NEPOOL
NEW ENGLAND POWER POOL

David T. Doot
Secretary

November 22, 2022

VIA ELECTRONIC MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of December 1, 2022 NEPOOL Participants Committee Annual Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the December meeting of the Participants Committee, the annual meeting for the Committee, will be held **in person on *Thursday*, December 1, 2022, at the Colonnade Hotel, 120 Huntington Avenue, Boston, MA in the Huntington Ballroom** for the purposes set forth on the attached agenda and posted with the meeting materials at nepool.com/meetings/. Please note two things about this meeting:

- As indicated on the Final Agenda, the first agenda item, which will begin **at 10:00 a.m.,** is the deferred Participant proposal to ballot changes to the Participants Agreement to raise the age limit for Board of Director nominees and is expected based on November discussions to be moved promptly into confidential executive session. Only voting Members, Alternates or their designees are permitted to participate. A confidential e-mail to Members and Alternates wishing to participate virtually in that portion of the meeting will be sent under separate cover. **For all other attendees, the general session is planned to begin at 10:30 a m.** If you plan to participate in that general session virtually, please use the following dial-in information: **866-803-2146; Passcode: 7169224.** To join using WebEx, click this link and enter the event password **nepool**.

- We are honored to be joined by FERC Commissioner Danly, who is planning to join in person and will address the Committee when it goes into the general session. We encourage members to attend in person if they are able.

For your information, the December 1 meeting will be recorded. NEPOOL meetings, while not public, are open to all NEPOOL Participants, their authorized representatives and, except as otherwise limited for discussions in executive session, consumer advocates that are not members, federal and state officials and guests whose attendance has been cleared with the Committee Chair. All those in attendance or participating, either in person or by phone, are required to identify themselves and their affiliation at the meeting. Official records and minutes of meetings are posted publicly. No statements made in NEPOOL meetings are to be quoted or published publicly.

By way of reminder, any Participant that wishes to change its Sector for next year ***must provide us with written notice of that request before the Annual Meeting.*** Under Section 6.3 of the NEPOOL Agreement, any Participant request to change the Sector in which it votes becomes effective *at the first annual meeting following that request.*

We will hold a New Member Orientation following the meeting for anyone wishing to learn more about or dive deeper into the aspects of the NEPOOL stakeholder process. There are 34 entities that became NEPOOL members in 2022. Representatives of these new members and anyone else wanting to learn more about the NEPOOL stakeholder process are welcome and encouraged to attend. Please let Pat Gerity (pmgerity@daypitney.com) know if you plan to attend the New Member Orientation so we can ensure sufficient space and copies of materials.

The NEPOOL reservations block at The Colonnade is now closed. If you are still in need of a room, please contact Kaitlyn Rogers (krogers@daypitney.com) who may be able to assist getting you into The Colonnade or an alternative venue if possible.

Respectfully yours,

/s/
David T. Doot, Secretary

FINAL AGENDA

Discussion on Item 1 will begin at 10:00 a.m. and is expected to be held partially in executive session, during which participation will be limited exclusively to voting Members and Alternates, or their designees.

1. To consider, and take action, as appropriate, on a Participant proposal to amend § 9.2.3(a)(i) of the Participants Agreement (Terms of Directors) to raise the age limitation prohibiting the election or re-election of any candidate to the Board of Director from 70 to 75. This matter was deferred from the November meeting. Background materials and a draft resolution to ballot a Participants Agreement amendment are included and posted with this supplemental notice.

The remainder of the meeting will be in general session, which is expected to begin at 10:30 a.m.:

2. To approve the draft minutes of the November 2, 2022 Participants Committee meeting. A copy of the draft minutes, marked to show the changes made since the minutes were circulated with the initial notice, is included with this supplemental notice and posted with the meeting materials.

3. [There is no Consent Agenda for this Meeting]**.**

3A. To consider, and take action, as appropriate, on changes to ISO New England Operating Procedure No. OP 24 (Protection Outages, Settlings, and Coordination) & Appendix D to OP-24 (Protection Outages, Settlings, and Coordination), as recommended by the Reliability Committee. But for timing of the RC action, this matter would have been on the Consent Agenda. Background materials and a draft resolution are included and posted with this supplemental notice.

4. To receive comments from the Honorable James Danly, Commissioner, Federal Energy Regulatory Commission.

5. To receive an ISO Chief Executive Officer report. The December CEO report will be circulated and posted in advance of the meeting.

6. To receive a report from the ISO Chief Operating Officer. The December COO report will be circulated and posted in advance of the meeting.

[continued on next page]

FINAL AGENDA
(cont.)

7. To receive the 2022 NEPOOL Annual Report, which will be distributed at the Participants Committee meeting and posted with the meeting materials.

8. To elect NEPOOL Participants Committee Officers for 2023. A draft resolution reflecting the outcome of the balloting for Participants Committee Chair and candidates for Secretary and Assistant Secretary is included and posted with this supplemental notice**.**

9. To adopt a NEPOOL Budget for 2023. Background materials and a draft resolution are included and posted with this supplemental notice.

10. 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.

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

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

12. Administrative matters.

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

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Pat Gerity, NEPOOL Counsel

DATE: November 22, 2022

RE: Participant proposal to amend § 9.2.3(a)(i) of the Participants Agreement

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Having been deferred from the November 2, 2022 Participants Committee meeting, you will be asked at the December Annual Meeting to consider, and potentially to approve the balloting of, a limited revision, proposed by a Participant, to amend § 9.2.3(a)(i) of the Participants Agreement (Terms of Directors) to raise the age limitation prohibiting the election or re-election of any candidate to the Board of Director from 70 to 75. Discussion on this item is expected to be held partially in executive session, during which participation will be limited exclusively to voting Members and Alternates, or their designees. For the benefit of those voting members, alternates or designees that may be participating virtually in the executive session, separate, confidential information as to how to join the executive session will be provided under cover. Materials describing the proposed revision in additional detail are not confidential and are included with this memorandum and posted with the materials for the Annual Meeting.

As we noted last month, a motion to approve balloting of the Participants Agreement amendment requires a NEPOOL Vote by the Participants Committee of two-thirds, or 66.67%. The following form of resolution may be used for Participants Committee action:

> RESOLVED that the Participants Committee authorizes and directs the Balloting Agent (as defined in the Second Restated NEPOOL Agreement) to circulate ballots for the approval of an agreement amending the Participants Agreement, to amend § 9.2.3(a)(i) of the Participants Agreement (Terms of Directors) to raise the age limitation prohibiting the election or re-election of any candidate to the Board of Director from 70 to 75 as presented at this meeting, together with [such changes as were discussed and agreed to by the Committee and] such non-substantive changes as may be agreed to after the meeting by the Chair or any Vice-Chair of the Participants Committee, to each Participant for execution by its voting member or alternate on this Committee or such Participant's duly authorized officer.

If approved, ballots will be circulated for signature. To be approved in balloting, changes to the Participants Agreement must be approved by a 70% Vote from enough members to satisfy the Minimum Response Requirement. Any change to the Participants Agreement also requires ISO approval.

ISO-NE Board Age Limit – Updated

Michelle Gardner, Executive Director – Northeast
NextEra Energy Resources
Vice-Chair, Generation Sector and Joint Nominating Committee Member

November 29, 2022 (New Slide 5 and 6)

Executive Summary

Participant-initiated proposal to revise age limit for ISO Board members from age 70 to age 75

Conforms with best practices for the recruitment of talent for the ISO Board and aligns ISO with the rest of the RTO/ISOs in the country

Change requires one edit to the Participants Agreement

- No further changes on age or term waivers
- All other mechanisms remain the same

Vote required by the NEPOOL Participants Committee

Age Limit in the Participants Agreement

PA between the ISO and NEPOOL currently prohibits "a director from being elected or re-elected if she or he is over 70 years old at the time of election or re-election."

The provision has been in the Participants Agreement since it was adopted in 2004.

There is also a term limit (three three-year terms) in the Participants Agreement.

Best Practices for Board Recruitment

Since 2004, best practices have changed.

The retirement ages of boards continue to rise.

Currently, 51% of boards with age limits have a mandatory retirement age of 75 or older, compared with 20% a decade ago.

- **Taken from the 2021 U.S. Spencer Stuart Board Index at page 20 us-spencer-stuart-board-index-2021.pdf (spencerstuart.com)**
- **Among boards with age limits, only 3% in 2021 have a retirement age of 70 and younger**

Age limits at the other ISOs conform to these trends. Two ISOs have age limits of 75; the others report that they have no age limits at all.

Challenges with Present Age Limit

- In recent years, the age limit has contributed to difficulty in finding high-quality director candidates to serve on the ISO Board.

- Heidrick & Struggles, Spencer Stuart, Egon Zehnder and most recently, Russell Reynolds (all four of the Joint Nominating Committee's director search partners), have expressed this concern to the Committee.

- The concern is related to the substantial time commitment required to serve on the ISO's Board, making it challenging for actively-employed executives to serve. As many executives are working well into their 60's and not assuming Board commitments like the ISOs until retirement, the present age limit shortens their service window.

- The limitations created by the age limit are exacerbated by other restrictions on the candidate pool, including the ISO's Code of Conduct. These challenges intersect in respect to potential candidates recently affiliated with market participants or who own investments in such companies. For most executives retiring from publicly traded market participants/affiliates, there is a multi-vesting cycle for unvested equity awards that still follows them in retirement. This means that those financial conflicts continue to exist for that period (typically 3-4 years) even after the executive retires. FERC's interlock rules create additional limitations.

A Snapshot of the ISO New England Candidate 2022 Pool

Russell Reynolds Associates (RRA) identified the potential candidate pool for outreach through their own research and sourcing efforts, as well as through referrals submitted through NEPOOL members/the JNC.

For the 2022 search cycle, the following represents the reasons that candidates who RRA directly engaged with did not progress to the candidate slate.

- **21% - Financial/ business conflicts**
- **20% - Age limit**
- **14% - Calendar conflicts/capacity constraints**
- **25% - Candidate declined interest**
- **20% - Candidate expressed interest but was not included by RRA for fit/alignment reasons after additional vetting**

Note that these numbers do not include candidates excluded from the candidate pool because the financial conflict or issue with the age limitation was previously known to RRA.

Participants Agreement Revision

The proposal is for an amendment to the Participants Agreement to make a simple change to the existing language, as follows:

"The Participants Agreement between the ISO and NEPOOL prohibits "a director from being elected or re-elected if she or he is over ~~70~~ 75 years old at the time of election or re-election."

PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held beginning at 2:05 p.m. on Wednesday, November 2, 2022, at the Renaissance Providence Downtown Hotel, Providence, Rhode Island, following meetings between each of the Sectors and ISO Board members. 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 meeting, either in person or by telephone.

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

APPROVAL OF OCTOBER 6, 2022 MEETING MINUTES

Mr. Cavanaugh referred the Committee to the preliminary minutes of the October 6, 2022 meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of that meeting were unanimously approved as circulated, with an abstention by Mr. Sam Mintz, but with Attachment 2 corrected to reflect, in the AR Sector tabulation, the right vote and abstention totals for Vote 1 and Sunrun's vote in favor on Vote 2, none of which changed the percentages in favor recorded for the AR Sector.

CONSENT AGENDA

Mr. Cavanaugh referred the Committee to the Consent Agenda that was circulated and posted in advance of the meeting. Following motion duly made and seconded, the Consent Agenda was approved as last circulated, with Consent Agenda Item 3 (IEP Eligibility Compliance Revisions) removed and to be discussed later in the meeting, and with oppositions noted by Calpine, Cross-Sound Cable (CSC) and LIPA, and abstentions noted by BP, Castleton

Commodities, Dominion, DTE, FirstLight, Galt Power, Granite Shore Power, Great River Hydro, HQUS, Mercuria, Mr. Mintz, Nautilus, and Shell. With the exception of Mr. Mintz, all of the representatives indicated that their oppositions or abstentions related to Consent Agenda Items 1 and 2 (HQICC Values and Installed Capacity Requirement (ICR) and Related Values for the 2023-24 3rd Annual Reconfiguration Auction (ARA), 2024-25 2nd ARA, and 2025-26 1st ARA) (together, the ARA Values). The representatives for Calpine, and for Granite Shore Power and Wheelabrator noted that their votes reflected their previously conveyed positions (objecting to the use of tie benefits (or any non-firm, non-committed external capacity) in the determination of the Values). The representatives for CSC and LIPA explained that their votes reflected their view that the ARA Values did not properly account for the reliability benefits and capacity import capability of the Cross-Sound Cable.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), referred the Committee to the summary of the ISO Board Information Technology and Cyber Security Committee meeting that had occurred since the October 6, 2022 Participants Committee meeting, which had been circulated and posted in advance of the meeting. There were no questions or comments on the summary.

ISO COO REPORT

Operations Highlights Report

Dr. Chadalavada began his report first by referring the Committee to his October operations report, which had been circulated and posted in advance of the meeting. Dr. Chadalavada noted that the data in the report was through October 25, 2022, unless otherwise noted. The report highlighted: (i) Energy Market value for October 2022 was $419 million, down $273 million from the updated September 2022 value and down $139 million from October 2021; (ii) October 2022 average natural gas prices were 24% lower than September average prices; (iii) average Real-Time Hub Locational Marginal Prices (LMPs) for October ($53.86/MWh) were 12% lower than September averages; (iv) average October 2022 natural gas prices and Real-Time Hub LMPs over the period were up 8.3% and down 3.7%, respectively, from October 2021 average prices; (v) average Day-Ahead cleared physical energy during peak hours as percent of forecasted load was 98.7% during October (down from the 99.9% reported for September), with the minimum value for the month of 94% on September 7; and (vi) Daily Net Commitment Period Compensation (NCPC) payments for October totaled $2.2 million, which was up $143,000 from September 2022 and down $1.3 million from October 2021. October NCPC payments, which were 0.5% of total Energy Market value, were comprised of $2.1 million in first contingency payments (up $0.2 million from September) and $128,000 in second contingency payments (down $11,000 from September).

Turning to operational highlights from October, Dr. Chadalavada reported that the average temperature for October was 55° F, resulting in a Real-Time peak load of 11,300 MWh~~s~~. He noted that October's average load was the lowest since 2003. He attributed that relatively low average load to the mild temperatures and increased behind-the-meter photovoltaic generation on the system. Then, Dr. Chadalavada reminded Participants of upcoming regional transmission outages on 345kV Line 347 (Killingly-Sherman Road), planned for November 16 through December 9, 2022, and 345kV Line 369 (Seabrook-Timber Swamp), planned for November 12 through November 17, 2022.

In response to questions, Dr. Chadalavada indicated that the scenario analysis of Mystic's Cost of Service Agreement, discussed at the October meeting, was underway and the ISO would circulate the resulting work-product later in November.

New England Winter Outlook 2022/2023

Turning to the New England winter analysis, Dr. Chadalavada highlighted a few points. He noted that: (i) the seasonal temperature outlook for the winter months of December-January-February indicated a 33-40% probability of above normal temperatures for southern New England and equal chances of above average or below average temperatures for the rest of New England; (ii) the seasonal temperature outlook for the winter months of December-January-February indicated a 33-40% probability of above normal temperatures for southern New England and equal chances of above average or below average temperatures for the rest of New England; and (iii) capacity analysis for the 50/50 and the 90/10 load forecasts indicated a surplus even after accounting for generation at risk due to gas supply. He explained that because Europe met its intended liquefied natural gas (LNG) fuel storage target ahead of the upcoming winter, LNG prices had dropped, although they were still elevated from prior years. The ISO was optimistic that there would be more LNG deliveries throughout the winter. He also reported that, despite supply chain tightness, the fuel stock on December 1 would be almost 50% and higher than previously predicted. In preparation for the winter, Dr. Chadalavada highlighted the ISO's recent Energy Shortfall Exercise with utilities, transmission owners, and government agencies to rehearse response actions in the event that the New England region experienced an energy shortfall. He then referred the Participants to the 2022/23 scenario assessments, that he explained assumed no LNG replenishment. Any LNG replenishment, therefore, would improve the outcomes for the projected scenarios.

Members expressed optimism with the ISO's projections and noted that the LNG market had changed drastically within the last six months. They concurred with the assessment that there would be more LNG supply for the winter at a lower price than previously feared. Finally, a member opined that, although the winter forecast had improved, the ISO should continue its work preparing the region for a winter similar to 2013/14.

IEP COMPLIANCE REVISIONS

Ms. Mariah Winkler, Markets Committee (MC) Chair, summarized the process leading up to the ISO's proposed revisions to the Tariff to make nuclear, coal, biomass, and hydroelectric generators ineligible to participate in the Inventoried Energy Program (IEP). She reported that the proposed changes, which the ISO concluded were needed to comply with the FERC's September 23, 2022 *IEP Remand Order Directing Compliance* (Remand Order), were unanimously supported with one abstention noted at the October 12-13, 2022 MC meeting. Ms. Winkler also explained that, after the MC meeting, the ISO identified and made several clarifying revisions to the proposed language relating to hydropower generation.

Following her overview, the following motion was duly made and seconded:

> Resolved, that the Participants Committee supports the revisions to Appendix K of Market Rule 1, as proposed by ISO New England and recommended by the Markets Committee to comply with the FERC's September 23, 2022 Order, together with additional, clarifying revisions to Appendix K proposed by the ISO following consideration by the Markets Committee, as circulated to this Committee in advance of this meeting, and also together with any non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

Brookfield Motion to Amend

With the main motion before the Committee, the Chair invited Brookfield Renewable's (Brookfield) representative to introduce its proposed amendment, as circulated and posted in advance of the meeting, to allow pumped hydro that is operated as an electric storage facility to be eligible to participate in the IEP. That member indicated Brookfield's agreement with the ISO that hydroelectric resources are ineligible from participating in the IEP following the D.C. Circuit's decision, but believed that storage facilities were eligible to participate in the IEP and pumped-storage facilities were properly considered energy storage rather than a hydroelectric resource. Thus, Brookfield argued the D.C. Circuit Court's holding was limited to hydroelectric resources with pondage but not pumped hydro. The Brookfield representative~~He~~ opined that it would not be reasonable for the ISO and FERC to pay chemical batteries under IEP while denying that revenue to a pumped storage hydro battery. He explained that payments to pumped storage under IEP were estimated to increase the cost of that program by approximately $1.5 million. The Brookfield motion to amend the main motion was moved and seconded

Members then discussed the motion to amend. The ISO's General Counsel, in response to a question, explained that the ISO read the D.C. Circuit's rationale to exclude those technologies from participating in the IEP that would not be incentivized to procure additional fuel or provide an incremental winter reliability benefit as a result of an incremental IEP payment. She clarified and the NEPOOL Chair confirmed that the FERC directed the ISO to modify its Tariff in compliance with the Remand Order. Thus, should the ISO reject Brookfield's amendment, the recourse of Brookfield and anyone else supporting the Brookfield Amendment would be to protest the ISO's proposal as not in compliance with the Remand Order and/or the Federal Power Act. The "jump ball" provision of the Participants Agreement, they added, would not apply in this situation. An ISO representative indicated in response to a question that the ISO would not adopt Brookfield's amendment in its compliance filing, even if supported, since the ISO viewed its compliance obligation as clear and not encompassing changes like those proposed by Brookfield. However, while it would not file the amendment, neither would the ISO oppose the amendment if the FERC concluded that it had not intended in its Remand Order to exclude pumped storage hydro from IEP compensation. A member questioned whether a protest of the compliance filing could delay implementation of IEP. Counsel for both NEPOOL and the ISO agreed that a delay in implementing the IEP was unlikely.

A number of members indicating support for the amendment, explained that if storage systems qualified for the IEP, then they should qualify regardless of the technology. Members that did not support the amendment expressed agreement with the ISO that the DC Circuit Decision and the FERC's direction were clear in excluding all hydroelectric facilities, including pumped-storage hydroelectric resources. A member referred the Committee to arguments made in support of NEPOOL's position on the then-expired Winter Reliability Program that did not pay pumped storage hydro. Other members questioned whether pumped storage would behave any differently in order to enhance reliability during the winter if they received IEP revenues. The Brookfield representative stated that IEP revenues to pumped-storage would change its behavior because the settlement rate would alter the spread analysis and incentivize operators to operate at times when it was previously not economical. Others indicated they were not persuaded that any change in the behavior of pumped storage justified the added expense.

The motion to amend to the main motion was then voted and passed with a 71.08% Vote in favor (Generation Sector – 16.7%; Transmission Sector – 11.13%; Supplier Sector – 16.7%;

AR Sector – 13.43%; Publicly Owned Entity Sector – 0%; End User Sector – 13.12%; and Provisional Members – 0.00%).[1] (See Vote 1 on Attachment 2.)

Once-Amended Main Motion

Without further discussion, the Committee then considered and approved the once-amended main motion with a 70.99% Vote in favor (Generation Sector – 10.02%; Transmission Sector – 16.7%; Supplier Sector – 16.7%; AR Sector – 14.48%; Publicly Owned Entity Sector – 0%; End User Sector – 13.12%; and Provisional Members – 0%).[2] (See Vote 2 on Attachment 2.)

Vote on Unamended Main Motion

At the request of the ISO, the Committee then considered and approved the unamended motion, as advocated by the ISO, with a 83.57% Vote in favor (Generation Sector – 11.13%; Transmission Sector – 16.7%; Supplier Sector – 15.51%; AR Sector – 16.5%; Publicly Owned Entity Sector – 16.7%; End User Sector – 7.03%; and Provisional Members – 0%). (See Vote 3 on Attachment 2.)

IEP CHANGES TO ISO FINANCIAL ASSURANCE AND BILLING POLICIES & MINISTERIAL CHANGE TO THE MONTHLY STATEMENTS ISSUANCE DATE

Mr. Kaslow, Budget & Finance Subcommittee Chair, introduced the proposed changes to the ISO Financial Assurance and Billing Policies to incorporate provisions necessary to implement the IEP and to reflect the correct date for the issuance of Monthly Statements. Mr. Kaslow reported that the proposed changes were reviewed by the Subcommittee at its August 23 and October 11 meetings and there were no concerns expressed. Following motion duly made

[1] Secretary's note: Following the meeting, two representatives whose votes on Vote 1 and Vote 2 were not communicated during the meeting requested that their votes be noted as follows: the vote of the AR Sector's Small LR Group as in favor on both and the vote of Harvard Dedicated Energy Limited as opposed to both.

[2] Secretary's note: Following the meeting, two representatives whose votes on Vote 1 and Vote 2 were not communicated during the meeting requested that their votes be noted as follows: the vote of the AR Sector's Small LR Group as in favor on both and the vote of Harvard Dedicated Energy Limited as opposed to both.

and seconded, the Committee unanimously approved the following motion, with an abstention by Mr. Mintz noted:

> RESOLVED, that the Participants Committee supports the changes to the ISO New England Financial Assurance Policy (FAP) and the ISO New England Billing Policy related to the ~~Inventoried Energy Program (~~IEP~~)~~ and the ministerial change to the ISO Tariff to reflect the correct date for the issuance of Monthly Statements, each as proposed by the ISO and as circulated to this Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair of the Budget and Finance Subcommittee.

PROPOSAL TO RAISE AGE LIMITATION ON ISO BOARD MEMBER ELECTION

Ms. Michelle Gardner, Generation Sector Vice-Chair and Joint Nominating Committee (JNC) Member, introduced a proposed change to the Participants Agreement to revise the age limit for ISO Board members from age 70 to age 75. She explained that other ISOs either have an age limit of 75 or no age limit for Board participation. Hence, she asserted, changing the Participants Agreement to raise the age limit would align the ISO with other ISO/RTOs and with industry standards. Ms. Gardner further noted that the difficulties created by the age limit were exacerbated by other restrictions on the Board Member candidate pool, including the ISO's Code of Conduct, which constrains the ability to consider candidates who either were recently affiliated with Market Participants or who own investments in such companies, and the FERC's interlock rules. She recommended increasing the age limit to broaden the talent pool for ISO Board Member positions.

Mr. Brook Colangelo, the ISO Board's Nominating and Governance Committee Chair, stated that the ISO Board supported the proposal.

During discussions on the proposal, a request was made to permit discussion of the matter in executive session. There was also a suggestion that the Committee should seek formal recommendations from the JNC when that Committee was reconstituted for the next selection cycle. Ms. Gardner explained that she had inquired of members of the most recent JNC and none of those members opposed the proposal. Further, her intent was to avoid this proposal being aimed at particular candidates or members, making consideration of the proposal at that time particularly timely since the JNC composition would not be known until after NEPOOL's officer elections at the December Annual Meeting. A member clarified that the Committee's vote noticed for potential action was only to authorize the balloting of an amendment to effect the proposed change, and not a vote on the proposed change itself.

Following further discussion, Ms. Gardner and the Committee agreed without objection to defer this matter to the December Annual Meeting, with notice to be provided that some portion of the discussion of the proposal may occur in executive session.

NUPOWER REQUEST FOR GIS WAIVER

Mr. Doot introduced NuPower Cherry Street, LLC's (NuPower) request for Committee action to waive certain Generation Information System (GIS) Operating Rules and portions of the GIS Agreement between APX and NEPOOL to allow for changes to NuPower's renewable energy certificates. He noted that NuPower's request has been discussed and considered in previous meetings of the Participants Committee, Markets Committee, and the GIS Operating Rules Working Group, and invited Participants to raise and comments or questions before a resolution was placed before the Committee.

Members speaking in opposition to the waiver expressed concern that, by granting NuPower's request, NEPOOL would~~will~~ set a precedent that would~~will~~ invite future waiver requests without any appropriate standard in place for addressing such requests. Some argued that the Connecticut Public Utilities Regulatory Authority (PURA), not NEPOOL, was the proper entity to address the errors in ~~C~~certificates that otherwise would satisfy Connecticut's renewable requirements.

Mr. Paul Belval, NEPOOL counsel for the GIS Working Group, indicated in response to a member's question that PURA had provided no guidance on whether NEPOOL should grant the waiver. He also confirmed that, if NEPOOL granted~~s~~ NuPow~~w~~er's request for a waiver, APX would not charge NEPOOL for time spent on the waiver, nor would it apply that time against the 500 annual development hours included in the fee paid under the GIS Agreement. He noted that APX had~~s~~ requested that the GIS Agreement be amended prospectively, though, to provide that APX could count time spent on any future waiver requests against annual development hours. He further confirmed that APX must also agree to waive the GIS Agreement and indicated it would only do so if NuPower affirmatively rescinded its claim of an error in the GIS software.

After further discussion, the following motion was duly made, seconded, and, by a show of hands, was determined to not have passed:

> RESOLVED, that the Participants Committee grants NuPower Cherry Street FC, LLC's request to waive certain NEPOOL ~~Generation Information System (~~GIS~~)~~ Operating Rules and sections of the Amended and Restated Generation Information System Administration Agreement dated as of October 1, 2017, between APX, Inc. and NEPOOL (GIS Agreement) and authorizes the Chair of the Participants Committee to execute and deliver a waiver of the GIS Agreement in a form acceptable to him and NEPOOL Counsel, as discussed in the materials circulated for this meeting.

LITIGATION REPORT

Mr. Doot referred the Committee to the November 1 Litigation Report that had been circulated and posted before the meeting. He highlighted for attention the following: a new complaint against Mystic and the ISO~~-NE~~ challenging the pass-through to ISO~~-NE~~ customers of firm pipeline transportation costs under the Mystic Cost-of-Service Agreement; recent filings by the ISO, including the *Modernizing Wholesale Electricity Market Design* report, annual budgets, and response to the FERC's FTR Collateral Show Cause Order; and recently filed initial comments to the Interconnection Notice of Proposed Rulemaking, noting that interested parties may filed reply comments. He encouraged anyone with questions on the status of any of the proceedings summarized in the Report to contact NEPOOL Counsel.

COMMITTEE REPORTS

Markets Committee. Mr. William Fowler, the MC Vice-Chair, reported that the MC had a three-day meeting in Milford scheduled the following week. Looking ahead, he noted that another three-day MC meeting would be scheduled for December. He further noted that, in addition to the in-person MC meetings, there were plans for an additional teleconference meeting later in December.

Transmission Committee. Mr. José Rotger, the TC Vice-Chair, reported that the next TC meeting was scheduled for November 22 and would include a vote on changes to the economic study process provisions in Attachment K which were being proposed in response to the Future Grid Reliability Study efforts.

Reliability Committee (RC). Mr. Robert Stein, the RC Vice-Chair, reported that the next RC meeting was scheduled for November 16 and was scheduled to include a presentation addressing changes to General Electric's (GE) Multi-Area Reliability Simulation Software Program (MARS) in connection with the Resource Capacity Accreditation (RCA) program.

Budget & Finance Subcommittee. Mr. Kaslow reported that the next B&F Subcommittee meeting was scheduled for November 29.

Membership Subcommittee. Ms. Sarah Bresolin reported that the next Membership Subcommittee meeting was scheduled for November 14.

~~[continued on next page]~~

ADMINISTRATIVE MATTERS

Mr. Doot reminded members that the December Annual Meeting was scheduled for December 1, 2022 at the Colonnade Hotel in Boston. He indicated that each Sector needed to submit its officer selection for 2023 soon, if it had not already done so, in order for the election of the 2023 Participants Chair election to take place. Mr. Doot also reported that final slate of 2023 Committee officers would not include his name for the Secretary position, as he planned to retire at the end of 2022.

There being no other business, the meeting adjourned at 3:55 p.m.

Respectfully submitted,

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David Doot, Secretary

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN NOVEMBER 2, 2022 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Actual Energy	Supplier	Diane Mero (tel)		
Advanced Energy Economy	Associate Non-Voting	Caitlin Marquis		
AR Large Renewable Gen. (RG) Group Member	AR-RG	Alex Worsley		
AR Small Load Response (LR) Group Member	AR-LR	Brad Swalwell (tel)		
Ashburnham Municipal Light Plant	Publicly Owned Entity		Matt Ide (tel)	
Associated Industries of Massachusetts (AIM)	End User			Mary Smith (tel)
AVANGRID: CMP/UI	Transmission	Alan Trotta	Jason Rauch	Zach Teti (tel)
Avangrid Renewables	Transmission	Kevin Kilgallen (tel)		
Bath Iron Works Corporation	End User			Bill Short; Gus Fromuth
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
Boylston Municipal Light Department	Publicly Owned Entity	Matt Ide (tel)		
BP Energy Company	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
Brookfield Renewable Trading and Marketing	Supplier	Aleks Mitreski		
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		Matt Ide (tel)	
CleaResult Consulting, Inc.	AR-DG	Tamera Oldfield (tel)		
Clearway Power Marketing LLC	Supplier			Pete Fuller
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw (tel)		
Connecticut Office of Consumer Counsel	End User	Claire Coleman		J.R. Viglione (tel)
Conservation Law Foundation (CLF)	End User		Priya Gandbnir	
Constellation Energy Generation	Supplier	Steve Kirk	Bill Fowler	
CPV Towantic, LLC	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Dominion Energy Generation Marketing	Generation		Weezie Nuara	
DTE Energy Trading, Inc.	Supplier			José Rotger
Durgin and Crowell Lumber Co., Inc.	End User			Bill Short; Gus Fromuth
Dynegy Marketing and Trade, LLC	Supplier	Andy Weinstein		Bill Fowler
ECP Companies Calpine Energy Services, LP New Leaf Energy	Supplier	Brett Kruse Liz Delaney		Bill Fowler
Elektrisola, Inc.	End User		Gus Fromuth	Bill Short
Emera Energy Services	Supplier			Bill Fowler
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Eversource Energy	Transmission	James Daly	Dave Burnham	Vandan Divatia
Environmental Defense Fund	End User	Jolette Westbrook		
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	José Rotger		
Garland Manufacturing Company	End User	Gus Fromuth		Bill Short
Generation Group Member	Generation		Abby Krich (tel)	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Granite Shore Power Companies	Generation			Bob Stein
Great River Hydro	AR-RG			Bill Fowler
Groton Electric Light Department	Publicly Owned Entity		Matt Ide (tel)	
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN NOVEMBER 2, 2022 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
H.Q. Energy Services (U.S.) Inc. (HQUS)	Supplier	Louis Guilbault (tel)	Bob Stein	
Hammond Lumber Company	End User	Gus Fromuth		Bill Short
Harvard Dedicated Energy Limited	End User			Jason Frost
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity		Matt Ide (tel)	
Holyoke Gas & Electric Department	Publicly Owned Entity		Matt Ide (tel)	
Hull Municipal Lighting Plant	Publicly Owned Entity		Matt Ide (tel)	
Icetec Energy Services, Inc.	AR-LR	Doug Hurley		
Ipswich Municipal Light Department	Publicly Owned Entity		Matt Ide (tel)	
Jericho Power LLC (Jericho)	AR-RG	Ben Griffiths	Nancy Chafetz	
Jupiter Power	Provisional Member			Ron Carrier (tel)
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	
Long Island Power Authority (LIPA)	Supplier	Bill Kilgoar (tel)		José Rotger
Maine Power LLC	Supplier	Jeff Jones (tel)		
Maine Public Advocate’s Office	End User			Jason Frost
Mansfield Municipal Electric Department	Publicly Owned Entity		Matt Ide (tel)	
Maple Energy LLC	AR-LR			Doug Hurley
Marblehead Municipal Light Department	Publicly Owned Entity		Matt Ide (tel)	
Mass. Attorney General’s Office (MA AG)	End User			Ashley Gagnon
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Dept. Capital Asset Management	End User		Paul Lopes (tel)	Nancy Chafetz
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Matt Ide (tel)		
Mercuria Energy America, LLC	Supplier			José Rotger
Merrimac Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Mintz, Samuel	End User	Sam Mintz		
Moore Company	End User			Bill Short; Gus Fromuth
Narragansett Electric Co. (d/b/a RI Energy)	Transmission	Brian Thomson	Amanda Rumsey	Lindsay Orphanides (tel)
Nautilus Power, LLC	Generation	Dan Pierpont	Bill Fowler	
New Hampshire Electric Cooperative	Publicly Owned Entity	Steve Kaminski (tel)		Brian Forshaw (tel)
New Hampshire Office of Consumer Advocate	End User	Jason Frost		
New England Power (d/b/a National Grid)	Transmission	Tim Brennan	Tim Martin	
New England Power Generators Assoc. (NEPGA)	Associate Non-Voting	Bruce Anderson	Dan Dolan	Molly Connors
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	Supplier		Pete Fuller	
Nylon Corporation of America	End User			Bill Short; Gus Fromuth
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Paxton Municipal Light Department	Publicly Owned Entity		Matt Ide (tel)	
Peabody Municipal Light Department	Publicly Owned Entity		Matt Ide (tel)	
PowerOptions, Inc.	End User			Jason Frost
Princeton Municipal Light Department	Publicly Owned Entity	Matt Ide (tel)		
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
RI Division of Public Utilities Carriers	End User	Paul Roberti		
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity	Matt Ide (tel)		
Saint Anselm College	End User	Gus Fromuth		Bill Short

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN NOVEMBER 2, 2022 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Shell Energy North America (US), L.P.	Supplier	Jeff Dannels		
Shipyard Brewing LLC	End User	Gus Fromuth		Bill Short
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Matt Ide (tel)	
South Hadley Electric Light Department	Publicly Owned Entity		Matt Ide (tel)	
Sterling Municipal Electric Light Department	Publicly Owned Entity		Matt Ide (tel)	
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Sunrun Inc.	AR-DG			Peter Fuller
Taunton Municipal Lighting Plant	Publicly Owned Entity	Devon Tremont	Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity	Matt Ide (tel)		
The Energy Consortium	End User		Mary Smith (tel)	
Union of Concerned Scientists	End User		Francis Pullaro	
Vermont Electric Power Company (VELCO)	Transmission	Frank Ettori		
Vermont Energy Investment Corp (VEIC)	AR-LR	David Westman	Jason Frost	
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw (tel)
Versant Power	Transmission	Lisa Martin (tel)		
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity	Dave Cavanaugh		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Matt Ide (tel)	
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		Matt Ide (tel)	
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler	
Z-TECH LLC	End User		Gus Fromuth	Bill Short

NOVEMBER 2, 2022 PARTICIPANTS COMMITTEE MEETING
VOTES TAKEN ON IEP COMPLIANCE CHANGES

TOTAL

Sector	Vote 1	Vote 2	Vote 3
Generation	16.70	10.02	11.13
Transmission	11.13	16.70	16.70
Supplier	16.70	16.70	15.51
Alternative Resources	13.42	14.45	16.50
Publicly Owned Entity	0.00	0.000	16.70
End User	13.12	13.12	7.03
% IN FAVOR	71.08	70.99	83.57

GENERATION SECTOR

Participant Name	Vote 1	Vote 2	Vote 3
CPV Towantic, LLC	F	F	O
Dominion Energy Generation Mktg	A	A	A
FirstLight Power Management, LLC	A	O	F
Generation Group Member	F	F	A
Granite Shore Power Companies	F	F	A
Nautilus Power, LLC	A	A	F
NextEra Energy Resources, LLC	A	O	A
IN FAVOR (F)	3	3	2
OPPOSED (O)	0	2	1
TOTAL VOTES	3	5	3
ABSTENTIONS (A)	4	2	4

TRANSMISSION SECTOR

Participant Name	Vote 1	Vote 2	Vote 3
Avangrid (CMP/UI)	A	F	F
Eversource Energy	F	F	F
Narragansett Electric (d/b/a Rhode Island Energy)	O	A	F
New England Power (d/b/a National Grid)	F	F	F
VELCO	A	A	F
Versant Power	--	--	--
IN FAVOR (F)	2	3	5
OPPOSED (O)	1	0	0
TOTAL VOTES	3	3	5
ABSTENTIONS (A)	2	2	0

ALTERNATIVE RESOURCES SECTOR

Participant Name	Vote 1	Vote 2	Vote 3
Renewable Generation Sub-Sector			
Central Rivers Power	F	F	A
ENGIE Energy Marketing NA, Inc.	F	F	F
Great River Hydro, LLC	A	F	F
Jericho Power LLC	O	O	--
Wheelabrator/Macquarie	A	F	F
Large RG Group Member	F	F	A
Distributed Gen. Sub-Sector			
CLEAResult Consulting, Inc.	A	F	A
Sunrun Inc.	F	F	F
Load Response Sub-Sector			
Icetec Energy Services, Inc.	F	F	F
Maple Energy	F	F	F
Vermont Energy Investment Corp.	F	F	F
Small LR Group Member	--	--	F
IN FAVOR (F)	7	10	8
OPPOSED (O)	1	1	0
TOTAL VOTES	3	11	2
ABSTENTIONS (A)	3	0	3

SUPPLIER SECTOR

Participant Name	Vote 1	Vote 2	Vote 3
Actual Energy	F	F	F
BP Energy Company	A	F	F
Brookfield Renew. Trading & Mktg	F	F	O
Castleton Comm. Merchant Trading	F	F	A
Clearway Power Marketing LLC	F	F	F
Constellation Energy Generation	F	F	F
Cross-Sound Cable Company	A	F	F
DTE Energy Trading, Inc.	A	F	F
Dynegy Marketing and Trade, LLC	F	F	F
ECP Companies	Split	Split	Split
Calpine	A	A	F
New Leaf Energy	A	F	F
Emera Energy Services Companies	A	A	A
Galt Power, Inc.	A	F	F
H.Q. Energy Services (U.S.) Inc.	F	F	A
LIPA	A	A	A
Maine Power, LLC	F	F	F
Mercuria Energy America, Inc.	A	F	F
New Brunswick Energy Marketing Corp.	A	A	--
NRG Power Marketing, LLC	F	F	F
Shell Energy North America (US)	F	F	F
IN FAVOR (F)	10	16	14
OPPOSED (O)	0	0	1
TOTAL VOTES	10	16	15
ABSTENTIONS (A)	10	4	4

NOVEMBER 2, 2022 PARTICIPANTS COMMITTEE MEETING
VOTES TAKEN ON IEP COMPLIANCE CHANGES

END USER SECTOR

Participant Name	Vote 1	Vote 2	Vote 3
Associated Industries of Mass.	A	A	F
Bath Iron Works Corporation	F	F	O
Conn. Office of Consumer Counsel	A	A	F
Conservation Law Foundation	A	A	A
Durgin and Crowell Lumber Co.	F	F	O
Elektrisola, Inc.	F	F	O
Environmental Defense Fund	A	A	A
Garland Manufacturing Co.	F	F	O
Hammond Lumber Company	F	F	O
Harvard Dedicated Energy Limited	--	--	F
High Liner Foods (USA) Inc.	F	F	O
Maine Public Advocate Office	O	O	F
Mass. Attorney General's Office	A	A	F
Mintz, Sam	A	A	A
Moore Company	F	F	O
New Hampshire OCA	O	O	F
Nylon Corporation of America	F	F	O
PowerOptions, Inc.	O	O	F
RI Division of Public Utilities Carriers	A	A	F
Shipyard Brewing Co.	F	F	O
St. Anselm College	F	F	O
The Energy Consortium	A	A	A
Union of Concerned Scientists	A	A	A
Z-TECH, LLC	F	F	O
IN FAVOR (F)	11	11	8
OPPOSED (O)	3	3	11
TOTAL VOTES	14	14	19
ABSTENTIONS (A)	9~~8~~	9~~8~~	~~4~~5

PUBLICLY OWNED ENTITY SECTOR

Participant Name	Vote 1	Vote 2	Vote 3
Belmont Municipal Light Dept.	O	O	F
Block Island Utility District	O	O	F
Braintree Electric Light Dept.	O	O	F
Chester Municipal Light Dept.	O	O	F
Concord Municipal Light Plant	O	O	F
Conn. Mun. Electric Energy Coop.	A	A	F
Danvers Electric Division	O	O	F
Georgetown Municipal Light Dept.	O	O	F
Groveland Electric Light Dept.	O	O	F
Hingham Municipal Lighting Plant	O	O	F
Littleton (MA) Electric Light Dept.	O	O	F
Mass. Bay Transportation Authority	O	O	F
Merrimac Municipal Light Dept.	A	A	F
Middleborough Gas and Elec. Dept.	O	O	F
Middleton Municipal Electric Dept.	O	O	F
New Hampshire Electric Cooperative	A	A	F
North Attleborough	O	O	F
Norwood Municipal Light Dept.	O	O	F
Pascoag Utility District	O	O	F
Reading Municipal Light Dept.	O	O	F
Rowley Municipal Lighting Plant	O	O	F
Stowe (VT) Electric Dept.	O	O	F
Taunton Municipal Lighting Plant	O	O	F
Village of Hyde Park (VT) Elec. Dept.	O	O	F
VT Public Power Supply Authority	A	A	F
Wallingford, Town of	O	O	F
Wellesley Municipal Light Plant	O	O	F
Westfield Gas & Electric Light Dept.	O	O	F
IN FAVOR (F)	0	0	28
OPPOSED (O)	24	24	0
TOTAL VOTES	24	24	28
ABSTENTIONS (A)	4	4	0

MEMORANDUM

TO: NEPOOL Participants Committee

FROM: Eric Runge, NEPOOL Counsel

DATE: November 22, 2022

RE: Vote on Revisions to OP-24 and Appendix D to OP-24

At the December 1, 2022 Participants Committee meeting you will be asked to vote to support revisions to the ISO's Operating Procedure 24 (Protection Outages, Settings and Coordination) and its Appendix D (Required Protection Outage Request Form and Examples) (together, the "OP-24 and 24-D Revisions").[1] At its November 16 meeting, the Reliability Committee unanimously recommended Participants Committee support for the OP-24 and 24-D Revisions. This item would have been on the Participants Committee Consent Agenda but for the timing of the meetings.

OP-24 establishes requirements for entities that own transmission or generation equipment to provide protective relay information to the ISO, and includes requirements for equipment owners to coordinate protection equipment and relay settings. The OP-24 and 24-D Revisions are in the nature of clean-up changes based on the ISO's periodic review of the documents. Most of the revisions are in Appendix D, which provides the required protection outage request form.

The following resolution could be used for Participants Committee consideration of the OP-24 and 24-D Revisions:

> RESOLVED, that the Participants Committee supports the OP-24 and 24-D Revisions, as recommended by the Reliability Committee at its November 16, 2022 meeting, together with [any changes agreed to at the meeting and] such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.

