologies.[11] Under Carbon Pricing, it is possible that carbon emissions do not decrease sufficiently to meet States' ambitious carbon reduction goals and requirements. Instead, generation units pay the Carbon Pricing to emit perhaps above the

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[10] In light of a recent New England FERC Order, careful consideration should be given as to whether these constructs would withstand scrutiny before the FERC. On December 2, 2020 FERC issued an order finding that ISO-NE's current 7-year price-lock mechanism for new capacity resources is no longer just and reasonable and directed ISO-NE to remove them from the Tariff. Specifically, the FERC found that, "in light of changed circumstances, the New Entrant Rules are unjust and unreasonable because they result in unreasonable price distortion." The FERC further found that the FCA price assurance that the FERC previously found necessary in approving these rules is no longer required to attract new entry, with the benefits provided by price certainty no longer outweighing their price suppressive effects. FERC directed ISO-NE to submit a compliance filing, on or before February 1, 2021, eliminating the price lock rules for new entrants starting in FCA16. *See December 2 Order* at: https://www.iso-ne.com/static-assets/documents/2020/12/el20-54-000_12-2-20_order_new_entrant_rules.pdf.

[11] For ease of explanation, the terms *carbon pricing* and *carbon emissions* are used generically to cover carbon dioxide and other greenhouse gases.

total emission levels set by States. States still could use their RPS combined with other policies to meet specific their specific clean energy goals with Carbon Pricing. Compared to options that are designed to procure clean energy resources such as FCEM, ICCM and integrated resource planning, Carbon Pricing using the SCC (either explicitly or setting emission caps to reflect the SCC) is generally viewed as more economically efficient these alternatives. Carbon Pricing does work by increasing the wholesale price of electricity, which does incentivize demand reduction but may not be politically palatable.

New England is part of the Regional Greenhouse Gas Initiative (RGGI), which prices carbon emissions using a cap-and-trade mechanism. The Carbon Pricing pathway would almost certainly increase the price put on carbon above that which is presently set implicitly through RGGI in order to achieve States' decarbonization goals. One way for New England to do this is via RGGI by agreeing to lower States' emission caps over time at a much faster rate than currently planned. Another Carbon Pricing alternative is for the SCC to be internalized into the offers of carbon emitting resources (after netting out the implicit price of carbon embedded in RGGI). These resources would have to pay the SCC minus the RGGI cost. If this is implemented by the ISO-NE, presumably FERC approval would be needed. The payments applicable generators would make to emit carbon would be collected by the ISO-NE and rebated to LSEs. The NYISO has developed a proposal along these lines that may serve as a starting point for discussions (NYISO, Jun. 20, 2019). One major issue is how to define precisely how the carbon revenues are allocated to LSEs. The Carbon Pricing alternative identified by ISO-NE, referred to as net-carbon pricing, contemplates having LSEs pay the net of the SCC minus what they receive via the rebates.

The cost to finance resources depends, in part, on policy certainty, which depends on the specific alternative within a given pathway but also on the underlying political jurisdiction and dynamics. Under Carbon Pricing, energy prices increase, thereby increasing the energy margins of low or non-emitting CO_2 resources. These resources offering into the FCM have larger energy margins with Carbon Pricing than without and recover more of their fixed costs in the energy market enabling them to be more competitive in the FCM given the MOPR. In the context of Carbon Pricing, an observed concern regarding financing is whether investors believe that sufficient carbon pricing will be implemented over the long-term to justify developing lower or non-carbon emitting resources. Some alternatives in other pathways have more direct, and longer-term commitments to finance resources than the Carbon Pricing pathway (e.g., FCEM and ICCM constructs).