---

[1] The OP-24 and 24-D Revisions and the ISO's presentation on them are available here: https://www.iso-ne.com/static-assets/documents/2022/11/a07_1_op_24_24d.zip.

Commissioner Danly

Commissioner James Danly was nominated Commissioner at the Federal Energy Regulatory Commission on February 12, 2020, and confirmed as a Commissioner by the United States Senate on March 12, 2020.

Danly served as Chairman of the Federal Regulatory Commission from November 5, 2020 to January 21, 2021.

Danly formerly served as general counsel to FERC. Prior to joining the Commission, he was a member of the energy regulation and litigation group at Skadden, Arps, Slate, Meagher and Flom LLP.

Prior to this Danly served as law clerk to Judge Danny Boggs at the U.S. Court of Appeals for the Sixth Circuit. He was a managing director of the Institute for the Study of War, a military think tank in Washington, D.C., and served an International Affairs Fellowship at the Council on Foreign Relations. Danly is a former U.S. Army officer who served two tours in Iraq, first with an infantry company in Baghdad and then on staff at Multi-National Force—Iraq, receiving a Bronze Star and Purple Heart.

Danly earned his juris doctor from Vanderbilt University Law School, and his bachelor's degree from Yale University. He is licensed to practice law before the District of Columbia Court of Appeals.

Sworn In

March 31, 2020

Term Expires

June 30, 2023

Follow on Social Media

Contact

Telephone: 202-502-8338

Request a Meeting →

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This page was last updated on September 21, 2021

Summary of ISO New England Board and Committee Meetings

December 1, 2022 Participants Committee Meeting

Since the last update, the Audit and Finance Committee, the Compensation and Human Resources Committee, the Markets Committee, the Nominating and Governance Committee, and the System Planning and Reliability Committee each met on October 31. The Board of Directors met on November 1. All of the meetings were held in person in Providence, Rhode Island.

The Audit and Finance Committee received an annual report on employee and Board compliance with the Code of Conduct following the annual collection of certificates. The Committee then reviewed the structure of the Company's compliance and risk management programs, including the Company's physical security and business continuity plans. Management described the enterprise risk management program. Management noted that, to identify risks, they: assess the Company's strengths, weaknesses, opportunities and threats; assess external trends and scenario planning; and take input from the market monitors, auditors and others. The Board oversees the program through its individual committees, which have jurisdiction over topics within their purview. The Board also discussed how the risks identified through the enterprise risk management program feed into the Company's objectives and ultimately are reflected in its budget. The Board noted that, once risks are identified, the Company uses three lines of defense to monitor and mitigate them. These lines of defense are internal controls, compliance management through the Reliability and Operations Compliance Department and other personnel, and independent reviews through auditors and market monitors.

The Committee reviewed and approved the unaudited financial statements for the third quarter after receiving a report on the related disclosure control process. The Committee was provided with a report on current budget performance, which is on track, along with an update on interest rates. Next, the Committee met with representatives of KPMG, the Company's external auditors, to discuss the scope and preliminary results of the 2022 System and Organization Controls Report and resulting unqualified audit opinion. KPMG also provided an overview of work plans and timing for the financial statements audit. The Committee then met with the KPMG auditors in executive session to ensure that they had the opportunity to make any necessary reports without management present. Following the executive session with the external auditors, the Committee then received a report on internal audit activities, including the status of follow-up items related to internal reviews and the oversight of external audits. The Committee reviewed its calendar for the upcoming year, and discussed a report on consumer costs and retail rates. That report focused on state retail rates, including the breakdown between supply, transmission, distribution and retail adders. Finally, in executive session, the Committee reviewed and refined potential corporate goals for 2023.

The Compensation and Human Resources Committee discussed key dates and deliverables for 2023 goal setting and conducting the corporate performance review for 2022. Next, the Committee discussed the plan matching methodology for the Company's 401(k) plan, and then reviewed its calendar for the upcoming year. The Committee was also provided with updated survey data for salary increase budgets among other ISOs/RTOs, the energy industry, and industry generally, to ensure that the salary increase budget included in the 2023 budget remained reasonable given the data and the Company's needs. The Committee agreed that the new data is in line with the data previously presented. During an executive session, the Committee reviewed executive management and board compensation survey data with Mercer, the Company's compensation consultant, and discussed the methodology for recouping from executive compensation the amount of the penalty imposed by the recent settlement agreement with the FERC Office of Enforcement.

The Markets Committee began with a brief executive session. The Committee was provided with a summary of market performance for the 2022 summer season from the internal and external market monitors, including the impact of fuel costs on wholesale electricity prices. The Committee also discussed energy offer obligations for de-listed resources, noting that the Internal Market Monitor will be reviewing this issue with the NEPOOL Markets Committee. The Committee reviewed its calendar for the upcoming year, and discussed the Company's recent FERC-mandated markets report on modernizing energy and ancillary service markets design. The Committee noted that the report provides a roadmap for market design over the next ten years. The System Planning and Reliability Committee then joined the meeting to consider the New England winter outlook for 2022/2023. The Committees discussed the current outlook, reviewed the results of modeled scenarios, and reviewed next steps regarding energy adequacy. In particular, the Committees reviewed the energy adequacy actions reflected in the Company's recent work plan, and considered options for expanding the Inventoried Energy Program. Following that discussion, the Committees held a joint executive session to review and refine potential corporate goals for 2023.

The Nominating and Governance Committee discussed possible site visits and potential guest speakers to meet with the Board in 2023 as part of the Board's continuing education program. The Committee also discussed kicking off the 2023 Joint Nominating Committee process. The Committee then reviewed the Diversity, Equity, and Inclusion (DEI) Work Plan recently approved by the Board to ensure that the Board maximizes the benefits of diverse backgrounds and viewpoints on the Board, and discussed the development of a mission statement in order to communicate the Board's commitment to a diverse Board. The Committee also received an update on corporate communications, and reviewed its calendar for the upcoming year. The Committee then received an update on plans for facilitated evaluations of the Board and the committees, and discussed the Board's oversight of the Company's risk and compliance functions. Following this discussion, the Committee held an executive session.

The System Planning and Reliability Committee reviewed summer operations for 2022. The Committee received updates on various operations and planning activities, including regional planning, qualification results for Forward Capacity Auction #17, long-term transmission planning, integration of distributed energy resources, progress of significant renewables projects, and winter preparedness. The Committee reviewed key operations and planning metrics, as well as reliability standards compliance, and was informed of updates to Regional System Plan projects. Next, the Committee received a report on FERC's Cost Management Technical Conference, including Mr. Ethier's presentation, and discussed the concept of an Independent Transmission Monitor. The Committee also reviewed its calendar for the upcoming year and held a brief executive session. The Committee then joined the Markets Committee meeting to consider the New England winter outlook for 2022/2023 (see above), and held a joint executive session to discuss corporate goals for 2023.

The Board of Directors received a report from the CEO, including a quarterly update on goal achievement. The Board then prepared for its first annual open meeting, which was organized in response to the states' vision document, and their specific request for a public board meeting. The Board noted that this year's meeting has a focus on markets, and reviewed the agenda and public comments received to date. The Board also reviewed the various topics proposed for discussion at the next day's meetings with state representatives and the NEPOOL sectors. Next, the Board held its annual risk management review and, after reviewing trends and strengths, weaknesses, opportunities and threats, discussed the Company's overarching risks, mitigation strategies, and goals, including the risks identified by the Board's standing committees. The Board also heard reports from the standing committees. During the Compensation and Human Resources Committee report, the Board approved modifications to the Committee's charter to reflect the Committee's role in reviewing compensation for members of the Board of Directors. That revised charter has been posted to the Company's website. Last, the Board held an executive session.

NEPOOL Participants Committee Report

December 2022

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

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Regular Operations Report - Highlights

Highlights

Data is through November 21st

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Update: October 2022 Energy Market value totaled $512M
  - November 2022 Energy market value was $412M, down $99M from October 2022 and down $159M from November 2021
    - November natural gas prices over the period were 2.3% higher than October average values
    - Average RT Hub Locational Marginal Prices ($64.69/MWh) over the period were 24% higher than October averages
      - DA Hub: $56.62/MWh
    - Average November 2022 natural gas prices and RT Hub LMPs over the period were down 10% and up 10%, respectively, from November 2021 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 97% during November, down from 98.4% during October*
    - The minimum value for the month was 92.3% on Tuesday, November 8th

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

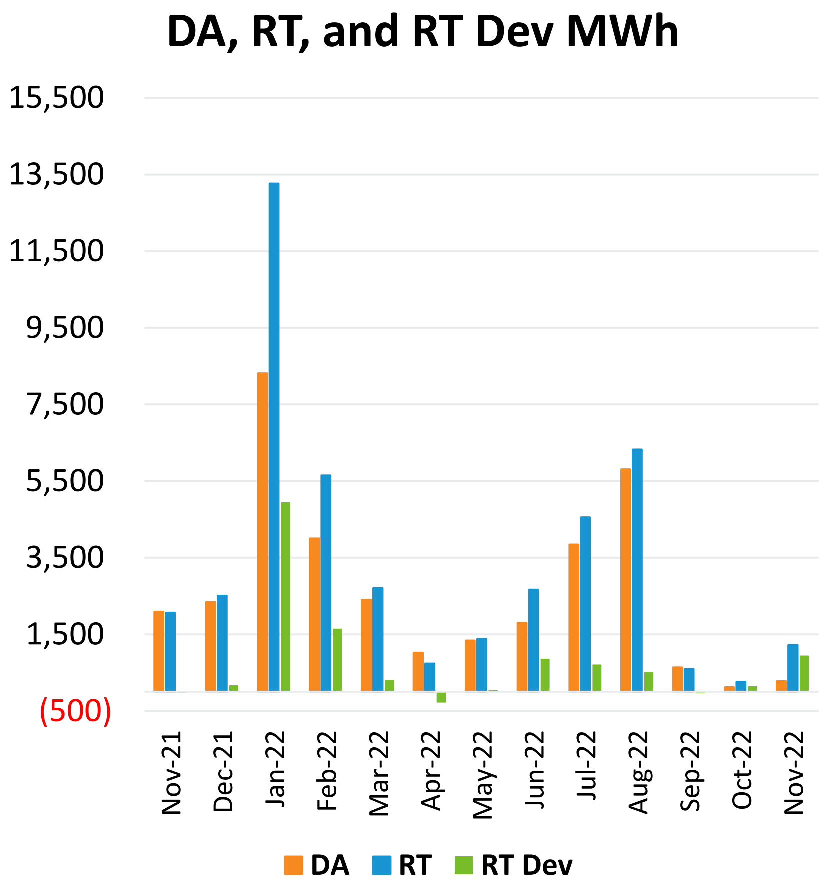
Underlying natural gas data furnished by:

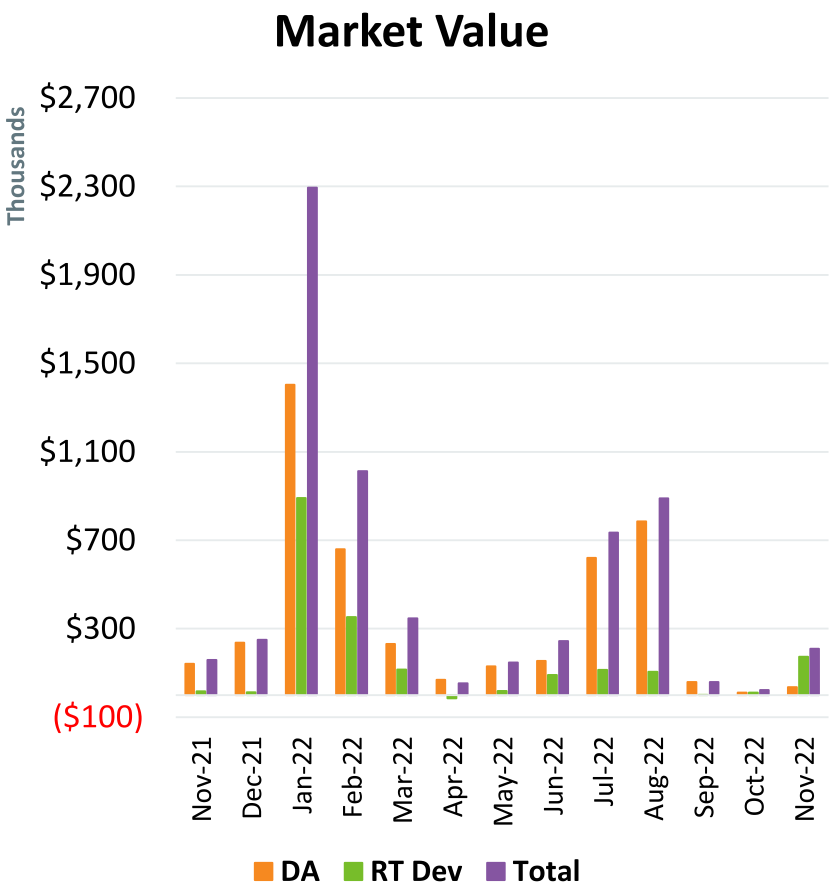
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - November 2022 NCPC payments totaled $3.0M over the period, up $0.1M from October 2022 and down $0.4M from November 2021
    - First Contingency payments totaled $2.9M, up $0.2M from October
      - $2.5M paid to internal resources, comparable to October
        - » $292K charged to DALO, $1.2M to RT Deviations, $961K to RTLO*
      - $472K paid to resources at external locations, up $207K from October
        - » $422K charged to DALO at external locations, $50K to RT Deviations
  - Second Contingency payments totaled $40K, down $100K from October
  - Voltage and Distribution payments were zero

*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $370K; Rapid Response Pricing (RRP) Opportunity Cost - $408K; Posturing - $0K; Generator Performance Auditing (GPA) - $183K**

Price Responsive Demand (PRD) Energy Market Activity by Month





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

Highlights

- ISO is working on solution development for the 2050 Transmission Study and expects to begin initial discussions at the December 13 PAC meeting
- The Economic Study Process Improvement project to update Attachment K of the OATT was approved by the TC in November and will be up for a vote at the January PC meeting
- Capacity zone discussions will begin at the December 13 PAC meeting
- FCA 17 Installed Capacity Requirement and related values were filed with FERC on November 8
- 2023 ARAs Installed Capacity Requirements and related values to be filed with FERC on November 30
- The next Load Forecast Committee meeting is scheduled for December 9 and will include discussions of electrification forecast updates
- The lowest 50/50 and 90/10 Winter Operable Capacity Margins are projected for week beginning January 7, 2023.

Forward Capacity Market (FCM) Highlights

- CCP 13 (2022-2023)
  - Third and final annual reconfiguration auction (ARA3) was held on March 1-3, and results were posted on March 30
- CCP 14 (2023-2024)
  - Second annual reconfiguration auction (ARA2) was held on August 1-3, and results were posted on August 31
- CCP 15 (2024-2025)
  - First annual reconfiguration auction (ARA1) was held on June 1-3, and results were posted on June 28
- CCP 16 (2025-2026)
  - Auction results were filed with FERC on March 21 and on July 18, FERC issued an order accepting the results effective July 19

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP 17 (2026-2027)
  - ISO submitted the “MOPR Removal” filing to FERC on March 31, which includes a “Transition Mechanism” for FCA 17 and FCA 18
    - FERC issued an order accepting ISO’s filing on May 27
  - FCA 17 will model the following zones:
    - Export-constrained zones: Northern New England and Maine nested inside Northern New England
    - Rest-of-Pool
  - Qualification determination notifications were issued on November 10
  - FCA 17 Installed Capacity Requirement and related values were filed with FERC on November 8

FCM Highlights, cont.

- CCP 18 (2027-2028)
  - The qualification process has started, and training materials are under development
  - Topology certifications were sent to the TOs on October 11
    - TOs 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 2023 meeting
  - Capacity zone development discussions will begin at the December 13 PAC meeting
    - All subsequent reconfiguration auctions model the same zones as the FCA

New England Winter Outlook 2022/2023

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT & CHIEF OPERATING OFFICER

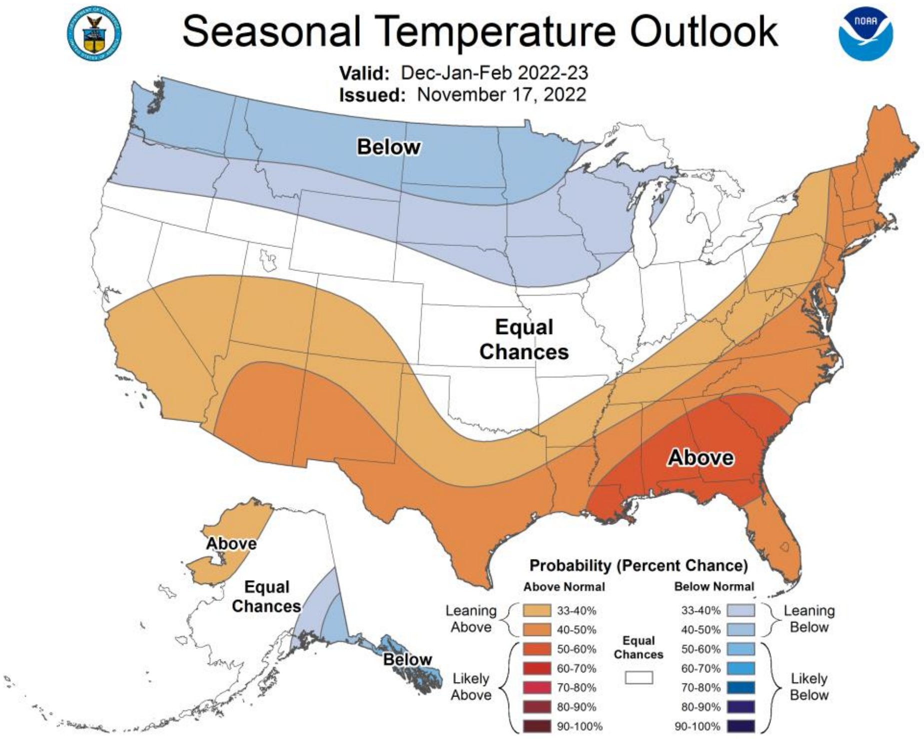
Introduction

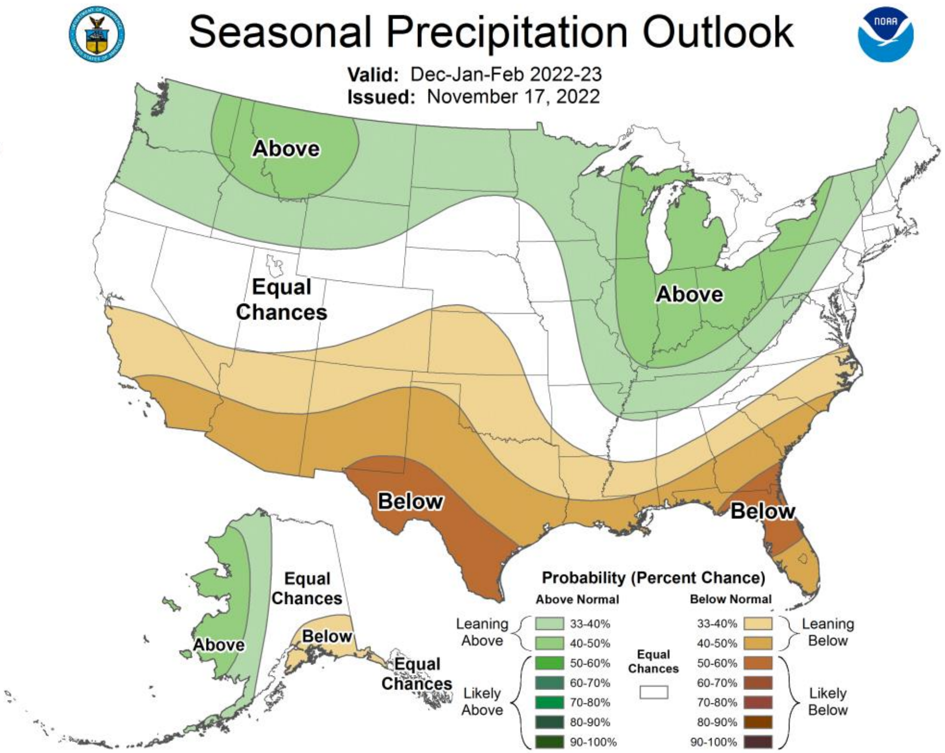
- This presentation is intended to accomplish the following:
  - Offer a current outlook of the 2022/2023 winter
  - Provide the results of a few modeled scenarios for the 2022/2023 winter
  - Present next steps

Highlights

- Winter Outlook
  - The seasonal temperature outlook for the winter months of December-January-February indicates a 40-50% probability of above normal temperatures in New England
  - A 33-40% probability of above normal precipitation is forecasted for northern New England while equal chances for above average or below average precipitation is forecasted for the rest of New England
  - Capacity analysis for the 50/50 and the 90/10 load forecasts indicates a surplus even after accounting for generation at risk due to gas supply
    - Capacity analysis is generally limited in that it assumes all resources that are not de-rated can supply energy when called

Winter Temperature & Precipitation Probability





Winter Expectations 2022/23

- Winter Demand Forecast
  - 50/50 winter peak demand forecast of 20,009 MW, which is 299 MW (1.5%) higher than the 2021/22 forecast
  - 90/10 winter peak demand forecast of 20,695 MW, which is 346 MW (1.7%) higher than the 2021/22 forecast
- Scheduled Generation and Transmission Outages
  - All generation and transmission outages continue to be coordinated to minimize adverse transmission or capacity conditions
  - No significant generation or transmission outages are currently scheduled
- Transfer Capability
  - Transfer capability on the New York Northern AC ties has been increased from 1,400 to 1,600 MW for the winter period

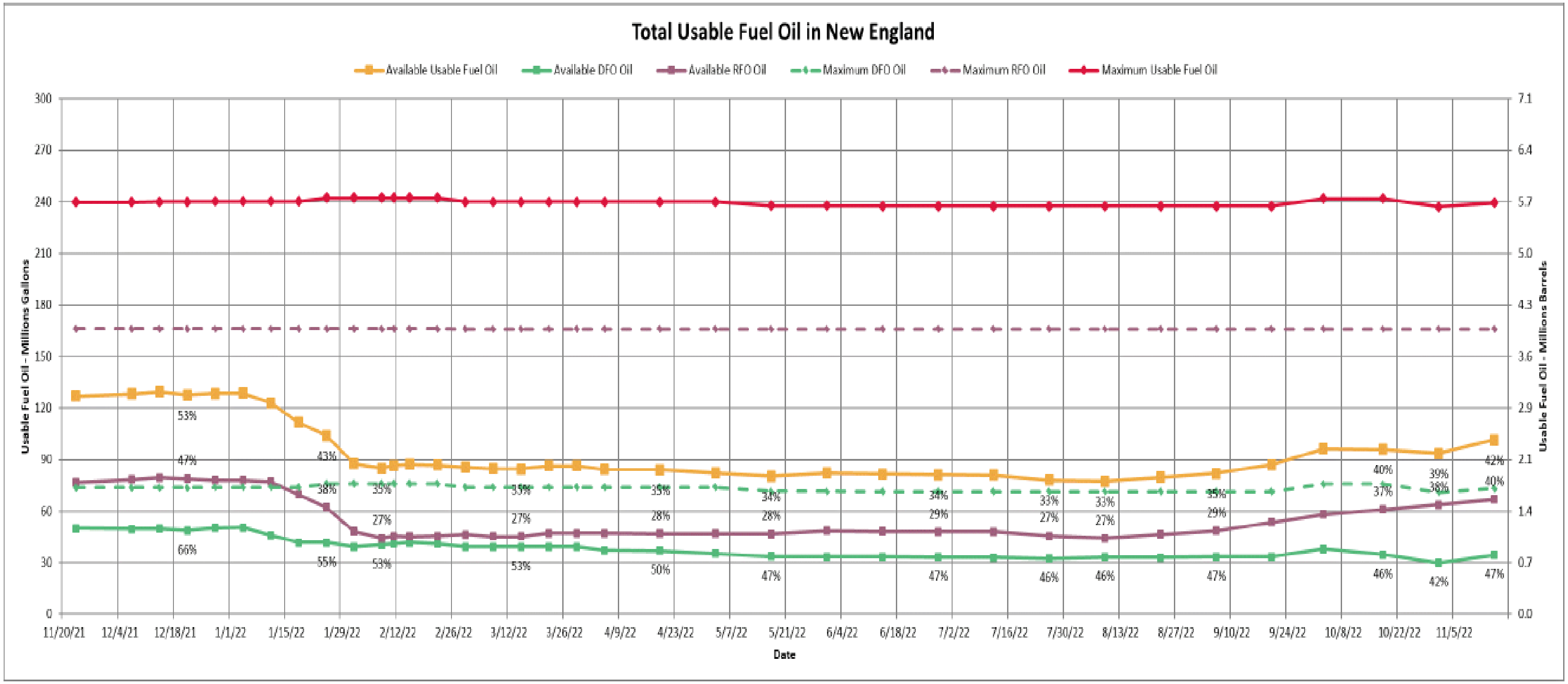
Winter Expectations 2022/23, cont.
LNG Replenishment

- Over the past ten winters (Dec-Feb), the region has averaged ~31.7 Bcf of LNG usage; the highest usage was ~42.9 Bcf in 2012/13, lowest usage was ~20.0 Bcf in 2021/22
- Winter 2022/23
  - Europe met its intended LNG fuel storage target ahead of winter
  - European natural gas prices continue to remain higher than in New England
  - In early October, European prices for January delivery were ~$60/MMBtu
    - Since then, the prices have trended down
  - Cost-of-Service contract with Mystic provides greater certainty of LNG availability this winter
  - ISO's current expectation is that ~31 Bcf will be available

Winter Expectations 2022/23, cont.
Fuel Oil Replenishment

- Due in large part to declining forward prices for fuel-oil, many stations have waited until fall to procure and finalize replenishment plans
- Based on recent replenishment activities and discussions with resource owners, ISO anticipates additional replenishment prior to winter
  - Additional fuel-oil replenishment is expected to increase the region's aggregate fuel-oil inventory from ~102M gallons (~42% of max) to ~120M gallons (~50% of max) prior to winter
- Discussions with resource owners have identified some level of concern with regard to the Distillate Fuel Oil (DFO) supply chain
- No concerns have been noted with regard to the Residual Fuel Oil (RFO) supply chain and RFO stations have robust replenishment plans in place
- The potential for emissions limitations at some dual-fuel units will have to be monitored closely in the event of significant oil burn

Total Usable Fuel Oil in New England



Winter Expectations 2022/23, cont.

- Natural Gas Deliverability
  - Continue to monitor natural gas deliverability throughout the winter
  - Approximately 4,100 – 5,100 MW[1] may be at risk due to constrained natural gas pipelines
- Winter Capacity Outlook
  - Projecting the lowest 50/50 operable capacity margin of ~3,900 MW and lowest 90/10 operable capacity margin of ~2,300 MW for the week beginning January 7, 2023[1]
  - Extended periods of cold weather may rapidly deplete stored fuel inventories and capacity outlook will be adjusted accordingly

[1]-Based on resource Winter Seasonal Claimed Capabilities

Winter Preparations 2022/23

- Energy Shortfall Exercise
  - Hosted a region-wide energy shortfall tabletop exercise on October 12, 2022
- Winter Readiness Seminar
  - Hosted a Generator Winter Readiness Seminar with Market Participants on November 14, 2022
- Winter Generator Readiness Survey
  - Distributed a Winter Generator Readiness Survey to all generating resources in the region on November 1, 2022 with responses due by December 1, 2022
- Completed the annual Natural Gas Critical Infrastructure Survey process to ensure critical infrastructure is not part of automatic or manual load shed schemes
- Generator Fuel and Emissions Surveys will be of weekly or daily frequency during the winter season
- 21-day energy assessment will be performed weekly with results published to the ISO public website
  - The assessment will performed daily if necessary

21-Day Energy Assessment & Alert Thresholds

- In order to identify and communicate potential reliability issues, the ISO performs a weekly 21-day energy assessment and posts the results on the ISO public website
  - The energy assessment is based on latest responses to generator surveys, as well as planned outages, load & weather forecasts, and anticipated LNG injections
- ISO's OP-21 describes the thresholds for declaration of an Energy Alert or Energy Emergency based on the 21-day energy assessment results
  - ISO will declare an **Energy Alert** if the energy assessment indicates either the use of OP-4 Actions 6-11 (voltage reduction and conservation appeals) or OP-7 Action in at least **1 hour on 1 or more consecutive days in days 6 through 21**
  - ISO will declare an **Energy Emergency** if the energy assessment indicates the use of OP-4 Actions 6-11 (voltage reduction and conservation appeals) or OP-7 Action in at least **1 hour on 1 or more consecutive days in days 1 through 5**

Requests for Government and Cross-Sector Assistance

- ISO and resource owners may request New England State and Federal Government Assistance
- In order to minimize or alleviate need for extreme operational measures, the ISO and/or resource owners may request:
  - Jones Act waivers
  - Waivers of emissions and/or air permitting limitations (if alternate fuel is available) under 202c of the Federal Power Act or state statutes
  - Waivers of Department of Transportation restrictions on drivers for fuel deliveries
  - Activation of military staff and equipment to move fuel supplies
  - Multi-day emergency conservation measures under OP-4 and request states to assist with cross-sector energy appeals for conservation of liquid fuels and natural gas

WINTER 2022/23 SCENARIOS

Introduction – 2022/23 Winter Scenarios

- The ISO routinely performs scenario assessments to prepare for the winter
- The following slides illustrate the qualitative and quantitative aspects of three scenarios
  - Scenario 1 assumes a mild winter as represented by the 2021/22 winter
  - Scenario 2 assumes a mild winter, but with a 13 day cold spell, as represented by the 2017/18 winter
  - Scenario 3 assumes a 'colder than normal' winter as represented by the 2013/14 winter
- Unless otherwise noted, scenarios assume the following:
  - Expected starting fuel oil inventories; fuel oil replenishment assumptions range from minimal to moderate
  - No LNG injections assumed beyond current projections
  - No significant or long-duration generator or transmission contingencies
  - System demand reduced to account for distributed PV resources
- The ISO's 21-day energy forecast tool will signal any potential energy emergencies, thereby alerting the market to procure necessary fuel replenishments, both to meet their obligation and to protect against scarcity

Scenario 1 – Mild Winter, Similar to 2021/22

- Winter 2021/22 overview:
  - Milder than normal winter with very few days staying below freezing
  - Average temperature departure from normal was +1.0°F (i.e., warmer than normal)
  - Winter peak load of 19,623 MW
  - Total energy modeled is 30,591 GWh
  - During some periods, fuel oil was more economic than natural gas for power generation
  - Approximately 80M gallons of fuel oil was burned
- ISO anticipates that there would be sufficient capacity and energy available to meet the expected peak loads and energy

Scenario 2 – Moderate Winter with a Deep and Prolonged Cold Spell; Similar to 2017/18

- Winter 2017/18 characteristics:
  - Milder than normal outside of a two-week span of significantly below normal temperatures
  - Average temperature departure from normal was +0.5°F degrees
  - The region was impacted by an extended stretch of cold weather between December 25 and January 9; all major cities in the region experienced temperatures below normal for at least 13 consecutive days, of which 10 days averaged more than 10°F below normal
  - Winter peak load of 20,631 MW
  - Total energy modeled is 31,291 GWh
  - The cold snap was marked by reductions in natural gas availability and price inversion contributed to high fuel oil usage; several oil-fired resources were postured to maintain fuel reserves
- ISO anticipates that system reliability will be maintained, but may require the use of capacity deficiency actions under OP-4 on 5-7 days

Scenario 3 – Cold Winter with Several Cold Stretches; Similar to 2013/14

- Winter 2013/14 characteristics:
  - Colder than normal overall highlighted by a polar vortex event which resulted in significant stretches of cold weather in New England and surrounding areas
  - Average temperature departure from normal was -2.3°F degrees
  - The region experienced six cold weather stretches of four or more consecutive days, including a stretch of ten consecutive days at or below freezing
  - Winter peak load of 21,514 MW
  - Total energy modeled is 33,881 GWh
  - Significant energy usage caused high demand on both the electric and natural gas systems
- Significant usage of all available capacity deficiency actions under OP-4 (including public appeal actions) may be necessary across several weeks, including the use of OP-7 across several days
  - In-season fuel replenishment will greatly mitigate this risk

Questions

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (4.2°F) Max: 77°F, Min: 25°F Precipitation: 2.03" – Below Normal Normal: 3.25"	Hartford	Temperature: Above Normal (4.3°F) Max: 78°F, Min: 21°F Precipitation: 3.76" – Above Normal Normal: 3.11"

Peak Load:	16,724 MW	Nov 21, 2022	18:00 (ending)

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

Procedure	Declared	Cancelled	Note
None for November 2022			

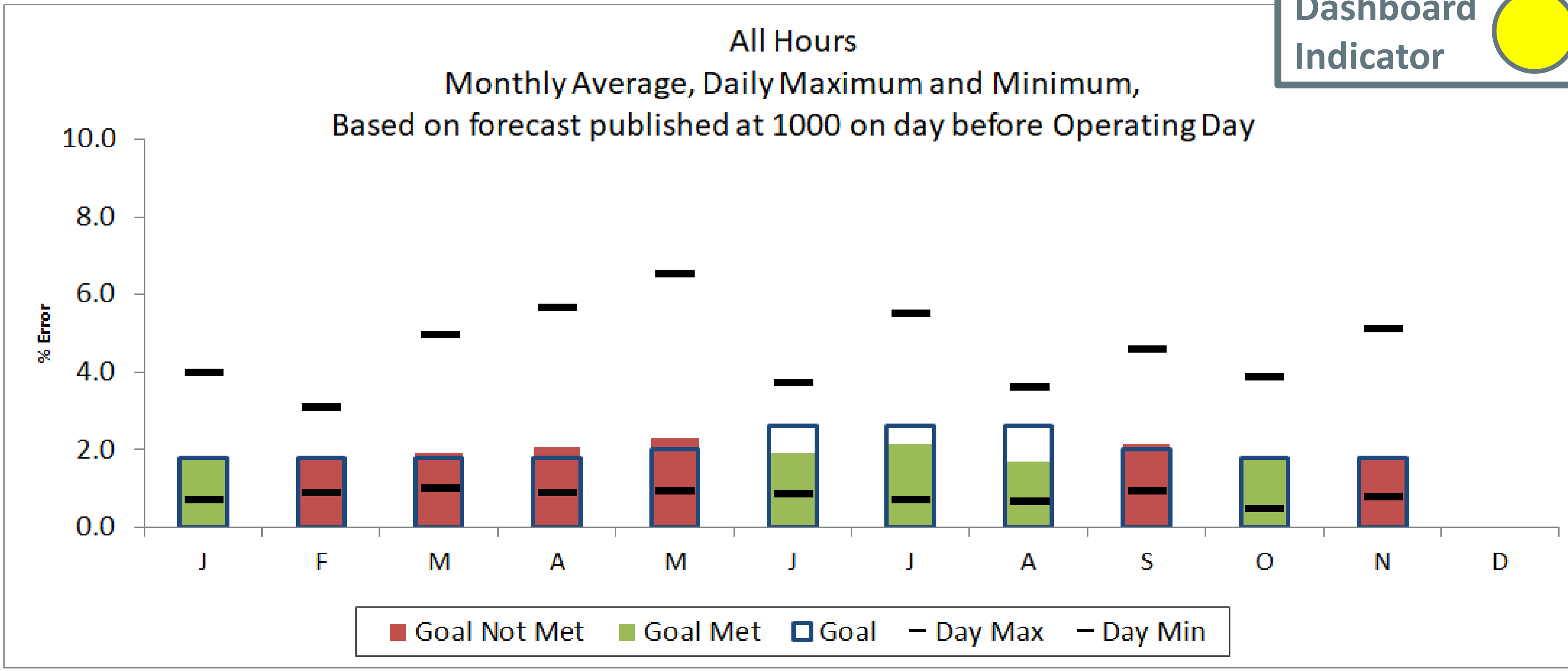
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
11/8	NYISO	700
11/15	IESO	525
11/21	NBSO	350
11/22	NBSO	350
11/24	NBSO	390

2022 System Operations - Load Forecast Accuracy

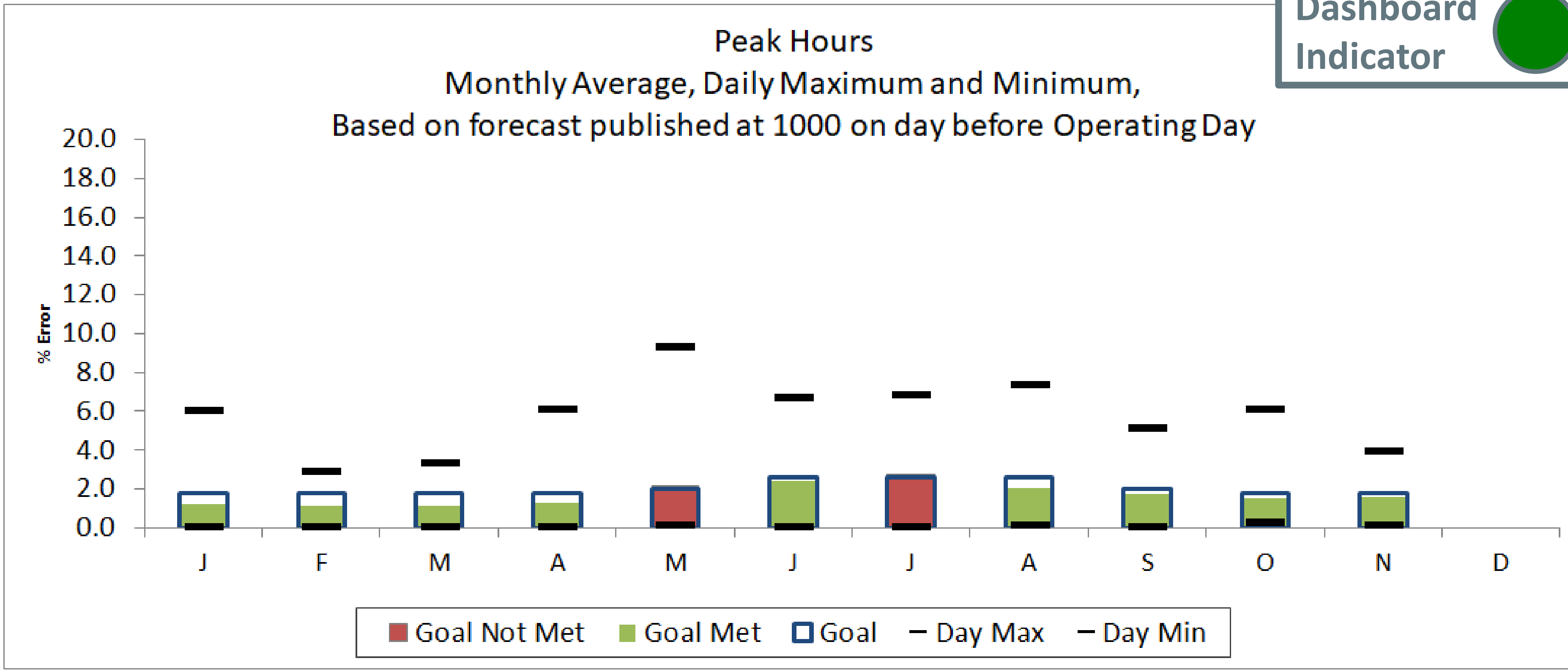
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	3.97	3.07	4.92	5.66	6.52	3.71	5.48	3.61	4.56	3.85	5.09		6.52
Day Min	0.69	0.87	0.97	0.85	0.91	0.83	0.69	0.66	0.90	0.46	0.77		0.46
MAPE	1.79	1.81	1.93	2.05	2.30	1.92	2.13	1.70	2.13	1.74	1.84		1.94
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80	1.80		

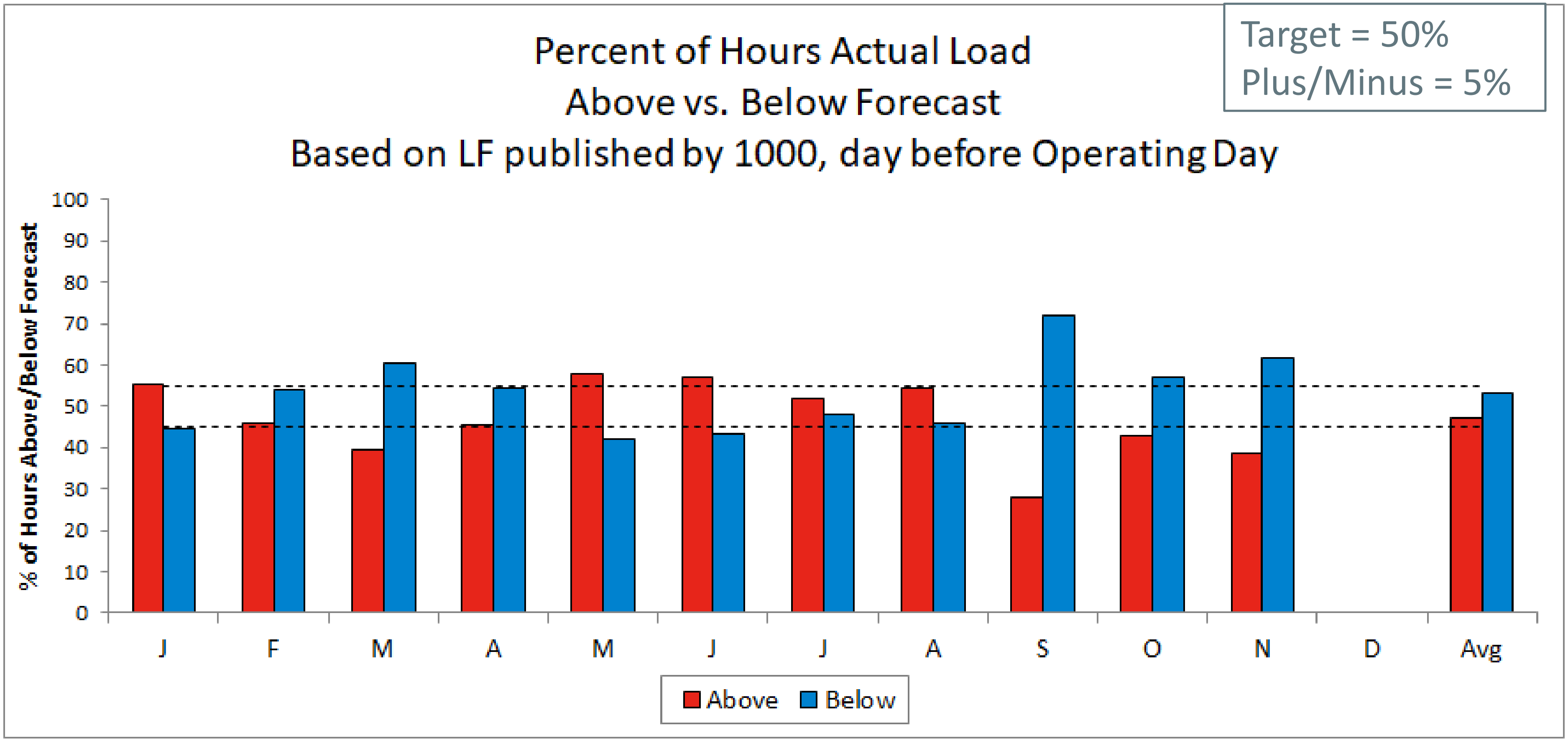
2022 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



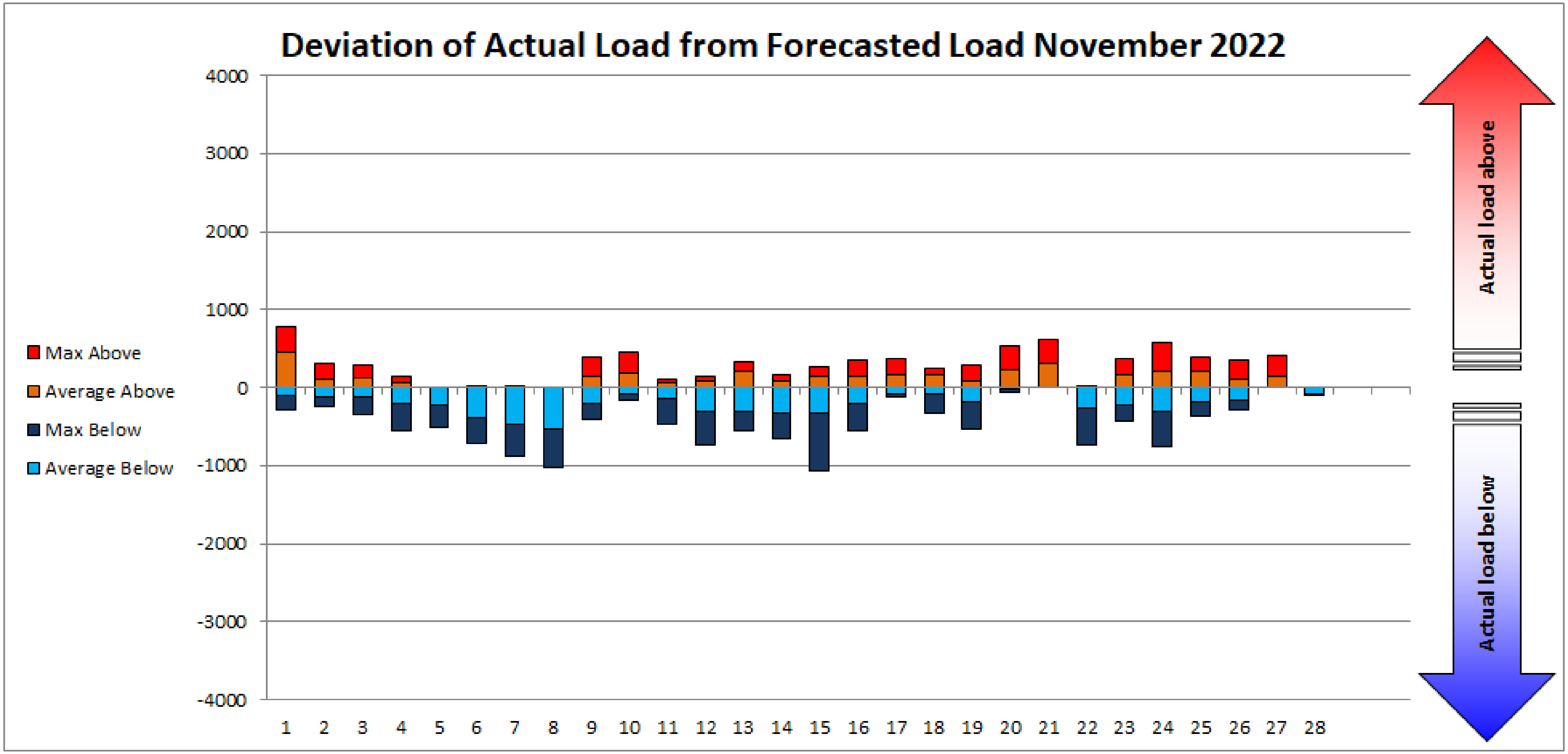
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	6.01	2.85	3.32	6.08	9.27	6.70	6.85	7.31	5.12	6.04	3.92		9.27
Day Min	0.02	0.03	0.04	0.00	0.06	0.01	0.02	0.08	0.01	0.21	0.06		0.00
MAPE	1.25	1.11	1.13	1.29	2.14	2.43	2.73	2.06	1.71	1.55	1.59		1.73
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80	1.80		

2022 System Operations - Load Forecast Accuracy cont.

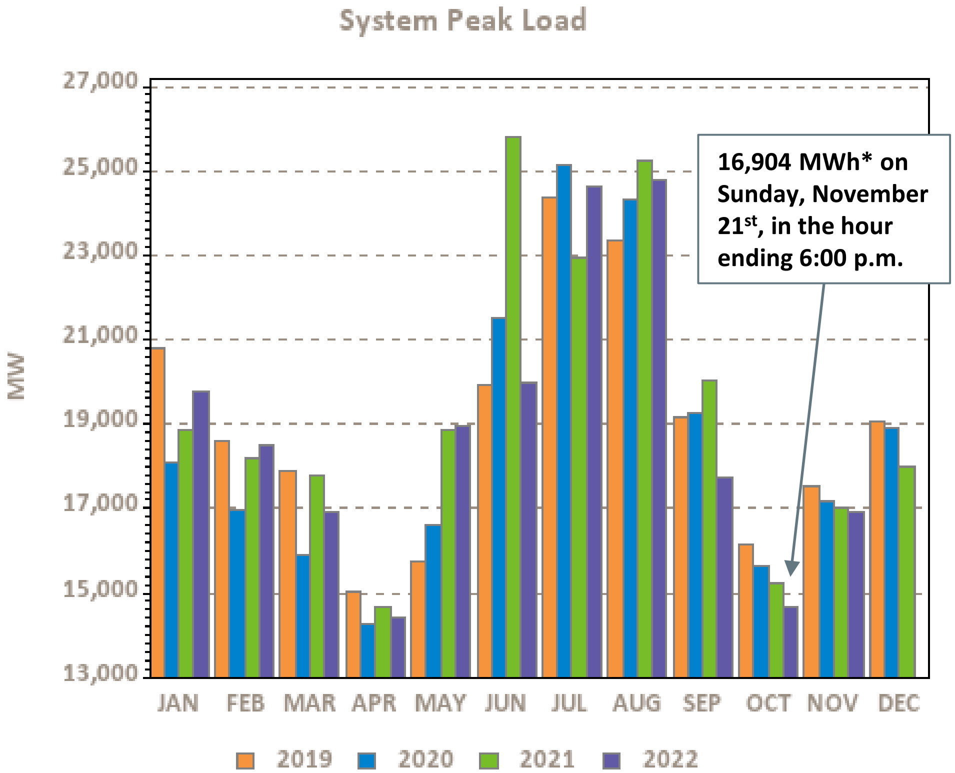


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	55.2	46	39.7	45.6	57.8	56.8	51.9	54.3	27.9	43.1	38.5		47
Below %	44.8	54	60.3	54.4	42.2	43.2	48.1	45.7	72.1	56.9	61.5		53
Avg Above	219.5	245.7	175.9	180	217.2	209.6	268.3	208.5	128.1	122.8	120		268
Avg Below	-223.1	-207.6	-240.0	-191.5	-192.2	-215.9	-295.8	-281.9	-255.3	-177.2	-191.5		-296
Avg All	22	6	-78	-18	30	23	5	-26	-134	-57	-87		-29

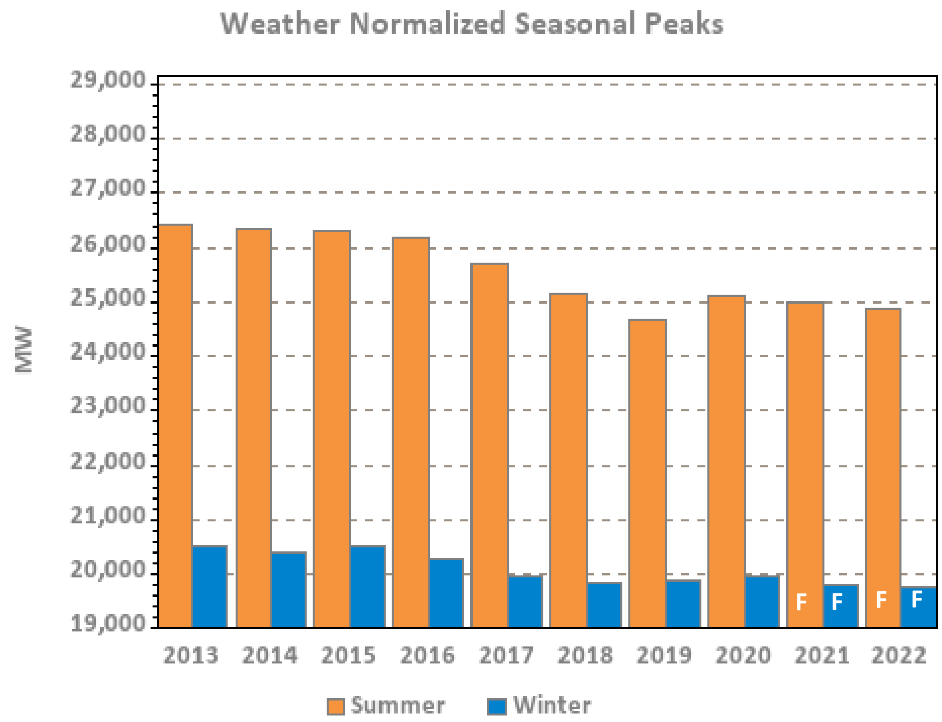
2022 System Operations - Load Forecast Accuracy cont.



Monthly Peak Loads and Weather Normalized Seasonal Peak History



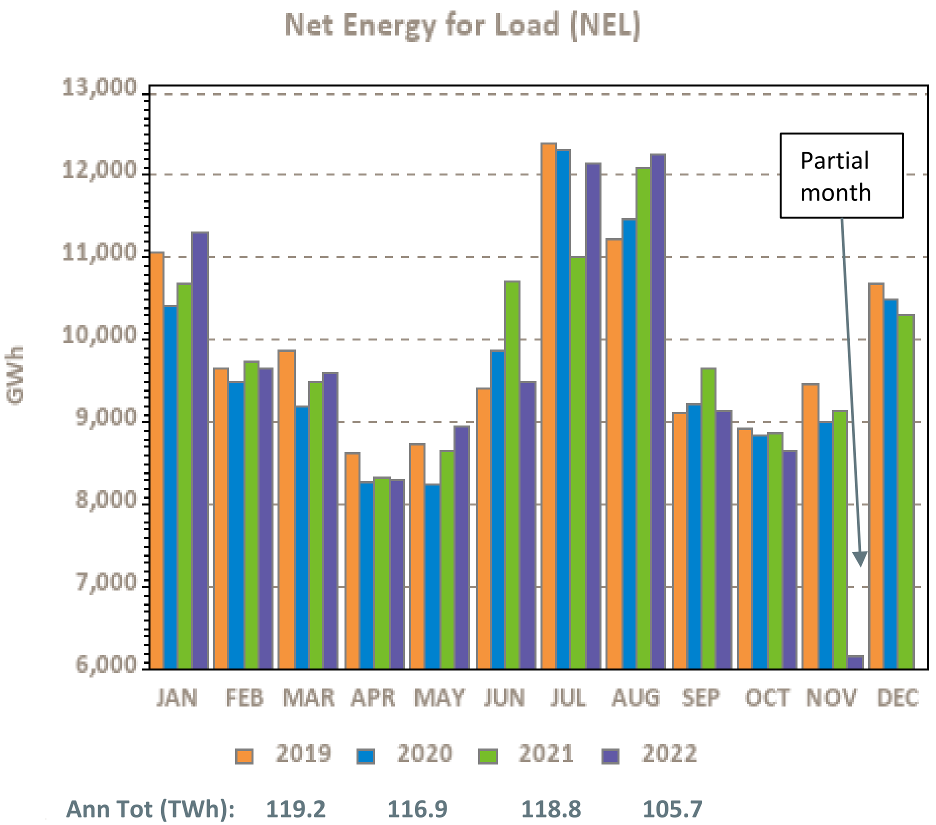
*Revenue quality metered value

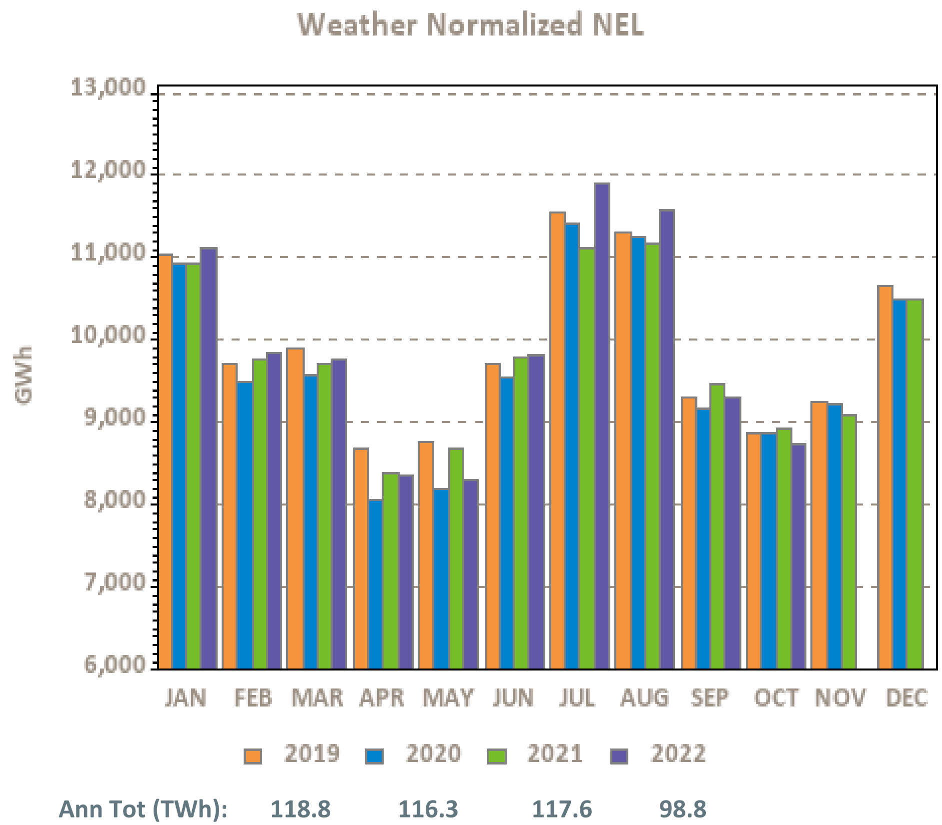


Winter beginning in year displayed

F – designates forecasted values, which are typically 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)

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

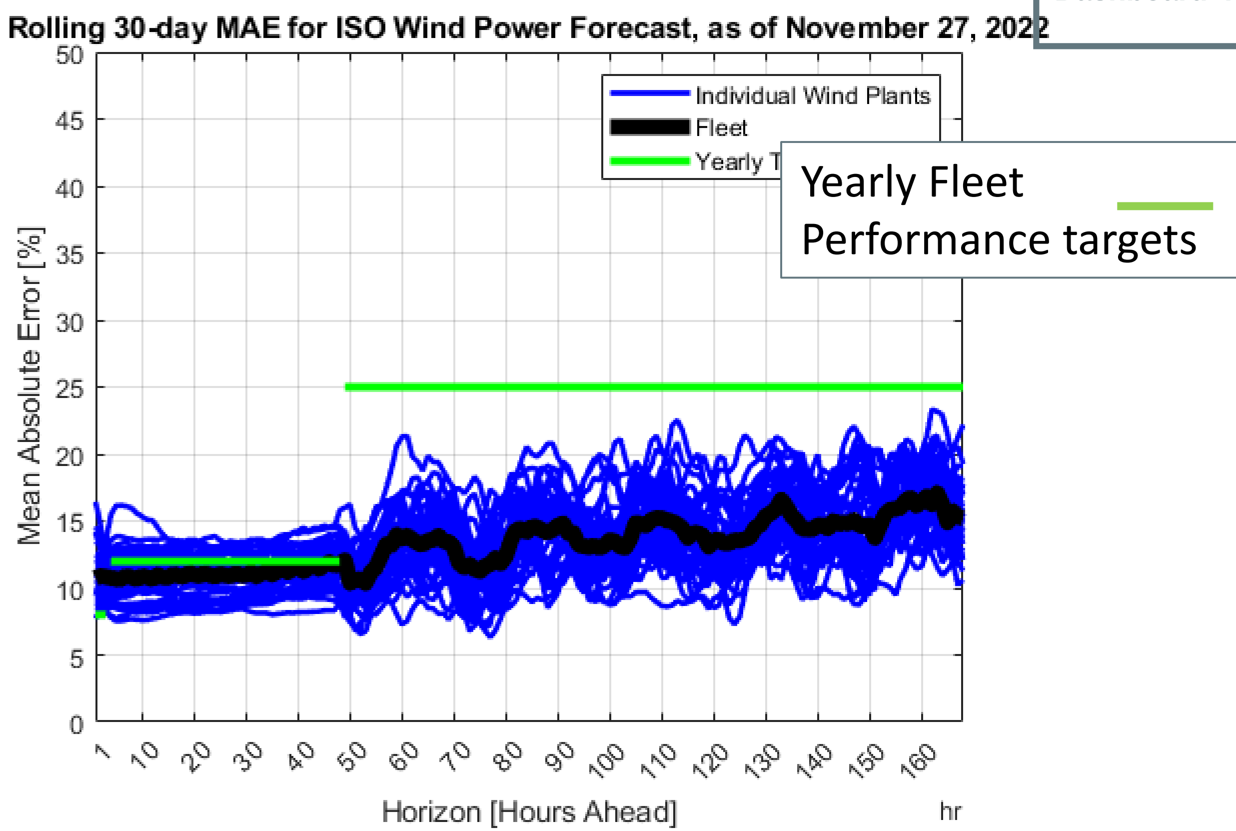




NEPOOL NEL is the total net revenue quality metered energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation – pumping load + net interchange where imports are positively signed. Current month's data may be preliminary. Weather normalized NEL is typically reported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

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

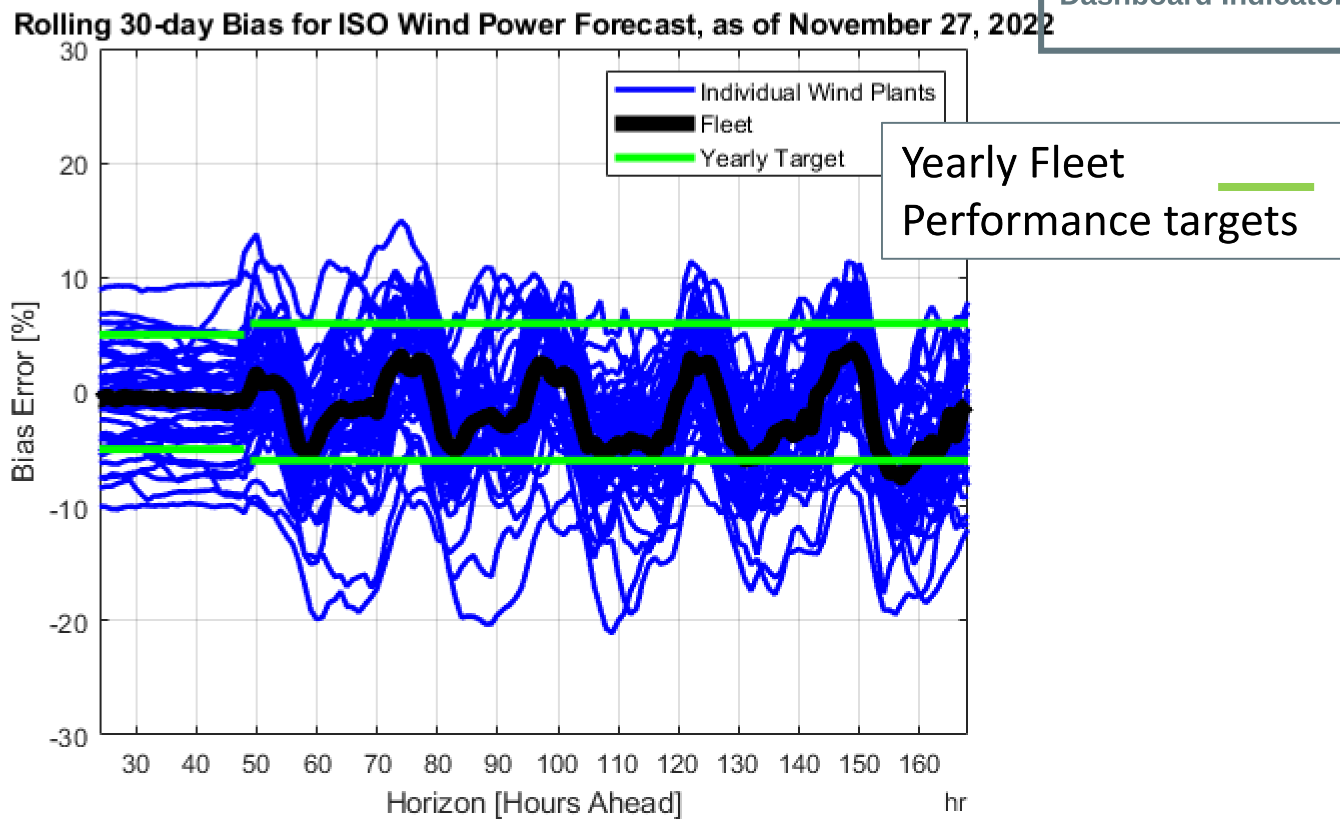
Dashboard Indicator



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 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

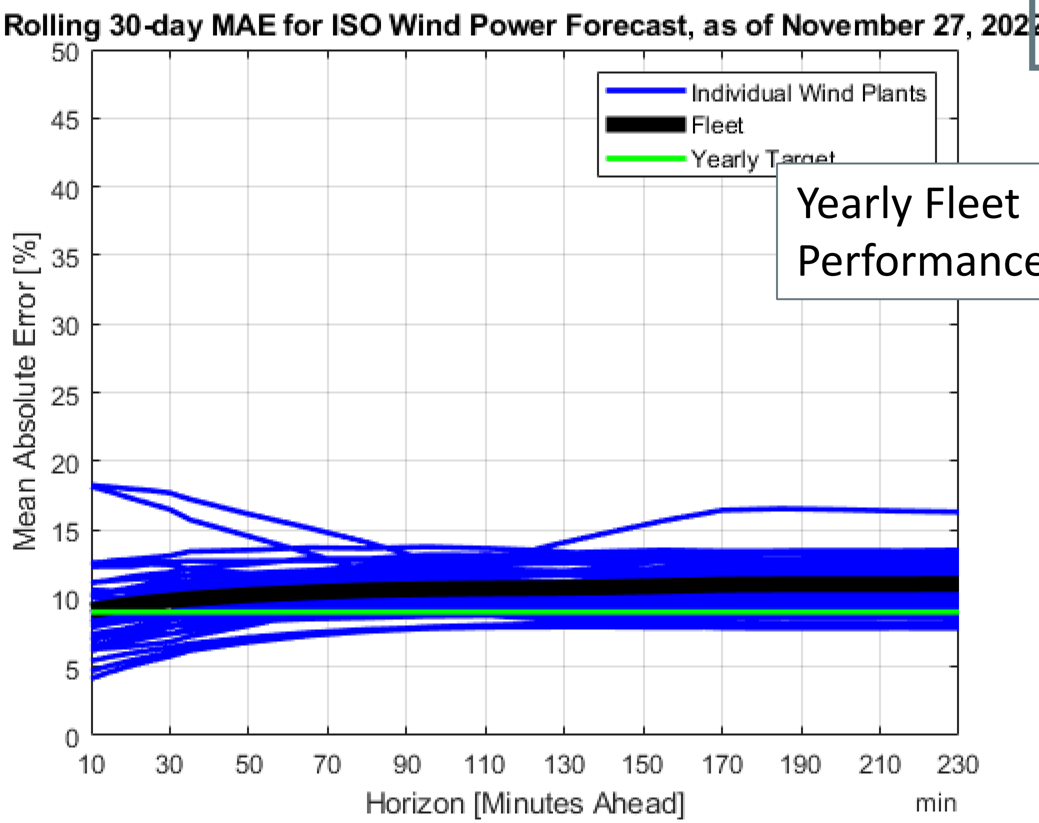
Dashboard Indicator



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 forecast compares well with industry standards, and monthly Bias is within yearly performance targets, but for hours 155 and 156 of the forecast horizon.

Wind Power Forecast Error Statistics: Short Term Forecast MAE

Dashboard Indicator

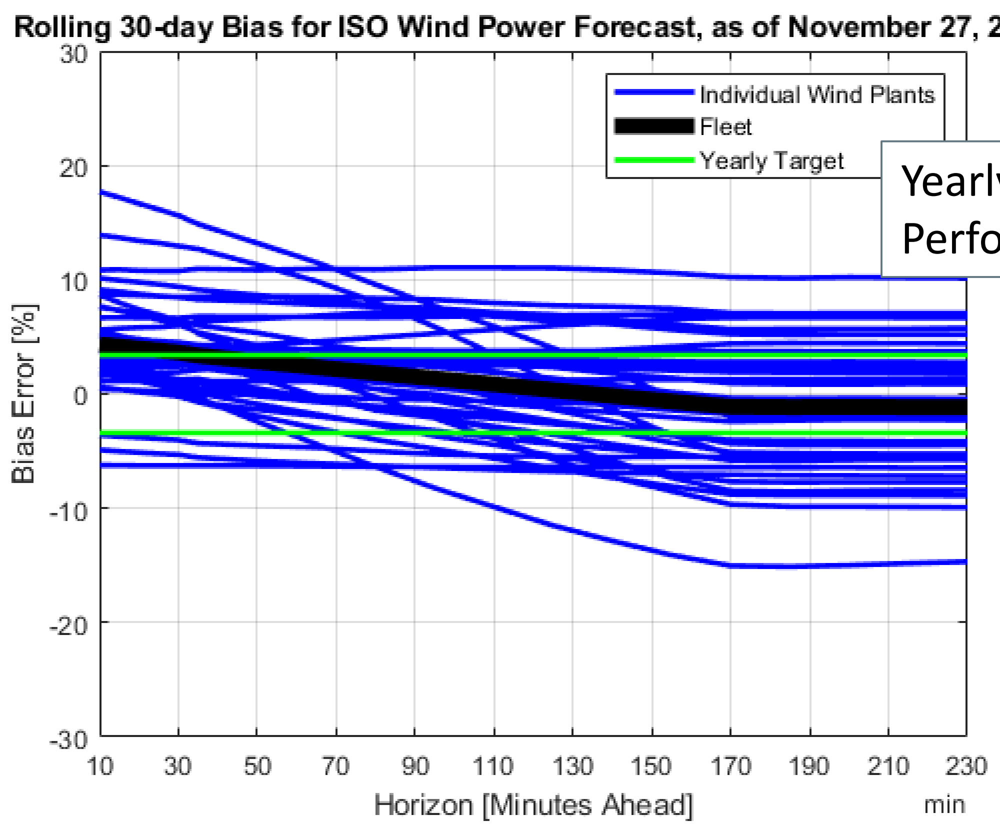


Yearly Fleet Performance targets

Ideally, MAE and Bias would be both equal to zero. As is typical, MAE increases with the forecast horizon. MAE and Bias for the fleet of wind power resources are less due to offsetting errors. Across all time frames, the ISO-NE/DNV forecast is very good compared to industry standards, but monthly MAE is not within the yearly performance targets. ISO is following up with our forecast provider.

Wind Power Forecast Error Statistics: Short Term Forecast Bias

Dashboard Indicator

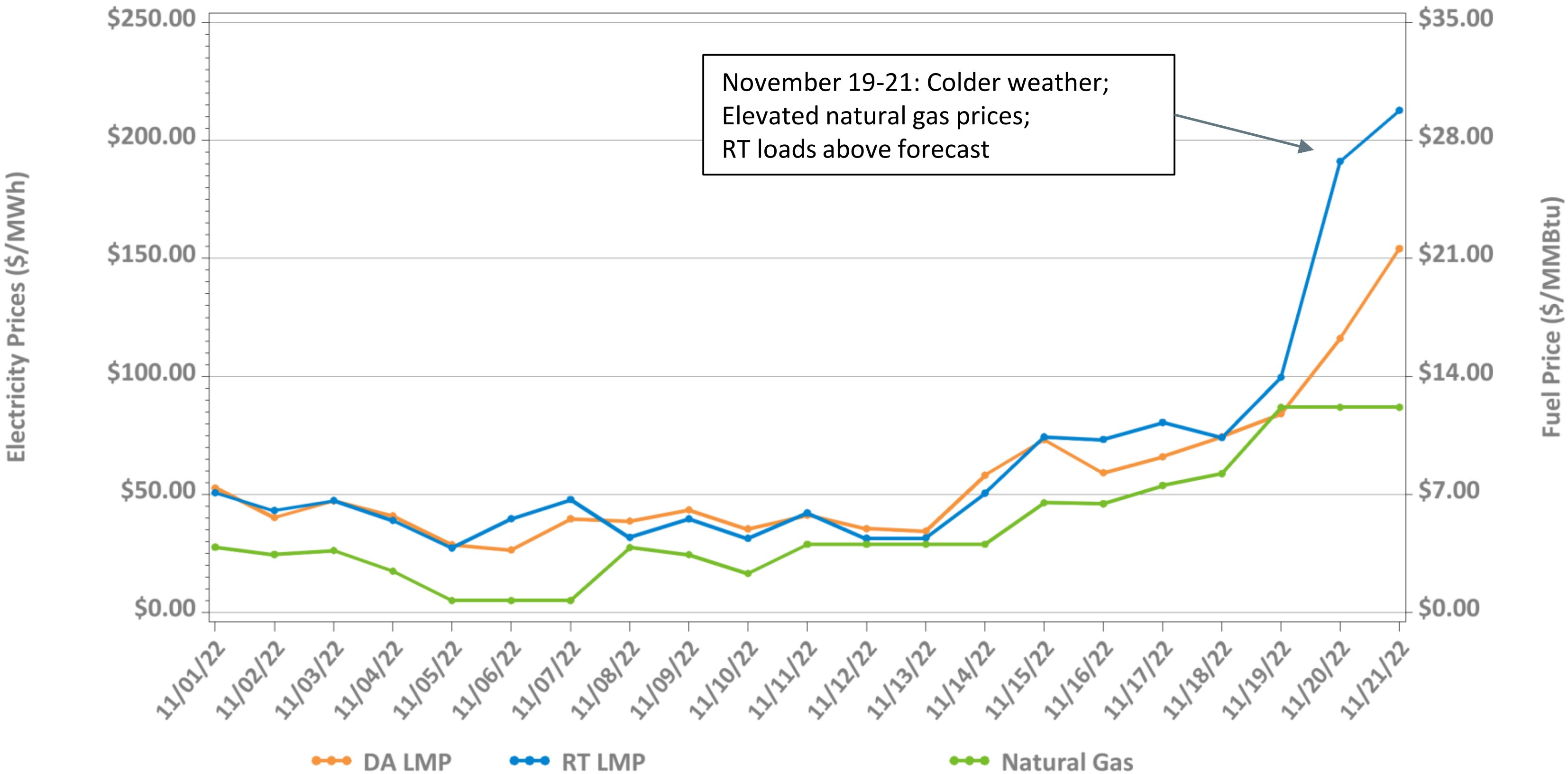


Yearly Fleet Performance targets

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 forecast compares well with industry standards, and monthly Bias is within yearly performance further than 30 minutes into the forecast horizon.

MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: November 1-21, 2022

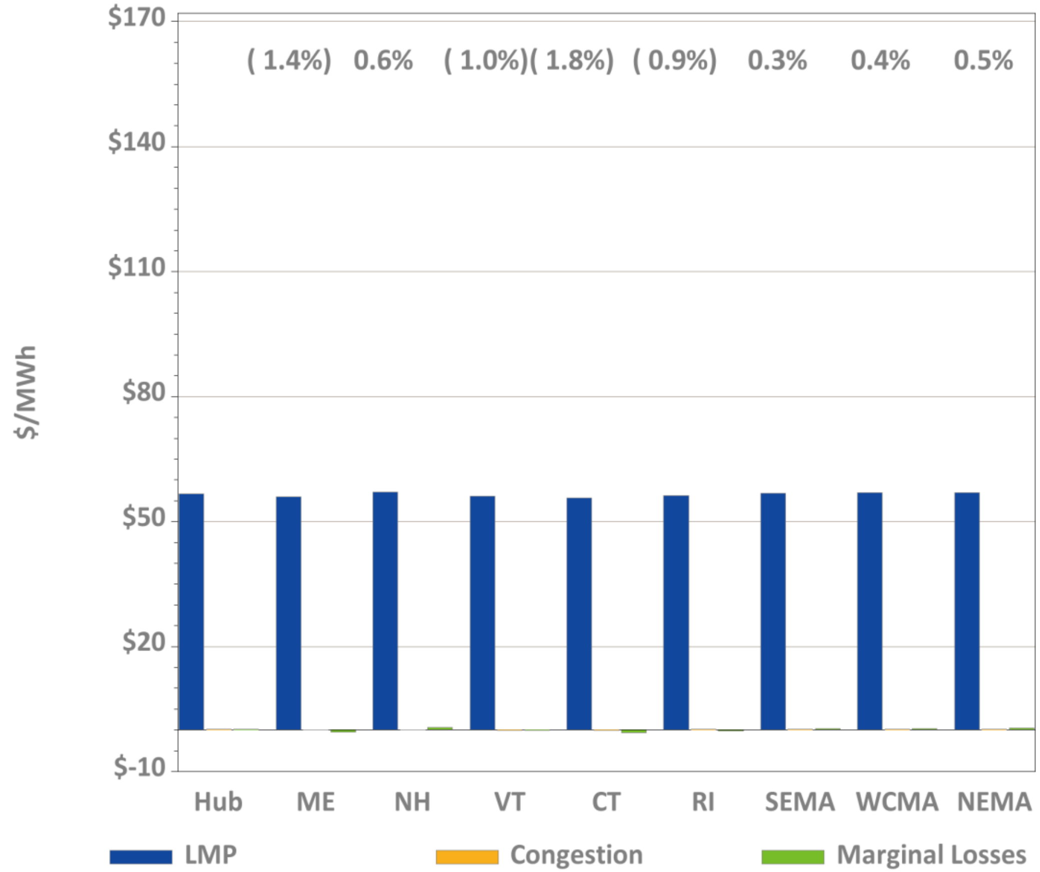


Underlying natural gas data furnished by:

ICE Global markets in clear view

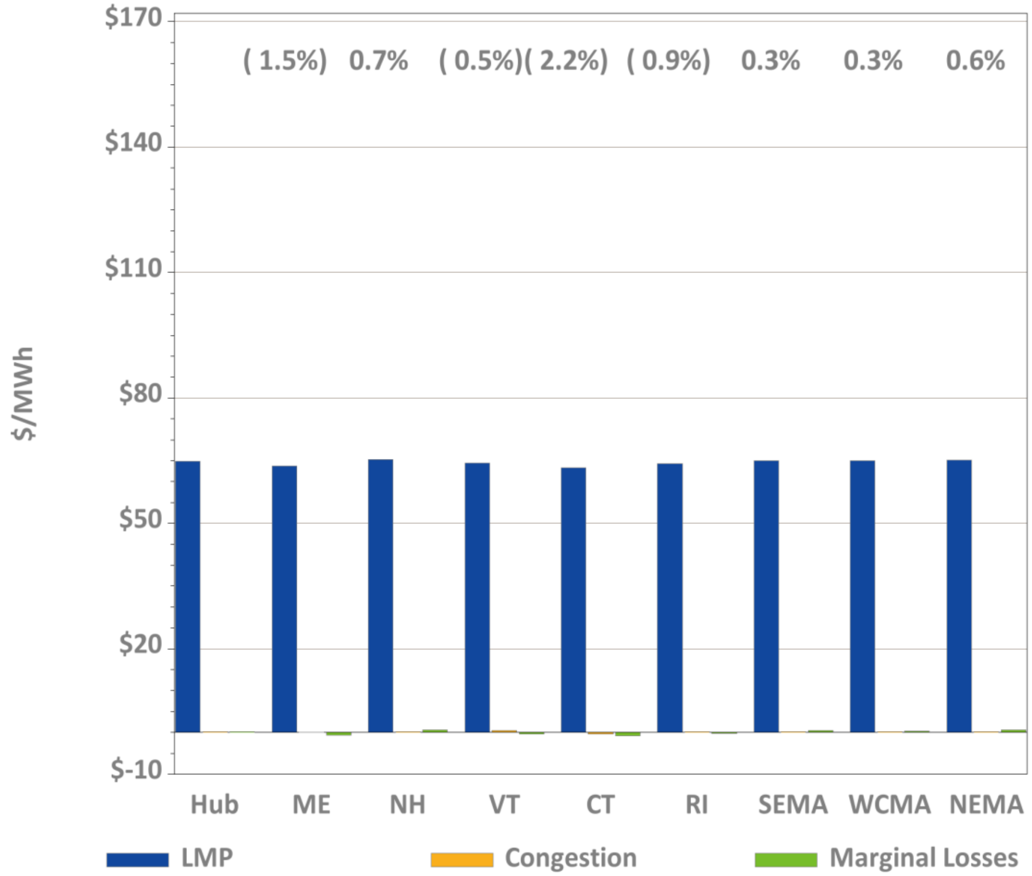
Average price difference over this period (DA-RT): $-8.07
Average price difference over this period ABS(DA-RT): $11.40
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 18%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, November 2022



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

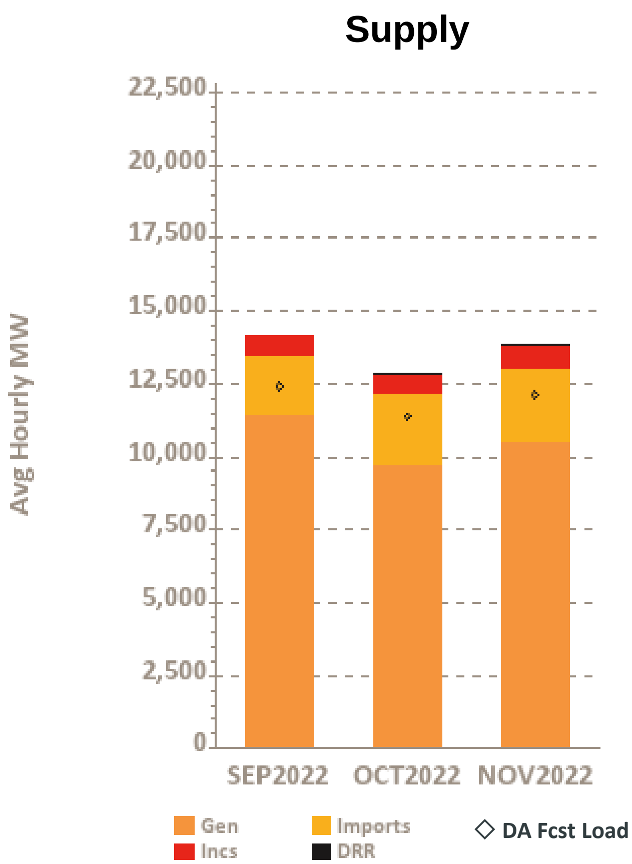
RT LMPs Average by Zone & Hub, November 2022

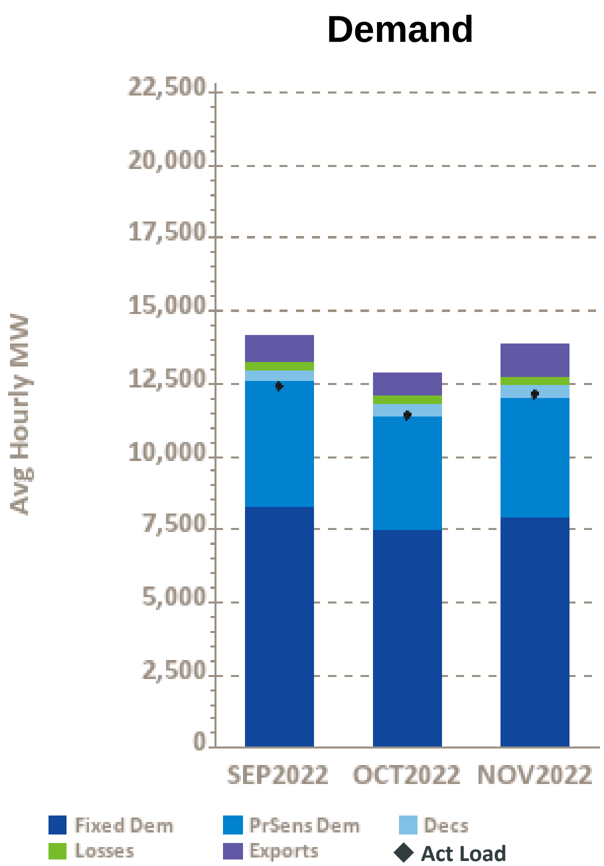


Definitions

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

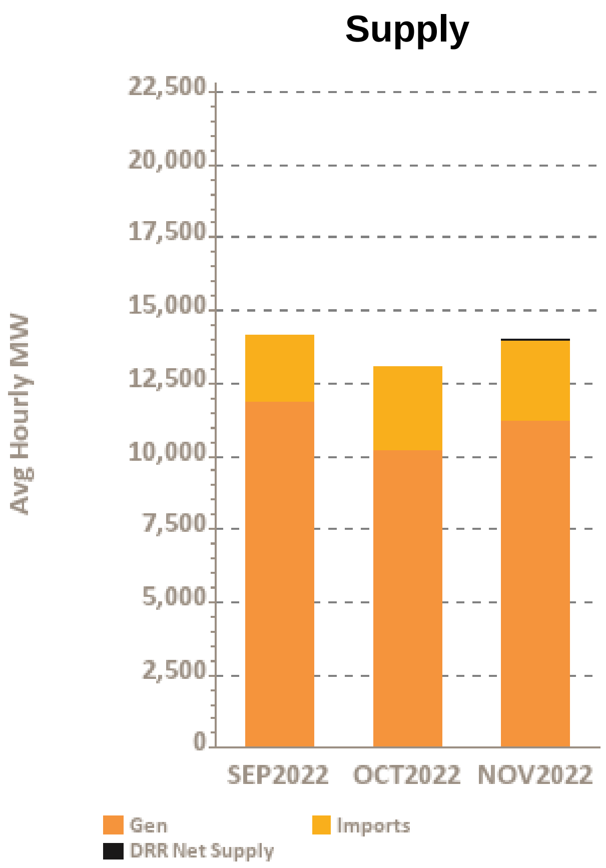


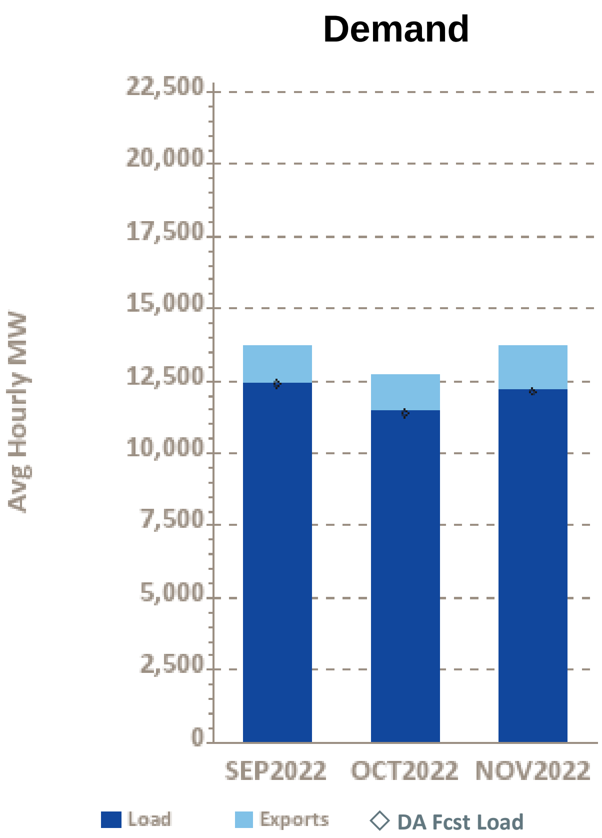


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load
DRR – Demand Response Resource