The interaction with Carbon Pricing and RPS/RES could be complicated given the MOPR. With the MOPR's restrictions on offers, owners of low and non-emitting carbon resources must decide if they earn more profits by selling RECs and not participating in the FCM or not selling RECs and participating in the FCM. As Carbon Pricing increases, these resources may become economic in the FCM even with the MOPR because their energy revenues increase sufficiently so that the MOPR is no longer an impediment to clearing the FCM. Thus, Carbon Pricing would likely help to mitigate the double capacity payment concern that States have with the MOPR, although, as noted above, at the expense of raising wholesale energy prices.

If New England increases the price on carbon compared to other RGGI regions, then, depending on the increase, that may materially affect inter-regional power flows within RGGI and regions bordering RGGI and beyond. This could increase leakage, i.e., the importation of low-cost but carbon emitting resources into New England, unless a mechanism is devised to account for the carbon emissions of imports. Conversely, exports of power from New England would likely be relatively more expensive if New England increases its carbon prices.

D. Energy Only Market Related Findings

As noted above, the EOM removes the FCM and therefore would eliminate the current mechanism that the FERC is employing to address price suppression, although it is conceivable that the FERC could implement some type of MOPR analog for the energy market. If the FERC does not do so, then the EOM should permit States to individually or collectively pursue their clean energy policies without facing the current "double payment" issue associated with application of the MOPR in the FCM. Under this scenario, price suppression would occur, which raises issues regarding having sufficient BR to meet the reliability requirements with increasing penetration of VRERs. EOM and existing ancillary service markets may not provide sufficient flexibility and ramping services. The need for BRs due to the penetration of VRERs under an EOM pathway may be addressed either via current wholesale market mechanisms (energy, ancillary services) and/or new constructs.

Shortage pricing, the key feature of EOM, can be combined with FCM and its variations (e.g., FCEM and ICCM) and ARACs. Doing so shifts the focus of revenue recovery to day-ahead and real-time energy markets away from capacity markets. Shortage pricing does not necessarily ensure sufficient balancing resources that are likely to be needed in a future state to provide flexibility and/or ramping capability beyond just the production of energy.

E. ARACs Related Findings

As discussed in the prior section, the two ARACs that had stand-alone presentations at the NPC, SFPFC and Capacity as a Commodity, did not explicitly propose mechanisms for the procurement of clean energy resources. Since Capacity as a Commodity retains a capacity market, presumably the MOPR would still be in place and therefore the double capacity pricing issue would remain a concern.

Other ARACs may address the MOPR double-payment issue by eliminating the capacity market such as the SFPFC or implementation of regional or State integrated resource planning (IRP). IRP alternatives could retain the resource adequacy construct but not have a capacity market. IRP alternatives may have explicit BR requirements or leave BR procurement to an ISO-NE administered market or markets.

Another ARAC is a Fixed Resource Requirement (FRR), which PJM has as an option in its Tariff. This FRR option is would permit States or LSEs the ability to satisfy their resource adequacy requirements (outside of PJM's Reliability Pricing Model market) by having a portfolio of resources that they have procured to prospectively serve load over a period of time, such as five years that met the load's capacity obligation. This option in PJM was designed for integrated utilities in States that do not have retail energy markets instead of LSEs that have much shorter time horizons than utilities given the mobility of load among LSEs. Based upon how current resource adequacy requirements are determined, the FRR does not address the need for BRs and may compound the problem if the capacity resources in the FRR are not BRs. FRR may also reduce the regional reach of the FCM and associated efficiency benefits of that auction and associated bilateral markets.

V. Summary

The New England region's discussions on, and exploration of, potential pathways to its future grid brings into focus the tensions between Federal wholesale markets and States' clean energy transition plans. In addition, the discussions I have observed to date have identified the importance of defining the criteria for determining the types and quantities of balancing resources needed to reliably plan and operate the regional power grid as the penetration of renewable energy resources increase. As these discussions continue, more detailed evaluations and assessments of pathways will be necessary (including quantitative analysis where able), which will require greater specificity on design details and probing the pathway's interaction with other regional policies such as transmission planning.

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