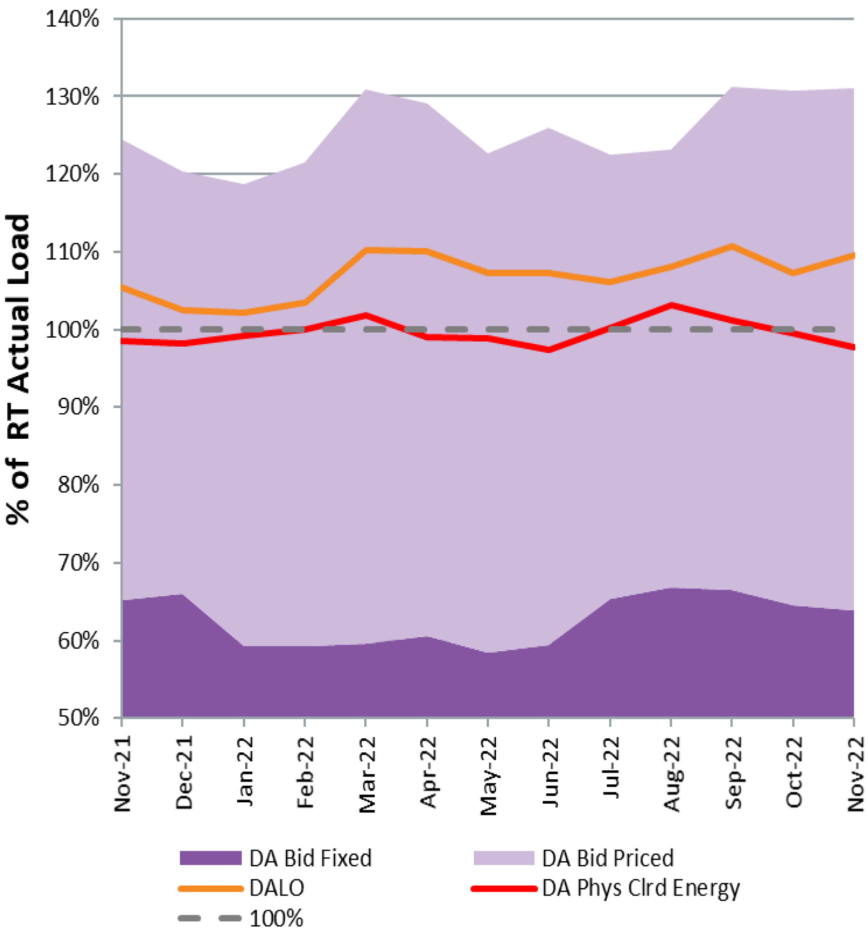
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

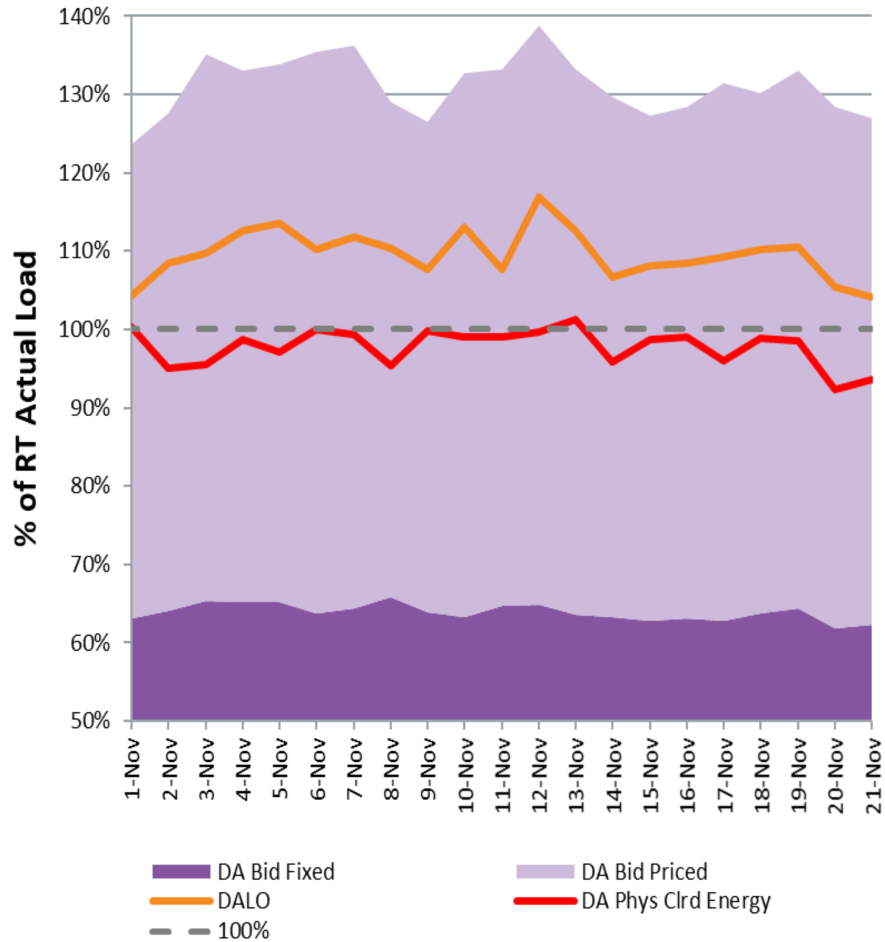
Components of RT Supply and Demand – Last Three Months





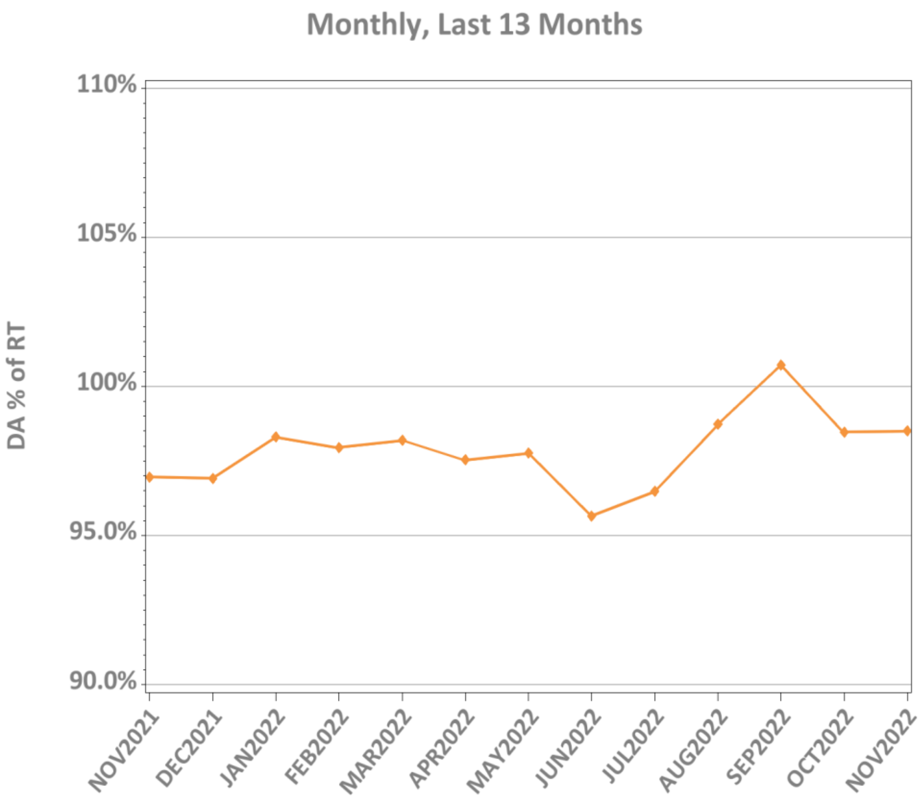
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

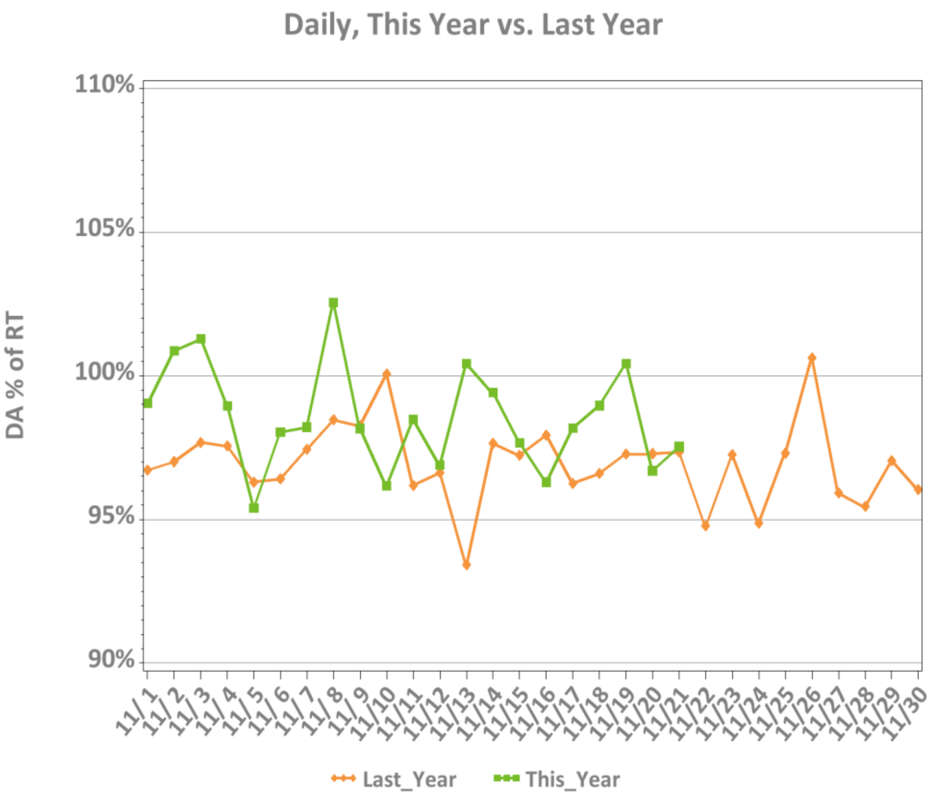




Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

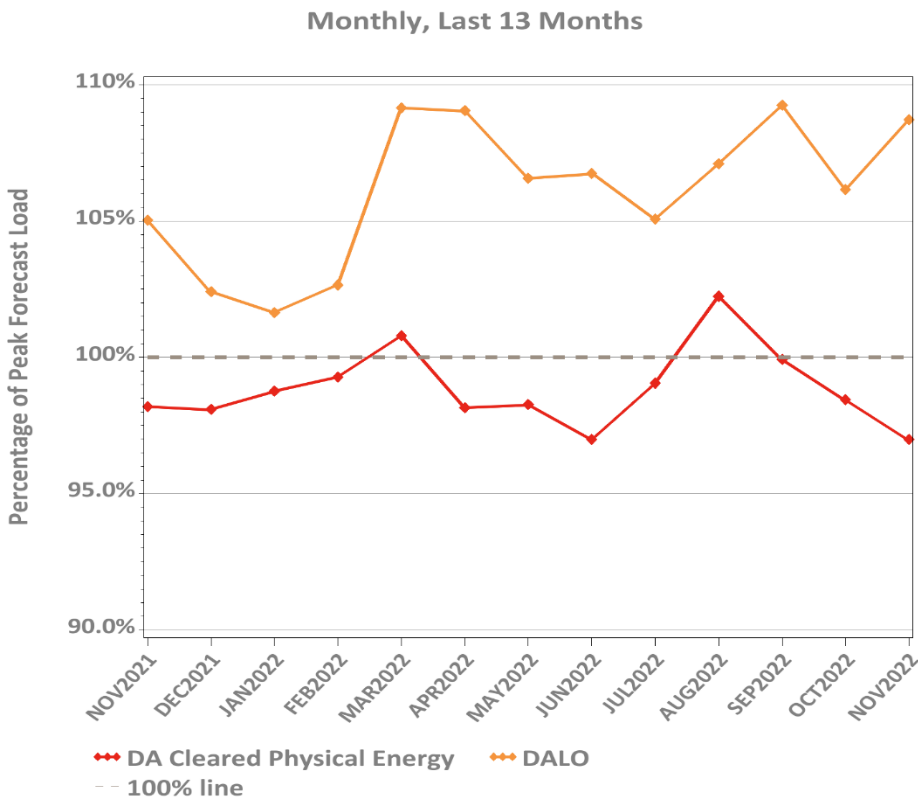
DA vs. RT Load Obligation: November, This Year vs. Last Year

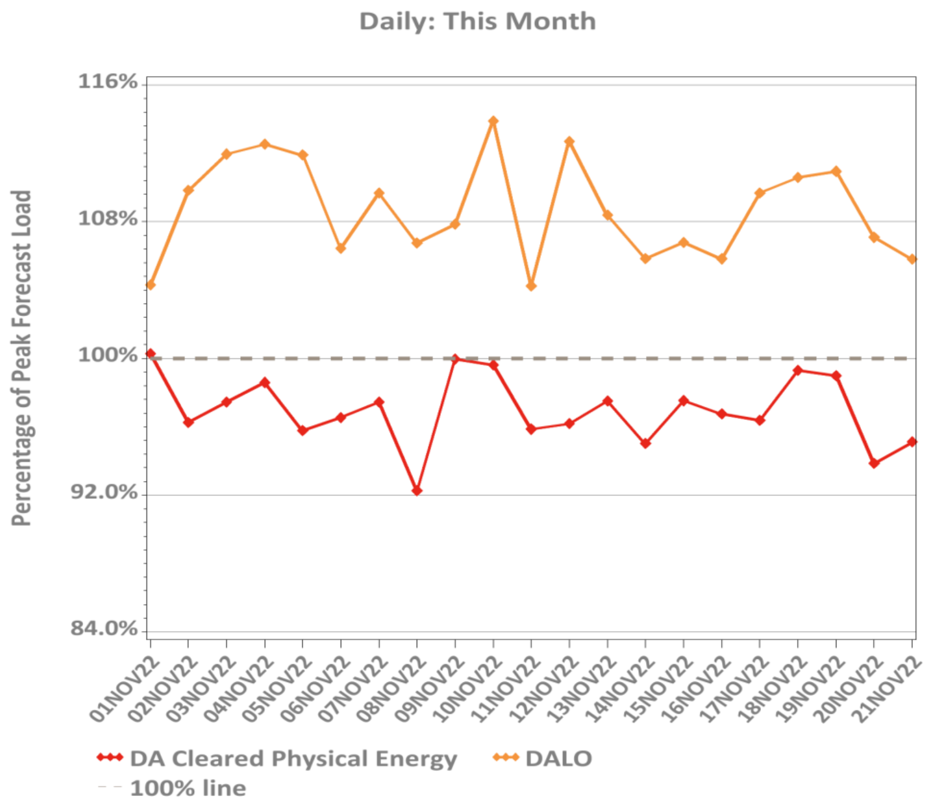




*Hourly average values

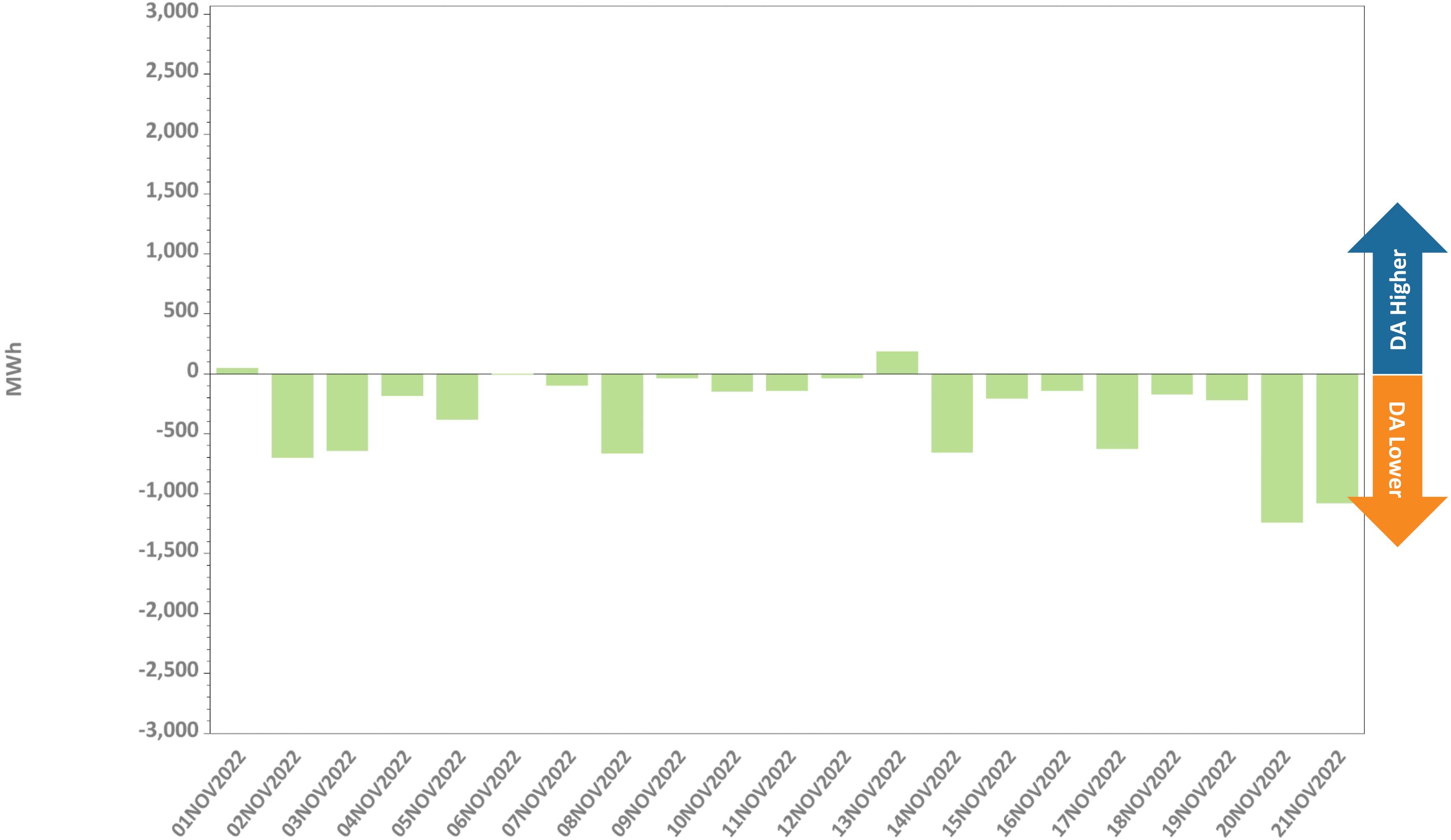
DA Volumes as % of Forecast in Peak Hour





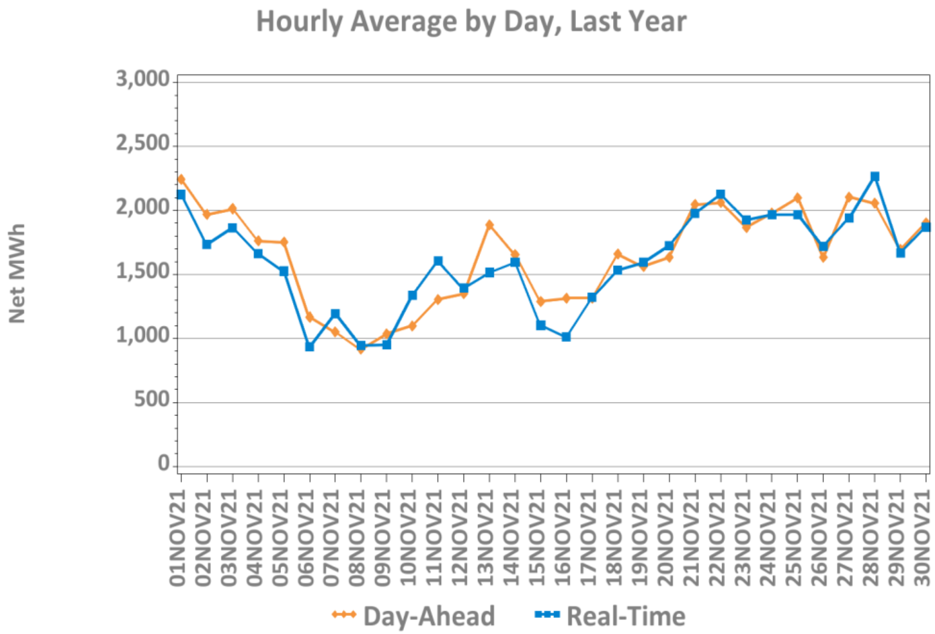
Note: There were three system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) period during the month.

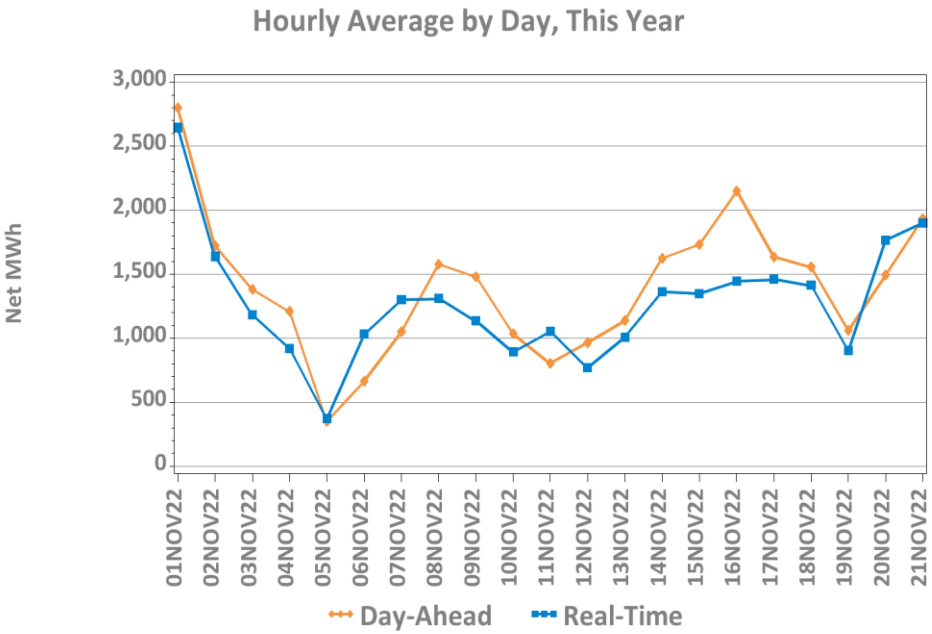
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour*



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

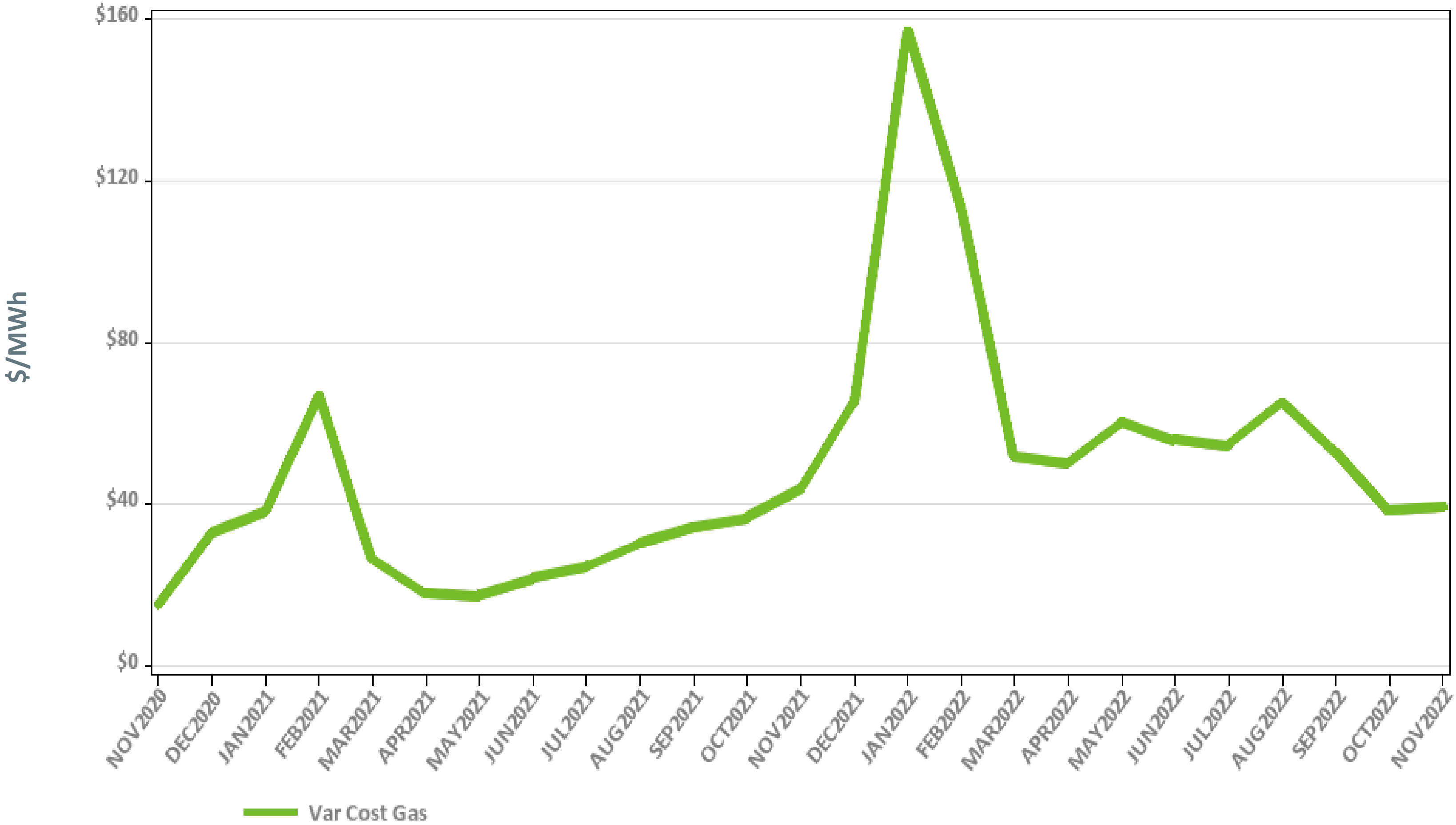
DA vs. RT Net Interchange November 2021 vs. November 2022





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

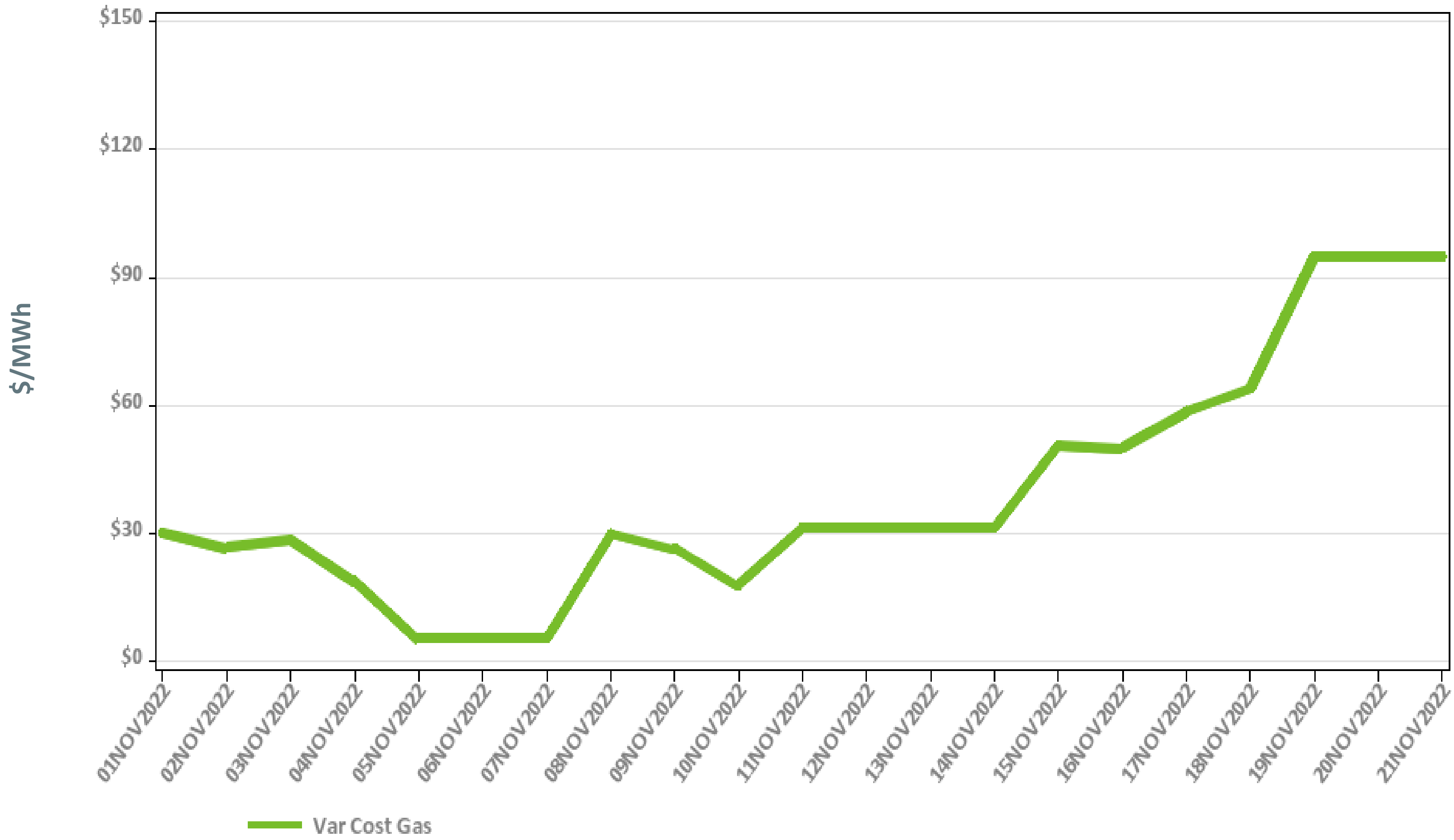
Variable Production Cost of Natural Gas: Monthly



Underlying natural gas data furnished by:

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

Variable Production Cost of Natural Gas: Daily

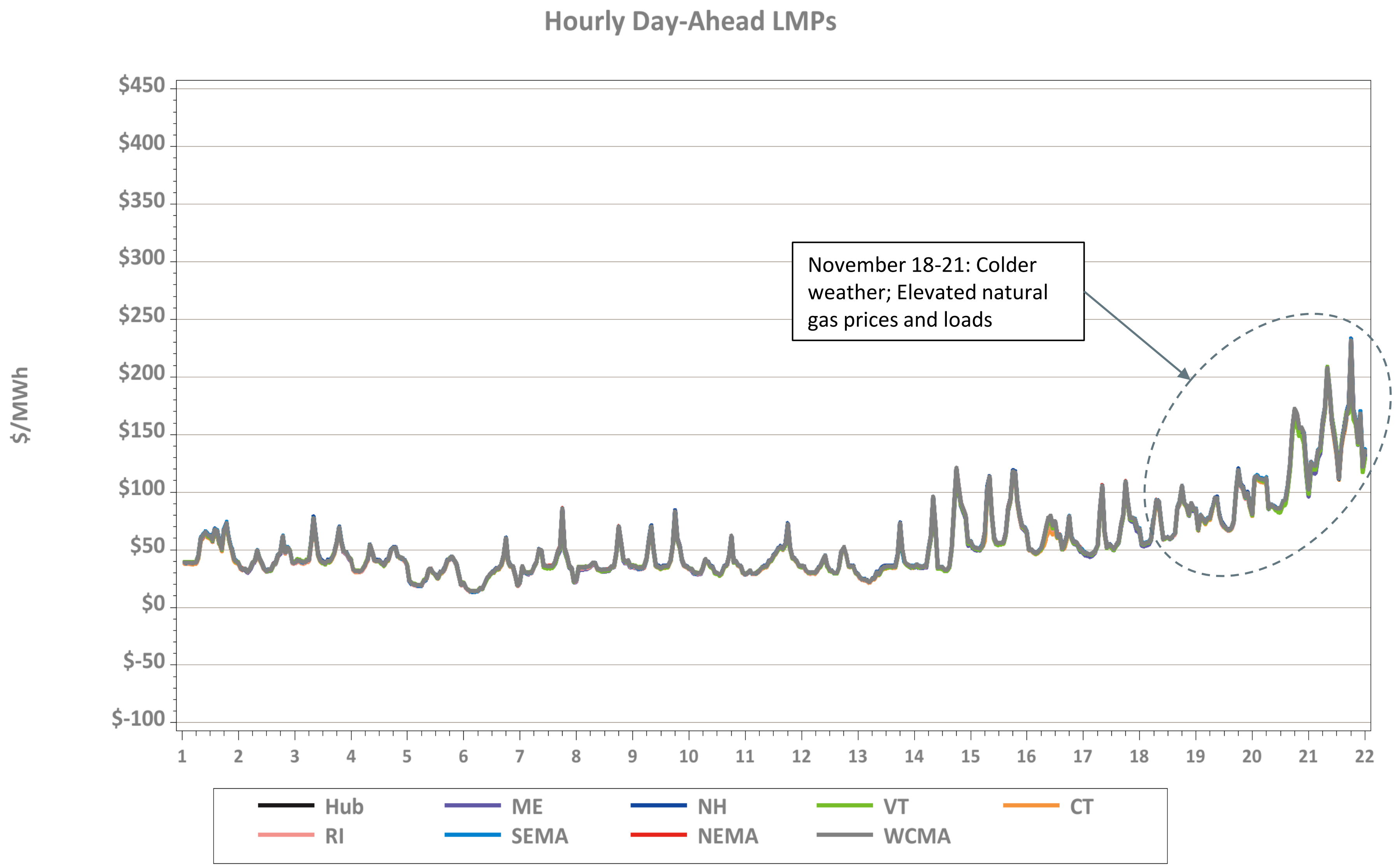


Underlying natural gas data furnished by:

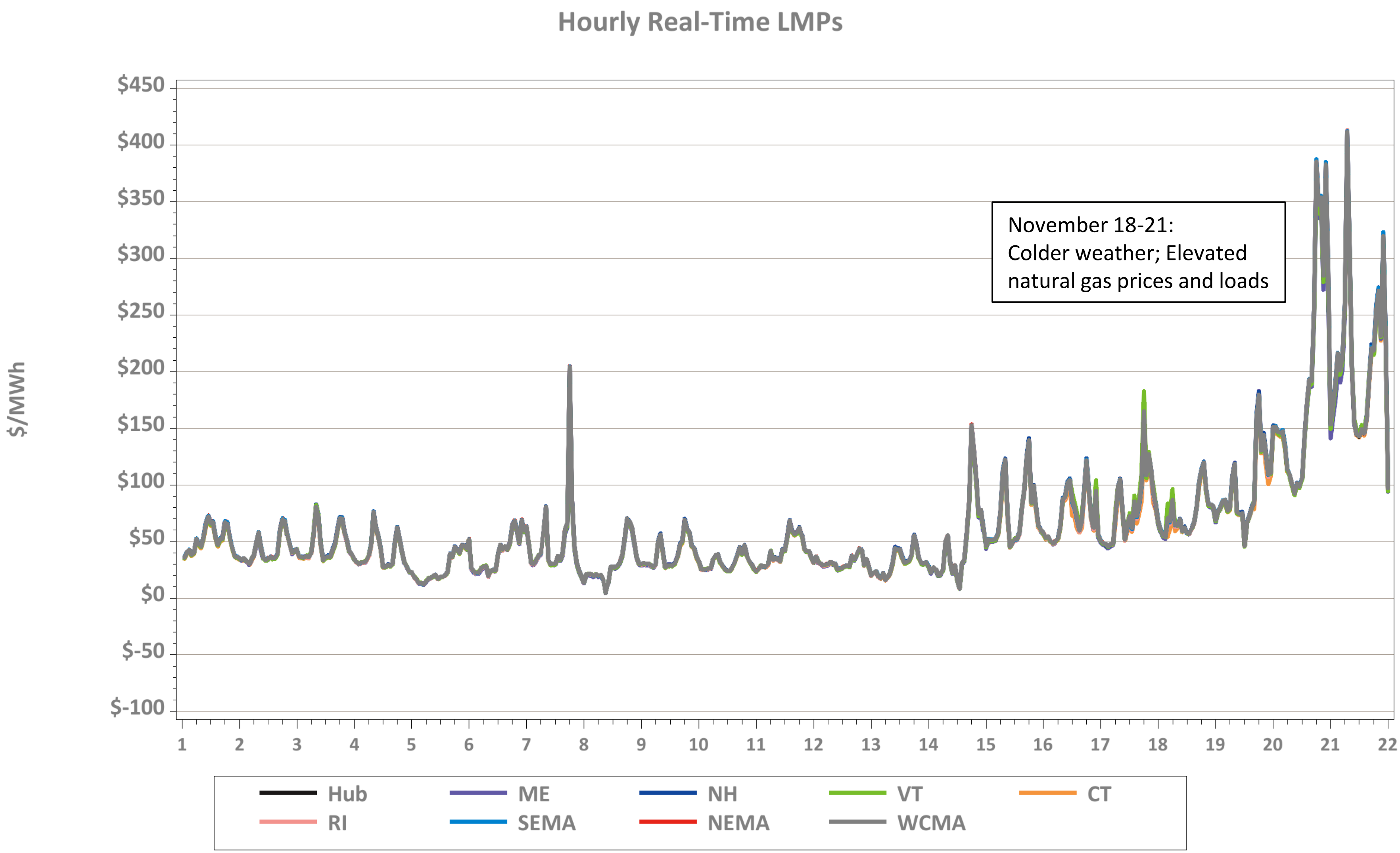
ICE Global markets in clear view

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

Hourly DA LMPs, November 1-21, 2022

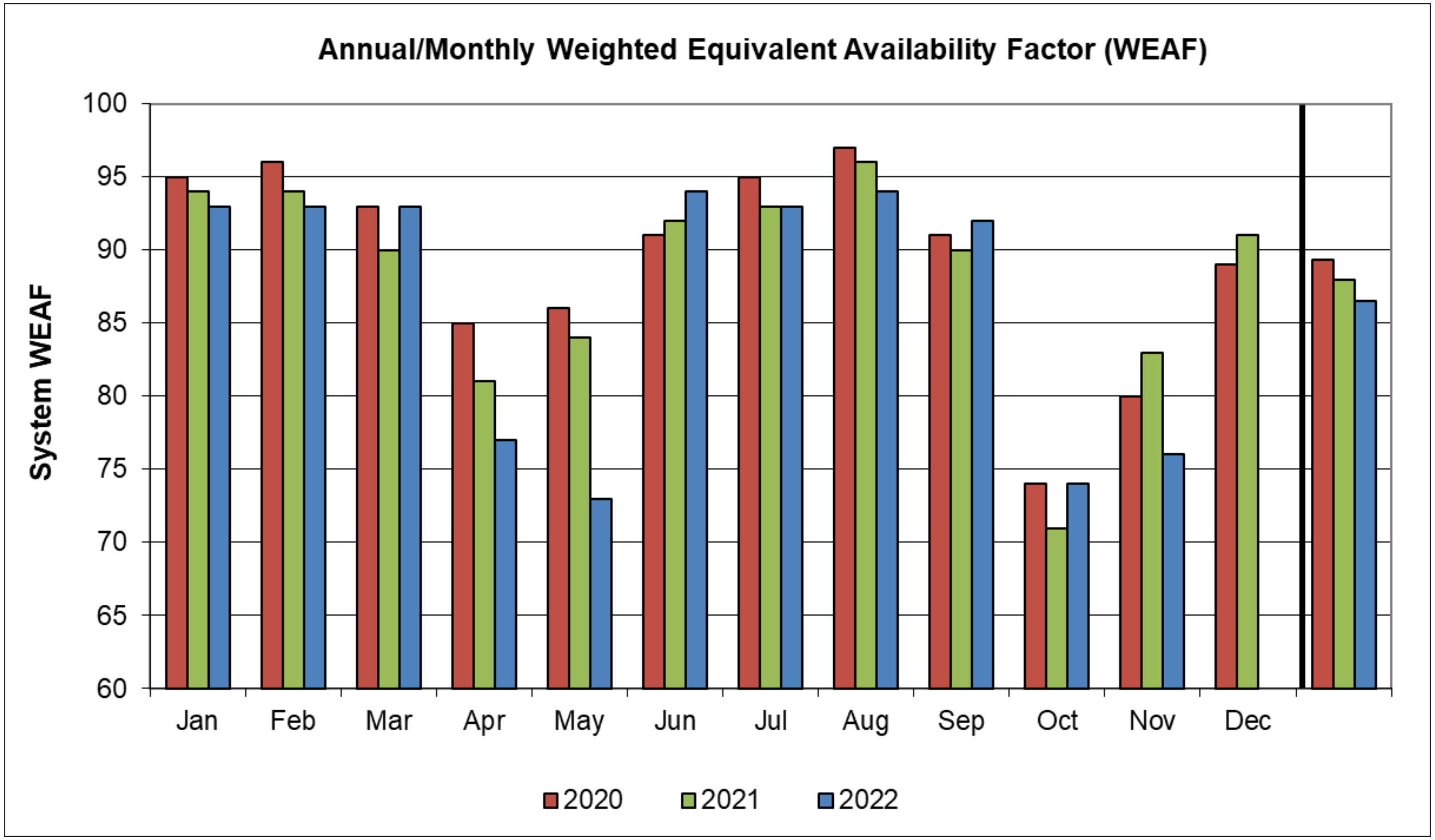


Hourly RT LMPs, November 1-21, 2022



* Telemetered load is referenced

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2022	93	93	93	77	73	94	93	94	92	74	76		87
2021	94	94	90	81	84	92	93	96	90	71	83	91	88
2020	95	96	93	85	86	91	95	97	91	74	80	89	89

Data as of 11/21/2022

BACK-UP DETAIL

DEMAND RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for December 2022

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	89.7	179.8	0.0	269.5
NH	33.3	180.0	0.0	213.2
VT	46.6	162.9	0.0	209.5
CT	121.0	110.9	687.4	919.3
RI	22.5	342.9	0.0	365.4
SEMA	38.0	510.6	0.0	548.6
WCMA	66.0	563.5	14.4	643.9
NEMA	49.0	857.2	0.0	906.2
Total	**466.1**	**2,907.9**	**701.8**	**4,075.9**

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

NEW GENERATION

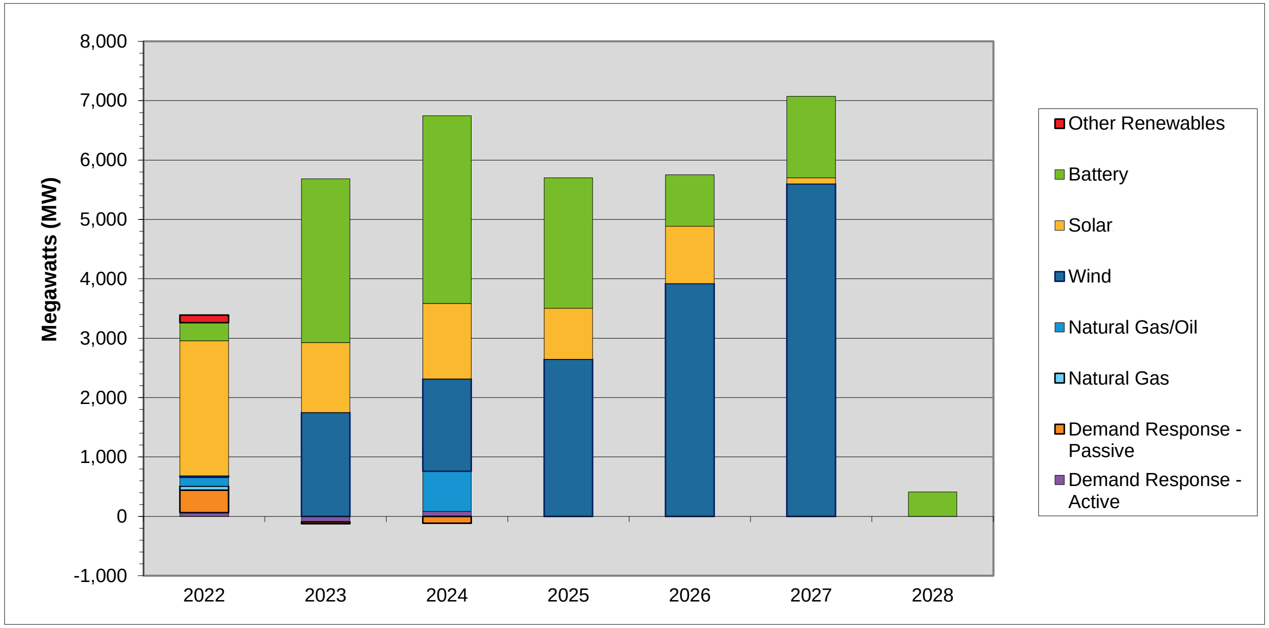
New Generation Update

Based on Queue as of 11/25/22

- Six projects totaling 910 MW were added to the interconnection queue since the last update
  - Four battery projects and two solar projects with in-service dates of 2023 to 2027
- No project was withdrawn and no project went commercial
- In total, 359 generation projects are currently being tracked by the ISO, totaling approximately 35,902 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



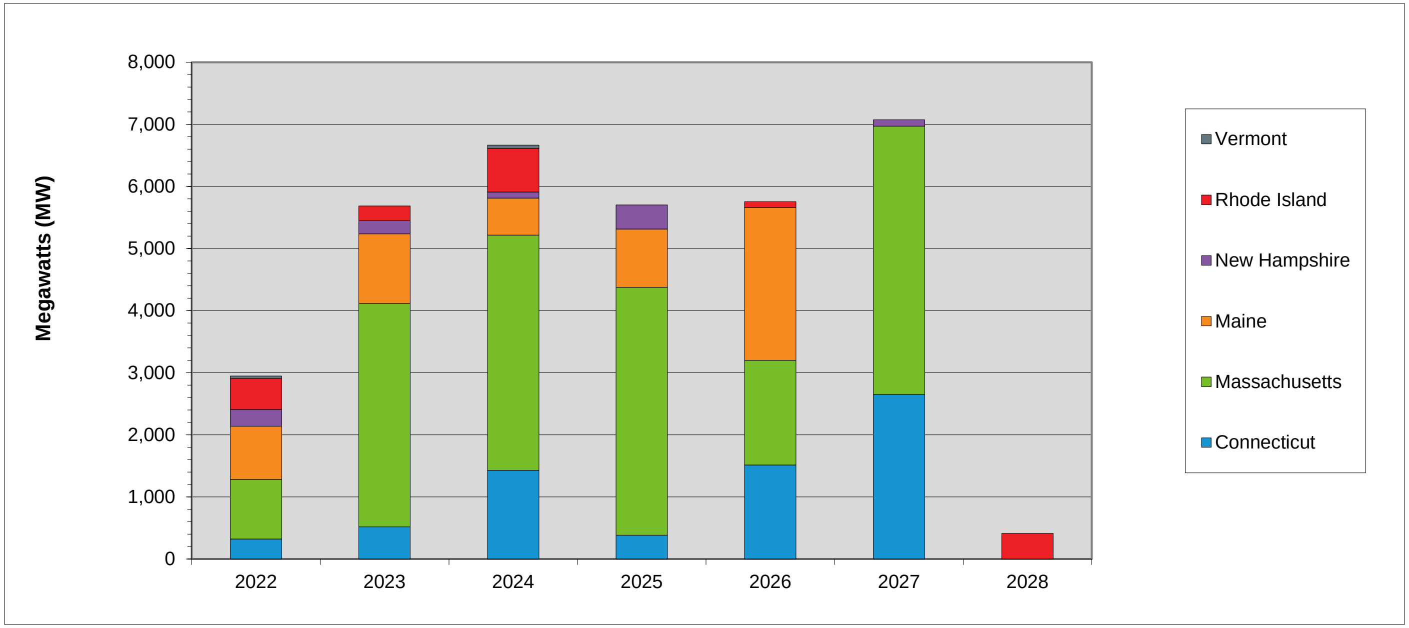
	2022	2023	2024	2025	2026	2027	2028	Total MW	% of Total[1]
Other Renewables	129	0	0	0	0	0	0	129	0.4
Battery	305	2,756	3,163	2,196	866	1,373	410	11,069	32.1
Solar[2]	2,272	1,176	1,272	859	964	102	0	6,645	19.2
Wind	24	1,752	1,556	2,645	3,923	5,599	0	15,499	44.9
Natural Gas/Oil[3]	151	0	672	0	0	0	0	823	2.4
Natural Gas	67	0	0	0	0	0	0	67	0.2
Demand Response - Passive	380	-28	-114	0	0	0	0	238	0.7
Demand Response - Active	62	-94	86	0	0	0	0	54	0.2
Totals	3,390	5,562	6,635	5,700	5,753	7,074	410	34,524	100.0

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

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

Actual and Projected Annual Generator Capacity Additions

By State



	2022	2023	2024	2025	2026	2027	2028	Total MW	% of Total[1]
Vermont	40	0	50	0	0	0	0	90	0.3
Rhode Island	502	236	704	0	91	0	410	1,943	5.7
New Hampshire	266	211	97	385	0	102	0	1,061	3.1
Maine	858	1,123	597	942	2,461	0	0	5,981	17.5
Massachusetts	959	3,594	3,786	3,989	1,686	4,324	0	18,338	53.6
Connecticut	323	520	1,429	384	1,515	2,648	0	6,819	19.9
Totals	**2,948**	**5,684**	**6,663**	**5,700**	**5,753**	**7,074**	**410**	**34,232**	**100.0**

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

New Generation Projection

By Fuel Type

Unit Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0
Battery Storage	77	11,069	3	32	74	11,037
Fuel Cell	2	30	0	0	2	30
Hydro	3	99	2	71	1	28
Natural Gas	7	67	0	0	7	67
Natural Gas/Oil	5	823	1	62	4	761
Nuclear	0	0	0	0	0	0
Solar	239	6,645	18	401	221	6,244
Wind	26	17,169	1	20	25	17,149
Total	359	35,902	25	586	334	35,316

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

New Generation Projection

By Operating Type

	Total		Green		Yellow	
Operating Type	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	5	70	1	5	4	65
Intermediate	7	804	0	0	7	804
Peaker	321	17,859	23	561	298	17,298
Wind Turbine	26	17,169	1	20	25	17,149
Total	359	35,902	25	586	334	35,316

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

New Generation Projection

By Operating Type and Fuel Type

Unit Type	Total		Baseload		Intermediate		Peaker		Wind Turbine	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0	0	0	0	0
Battery Storage	77	11,069	0	0	0	0	77	11,069	0	0
Fuel Cell	2	30	2	30	0	0	0	0	0	0
Hydro	3	99	2	33	0	0	1	66	0	0
Natural Gas	7	67	1	7	3	43	3	17	0	0
Natural Gas/Oil	5	823	0	0	4	761	1	62	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0
Solar	239	6,645	0	0	0	0	239	6,645	0	0
Wind	26	17,169	0	0	0	0	0	0	26	17,169
Total	359	35,902	5	70	7	804	321	17,859	26	17,169

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

FORWARD CAPACITY MARKET

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	658.659	-24.457	609.826	-48.833
	Passive Demand	3,354.69	3,407.507	52.817	3,450.899	43.392	3,512.604	61.705
Demand Total		**4,040.244**	**4,090.623**	**50.38**	**4,109.558**	**18.935**	**4,122.43**	**12.872**
Generator	*Non-Intermittent*	28,586.498	27,868.341	-718.157	28,105.411	237.07	27,426.242	-679.169
	Intermittent	1,024.792	901.672	-123.12	896.285	-5.387	778.962	-117.323
Generator Total		**2,9611.29**	**28,770.013**	**-841.28**	**29,001.696**	**231.683**	**28,205.204**	**-796.492**
Import Total		**1,187.69**	**1,292.41**	**104.72**	**1,292.41**	**0**	**1,115.22**	**-177.19**
Grand Total*		**34,839.224**	**34,153.046**	**-686.18**	**34,403.664**	**250.618**	**33,442.854**	**-960.81**
Net ICR (NICR)		**33,750**	**32,465**	**-1,285**	**32,765**	**300**	**31,590**	**-1,175**

* 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.

ARA – Annual Reconfiguration Auction
CSO – Capacity Supply Obligation
FCA – Forward Capacity Auction
ICR – Installed Capacity Requirement

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	688.07	96.027	659.671	-28.399		
	Passive Demand	3,327.071	3,327.932	0.861	3,315.207	-12.725		
Demand Total		**3,919.114**	**4,016.002**	**96.888**	**3,974.878**	**-41.124**		
Generator	*Non-Intermittent*	27,816.902	28,275.143	458.241	27,697.714	-577.429		
	Intermittent	1,160.916	1,128.446	-32.47	925.942	-202.504		
Generator Total		**28,977.818**	**29,403.589**	**425.771**	**28,623.656**	**-779.933**		
Import Total		**1,058.72**	**1,058.72**	**0**	**1,029.800**	**-28.92**		
Grand Total*		**33,955.652**	**34,478.311**	**522.661**	**33,628.334**	**-849.977**		
Net ICR (NICR)		**32,490**	**32,980**	**490**	**31,480**	**-1,500**		

* 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 2015-2022 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 15

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	677.673	673.401	-4.272				
Demand	*Passive Demand*	3,212.865	3,211.403	-1.462				
Demand Total		**3,890.538**	**3,884.804**	**-5.734**				
Generator	*Non-Intermittent*	28,154.203	27,714.778	-439.425				
Generator	*Intermittent*	1,089.265	1,073.794	-15.471				
Generator Total		**29,243.468**	**28,788.572**	**-454.896**				
Import Total		**1,487.059**	**1297.132**	**-189.927**				
Grand Total*		**34,621.065**	**33,970.508**	**-650.557**				
Net ICR (NICR)		**33,270**	**31,775**	**-1,495**				

* 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 2015-2022 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 16

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*	765.35						
	Passive Demand	2,557.256						
Demand Total		**3,322.606**						
Generator	*Non-Intermittent*	26,805.003						
	Intermittent	1,178.933						
Generator Total		**27,983.936**						
Import Total		**1,503.842**						
Grand Total*		**32,810.384**						
Net ICR (NICR)		**31,645**						

* 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 2015-2022 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Active/Passive Demand Response

CSO Totals by Commitment Period

Commitment Period	Active/Passive	Existing	New	Grand Total
2019-20	Active	357.221	20.304	377.525
	Passive	2,018.20	350.43	2,368.63
	Grand Total	**2,375.422**	**370.734**	**2,746.156**
2020-21	Active	334.634	85.294	419.928
	Passive	2,236.73	554.292	2,791.02
	Grand Total	**2,571.361**	**639.586**	**3,210.947**
2021-22	Active	480.941	143.504	624.445
	Passive	2,604.79	370.568	2,975.36
	Grand Total	**3,085.734**	**514.072**	**3,599.806**
2022-23	Active	598.376	87.178	685.554
	Passive	2,788.33	566.363	3,354.69
	Grand Total	**3,386.703**	**653.541**	**4,040.244**
2023-24	Active	560.55	31.493	592.043
	Passive	3,035.51	291.565	3,327.07
	Grand Total	**3,596.056**	**323.058**	**3,919.114**
2024-25	Active	674.153	3.520	677.673
	Passive	3,046.064	166.801	3,212.865
	Grand Total	**3,720.217**	**170.321**	**3,890.538**
2025-26	Active	664.01	101.34	765.35
	Passive	2,428.638	128.618	2557.256
	Grand Total	**3,092.648**	**229.958**	**3,322.606**

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

What are Daily NCPC Payments?

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

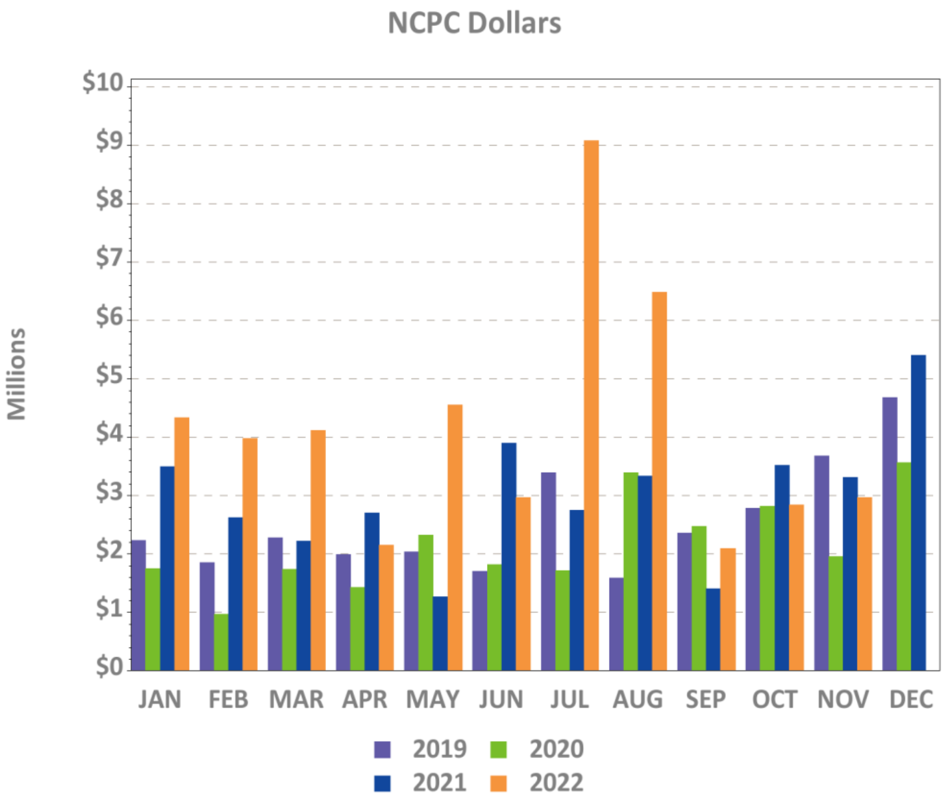
Definitions

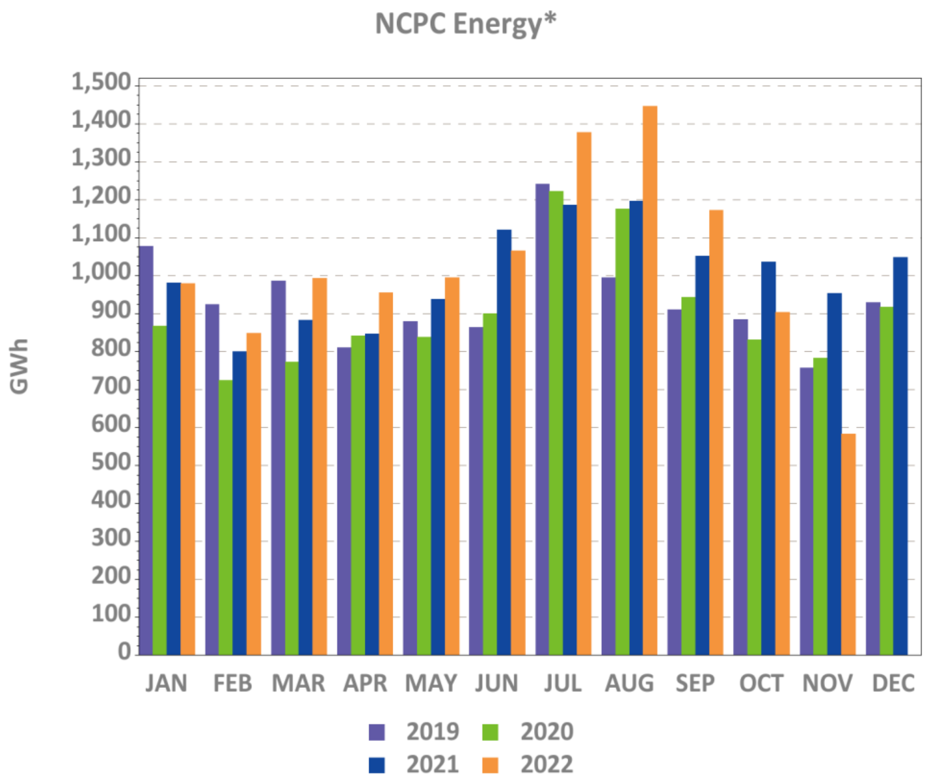
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing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

Charge Allocation Key

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

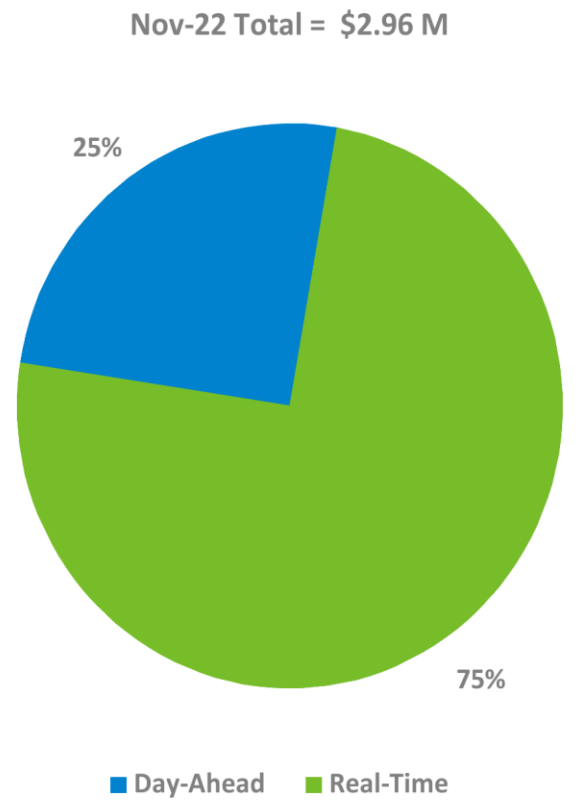
Year-Over-Year Total NCPC Dollars and Energy

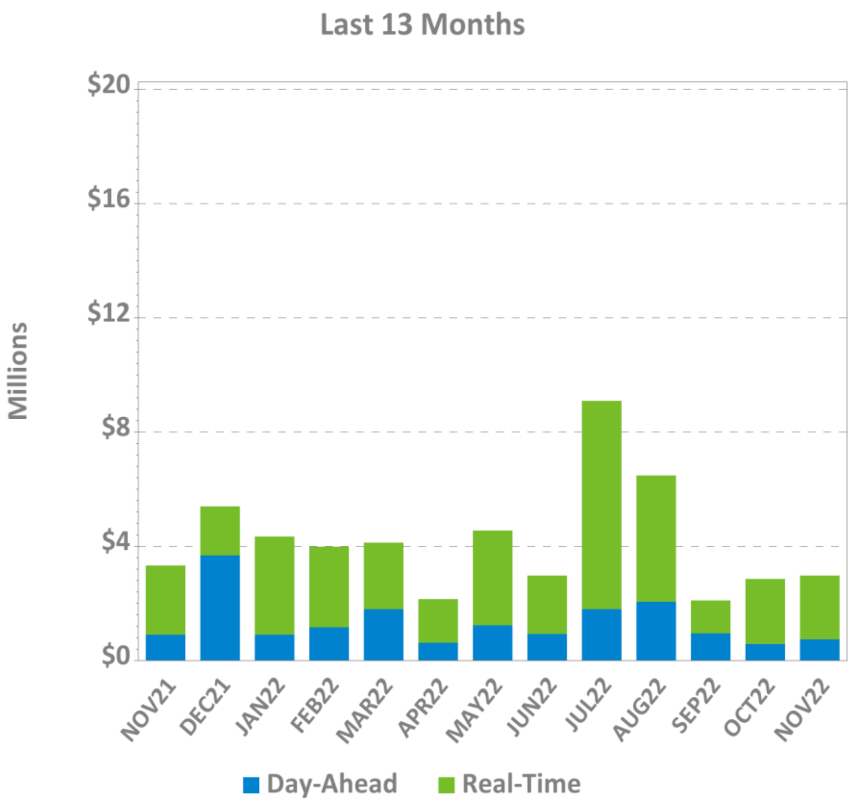




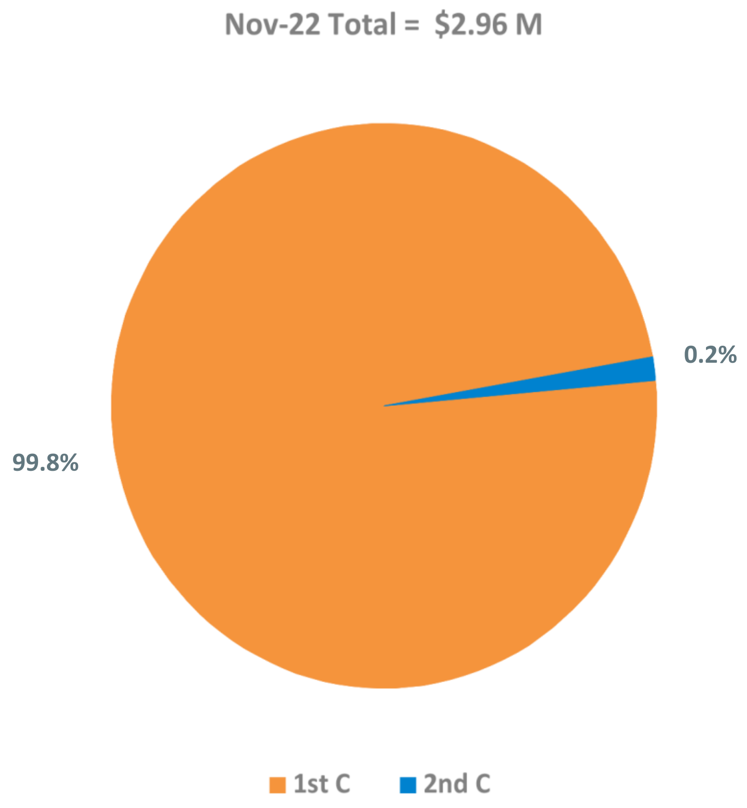
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

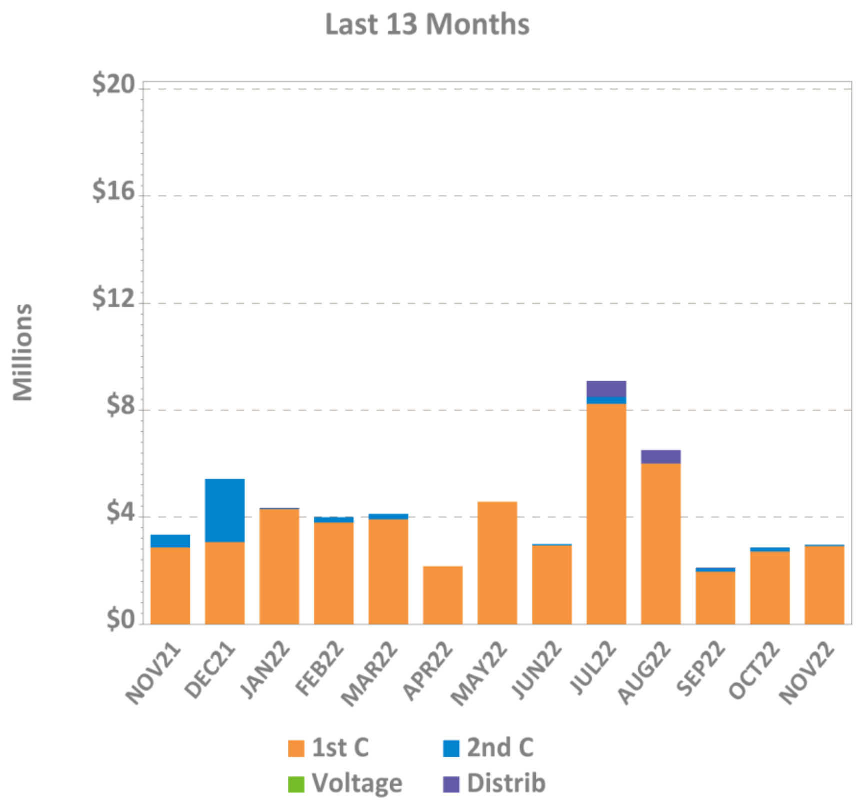
DA and RT NCPC Charges





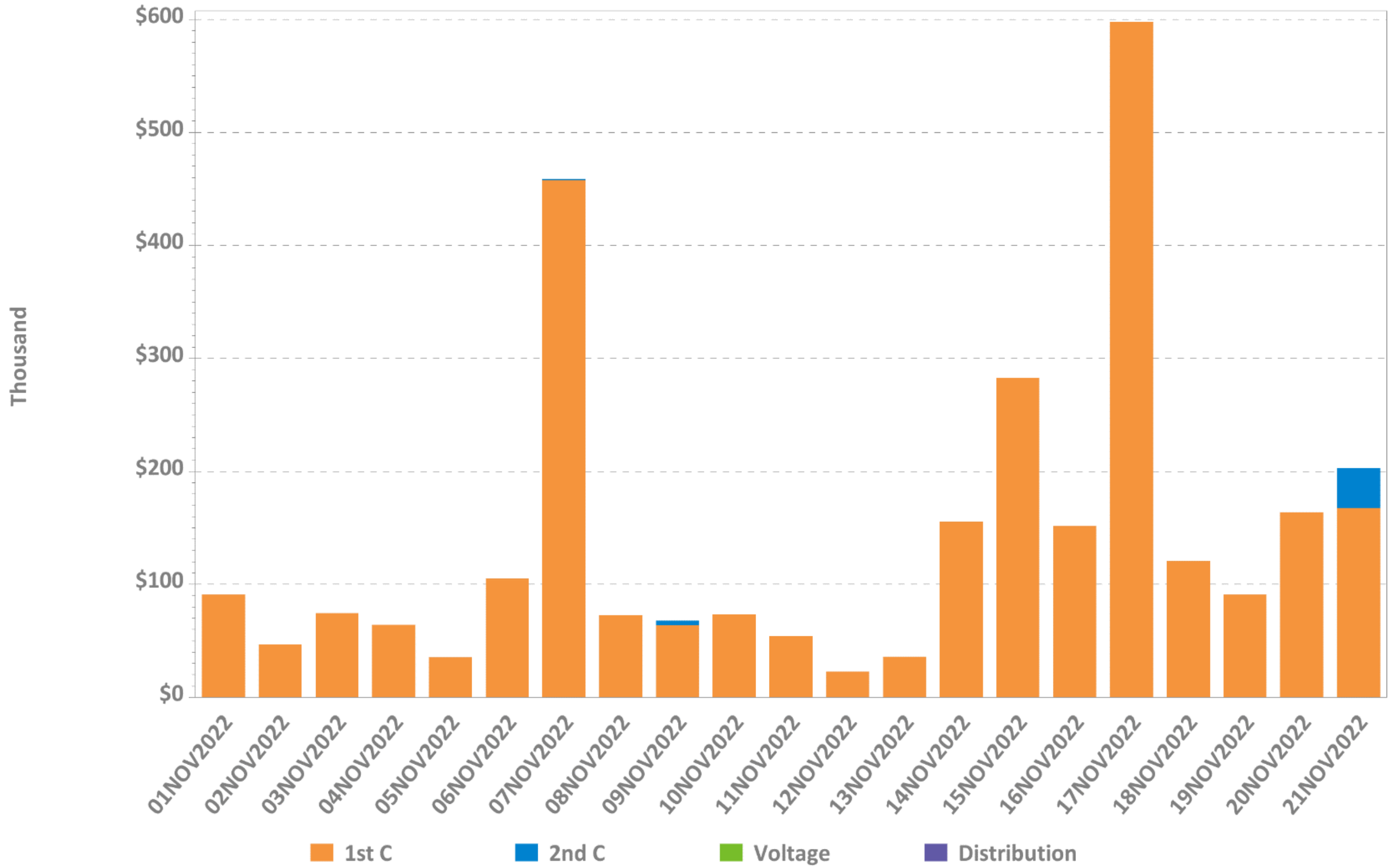
NCPC Charges by Type



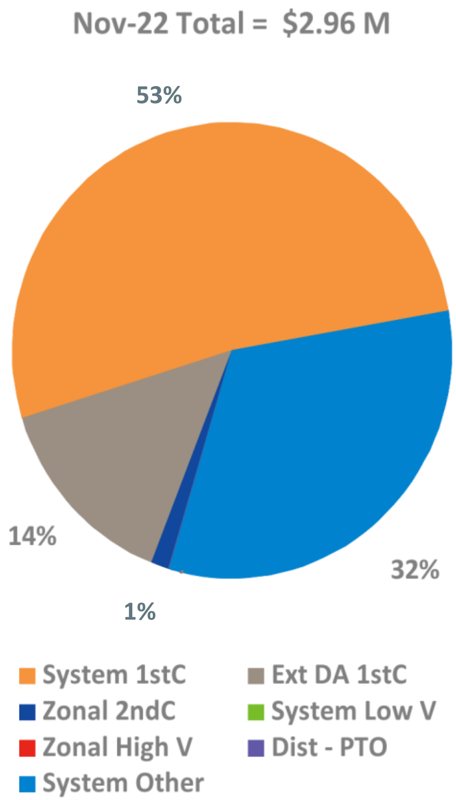


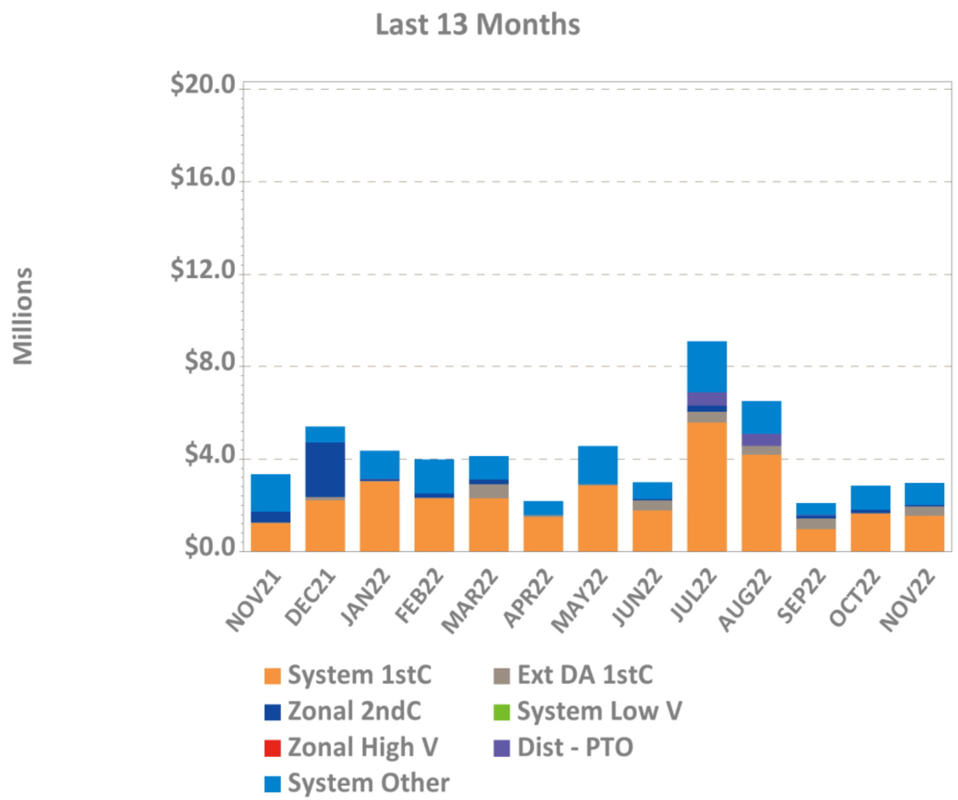
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



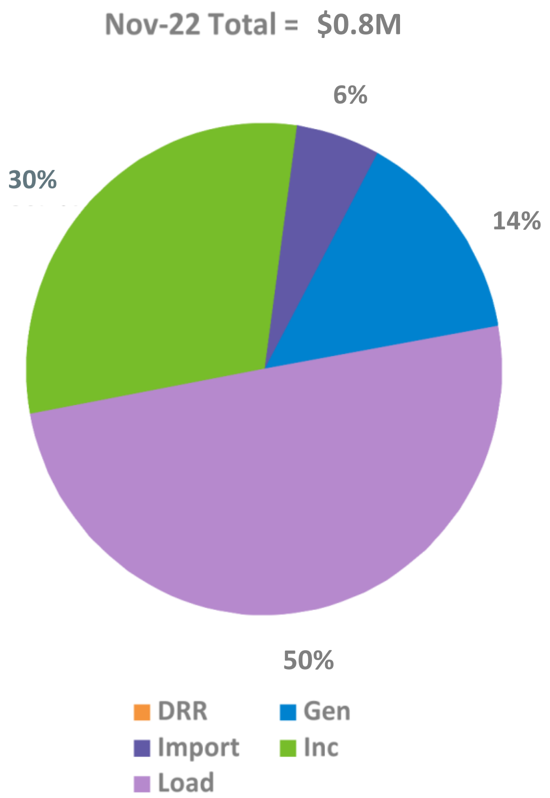
NCPC Charges by Allocation

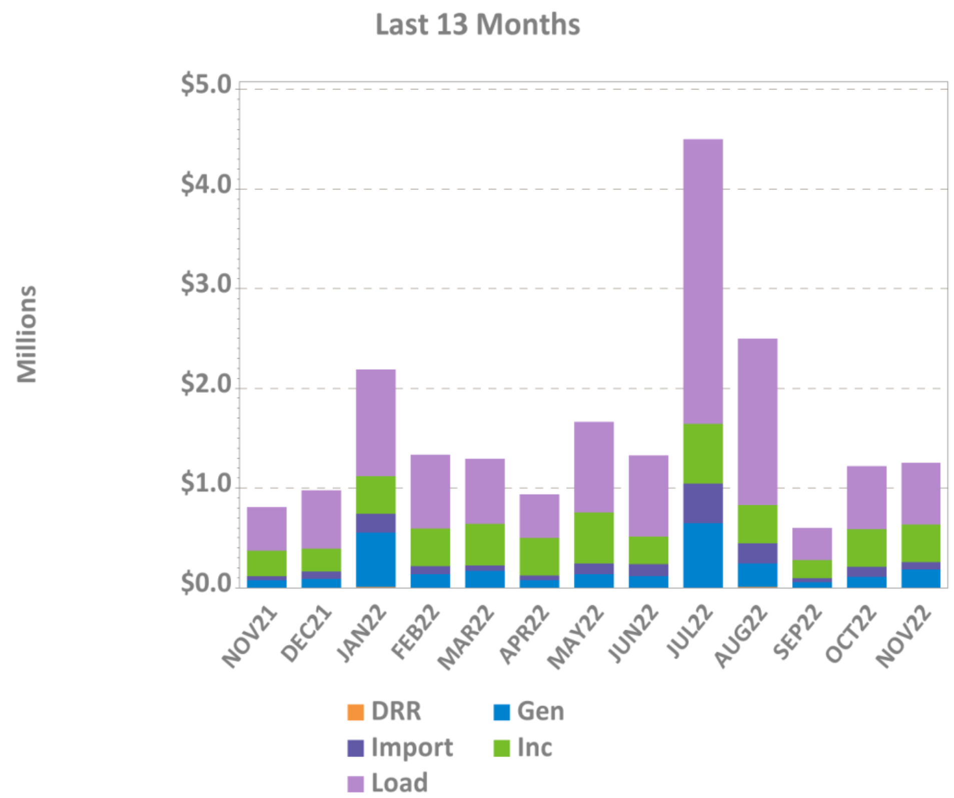




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

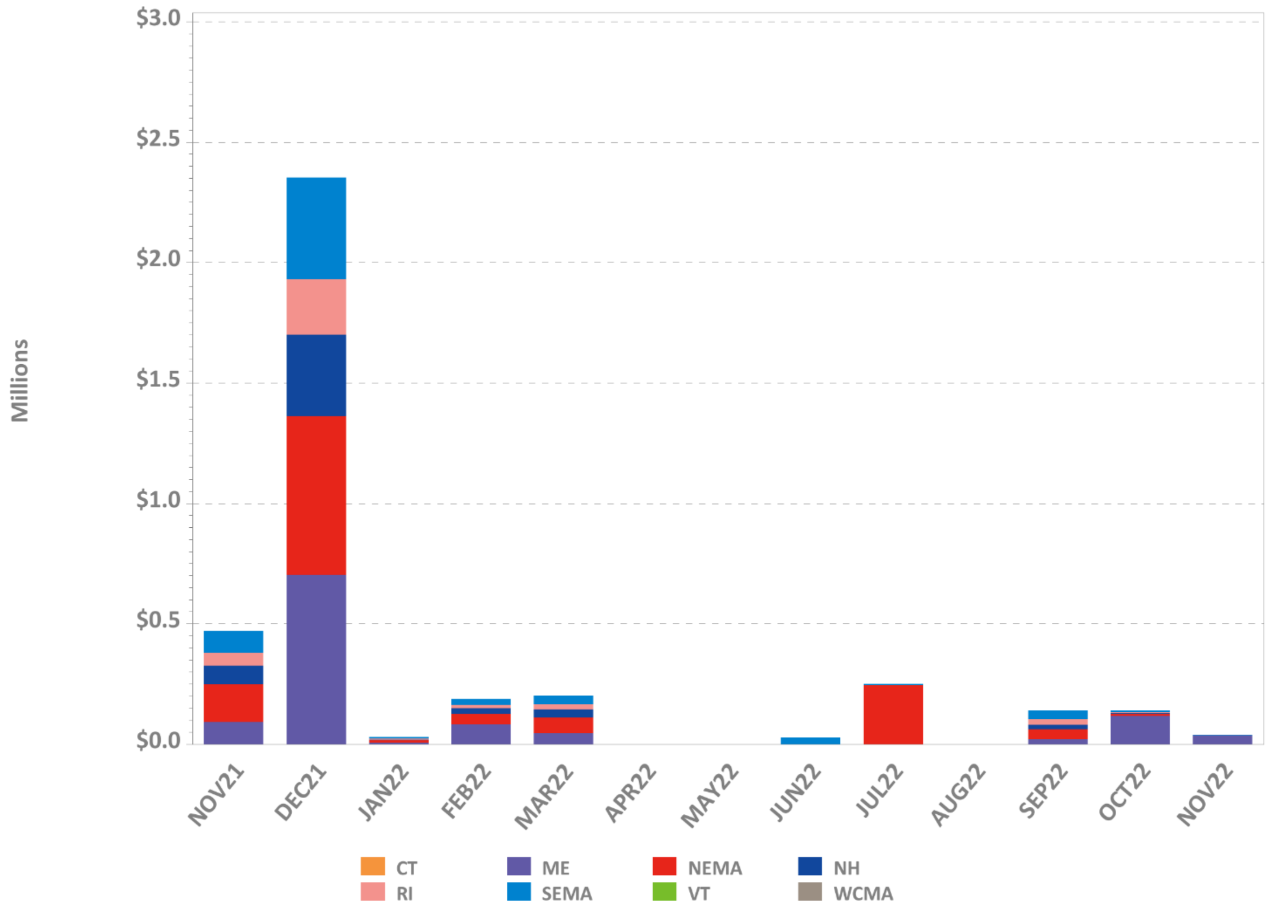
RT First Contingency Charges by Deviation Type





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

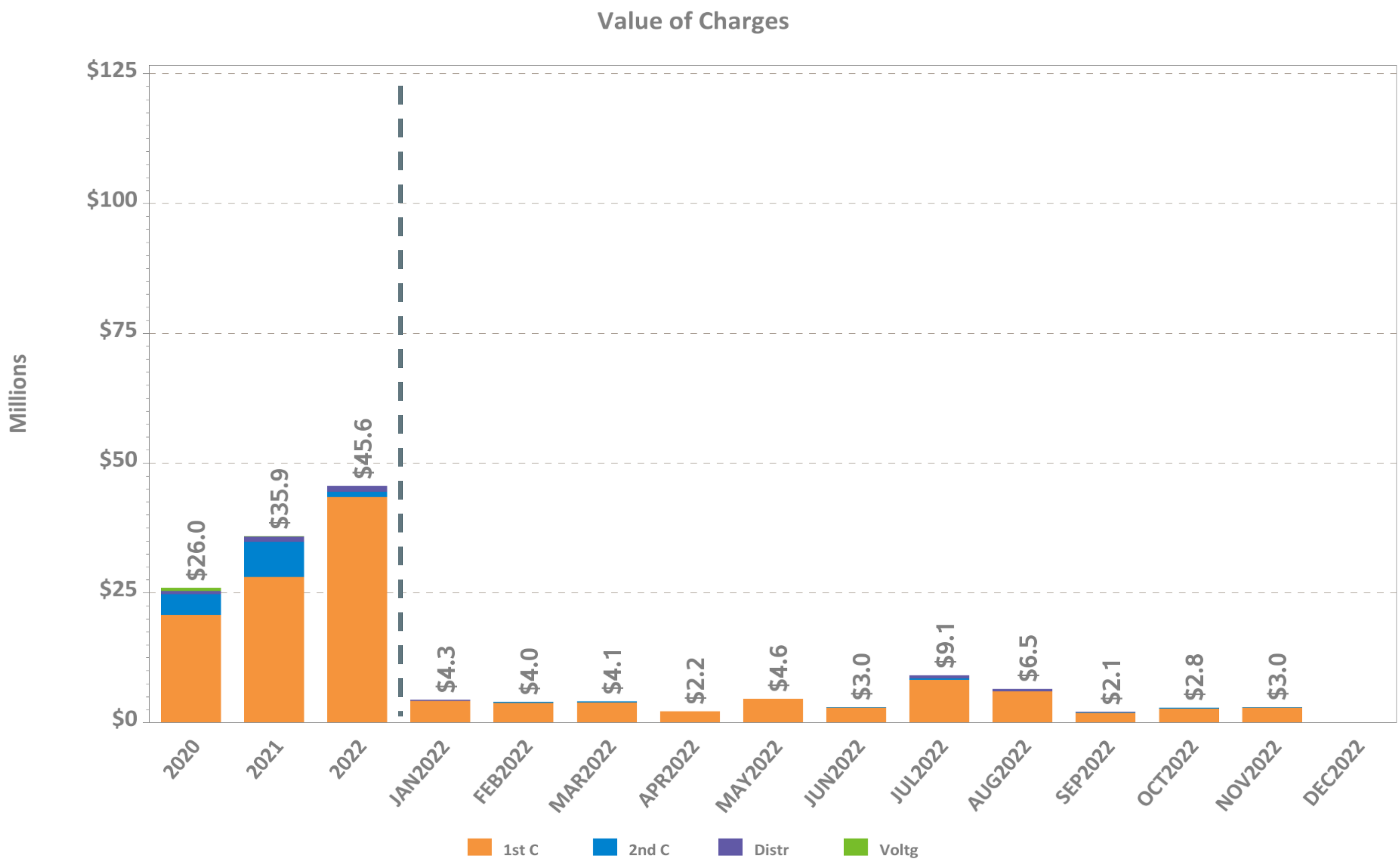
LSCPR Charges by Reliability Region



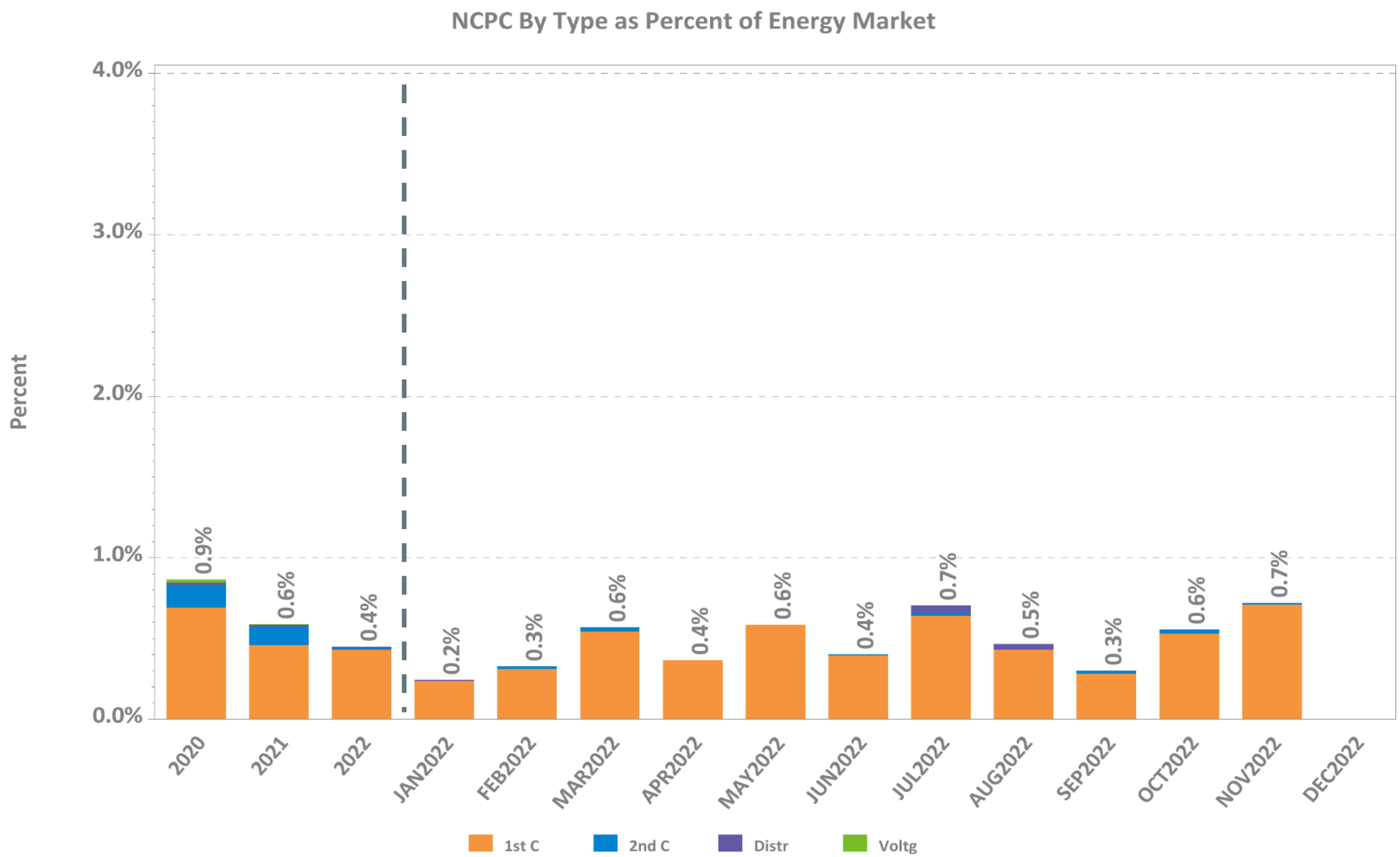
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

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

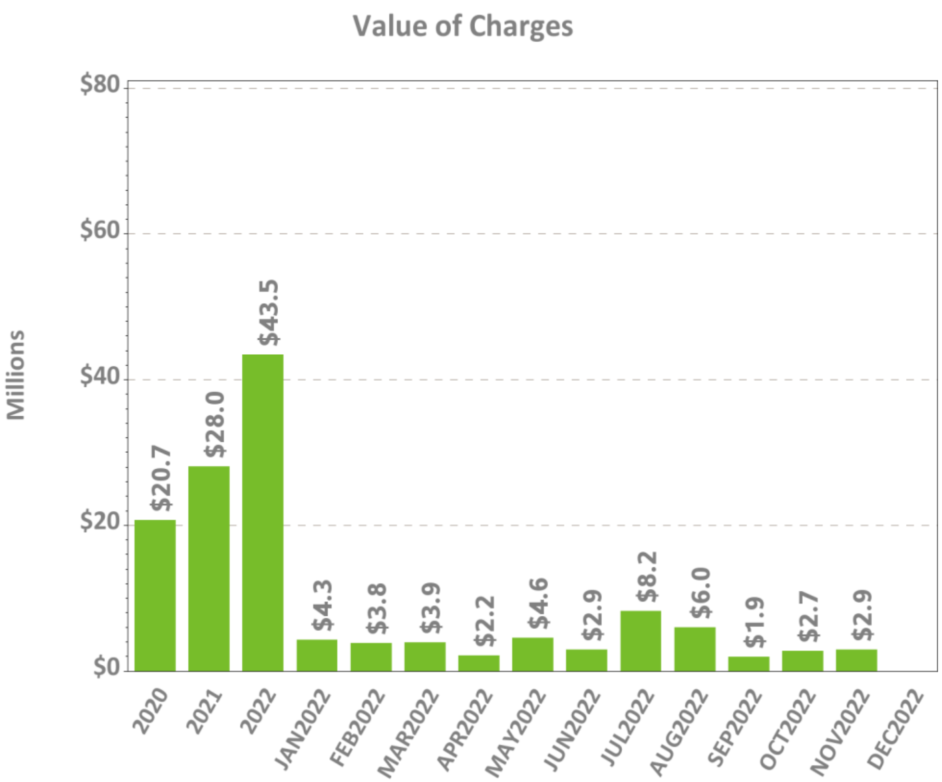
NCPC Charges by Type

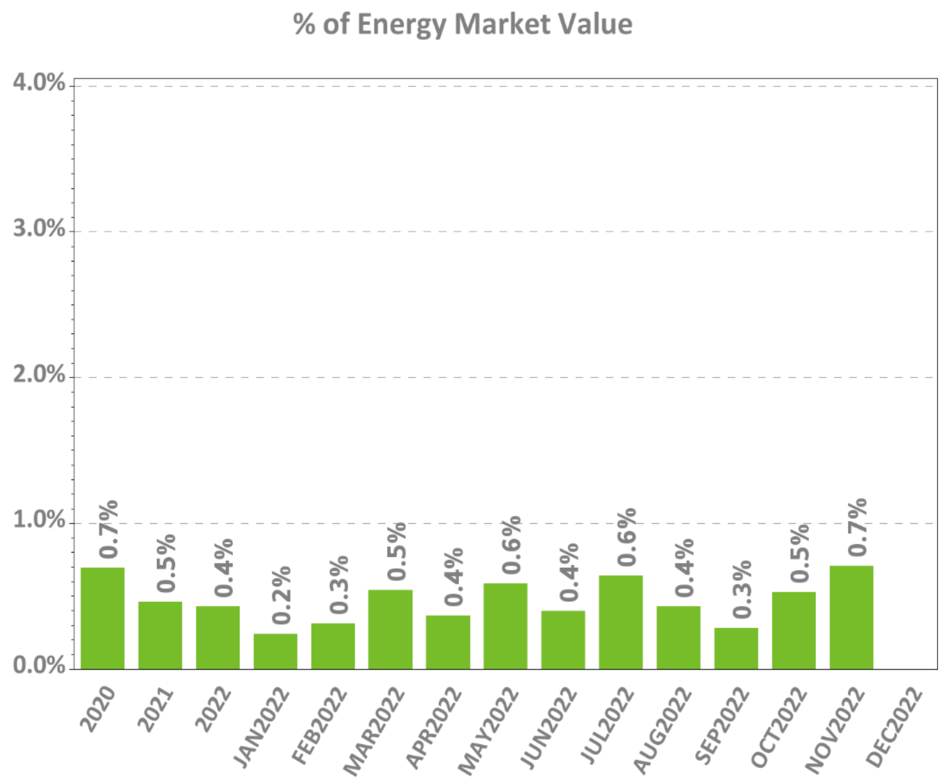


NCPC Charges as Percent of Energy Market



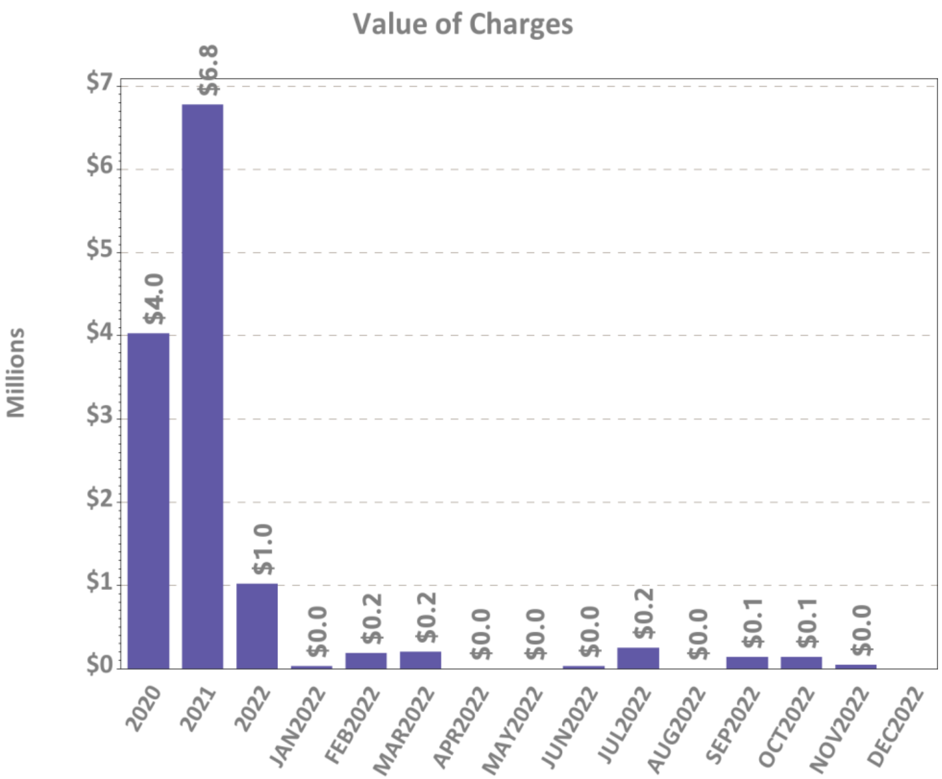
First Contingency NCPC Charges

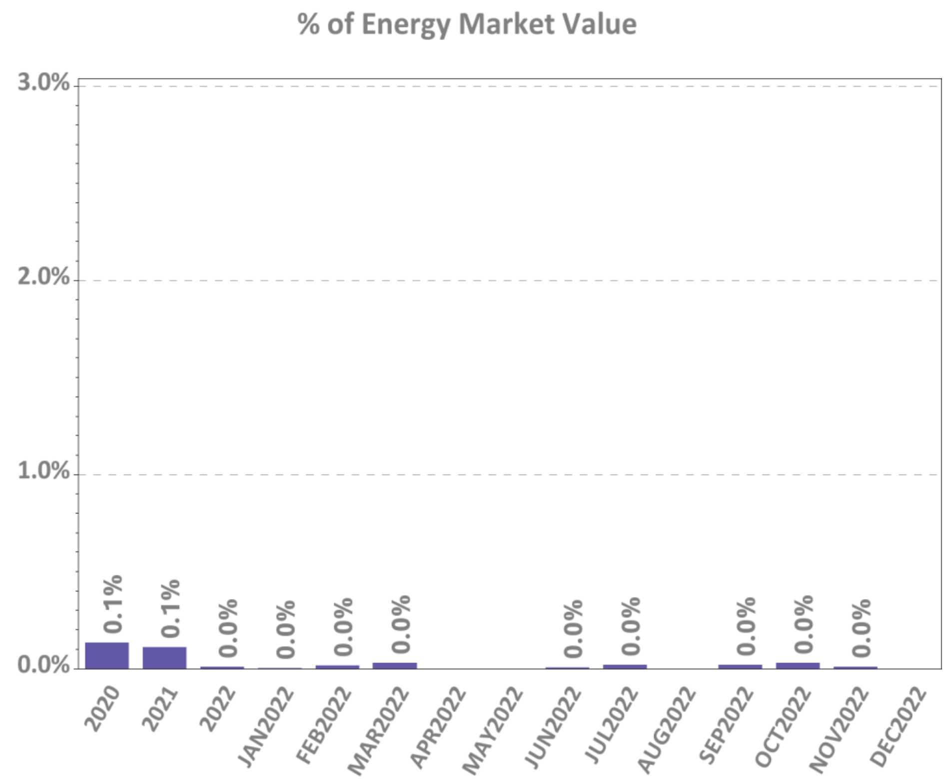




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

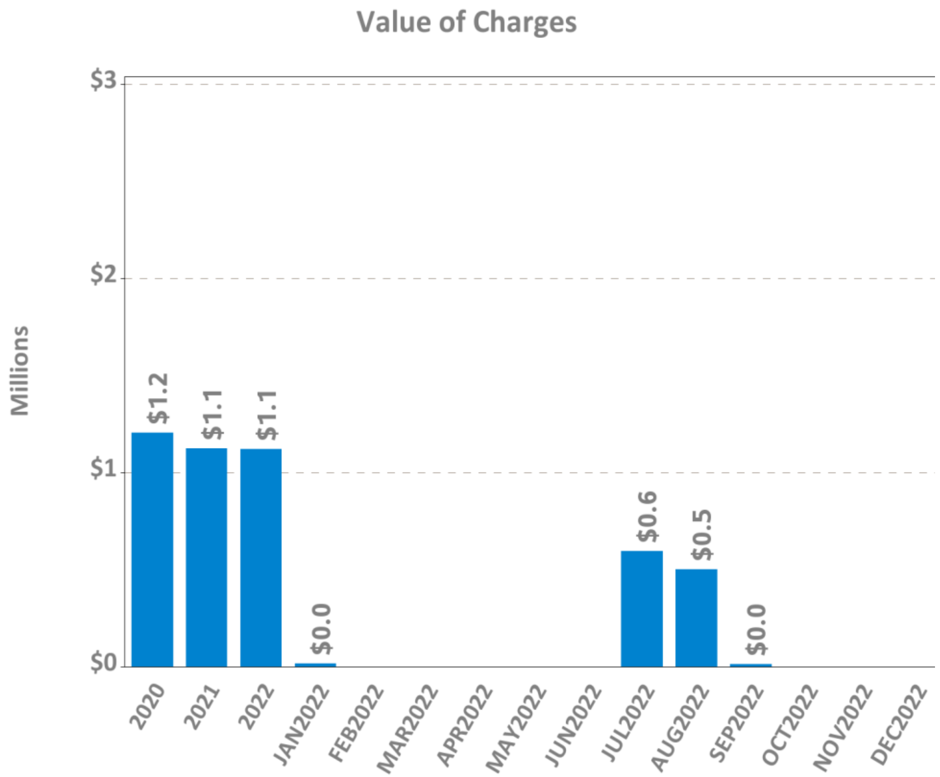
Second Contingency NCPC Charges

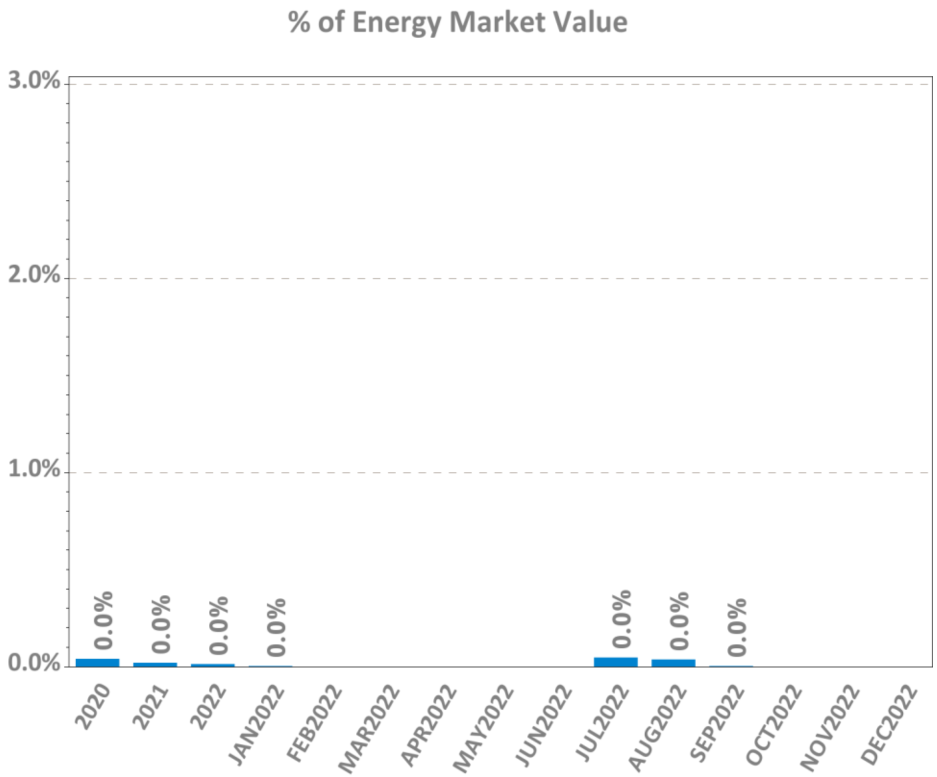




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

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

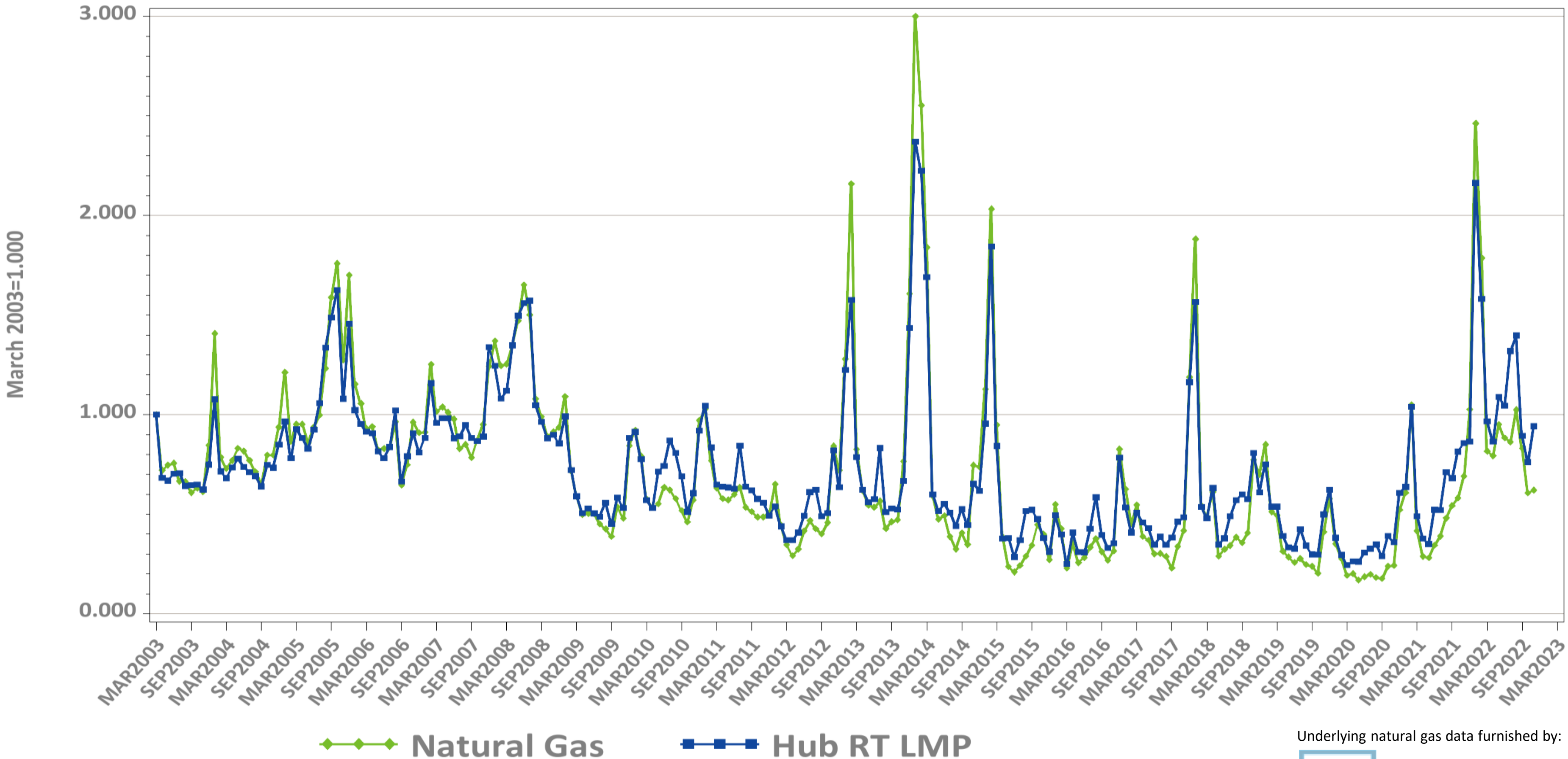
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 2020	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$23.62	$22.59	$23.27	$23.50	$22.76	$23.27	$23.57	$23.30	$23.32
Real-Time	$23.62	$22.91	$23.23	$23.54	$22.90	$23.29	$23.56	$23.37	$23.38
RT Delta %	0.0%	1.4%	-0.2%	0.2%	0.6%	0.1%	-0.1%	0.3%	0.3%
Year 2021	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$46.54	$44.60	$45.52	$46.27	$45.05	$45.88	$46.38	$45.91	$45.92
Real-Time	$45.25	$43.97	$44.28	$45.10	$44.15	$44.61	$45.09	$44.85	$44.84
RT Delta %	-2.8%	-1.4%	-2.7%	-2.5%	-2.0%	-2.8%	-2.8%	-2.3%	-2.3%

November-21	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$57.75	$54.51	$56.46	$57.51	$55.40	$56.54	$57.33	$56.69	$56.69
Real-Time	$59.47	$57.31	$58.30	$59.39	$57.93	$58.25	$59.04	$58.87	$58.83
RT Delta %	3.0%	5.1%	3.3%	3.3%	4.6%	3.0%	3.0%	3.8%	3.8%
November-22	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$56.89	$55.60	$55.81	$56.94	$56.07	$56.10	$56.77	$56.82	$56.62
Real-Time	$65.06	$63.25	$63.70	$65.16	$64.37	$64.14	$64.91	$64.86	$64.69
RT Delta %	14.4%	13.8%	14.1%	14.4%	14.8%	14.3%	14.3%	14.2%	14.3%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	-1.5%	2.0%	-1.2%	-1.0%	1.2%	-0.8%	-1.0%	0.2%	-0.1%
Yr over Yr RT	9.4%	10.4%	9.2%	9.7%	11.1%	10.1%	9.9%	10.2%	10.0%

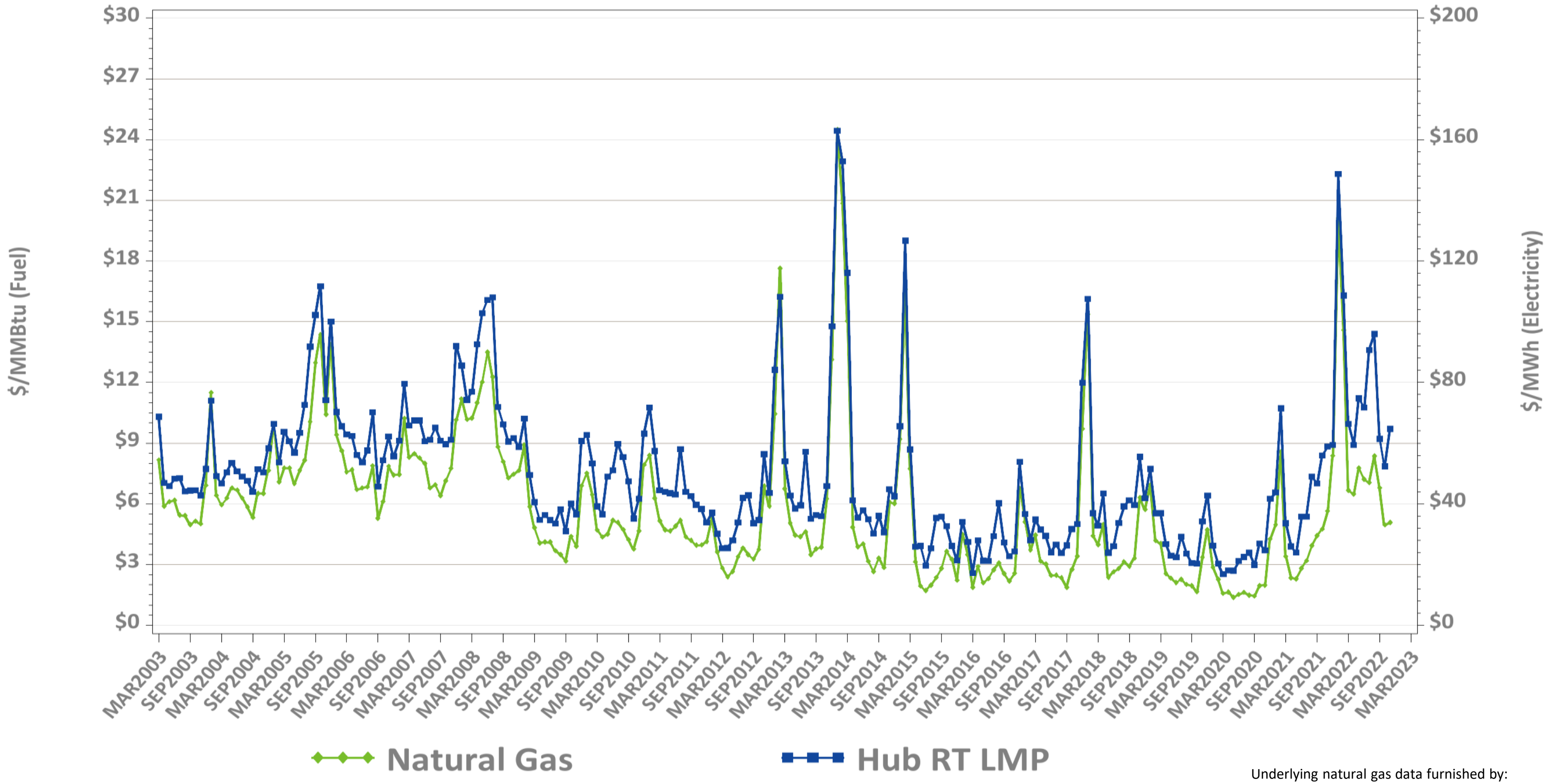
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ice Global markets in clear view

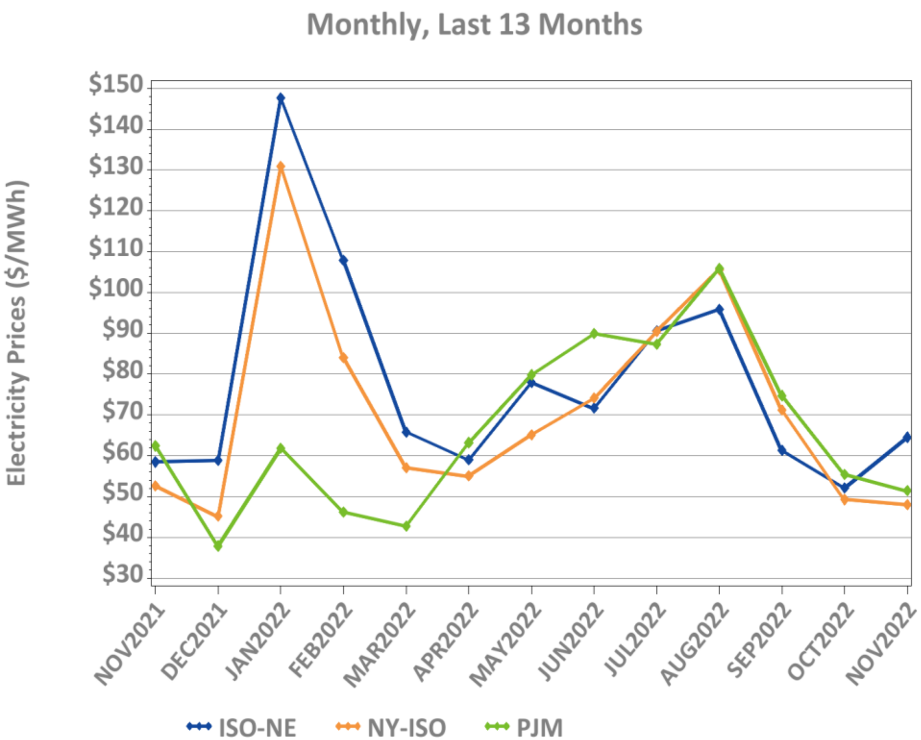
Monthly Average Fuel Price and RT Hub LMP



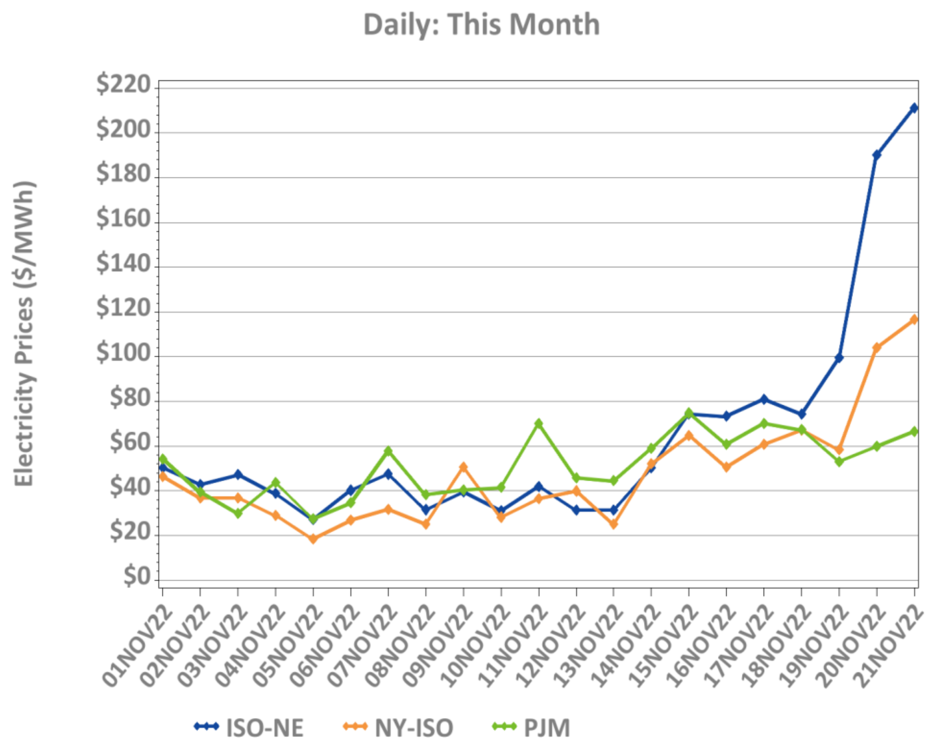
Underlying natural gas data furnished by:

ice Global markets in clear view

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

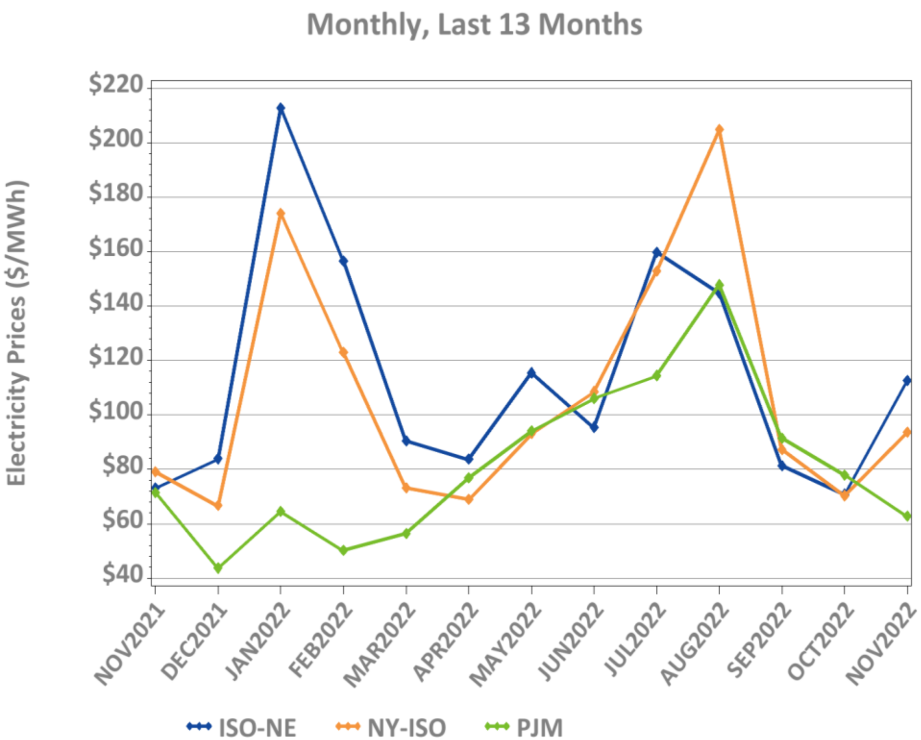


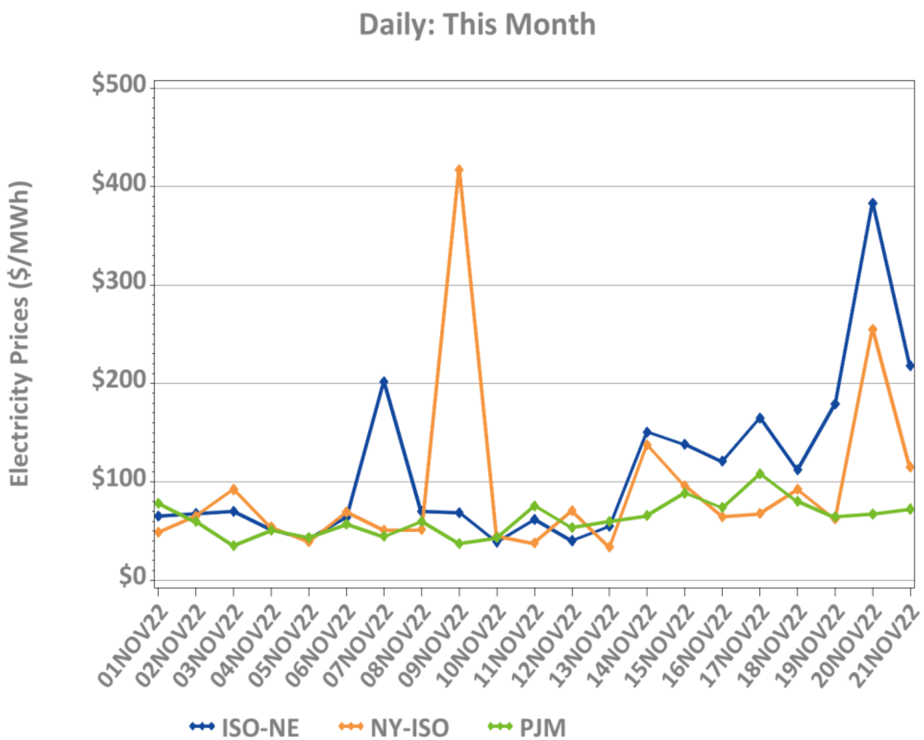
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





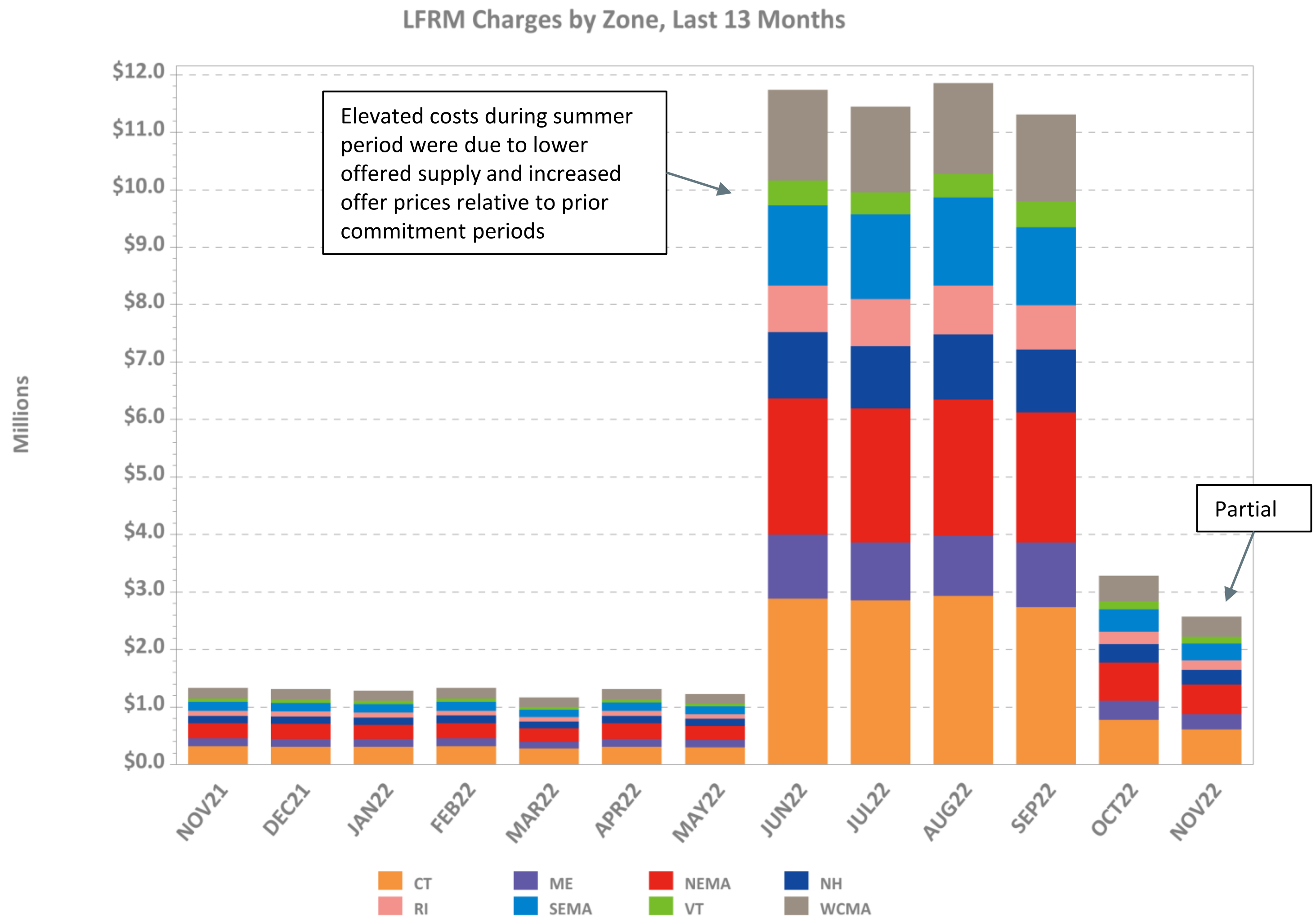
***Forecasted New England daily peak hours reflected**

Reserve Market Results – November 2022

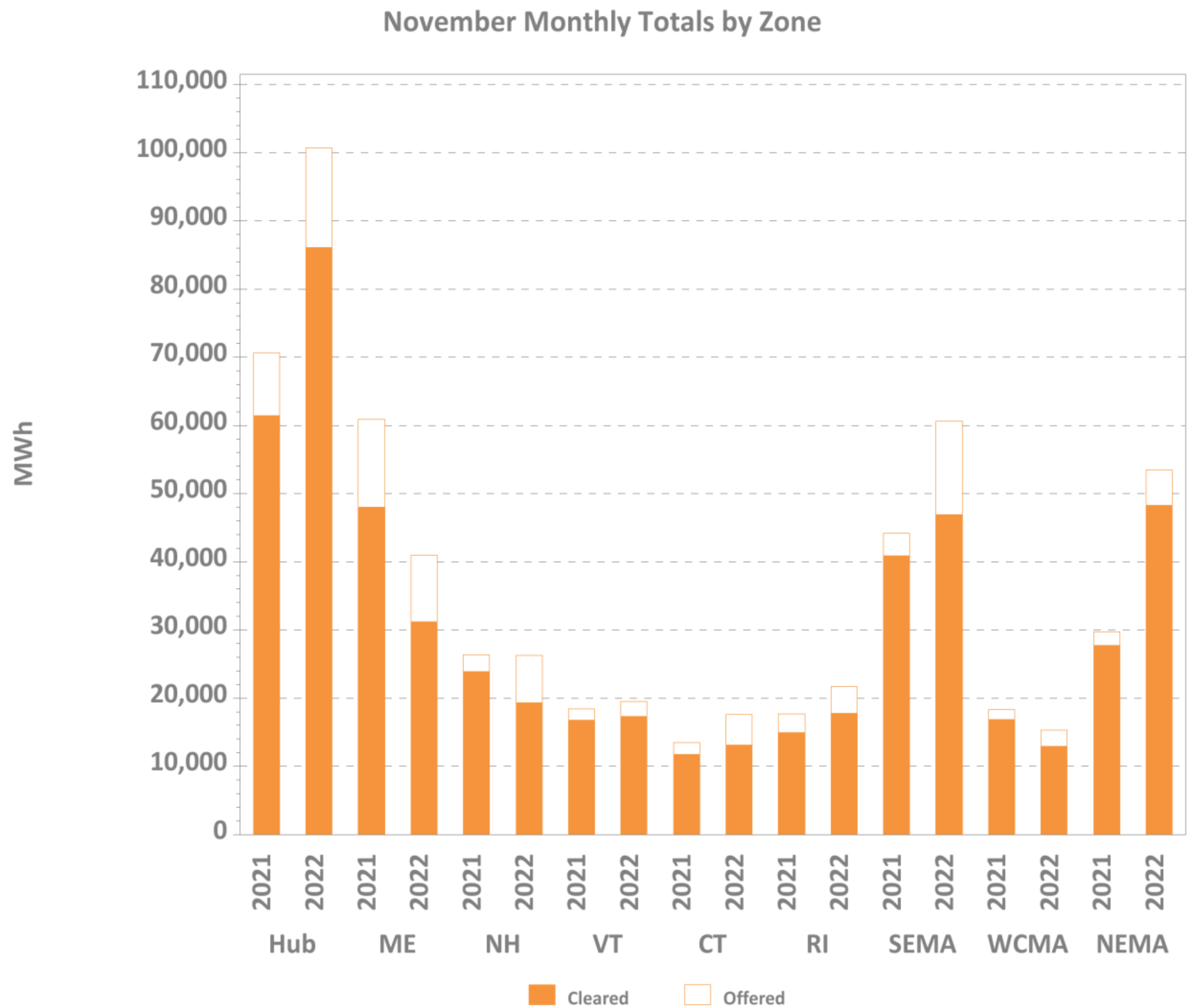
- Maximum potential Forward Reserve Market payments of $2.7M were reduced by credit reductions of $44K, failure-to-reserve penalties of $71K and failure-to-activate penalties of $87, resulting in a net payout of $2.6M or 96% of maximum
  - Rest of System: $1.79M/1.85M (97%)
  - Southwest Connecticut: $0.03M/0.03M (100%)
  - Connecticut: $0.75M/0.8M (94%)
- $563K total Real-Time credits were reduced by $185K in Forward Reserve Energy Obligation Charges for a net of $379K in Real-Time Reserve payments
  - Rest of System: 140 hours, $244K
  - Southwest Connecticut: 140 hours, $89K
  - Connecticut: 140 hours, $29K
  - NEMA: 140 hours, $17K

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.

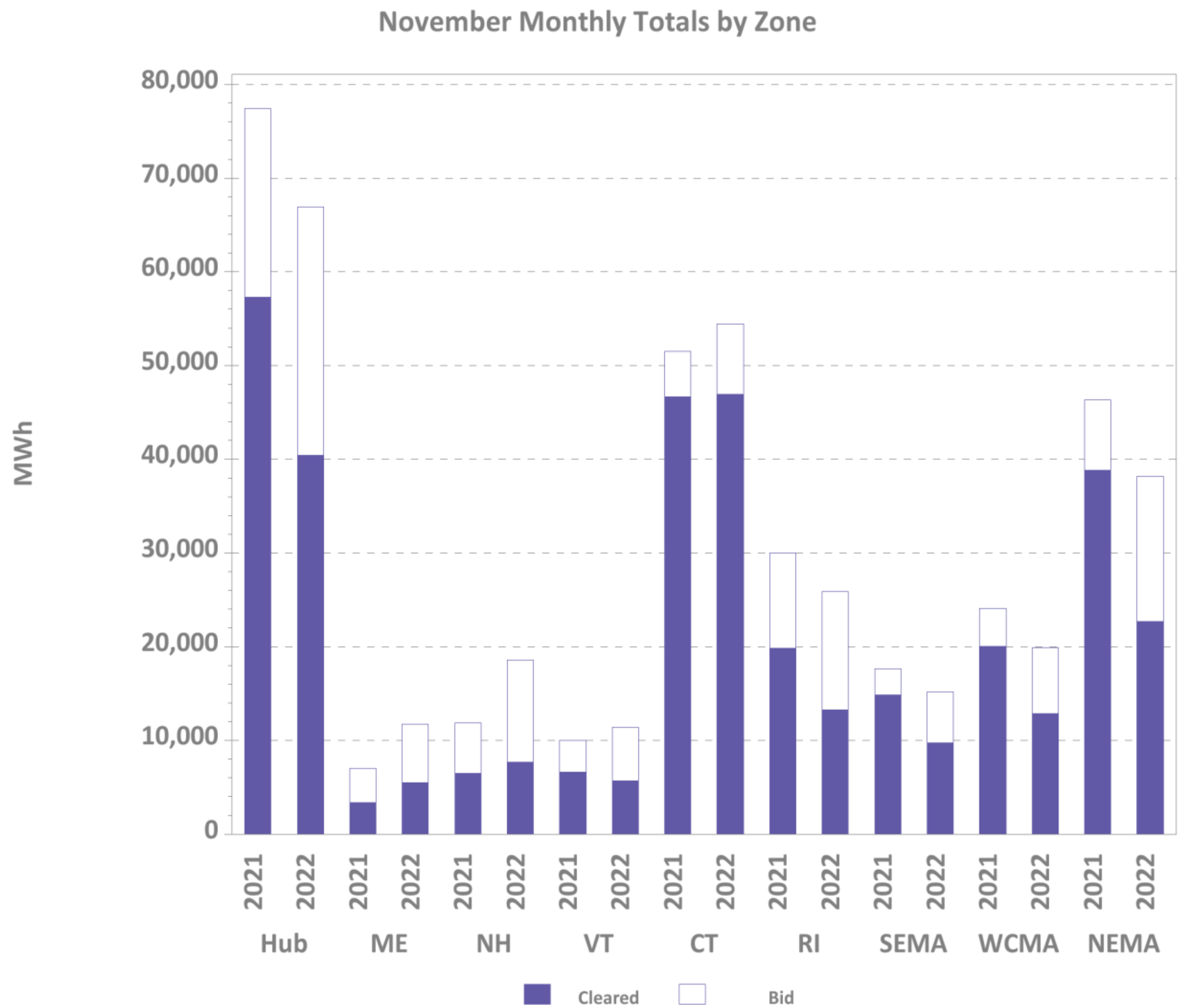
LFRM Charges to Load by Load Zone ($)



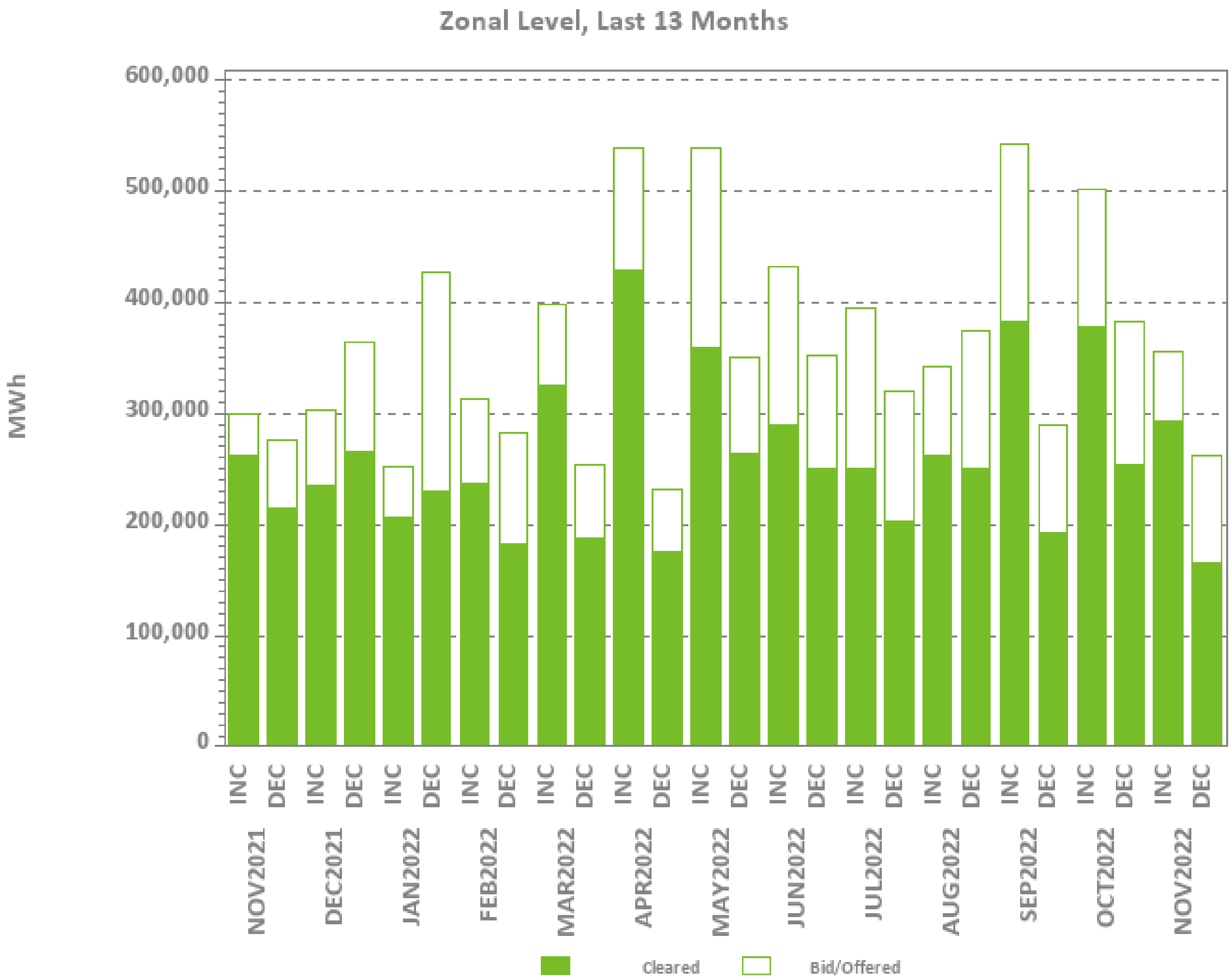
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

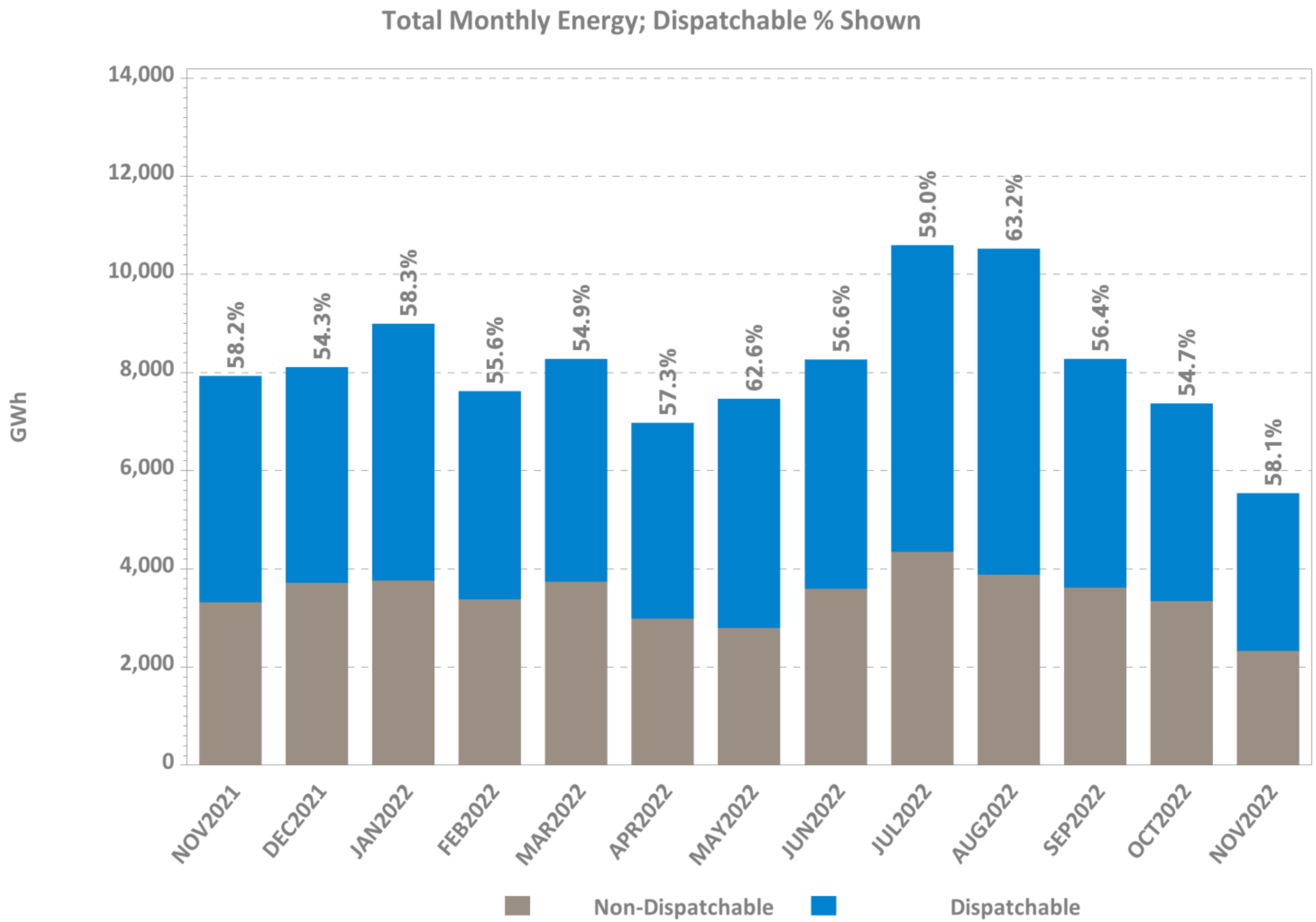


Total Increment Offers and Decrement Bids



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)

- December 13 PAC Meeting Agenda Topics*
  - Asset Condition Projects
    - High Hill Station 644 Control House Replacement (Eversource)
    - CT 115 kV Lattice Tower, Shield Wire and Conductor Replacements (Eversource)
  - Moody's Update
  - 2050 Transmission Study: Solution Development Update
  - Economic Planning for the Clean Energy Transition (EPCET) – Assumptions & Results Part 3
  - Forward Capacity Auction 18 (FCA 18) Capacity Zone Development Preview
  - Boston 2032 Needs Assessment
  - Vermont 2032 Needs Assessment

* 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 (TPCET)

- On 9/24/20, the ISO initiated discussions with the PAC about proposed refinements to transmission planning study assumptions that better reflect long-term trends, such as increased amounts of distributed-energy resources (primarily solar PV), offshore wind generation, and battery energy storage
- A follow-up presentation at the 11/19/20, 12/16/20, and 1/21/21 PAC meetings 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
- Results were discussed at the 6/16/21, 7/22/21, and 8/18/21 PAC meetings
- The ISO published final revisions to the Transmission Planning Technical Guide reflecting these changes on 9/30/21
- CEII supplement to the PAC presentations was released on 10/5/21
- The final TPCET Pilot Study Report was posted to the PAC website on 1/14/22
- Status updates on ongoing transient stability modeling and performance criteria were discussed at the 4/28/22, 5/18/22, 6/15/22, and 8/24/22 PAC meetings; draft changes to the Transmission Planning Technical Guide (TPTG) reflecting assumption changes were discussed at the 11/15/22 PAC meeting; draft revisions to the TPTG are expected to be posted in late November/early December 2022

2050 Transmission Study

- A meeting with the states was held on 10/15/21 to review the draft study scope
- The draft study scope was discussed with the PAC on 11/17/21
- Written stakeholder comments were due on 12/2/21
- ISO worked with NESCOE to address the comments and finalized the scope on 12/22/21
- ISO provided initial results at the 3/16/22 PAC meeting
- Sensitivity results, as well as a high-level approach to solutions development, were discussed at the 4/28/22 PAC meeting
- ISO discussed updated results and the approximate duration of overloads at the 7/20/22 PAC meeting
- ISO is working on solution development and expects to begin initial discussions with the PAC at the 12/13/22 PAC meeting
- Consultant to perform cost estimates has been selected – Electrical Consultants Inc. (ECI)

Economic Studies

- 2021 Economic Study Request
  - Also known as Future Grid Reliability Study – Phase 1 (FGRS)
  - Study proponent is NEPOOL
  - Final report was posted on July 29
  - Draft production cost technical appendix was posted on November 8, and other technical appendices are expected to be posted during Q4 2022
- Economic Planning for the Clean Energy Transition Pilot Study
  - New effort is to review all assumptions in economic planning and perform a test study consistent with the proposed changes to the Tariff
  - Initial scope of work was presented at the April PAC meeting; new modeling features, initial benchmark and market efficiency scenario assumptions and results were presented at the August, October, and upcoming December PAC meetings

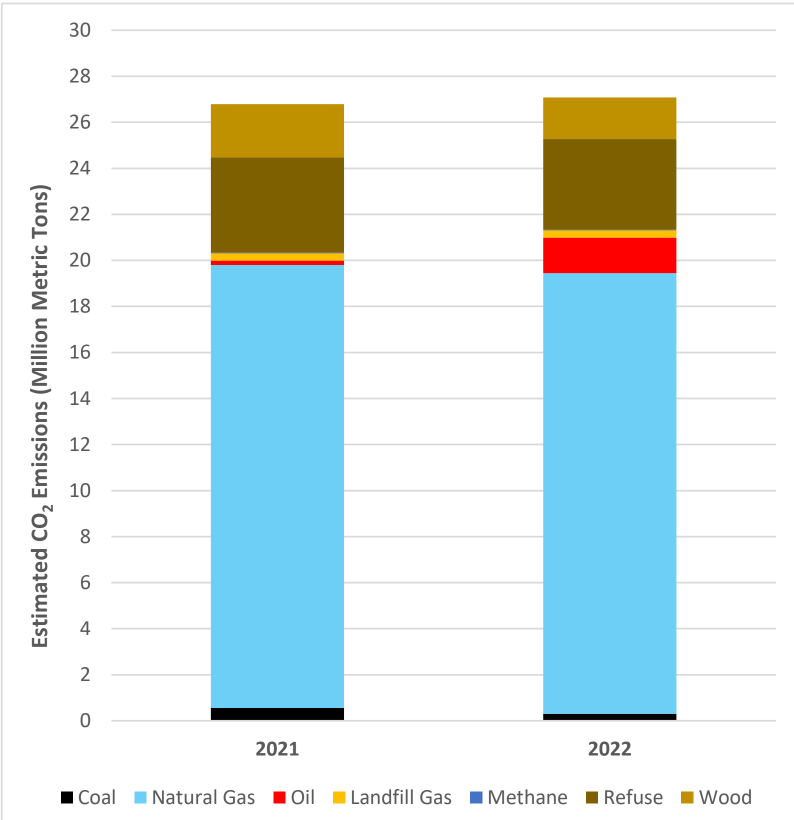
Future Grid Reliability Study (FGRS)

- Phase 1
  - Studies included: Production Cost Simulations; Ancillary Services Simulations; Resource Adequacy Screen; and Probabilistic Resource Availability Analysis
  - Phase 1 work was completed as the 2021 Economic Study
- Phase 2
  - In Phase 2, modeling tools and assumptions from the Pathways and FGRS Phase 1 studies will be used to solve for the set of clean-energy resources that are revenue sufficient and meet the 1-in-10 resource adequacy standard, including for a “preferred pathway” if established
  - Reliability attributes/capabilities of this revenue-sufficient resource mix and any potential reliability “gaps” that remain will be identified
  - High-level outline expected to be shared with stakeholders in January 2023

New England Power System Carbon Emissions

CO_2 emissions Up 1% year to year, reflects January oil-fired generation spike

2021 vs. 2022 New England Power System Estimated Carbon Dioxide (CO_2) Emissions



RGGI Allowance Prices Affected by Factors External to New England

- 11/18/22: RGGI allowance spot price - $13.35 per allowance (1 allowance = 1 short ton CO_2)
- 9/7/22 57th RGGI auction cleared at $13.45
  - Slight decrease in auction price from $13.90 in previous (6/1/22) auction

Data as of 11/13/22

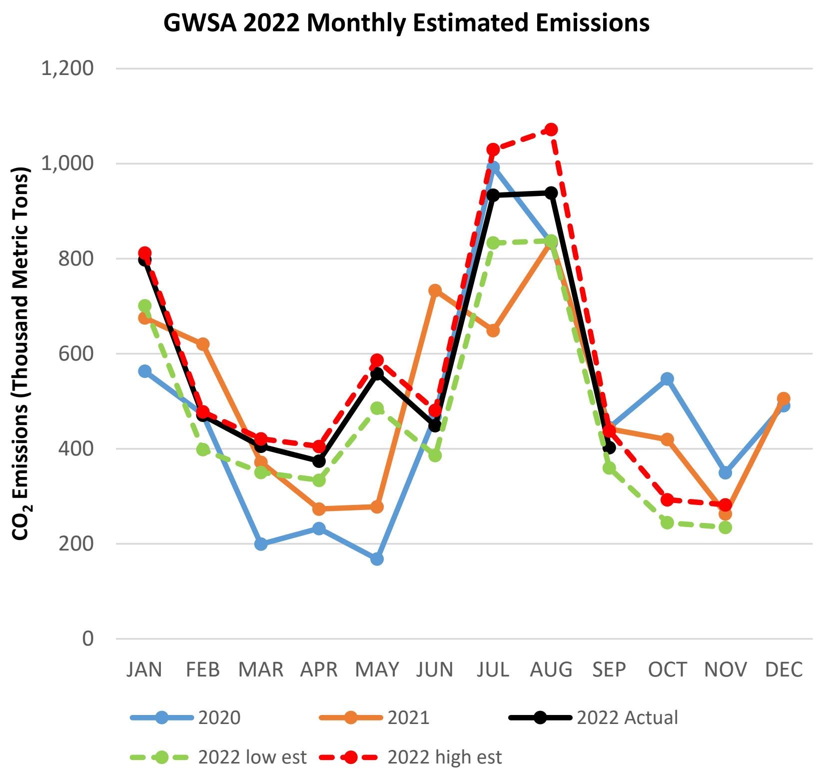
RGGI – Regional Greenhouse Gas Initiative

Massachusetts CO_2 Generator Emissions Cap

2022 Estimated Emissions Under CO_2 Cap

- 11/20/22: 2022 estimated GWSA CO_2 emissions range between 5.2 and 6.3 MMT
  - 64% to 78% of the 8.06 MMT 2022 cap
- 9/14/22 GWSA auction cleared at $14.73; 1.20 million 2022 vintage allowances sold
  - Clearing price was nearly $5 above the previous auction
  - 0.39 million 2023 vintage GWSA allowances were also offered, clearing at $7.51
- 2022 YTD estimated GWSA emissions range between 7% lower and 14% higher than YTD 2021 emissions

2020-2022 Estimated Monthly Emissions (Thousand Metric tons)



GWSA – Global Warming Solutions Act
MMT – Million Metric Tons

Sources: ISO-NE (estimated emissions); EPA (actual emissions)

RSP Project Stage Descriptions

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

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

Greater Boston Projects

Status as of 11/18/2022

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1213, 1220, 1365	Install new 345 kV line from Scobie to Tewksbury	Dec-17	4
1527, 1528	Reconductor the Y-151 115 kV line from Dracut Junction to Power Street	Apr-17	4
1212, 1549	Reconductor the M-139 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
1549	Reconductor the N-140 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
1260	Reconductor the F-158N 115 kV line from Wakefield Junction to Maplewood and associated work at Maplewood	Dec-15	4
1550	Reconductor the F-158S 115 kV line from Maplewood to Everett	Jun-19	4
1551, 1552	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*	Dec-23	3*
1329	Refurbish X-24 69 kV line from Millbury to Northboro Road	Dec-15	4
1327	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 11/18/2022

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1330	Separate X-24 and E-157W DCT	Dec-18	4
1363	Separate Q-169 and F-158N DCT	Dec-15	4
1637, 1640	Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap	May-17	4
1516	Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook	Sep-20	4
965	Install third 115 kV line from West Walpole to Holbrook	Sep-20	4
1558	Install new 345 kV breaker in series with the 104 breaker at Stoughton	May-16	4
1199	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
1335	Install a new 115 kV line from Sudbury to Hudson	Dec-23	2

Greater Boston Projects, cont.

Status as of 11/18/2022

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1336	Replace 345/115 kV autotransformer, 345 kV breakers, and 115 kV switchgear at Woburn	Dec-19	4
1553	Install a 345 kV breaker in series with breaker 104 at Woburn	Jun-17	4
1337	Reconfigure Waltham by relocating PARs, 282-507 line, and a breaker	Dec-17	4
1339	Upgrade 533-508 115 kV line from Lexington to Hartwell and associated work at the stations	Aug-16	4
1521	Install a new 115 kV 54 MVAR capacitor bank at Newton	Dec-16	4
1522	Install a new 115 kV 36.7 MVAR capacitor bank at Sudbury	May-17	4
1352	Install a second Mystic 345/115 kV autotransformer and reconfigure the bus	May-19	4
1353	Install a 115 kV breaker on the East bus at K Street	Jun-16	4
1354, 1738	Install 115 kV cable from Mystic to Chelsea and upgrade Chelsea 115 kV station to BPS standards	Jul-21	4
1355	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	4

Greater Boston Projects, cont.

Status as of 11/18/2022

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1356	Install a second 115 kV cable from Mystic to Woburn to create a bifurcated 211-514 line	Dec-23	3
1357	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
1518	Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard	Mar-19	4
1519	Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-16	4

Greater Boston Projects, cont.

Status as of 11/18/2022

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1520	Upgrade North Cambridge to mitigate 115 kV 5 and 10 stuck breaker contingencies	Dec-17	4
1643	Install a 200 MVAR STATCOM at Coopers Mills	Nov-18	4
1341, 1645	Install a 115 kV 36.7 MVAR capacitor bank at Hartwell	May-17	4
1646	Install a 345 kV 160 MVAR shunt reactor at K Street	Dec-19	4
1647	Install a 115 kV breaker in series with the 5 breaker at Framingham	Mar-17	4
1554	Install a 115 kV breaker in series with the 29 breaker at K Street	Apr-17	4

SEMA/RI Reliability Projects

Status as of 11/18/2022

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

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

SEMA/RI Reliability Projects, cont.

Status as of 11/18/2022 *Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area*

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1718	Add 115 kV circuit breaker at Robinson Ave substation and re-terminate the Q10 line	Mar-22	4
1719	Install 45.0 MVAR capacitor bank at Berry Street substation	Cancelled*	N/A
1720	Separate the N12/M13 DCT and reconductor the N12 and M13 between Somerset and Bell Rock substations	May-25	2
1721	Reconfigure Bell Rock to breaker-and-a-half station, split the M13 line at Bell Rock substation, and terminate 114 line at Bell Rock; install a new breaker in series with N12/D21 tie breaker, upgrade D21 line switch, and install a 37.5 MVAR capacitor	Dec-23	3
1722	Extend the Line 114 from the Dartmouth town line (Eversource-National Grid border) to Bell Rock substation	Dec-24	2
1723	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 11/18/2022

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1725	Build a new 115 kV line from Bourne to West Barnstable substations which includes associated terminal work	May-24	1
1726	Separate the 135/122 DCT from West Barnstable to Barnstable substations	Dec-21	4
1727	Retire the Barnstable SPS	Nov-21	4
1728	Build a new 115 kV line from Carver to Kingston substations and add a new Carver terminal	Jun-23	3
1729	Install a new bay position at Kingston substation to accommodate new 115 kV line	Jun-23	3
1730	Extend the 114 line from the Eversource/National Grid border to the Industrial Park Tap	Dec-24	1

SEMA/RI Reliability Projects, cont.

Status as of 11/18/2022

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1731	Install 35.3 MVAR capacitors at High Hill and Wing Lane substations	Dec-21	4
1732	Loop the 201-502 line into the Medway substation to form the 201-502N and 201-502S lines	Dec-25	3
1733	Separate the 325/344 DCT lines from West Medway to West Walpole substations	Cancelled**	N/A
1734	Reconductor and upgrade the 112 Line from the Tremont substation to the Industrial Tap	Jun-18	4
1736	Reconductor the 108 line from Bourne substation to Horse Pond Tap*	Oct-18	4
1737	Replace disconnect switches on 323 line at West Medway substation and replace 8 line structures	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 11/18/2022

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1741	Rebuild the Middleborough Gas and Electric portion of the E1 line from Bridgewater to Middleborough	Apr-19	4
1782	Reconductor the J16S line	May 22	4
1724	Replace the Kent County 345/115 kV transformer	Mar-22	4
1789	West Medway 345 kV circuit breaker upgrades	Apr-21	4
1790	Medway 115 kV circuit breaker replacements	Nov-20	4

Eastern CT Reliability Projects

Status as of 11/18/2022

Project Benefit: Addresses system needs in the Eastern Connecticut area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1815	Reconductor the L190-4 and L190-5 line sections	Dec-24	2
1850	Install a second 345/115 kV autotransformer (4X) and one 345 kV breaker at Card substation	Mar-23	3
1851	Upgrade Card 115 kV to BPS standards	Mar-23	3
1852	Install one 115 kV circuit breaker in series with Card substation 4T	Mar-23	3
1853	Convert Gales Ferry substation from 69 kV to 115 kV	Dec-23	3
1854	Rebuild the 100 Line from Montville to Gales Ferry to allow operation at 115 kV	Jun-23	3

Eastern CT Reliability Projects, cont.

Status as of 11/18/2022

Project Benefit: Addresses system needs in the Eastern Connecticut area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1855	Re-terminate the 100 Line at Montville station and associated work. Energize the 100 Line at 115 kV	Dec-23	3
1856	Rebuild 400-1 Line section to allow operation at 115 kV (Tunnel to Ledyard Jct.)	Dec-22	3
1857	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	3
1858	Rebuild 400-2 Line section to allow operation at 115 kV (Ledyard Jct. to Border Bus with CMEEC)	Dec-22	3
1859	Rebuild the 400-3 Line Section to allow operation at 115 kV (Gales Ferry to Ledyard Jct.)	Dec-22	3
1860	Install a 25.2 MVAR 115 kV capacitor and one capacitor breaker at Killingly	Dec-21	4

Eastern CT Reliability Projects, cont.

Status as of 11/18/2022

Project Benefit: Addresses system needs in the Eastern Connecticut area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1861	Install one 345 kV series breaker with the Montville 1T	Nov-21	4
1862	Install a +55/-29 MVAR synchronous condenser with two 115 kV breakers at Shunock	Dec-23	3
1863	Install a 1% series reactor with bypass switch at Mystic, CT on the 1465 Line	Mar-22	4
1864	Convert the 400-2 Line Section to 115 kV (Border Bus to Buddington)	Dec-23	3
1904	Convert 69 kV equipment at Buddington to 115 kV to facilitate the conversion of the 400-2 line to 115 kV	Dec-23	3

Boston Area Optimized Solution Projects

Status as of 11/18/2022

Project Benefit: Addresses system needs in the Boston area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1874	Install two 11.9 ohm series reactors at North Cambridge Station on Lines 346 and 365	Dec-21	4
1875	Install a direct transfer trip (DTT) scheme between Ward Hill and West Amesbury Substations for Line 394	Apr-22	4
1876	Install one +/- 167 MVAR STATCOM at Tewksbury 345 kV Substation	Oct-23	3

New Hampshire Solution Projects

Status as of 11/18/2022

Project Benefit: Addresses system needs in the New Hampshire area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1878	Install a +55/-32.2 MVAR synchronous condenser at N. Keene 115 kV Substation with a 115 kV breaker	Dec-23	3
1879	Install a +55/-32.2 MVAR synchronous condenser at Huckins Hill 115 kV Substation with a 115 kV breaker	Dec-23	3
1880	Install a +127/-50 MVAR synchronous condenser at Amherst 345 kV Substation with two 345 kV breakers	Dec-23	3
1881	Install two 50 MVAR capacitors on Line 363 near Seabrook Station with three 345 kV breakers	Oct-23	2

Upper Maine Solution Projects

Status as of 11/18/2022

Project Benefit: Addresses system needs in the Upper Maine area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1882	Rebuild 21.7 miles of the existing 115 kV line Section 80 Highland – Coopers Mills 115 kV line	Dec-24	2
1883	Convert the Highland 115 kV substation to an eight breaker, breaker-and-a-half configuration with a bus connected 115/34.5 kV transformer	Dec-27	1
1884	Install a 15 MVAR capacitor at Belfast 115 kV substation	Dec-27	1
1885	Install a +50/-25 MVAR synchronous condenser at Highland 115 kV substation	Dec-27	1
1886	Install +50/-25 MVAR synchronous condenser at Boggy Brook 115 kV substation, and install a new 115 kV breaker to separate Line 67 from the proposed solution elements	Jun-24	2

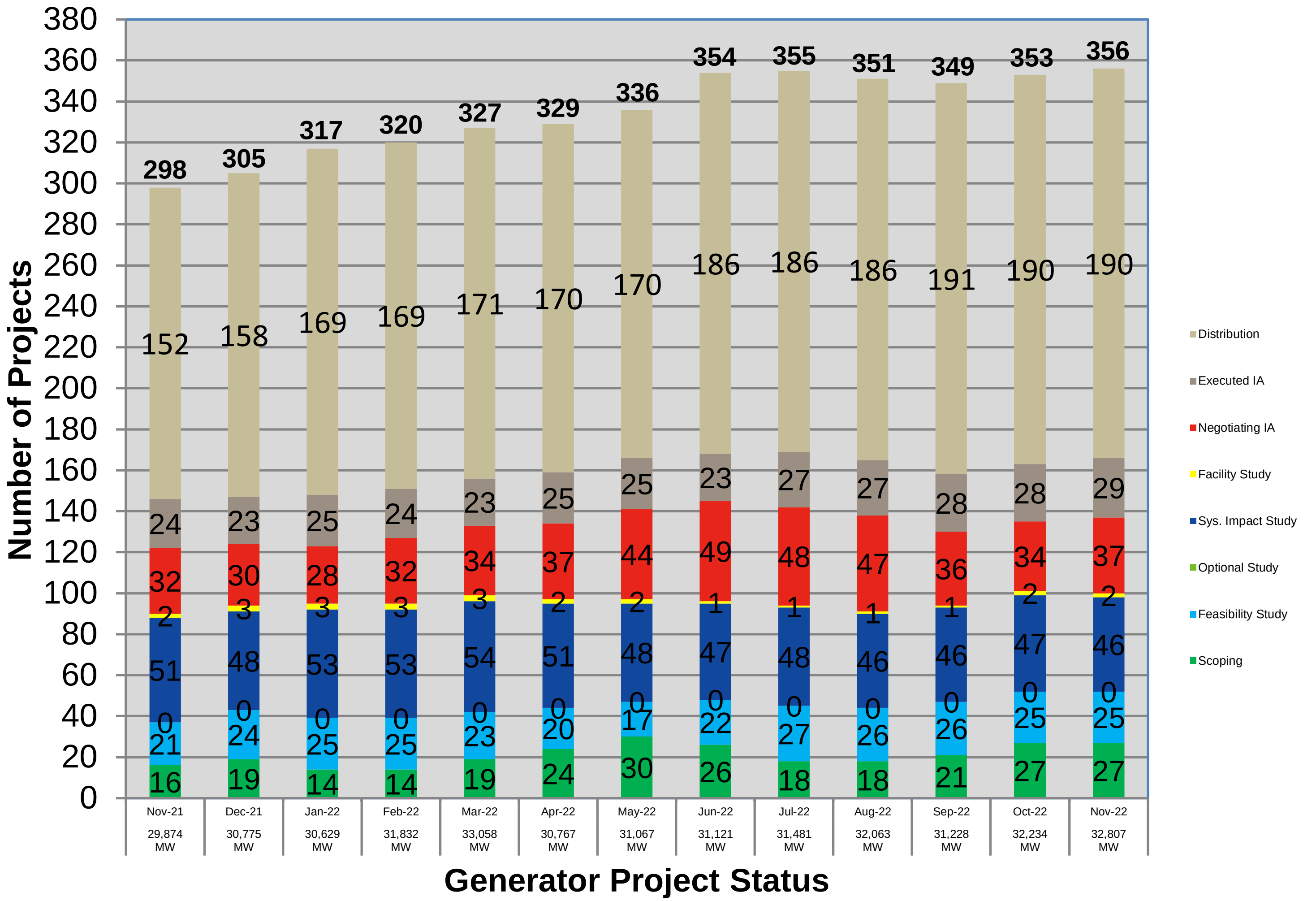
Upper Maine Solution Projects, cont.

Status as of 11/18/2022

Project Benefit: Addresses system needs in the Upper Maine area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1887	Install 25 MVAR reactor at Boggy Brook 115 kV substation	Jun-24	2
1888	Install 10 MVAR reactor at Keene Road 115 kV substation	Jun-24	2
1889	Install three remotely monitored and controlled switches to split the existing Orrington reactors between the two Orrington 345/115 kV autotransformers	Dec-23	2

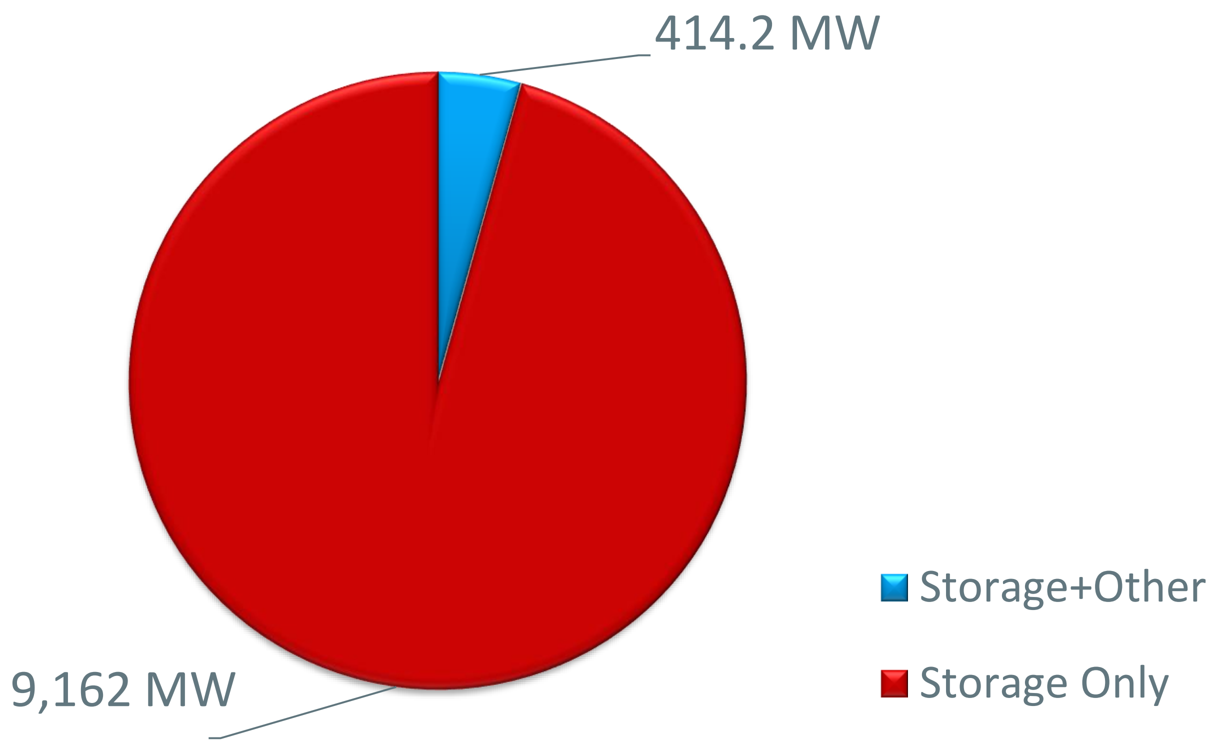
Status of Tariff Studies as of November 16, 2022



Note: November 2022 is based on partial data.
11 ETUs in Scoping, 2 in FS, 0 in SIS, 0 in OIS, 0 in FAC, 2 Negotiating IA, and 3 with Executed IA
Transmission Service Requests needing study: 4 in Scoping and 1 in SIS
https://irtt.iso-ne.com/external.aspx

What is in the Queue (as of November 16, 2022)

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



OPERABLE CAPACITY ANALYSIS

Winter 2022/23 Analysis

Winter 2022/23 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Jan. - 2023[2] CSO (MW)	Jan. - 2023[2] SCC (MW)
Operable Capacity MW [1]	28,257	31,980
Active Demand Capacity Resource (+) [5]	559	405
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,070	1,070
Non Commercial Capacity (+)	60	60
Non Gas-fired Planned Outage MW (-)	128	248
Gas Generator Outages MW (-)	0	125
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	3,735	4,162
Net Capacity (NET OPCAP SUPPLY MW)	23,283	26,180
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,009	20,009
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,314	22,314
Operable Capacity Margin	969	3,866

[1]Operable Capacity is based on data as of **November 21, 2022** 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 **November 21, 2022.**

[2] Load forecast that is based on the 2022 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 7, 2023.**

[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 2022/23 Operable Capacity Analysis

90/10 Load Forecast	Jan. - 2023[2] CSO (MW)	Jan. - 2023[2] SCC (MW)
Operable Capacity MW [1]	28,257	31,980
Active Demand Capacity Resource (+) [5]	559	405
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,070	1,070
Non Commercial Capacity (+)	60	60
Non Gas-fired Planned Outage MW (-)	128	248
Gas Generator Outages MW (-)	0	125
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	4,546	5,092
Net Capacity (NET OPCAP SUPPLY MW)	22,472	25,250
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,695	20,695
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,000	23,000
Operable Capacity Margin	-528	2,250

[1]Operable Capacity is based on data as of **November 21, 2022** 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 **November 21, 2022.**

[2] Load forecast that is based on the 2022 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 7, 2023.**

[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 2022/23 Operable Capacity Analysis
50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

November 21, 2022 - 50-50 FORECAST using CSO MW

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 from November through March.

Report created: 11/21/2022

Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 50-50PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 50-50PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
12/10/2022	28194	432	1094	13	878	464	3200	2117	23074	19205	2305	21510	1564	N	Winter 2022/2023
12/17/2022	28194	432	1094	13	487	300	3200	2494	23252	19216	2305	21521	1731	N	Winter 2022/2023
12/24/2022	28194	432	1094	13	86	258	3200	2883	23306	19278	2305	21583	1723	N	Winter 2022/2023
12/31/2022	28257	559	1070	60	147	0	2800	3740	23259	19549	2305	21854	1405	N	Winter 2022/2023
1/7/2023	**28257**	**559**	**1070**	**60**	**128**	**0**	**2800**	**3735**	**23283**	**20009**	**2305**	**22314**	**969**	**Y**	**Winter 2022/2023**
1/14/2023	28257	559	1070	60	91	0	2800	3590	23465	20009	2305	22314	1151	N	Winter 2022/2023
1/21/2023	28257	559	1070	60	91	6	2800	3135	23914	20009	2305	22314	1600	N	Winter 2022/2023
1/28/2023	28251	559	1070	60	64	13	3100	2829	23934	19789	2305	22094	1840	N	Winter 2022/2023
2/4/2023	28251	559	1070	60	64	13	3100	2530	24233	19524	2305	21829	2404	N	Winter 2022/2023
2/11/2023	28251	559	1070	60	64	13	3100	2231	24532	19496	2305	21801	2731	N	Winter 2022/2023
2/18/2023	28251	559	1070	60	16	13	3100	1782	25029	19236	2305	21541	3488	N	Winter 2022/2023
2/25/2023	28251	559	1070	60	208	13	3100	1483	25136	18258	2305	20563	4573	N	Winter 2022/2023
3/4/2023	28251	559	1070	60	181	1328	2200	0	26231	17912	2305	20217	6014	N	Winter 2022/2023
3/11/2023	28251	559	1070	60	179	305	2200	293	26963	17718	2305	20023	6940	N	Winter 2022/2023
3/18/2023	28251	559	1070	60	1444	1493	2200	0	24803	17357	2305	19662	5141	N	Winter 2022/2023
3/25/2023	28251	559	1070	60	1404	2164	2200	0	24172	16797	2305	19102	5070	N	Winter 2022/2023

Column Definitions

1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).

2. CSO Demand Resource Capacity MW: 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 particpate in the Day-Ahead and Real-Time Energy Markets.

3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.

4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.

5. CSO Non Gas-Only Generator Planned Outages MW: All 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.Outages.

6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.

7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.

8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.

9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)

10. Peak Load Forecast MW: Provided in the annual 2022 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).

11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.

12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)

13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)

14. Operable Capacity Season Label: Applicable season and year.

15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

Winter 2022/23 Operable Capacity Analysis 90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

November 21, 2022 - 90/10 FORECAST using CSO MW

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 in November.

Report created: 11/21/2022

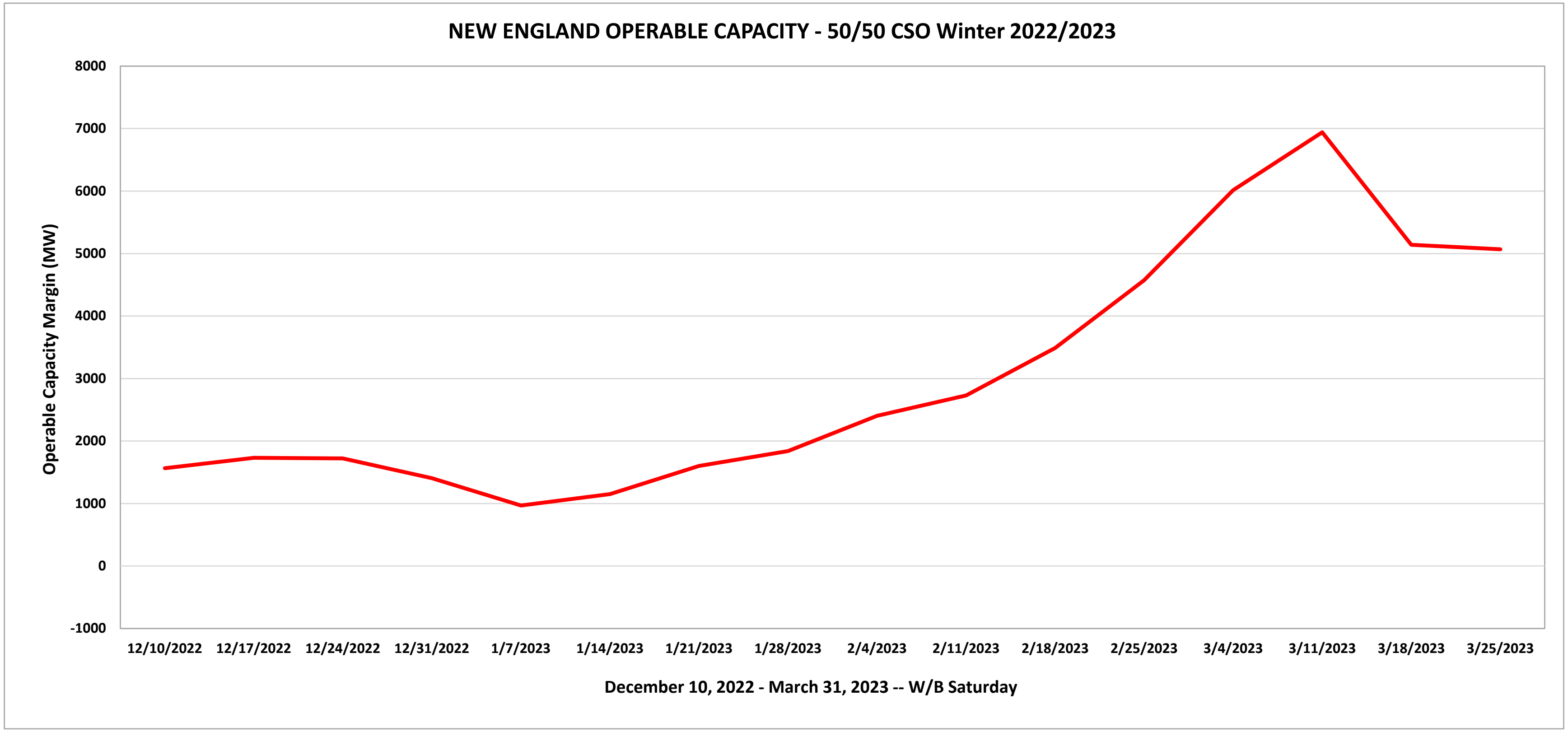
Study Week (Week Beginning, Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 90-10PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 90-10PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
12/10/2022	28194	432	1094	13	878	464	3200	3104	22087	19866	2305	22171	-84	N	Winter 2022/2023
12/17/2022	28194	432	1094	13	487	300	3200	3613	22133	19877	2305	22182	-49	N	Winter 2022/2023
12/24/2022	28194	432	1094	13	86	258	3200	4029	22160	19941	2305	22246	-86	N	Winter 2022/2023
12/31/2022	28257	559	1070	60	147	0	2800	4415	22584	20220	2305	22525	59	N	Winter 2022/2023
1/7/2023	**28257**	**559**	**1070**	**60**	**128**	**0**	**2800**	**4546**	**22472**	**20695**	**2305**	**23000**	**-528**	**Y**	**Winter 2022/2023**
1/14/2023	28257	559	1070	60	91	0	2800	4338	22717	20695	2305	23000	-283	N	Winter 2022/2023
1/21/2023	28257	559	1070	60	91	6	2800	4033	23016	20695	2305	23000	16	N	Winter 2022/2023
1/28/2023	28251	559	1070	60	64	13	3100	4026	22737	20468	2305	22773	-36	N	Winter 2022/2023
2/4/2023	28251	559	1070	60	64	13	3100	3577	23186	20195	2305	22500	686	N	Winter 2022/2023
2/11/2023	28251	559	1070	60	64	13	3100	3278	23485	20166	2305	22471	1014	N	Winter 2022/2023
2/18/2023	28251	559	1070	60	16	13	3100	2680	24131	19898	2305	22203	1928	N	Winter 2022/2023
2/25/2023	28251	559	1070	60	208	13	3100	2231	24388	18889	2305	21194	3194	N	Winter 2022/2023
3/4/2023	28251	559	1070	60	201	798	2200	1296	25445	18533	2305	20838	4607	N	Winter 2022/2023
3/11/2023	28251	559	1070	60	179	305	2200	1191	26065	18333	2305	20638	5427	N	Winter 2022/2023
3/18/2023	28251	559	1070	60	1444	1493	2200	0	24803	17960	2305	20265	4538	N	Winter 2022/2023
3/25/2023	28251	559	1070	60	1404	2164	2200	0	24172	17383	2305	19688	4484	N	Winter 2022/2023

Column Definitions

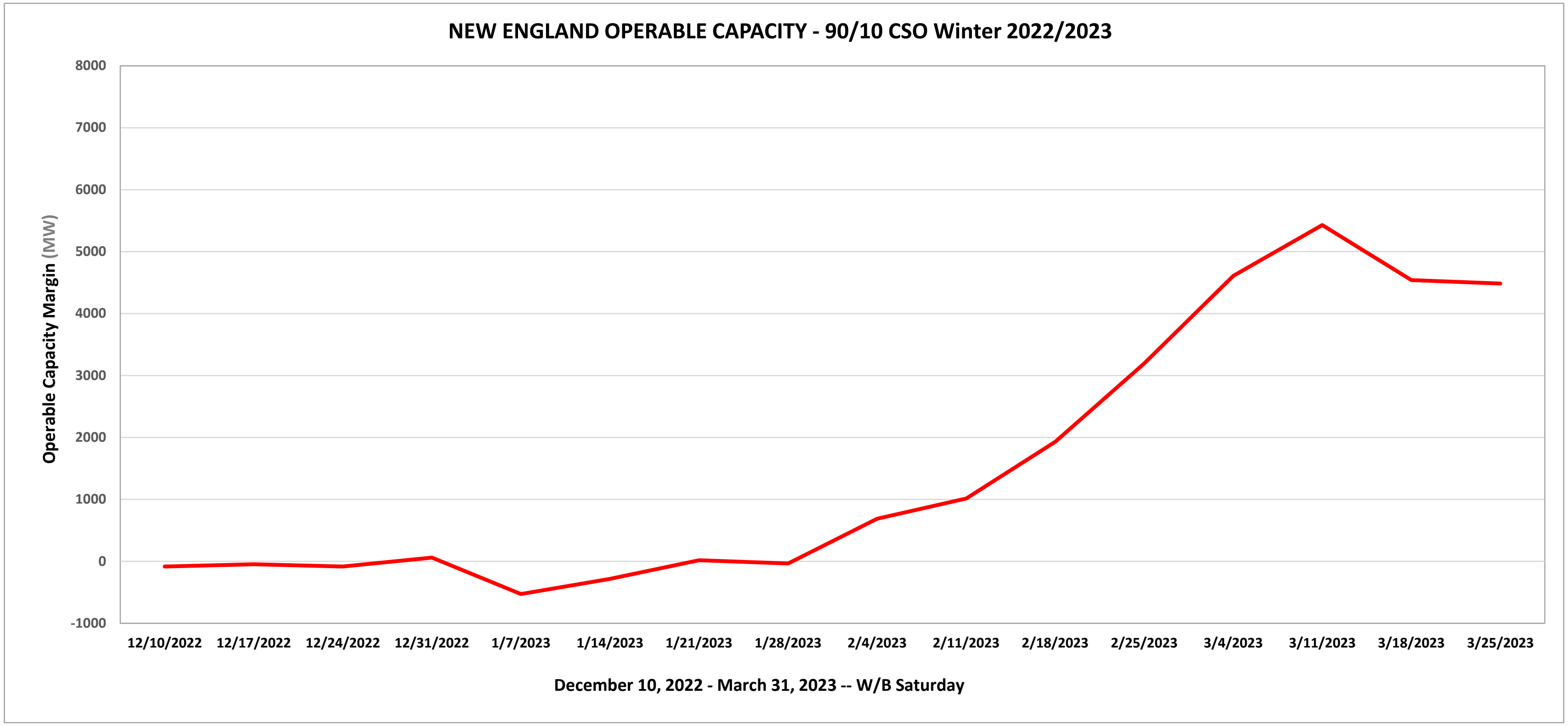
1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.
5. CSO Non Gas-Only Generator Planned Outages MW: All 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.Outages.
6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 2022 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

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

Winter 2022/23 Operable Capacity Analysis
50/50 Forecast (Reference)



Winter 2022/23 Operable Capacity Analysis
90/10 Forecast



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

NEW ENGLAND POWER POOL
PARTICIPANTS COMMITTEE MEETING

December 1, 2022

RESOLUTION REGARDING ELECTION OF OFFICERS FOR 2023

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 indentified in the following resolution were nominated and elected for 2023 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 2023 to the offices set forth opposite their names to serve until their successors are elected and qualified:

Chair	David A. Cavanaugh
Vice-Chair	Paul J. Roberti
Vice-Chair	Sarah Bresolin
Vice-Chair	Alan Trotta
Vice-Chair	Michelle C. Gardner
Vice-Chair	Aleksander Mitreski
Secretary	Sebastian M. Lombardi
Assistant Secretary	Patrick M. Gerity

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Tom Kaslow, Chair, NEPOOL Budget & Finance Subcommittee
Paul Belval, NEPOOL Counsel

DATE: November 22, 2022

RE: Estimated Budget for 2023 Participant Expenses

The Participants Committee will be asked at its December 1 meeting to approve the estimated NEPOOL expense budget for 2023, which is attached to this memorandum (the "2023 Budget"). As in prior years, the proposed 2023 Budget estimates are compared to both the current-year estimated expenses approved by the Participants Committee at its last annual meeting and the current forecast of actual expenses for this year (Attachment A). Also as in prior years, an estimated calculation of the per-Participant share of the 2023 Budget expenses are compared to per-Participant shares of expenses five years ago (Attachment B). Impacted by the number of members over which expenses are allocated, 2023 per-Participant expenses are projected, when compared to 2018 numbers, to generally increase (by 3.8% for most Participants (Generation, Supplier and Large AR Providers), by 5.1% for Publicly Owned Entities, but to decrease 4.1% for the voting Transmission Owners).

Consistent with the practice in previous years, the NEPOOL Budget and Finance Subcommittee (the "Subcommittee") has worked with NEPOOL Counsel, the GIS Administrator, the ISO and NEPOOL's Independent Financial Advisor to develop the 2023 Budget. The Subcommittee will discuss the proposed 2023 Budget at its November 29 meeting, and we will report the results of that discussion at the December 1 Participants Committee meeting.

As of the date of this memorandum, the amounts for the 2022 forecasted credit insurance premium and the 2023 budgeted credit insurance premium are not yet known. The amounts included in the 2023 Budget are the maximum amounts expected for each premium, and the ISO expects to have the final figures for the November 29 Subcommittee meeting. Those final figures will be reported at the December 1 Participants Committee meeting.

The following form of resolution may be used in acting on the 2023 Budget:

> RESOLVED, that the Participants Committee adopts the estimated NEPOOL expense budget for 2023 as presented at this meeting.

ESTIMATED 2023 NEPOOL BUDGET COMPARED TO 2022 NEPOOL BUDGET AND 2022 PROJECTED ACTUAL EXPENSES

Line Items	2022 Approved Budget	2023 Proposed Budget	2022 Current Forecast
NEPOOL Counsel Fees (1)	$4,200,000	$4,350,000	$4,200,000
NEPOOL Counsel Disbursements (1)	$ 30,000	$ 30,000	$ 30,000
Independent Financial Advisor Fees and Disbursements (2)	$ 45,000	$ 48,000	$ 48,000
Committee Meeting Expenses (3)(4)	$ 725,000	$ 900,000	$ 550,000
Generation Information System (5)	$ 950,000	$1,022,438	$ 976,000
Credit Insurance Premium (3) (9)	$ 637,000	$ 799,000	$ 757,400
NEPOOL Audit Management Subcommittee ("NAMS") Consultant (6)	$ 0	$ 0	$ 0
SUBTOTAL EXPENSES	$6,587,000	$7,149,438	$6,561,400
Revenue			
NEPOOL Membership Fees (3)	($2,140,000)	($2,300,000)	($2,301,700)
Generation Information System (5) (7)	($ 950,000)	($1,022,438)	($ 976,000)
Credit Insurance Premium (3) (8) (9)	($ 637,000)	($ 799,000)	($ 757,400)
TOTAL REVENUE	($3,727,000)	($4,121,438)	($4,035,100)
TOTAL NEPOOL EXPENSES	**$2,860,000**	**$3,028,000**	**$2,526,300**

Notes

(1) 2023 proposed estimate provided by Day Pitney LLP, NEPOOL counsel, reflecting modest increase in billing rates and challenging work plan in 2023.

(2) 2023 proposed estimate provided by Michael M. Mackles, NEPOOL's Independent Financial Advisor, and reflects increased responsibility for reviewing meeting and travel expenses.

(3) 2023 proposed estimate provided by ISO New England Inc. ("ISO").

(4) 2023 proposed estimate is based on continuation of in-person meetings for NPC and Technical Committees and reflects increased charges imposed by venues when compared to pre-pandemic charges.

(5) Based on fee arrangement in Extension of and First Amendment to Amended and Restated Generation Information System Administration Agreement, pursuant to which the annualized fixed fee for 2023 is projected to be $997,500 for six months and $1,047,375 for six months. Estimate assumes NEPOOL will not exceed 500 development hours for changes to GIS, and any additional development hours would impose additional charges on NEPOOL. Estimate also assumes that costs incurred in connection with requested waivers of GIS Rules will be paid by the party seeking that waiver.

(6) If NEPOOL determines that an audit should be performed in 2023, funding for that audit will be addressed separately.

(7) 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, 2001. GIS costs associated with accessing the GIS through the API are paid by the GIS account holders using that API.

(8) Credit insurance premium is paid by Qualifying Market Participants according to methodology described in Section IX of the ISO Financial Assurance Policy.

(9) Due to increased costs in the New England Markets, the credit insurance premiums for the renewal period of December 1, 2022 - November 30, 2023 have increased. The final true-up of the premium for the period of December 1, 2021 to November 30, 2022 has not yet been determined, and the ISO was able to negotiate the premium for the 2022- 2023 period to be $688,500 (which is based on 2022 annual policy sales, escalated by a factor based on future expected fuel cost increases). The amounts shown for the 2022 forecast includes the 2022-2023 premium of $688,500 along with a true-up of $68,900 for the period of 2020-2021.

ESTIMATED BREAKDOWN OF PROJECTED 2023 NEPOOL EXPENSE BUDGET AMONG SECTOR MEMBERS

(2023 figures assume no change in current NEPOOL membership)
(2018 figures as projected and budgeted at 2017 Annual Meeting)

CALCULATION OF COSTS TO BE ALLOCATED TO NEPOOL SECTORS			
		2023	**2018**
A.	Total Projected NEPOOL Expenses (not including costs associated with GIS, credit insurance premium, which are funded separately)	**5,000,000**	**4,630,000**
B.	Projected NEPOOL Membership Fees	**2,140,000**	**1,945,000**
C.	Total Projected NEPOOL Expenses to be Funded Through Non-Hourly Charges (A – B)	**2,860,000**	**2,685,000**
D.	Projected Amount to be paid by all Market Participant End Users (based on highest hourly load in any month in preceding calendar year) (figure used here for 2020 is based on 2018 peak loads of MPEU members)	**35,625**	**56,352**
E.	Total Amount paid by all Load Response, Distributed Generation, and Small Renewable Generation Resource Providers in AR Sector (figure used here for 2023 is estimated amount based on 2022 membership data)	**72,834**	**77,681**
F.	[Reserved]	**0**	**0**
G.	Large Renewable Generation Sub-Sector Share (C-(D+E)) x RG%	**291,954**	**268,500**
H.	Total Amount to be Allocated among Transmission, Generation, Supplier and Publicly Owned Entity Sectors (“Remaining Sectors”) (C – (D+E+G))	**2,627,587**	**2,282,467**

CALCULATION OF SECTOR ALLOCATIONS			
		2023	**2018**
I.	Amount to be allocated to each of the Remaining Sectors (H ÷ 4)	**656,897**	**570,617**
J.	Total Amount paid by Related Person Suppliers (2 voting members) $(I \div s_y) \times rps_y$	**13,977**	**8,847**
K.	Aggregate Share to be paid by Generation Sector/Supplier Sector/ Large Renewable Generation Resource Providers ((I x 2) + G – J)	**1,591,771**	**1,400,887**
L.	[Reserved]	**0**	**0**
M.	Remainder of Aggregate Share to be paid, on a per member basis, by voting members in the Generation Sector, Supplier Sector (excluding Related Person Suppliers), and Large Renewable Generation Resource Providers $(K \div (g_y + (s_y - rps_y) + lrg_y))$	**9,887**	**9,530**
N.	Transmission Sector Share per full voting member $(I \div t_y)$	**109,483**	**114,123**
O.	[Reserved]	**0**	**0**
P.	Publicly Owned Entity Sector Member Share (assuming equal sharing of Publicly Owned Entity Sector Share Participant Expense among voting Sector members)[i] $(I \div poe_y)$	**11,134**	**10,593**

ANNUAL VARIABLES			
		2023	**2018**
s_y	# Supplier Sector voting members	**141**	**129**
rps_y	# Supplier Sector Related Person Suppliers	**3**	**2**
g_y	# Generation Sector voting members	**12**	**13**
lrg_y	# AR Sector Large Renewable Generation Resource Providers	**11**	**7**
RG%	Lesser of (lrg_y*2%) or 10%	**10%**	**10%**
t_y	# Transmission Sector voting members	**6**	**5**
poe_y	# Publicly Owned Entity voting members	**59**	**57**

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EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of November 30, 2022

The following activity, as more fully described in the attached litigation report, has occurred since the report dated November 1, 2022 ("last Report") was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

I. Complaints/Section 206 Proceedings

	1	ENECOS Mystic COSA Complaint (EL23-4)	Nov 16	Mystic, ISO-NE respond to Complaint; MMWEC/NHEC, CT Parties support Complaint
			Nov 7-16	NEPOOL, Eversource, National Grid, NRG intervene
	3	RENEW/ACPA RCA & Operating Reserve Designation Complaint (EL22-42)	Nov 7	RENEW/ACPA submit comments in response to New England Winter Gas-Electric Forum to draw attention to, reiterate its arguments in, and urge the FERC to expeditiously act on, this Complaint
	4	NMISA Complaint Against PTO AC (Reciprocal TOUT Discount) (EL22-31)	Nov 21	FERC modifies the discussion in, but reaches the same the result as, the *NMISA Order*

II. Rate, ICR, FCA, Cost Recovery Filings

*	9	ICR-Related Values and HQICCs – Annual Reconfiguration Auctions (ER23-)	Nov 30	ISO-NE and NEPOOL jointly file ICR-Related Values and HQICCs for the 2023/24 ARA3, 2024/25 ARA2; and 2025/26 ARA1; comment deadline ***Dec 21, 2022***
*	10	ICR-Related Values and HQICCs – FCA17 (2026-27) Capacity Commitment Period (ER23-405)	Nov 8	ISO-NE and NEPOOL file ICR-Related Values for the 2026-27 Capacity Comm. Period
			Nov 14-29	Calpine, Dominion, Eversource, National Grid, NESCOE intervene
	10	2023 NESCOE Budget (ER23-100)	Nov 2-3	Eversource, RI Energy intervene
			Nov 4	NEPOOL submits comments supporting 2023 NESCOE Budget
	10	2023 ISO-NE Administrative Costs and Capital Budgets (ER23-94)	Nov 2-3	Eversource, RI Energy intervene
	11	FirstLight CIP IROL (Schedule 17) Cost Recovery Schedule Filing (ER22-2876)	Nov 15	FERC accepts cost recovery schedule, eff. Sep 16, 2022
	12	Mystic COSA Updates to Reflect Constellation Spin Transaction (ER22-1192)	Nov 2	FERC approves Offer of Settlement; Mystic directed to make a 30-day compliance filing reflecting the FERC's action in this matter
	12	Mystic I Remand	Nov 22	Mystic and Constellation file emergency motion requesting expedited action by ***Jan 9, 2022***, on the Cost Allocation and Clawback issues remanded to the FERC in the *Mystic I Remand Order*
	12	Mystic 8/9 COSA *Second* CapEx Info Filing (ER18-1639-000)	Nov 16	Mystic responds to NESCOE's formal challenge; MMWEC/NHEC support ENECOS' formal challenge
			Nov 17	Mystic responds to ENECOS' formal challenge
	12	Mystic 8/9 COSA *First* CapEx Info Filing (ER18-1639-015)	Nov 17	Second settlement conference held
			Nov 18	Settlement Judge McBarnette schedules third settlement conference by WebEx for ***Dec 20, 2022***

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

*	15	Solar DNE Dispatch Changes (ER23-517)	Nov 30	ISO-NE and NEPOOL file changes; comment deadline ***Dec 21, 2022***
*	15	Waiver Request: Attachment F (NEP) (ER23-370)	Nov 2 Nov 8-22	New England Power (NEP) requests limited waiver Eversource, NESCOE, RI Division, RI Energy intervene
	14	FCM Parameters Recalculation Schedule Modification (ER23-74)	Nov 22	FERC accepts changes that defer and modify the FCM Parameters Recalculation Schedule, eff. Dec 12, 2022
*	16	IEP Remand (ER19-1428-006)	Nov 22 Nov 23	ISO-NE files Tariff provisions governing the IEP consistent with the D.C. Circuit's *IEP Decision*; comment deadline ***Dec 13, 2022*** Calpine intervenes

IV. OATT Amendments / TOAs / Coordination Agreements

	16	Attachment F Revisions reflecting RI Energy Addition as PTO (ER23-299)	Nov 8-18 Nov 18 Nov 21	Eversource, NESCOE intervene National Grid submits comments supporting the revisions RI Division submits comments not opposing the revisions
	17	Attachment F Depreciation Normalization Requirement Revisions (ER23-197)	Nov 15	MPUC files a notice of intervention
*	17	Attachment F, Appendix D-PSNH: Establishment of Depreciation Rate for Accounts 357 and 358 (ER22-2953)	Nov 2	PSNH amends its Sep 29, 2022 filing to adjust the proposed depreciation rates for Accounts 357 and 358 (1.73% and 2.19%, respectively)

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes & Agreements

	19	Schedule 21-RIE (ER23-16)	Nov 14 Nov 21	RI Energy answers RI Division's Oct 25 comments RI Division answers RI Energy's Nov 14 answer

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

	21	Capital Projects Report - 2022 Q3 (ER23-114)	Nov 17	FERC issues notice setting comment deadline at ***Dec 8, 2022***
*	21	Interconnection Study Metrics Processing Time Exceedance Report Q3 2022 (ER19-1951)	Nov 16	ISO-NE files required quarterly report
*	22	IMM Quarterly Markets Reports - 2022 Summer (ZZ22-4)	Nov 2	IMM files Summer 2022 Report
*	22	ISO-NE FERC Form 3Q (2022/Q3) (not docketed)	Nov 28	ISO-NE submits its 2022 Q3 FERC Form 3Q

IX. Membership Filings

*	22	December 2022 Membership Filing (ER23-518)	Nov 30	***New Member***: 11772244 Canada Inc.; comment deadline ***Dec 20, 2022***

*	22	November 2022 Membership Filing II (ER23-402)	Nov 9	***New Member***: Windham Energy Center; comment deadline ***Nov 30, 2022***
	22	October 2022 Membership Filing (ER22-2982)	Nov 25	FERC accepts (i) the memberships of Danske Commodities US; Mass. Climate Action Network; MFT Energy US 1; and Spotlight Power LLC; and (ii) the termination of the Participant status of IPKeys Power Partners, Inc.

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

*	23	Revised Reliability Standards: EOP-011-3 and EOP-012-1 (RD23-1)	Nov 29	FERC extends comment deadline on proposed Cold Weather Standards to ***Dec 8, 2022***
*	23	Revised Reliability Standards: FAC-001-4 and FAC-002-4 (RD22-5)	Nov 17	FERC approves revised FAC Standard, eff. Jan 1, 2024 (or Jan 1, 2025 under certain circumstances)
*	23	Inverter-Based Resource Registration (RD22-4)	Nov 17	FERC directs NERC to submit a work plan on or before ***Feb 15, 2023*** describing how it plans to identify and register unregistered IBR owners and operators that have IBRs that, in the aggregate, have a material impact on the reliable operation of the BPS
	24	2023 NERC/NPCC Business Plans and Budgets (RR22-4)	Nov 2	FERC approves 2023 NERC and Regional Entity budgets, subject to a 60-compliance filing due on before ***Jan 3, 2023***, providing additional information related to E-ISAC costs, vendor affiliate program, and the E-ISAC and natural gas stakeholder partnership

XI. Misc. - of Regional Interest

*	25	203 Application: Agilitas Companies / AB CarVal Funds (EC23-30)	Nov 21	Agilitas Companies request authorization for AB CarVal Funds to convert their existing passive, non-voting ownership interest in Agilitas Energy, Inc. into 21.3% of the voting interests in Agilitas Energy; comment deadline ***Dec 12, 2022***
*	25	203 Application: Central Rivers Power / LSPower (EC23-22)	Nov 2	Central Rivers Power and LSPower request authorization for a portion of a larger transaction pursuant to which LSPower will acquire Central Rivers Power's QF assets in New England
			Nov 10	PJM intervenes
	26	203 Application: ConEd / RWE (EC23-17)	Nov 10-14	PJM, Public Citizen intervene
	26	203 Application: EDF Energy / BP Retail (EC22-122)	Nov 14	FERC authorizes BP Retail acquisition of 100% of the membership interests in EDF Energy
	27	203 Application: Stonepeak / JERA Americas (EC22-71)	Nov 23	FERC authorizes the sale of 100% of the interests in Canal Power Holdings LLC, including Stonepeak Kestral Energy Marketing, to a wholly-owned affiliate of JERA Americas
*	27	LGIA: ISO-NE / NSTAR / Vineyard Wind I (ER23-488)	Nov 23	ISO-NE and NSTAR file First Revised LGIA with Vineyard Wind 1, LLC to reflect the assignment of the LGIA to by Vineyard Wind, LLC to Vineyard Wind I, LLC; comment deadline ***Dec 14, 2022***
*	27	Cost Reimbursement Agreement: NEP/Holden (ER23-396)	Nov 9	New England Power files Cost Reimbursement Agreement
*	27	NEP Tariff No. 1 Revisions (ER23-348)	Nov 2	NEP files Revisions
			Nov 4	RI Energy intervenes
*	27	MPD OATT: Changes to Treatment of CIS Costs and Expenses (ER23-345)	Nov 2	Versant Power files proposed changes to the formula rate in its MPD OATT to modify the treatment of costs and expenses associated with the company's Customer Information System
			Nov 15	MPUC intervenes

28	Service Agreement Cancellation: NEP/Pawtucket (ER23-144)	Nov 28	FERC accepts Notice of Cancellation, eff. Dec 19, 2022
28	D&E Agreement: CL&P/NY Transco (ER22-2830)	Nov 9	FERC accepts D&E Agreement, eff. Sep 13, 2022

XII. Misc. - Administrative & Rulemaking Proceedings

29	Interregional HVDC Merchant Transmission (AD22-13)	Nov 10	Invenergy again urges the FERC to "hold a technical conference to examine and to improve the policy and processes relating to the interconnection of interregional MHVDC systems"
29	Reliability Technical Conference (Nov 10) (AD22-10)	Nov 10	FERC holds tech conf Post-tech conf comments due ***Jan 9, 2023***
30	New England Gas-Electric Winter Forum (AD22-9)	Nov 4-21 Nov 22	Parties file over 50 sets of post-Forum comments National Grid files reply comments
31	Joint Federal-State Task Force on Electric Transmission (AD21-15)	Nov 15	JFSTF holds 5th meeting in New Orleans, LA
31	Modernizing Electricity Market Design - Resource Adequacy (AD21-10)	Nov 30	EEI requests a 30-day extension of time to comments on ISO/RTO Reports; if not granted, comment deadline ***Dec 19, 2022***
32	NOPR: Duty of Candor (RM22-20)	Nov 10-14	Over 30 sets of comments filed, including by: ISO-NE, ISO-NE IMM, ISO-NE EMM, PJM IMM, ABA, AGA, APGA, APPA, EEI, Energy Trade Associations, INGA, NGSA, Nodal Exchange, NRECA, State Agencies, US Chamber of Commerce, DE Riverkeeper Network, New Civil Liberties Alliance, Nodal Exchange
32	NOPR: Advanced Cybersecurity Investment (RM22-19)	Nov 3-8 Nov 21-22	Nearly 30 sets of initial comments filed, including by: Avangrid, APPA, EEI, EPSA, INGA, Joint Consumer Advocates, Microsoft, MISO TOs, PJM TOs, NERC, NRECA, TAPS, and the Operational Technology Cybersecurity Coalition Reply comments filed by DOE, EEI, ELCON, CA PUC, AEP, and Anterix
33	NOPR: Interconnection Reforms (RM22-14)	 Nov 4, 15	Reply comments deadline ***Dec 14, 2022*** Reply comments filed by R. Shanker, R. Lathrop
35	NOPR: ISO/RTO Credit Information Sharing (RM22-13)	Nov 7	Reply comments filed by the IRC and a couple of persons from Augusta University
37	*Transmission NOPR* (RM21-17)	Nov 28	New Jersey BPU moves to lodge its recently issued Board Order selecting transmission projects to be built pursuant to PJM's SAA, the Brattle Group's SAA Evaluation Report, and PJM's SAA Economic Analysis Report
38	NOPR: Accounting and Reporting Treatment of Certain Renewable Energy Assets (RM21-11)	Nov 17-18	Dominion, ACPA/SEIA, EEI, Liquid Energy Pipeline Assoc., RESA, PG&E/SDG&E, C. Pechman file comments

XIII. FERC Enforcement Proceedings

43	Total Gas & Power North America, Inc. et al. (IN12-17)	Nov	Discovery on-going; Discovery closes ***Dec 2, 2022***

XIV. Natural Gas Proceedings

No Activity to Report

XV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XVI. Federal Courts

49	Northern Access Project (22-1233)	Nov 4	the FERC withdraws its motion to hold this proceeding in abeyance
		Nov 9	Court issues scheduling order
		Nov 16	FERC files Certified Index to the Record

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: December 1, 2022

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 November 30, 2022. If you have questions, please contact us.

I. Complaints/Section 206 Proceedings

- **ENECOS Mystic COSA Complaint (EL23-4)**

On October 17, 2022, Eastern New England Consumer-Owned Systems ("ENECOS") filed a Complaint against Mystic and ISO-NE challenging the pass-through to ISO-NE customers of firm pipeline transportation costs under the 2nd Amended and Restated Mystic Cost-of-Service Agreement ("COSA"), which ENECOS claimed are associated with pipeline facilities that are neither used nor usable to supply fuel to Mystic 8 and 9, and therefore should not be charged to ISO-NE and its customers under the COSA. Specifically, ENECOS asked that all references to "Pipeline Transportation Agreements" be stricken from the COSA, template Line No. 7 "Fixed Pipeline Transportation" be removed from the true-up methodology, and Mystic be precluded from recovering the dollar amounts associated with that line item. ENECOS explained that the Complaint was filed as a procedural precaution as the charges that are the subject of the Complaint can be addressed by the FERC in proceedings on the DC Circuit's remand of issues relating to the FERC's allocation of Everett Marine Terminal costs under the COSA.[2]

Responses and Comments. Responses to and comments on ENECOS' Complaint were due on or before November 16, 2022. Mystic and ISO-NE filed responses. In its response, ***Mystic*** urges the FERC to dismiss the Complaint by asserting that (i) ENECOS have not, as required, sufficiently alleged changed circumstances since the pipeline transportation costs recovery mechanisms were found just & reasonable by the FERC; (ii) ENECOS are wrong on the merits; (iii) Mystic and the COSA are cost causative for Everett; and (iv) allocation of the costs is justified by tank management, which allows Mystic to meet the reliability need that the COSA is intended to address. For its part, ***ISO-NE*** also requested that the FERC deny the Complaint because the costs challenged are encompassed by the *Mystic Remand Order*. However, if the FERC does not dismiss the Complaint, ISO-NE urged the FERC to either consolidate the Complaint with the Mystic Remand Proceeding or hold the Complaint in abeyance. Comments supporting the Complaint were filed by MMWEC/NHEC (together, "Public Systems"), and by the Connecticut Public Utilities Regulatory Authority ("CT PURA") and the Connecticut Office of Consumer Counsel ("CT OCC", and together with CT PURA, the "CT Parties"). Doc-less interventions only were filed by NEPOOL, Calpine, Eversource, MA AG, National Grid, NESCOE, NRG, and the CT DEEP have intervened doc-lessly. This

[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] *Constellation Mystic Power, LLC v. FERC*, 45 F.4th 1028, 1050-1052 (D.C. Cir. 2022) ("*Mystic Remand Order*").

matter is pending before the FERC. If you have questions on this proceeding, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

- **206 Proceeding: FTR Collateral Show Cause Order (EL22-63)**

On July 28, 2022, the FERC instituted a Section 206 proceeding finding that the existing tariffs of certain ISO/RTOs, including the ISO-NE Tariff, appear to be unjust and unreasonable.[3] The FERC found that ISO-NE's Tariff appears to be unjust and unreasonable in the absence of volumetric minimum collateral requirements for FTR Market Participants ("volumetric FTR collateral requirements"). Accordingly, ISO-NE was directed, on or before October 26, 2022, to either: (1) show cause as to why the Tariff remains just and reasonable and not unduly discriminatory or preferential; or (2) explain what changes to the Tariff it believes would remedy the identified concerns if the FERC were to determine that the Tariff has in fact become unjust and unreasonable or unduly discriminatory or preferential.[4] As noted below, ISO-NE answered by explaining why it believes its existing Tariff provisions to be just and reasonable and changes not necessary.

By way of background, the *FTR Collateral Show Cause Order* follows PJM's *Green Hat* experience,[5] a 2019 request by the Energy Trading Institute requesting a FERC-convened technical conference to consider a potential rulemaking to improve ISO/RTO credit practices,[6] and a two-day technical conference in February 2021 that discussed principles and best practices for credit risk management in organized wholesale electric markets.[7] In the *FTR Collateral Show Cause Order*, the FERC stated that, although the record developed through the technical conference highlighted numerous different approaches to managing credit risk, "we believe that two specific practices may be particularly critical to effectively managing credit risk for FTRs: the use of a mark-to-auction mechanism and a volumetric minimum collateral requirement for FTRs."[8] ISO-NE currently employs a mark-to-auction mechanism but not volumetric FTR collateral requirements.

The FERC issued on July 28, 2022, a notice of this proceeding and of the refund effective date, August 3, 2022.[9] Those interested in participating in this proceeding were required to intervene on or before August 18, 2022. Doc-less interventions were filed by NEPOOL, Calpine, DC Energy, NRG, the Maine Public Utilities

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[3] *CAISO, ISO-NE, NYISO, and SPP*, 180 FERC ¶ 61,049 (July 28, 2022) ("*FTR Collateral Show Cause Order*").

[4] *Id.* at P 31.

[5] *See GreenHat Energy, LLC*, 175 FERC ¶ 61,138 (2021) (order to show cause) (GreenHat Show Cause Order); *GreenHat Energy, LLC*, 177 FERC ¶ 61,073 (2021) (order assessing civil penalties). In June 2018, GreenHat Energy LLC ("GreenHat") defaulted on its obligations to PJM after amassing one of the largest FTR portfolios in the PJM region. At the time of its default, GreenHat had only $559,447 on deposit as collateral with PJM and no other material assets. However, over the subsequent three-year period ending in May 2021, this FTR portfolio incurred approximately $179 million in losses, which were borne by non-defaulting market participants in PJM.

[6] Energy Trading Institute Request for Technical Conference and Petition for Rulemaking to Update Credit and Risk Management Rules and Procedures in the Organized Markets, *Credit Reforms in Organized Wholesale Electric Markets*, Docket No. AD20-6-000 (Dec. 16, 2019).

[7] *See* Supp. Notice of Tech. Conf., *RTO/ISO Credit Principles and Practices*, Docket No. AD21-6, et al. (Feb. 10, 2021).

[8] The FERC explained that (i) the mark-to-auction mechanism mitigates the risk of default by updating collateral requirements to reflect the most recent valuation of the FTR position and (ii) volumetric FTR collateral requirements ensure that a market participant is required to post a minimum amount of collateral to cover potential defaults, even when the market participant has offsetting positions. With respect to volumetric FTR collateral requirements, the FERC expressed a concern that netting of FTRs with negative collateral requirements against FTRs with positive collateral requirements can lead to insufficient collateral for a portfolio's risk should future congestion be significantly different than historical congestion. Without explicit $/MWh volumetric FTR collateral requirements, the FERC is "concerned that market participants may be able to minimize their collateral requirements without a corresponding reduction in risk". The ISO-NE Financial Assurance Policy ("FAP") allows for some limited offsetting. *See* FAP § VI (allowing for netting of FTRs with the same or opposite path, same contract month and type). *FTR Collateral Show Cause Order* at PP 28-29.

[9] The *Notice* was published in the *Fed. Reg.* on Aug 3, 2022 (Vol. 87, No. 148) p. 47,409.

Commission ("MPUC"), Electric Power Supply Association ("EPSA"), PJM, SPP, Public Citizen, and Financial Marketers Coalition[10] (out-of-time).

ISO-NE Response. On October 26, 2022, ISO-NE submitted its answer in response to the *FTR Collateral Show Cause Order*. In its Answer, ISO-NE explained how the FTR financial assurance calculations contained in the Financial Assurance Policy ("FAP") remain just and reasonable, adequately accounting for FTR risk in the absence of a more sophisticated risk management solution such as a clearing solution. ISO-NE asked that, should the FERC not agree and proceed to require volumetric FTR collateral requirements, that it be permitted to follow the Participants Processes to propose revisions to the FAP consistent with any such order. Comments on ISO-NE's response are due on or before November 25, 2022; none were filed. This matter is pending before the FERC.

If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **RENEW/ACPA Resource Capacity Accreditation & Operating Reserve Designation Complaint (EL22-42)**

As previously reported, RENEW Northeast, Inc. ("RENEW") and the American Clean Power Association ("ACPA") filed a Complaint on March 15, 2022 under Section 206 of the Federal Power Act ("FPA") against ISO-NE seeking a FERC order directing ISO-NE to make changes to its rules for capacity accreditation and operating reserve designations, effective no later than the eighteenth Forward Capacity Auction ("FCA18") with respect to capacity accreditation and promptly with respect to operating reserve designations. RENEW/ACPA asserted that the changes are needed to address undue preferences granted under ISO-NE's rules and procedures to gas-fired generation resources that have neither dual-fuel capability nor dedicated, firm natural gas supply arrangements ("Gas-Only Resources"). Complainants asserted that the undo preferences arise in the context of capacity accreditation through an assumption of 100% fuel availability for Gas-Only Resources, and in the context of operating reserves, through the absence of any pre-dispatch requirements to confirm fuel availability. ISO-NE's response and comments, following a request for extension of time granted by the FERC, were due on or before April 14, 2022.

On April 14, 2022, ISO-NE responded to the Complaint. Protests and comments on the Complaint were filed by: NEPOOL, AEE, Calpine, EDF, FirstLight, LS Power, NEPGA, NESCOE, Public Interest Orgs ("PIOs",[11] Vistra/LSP Power, State Parties,[12] EPSA, National Hydropower Assoc., and the Solar Energy Industries Association ("SEIA"). On April 29, RENEW/ACPA answered the ISO-NE and NEPOOL motions to dismiss and answered the protests and comments filed in opposition to the Complaint. On May 17, ISO-NE answered the April 29 RENEW/ACPA answer. Interventions only were filed by AEP, Avangrid, Avangrid Renewables, Borrego, Brookfield, Constellation, CPV Towantic, Dominion, ENE, Excelerate, National Grid, NextEra, NH OCA, North East Offshore, NRG, Public Systems,[13] CT PURA, MA DPU, MPUC, Repsol, APPA, EPSA, the Institute for Policy Integrity at New York University School of Law, and Public Citizen. On July 20, 2022, ISO-NE submitted a letter requested expeditious action on the Complaint (a request NEPOOL supported). RENEW/ACPA supported the request for expedited action on August 1, 2022 (adding that the FERC "should grant the Complaint and direct ISO-NE to submit a

[10] "Financial Marketers Coalition" identified themselves in their doc-less intervention as "financial market participants participating in the various ISO/RTO markets, including those operated by CAISO, SPP, NYISO and ISO-NE. Many of the Coalition members participate in these ISO/RTOs' FTR markets."

[11] "Public Interest Orgs" are the Sustainable FERC Project, Acadia Center, Conservation Law Foundation ("CLF"), Sierra Club, and Natural Resources Defense Council ("NRDC").

[12] "State Parties" are the Connecticut Department of Energy and Environmental Protection ("CT DEEP"), the Massachusetts Attorney General ("MA AG"), and the Connecticut Attorney General ("CT AG").

[13] "Public Systems" are Connecticut Municipal Electric Energy Cooperative ("CMEEC"), Massachusetts Municipal Wholesale Electric Company ("MMWEC"), New Hampshire Electric Cooperative, Inc. ("NHEC"), and Vermont Public Power Supply Authority ("VPPSA").

compliance filing that timely implements the proposed remedies", and could address the wish for "constructive *ex parte* communications with [FERC] Staff … with an appropriately crafted waiver of the *ex parte* limitations").

Since the last Report, on November 7, 2022, RENEW and ACPA, in comments submitted also in the New England Winter Gas-Electric Forum proceeding (*see* AD22-9 below), drew attention to, reiterated its arguments in, and urged the FERC to expeditiously act on, this Complaint. This Complaint remains pending before the FERC. If you have any questions concerning this Complaint, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **NMISA Complaint Against PTO AC (Reciprocal TOUT Discount) (EL22-31)**

On September 26, 2022, the FERC issued a notice[14] that the Northern Maine Independent System Administrator's ("NMISA") request for rehearing of the FERC's order[15] denying NMISA's complaint against ISO-NE and the Participating Transmission Owners ("PTOs") Administrative Committee ("PTO AC")[16] may be deemed denied by operation of law, triggering the 60-day period during which a petition for review of the *NMISA Order* can be filed with an appropriate federal court. The notice also indicated that the FERC, as is its right, "may modify or set aside [the *NMISA Order*], in whole or in part, in such manner as it shall deem proper". The FERC issued that order on November 21, 2022, modifying the discussion in the *NMISA Order*, but reaching the same the result.[17] If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **206 Proceeding: ISO-NE Tariff Schedule 25 and Section I.3.10 (EL21-94)**

Still pending before the FERC is the FERC-instituted FPA Section 206 proceeding under which the FERC is considering whether Schedule 25 and Tariff § I.3.10 may be unjust and unreasonable.[18] As previously reported, this proceeding arises out of issues raised in the NECEC Transmission LLC ("NECEC")/Avangrid Complaint Against NextEra/Seabrook (related to the interconnection of the New England Clean Energy Connect transmission project ("NECEC Project")) summarized below (EL21-6). Specifically, the FERC identified a concern that "Schedule 25's definition of Affected Party and Tariff section I.3.10 may be unjust and unreasonable to the extent they may allow generating facilities and their components to be identified as facilities on which adverse impacts must be remedied before an elective transmission upgrade can interconnect to the ISO-NE transmission system, even though generators are not subject to the [FERC]'s open access transmission principles," and could result in upgrades identified on an Affected Party's system without any obligation for the Affected Party to construct the identified upgrades.[19]

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[14] *Northern Maine Indep. Sys. Administrator, Inc. v. ISO New England Participating Transmission Owners Administrative Comm.*, 180 FERC ¶ 61,044 (Sep. 23, 2022) (notice that req. for reh'g of July 28 order may be deemed denied).

[15] *Northern Maine Indep. Sys. Administrator, Inc. v. ISO New England Participating Transmission Owners Administrative Comm.*, 180 FERC ¶ 62,168 (July 28, 2022) ("*NMISA Order*") (order denying reciprocal TOUT discount complaint).

[16] As previously reported, the FERC found in the *NMISA Order* that "NMISA has not demonstrated that the failure of the PTO AC and ISO-NE to offer NMISA reciprocal treatment is unduly discriminatory or preferential". Specifically, the FERC citied its longstanding policy permitting such charges, found for a number of reasons NYISO and NMISA not similarly situated, and noted that NMISA's showing that the proposed approach might be superior for NMISA insufficient to meet its FPA Section 206 statutory burden. In requesting rehearing, NMISA asserted that the FERC erred by (i) failing to provide a reasoned explanation for its determination that NMISA and NYISO are not similarly situated; and (ii) failed to justify its decision not to enforce the requirement that ISO-NE engage in extensive efforts to reduce seams with neighboring control areas.

[17] *Northern Maine Indep. Sys. Administrator, Inc. v. ISO New England Participating Transmission Owners Administrative Comm.*, 181 FERC ¶ 61,148 (Nov. 21, 2022) ("*NMISA Allegheny Order*") (order modifying the *NMISA Order* and sustaining the result).

[18] *NECEC Transmission LLC and Avangrid, Inc. v. NextEra Energy Resources, LLC et al. and ISO New England Inc.*, 176 FERC ¶ 61,148 (Sep. 7, 2021) ("*Sep 7 Order*").

[19] *Id.* at P 20.

The FERC directed ISO-NE to: (1) show cause as to why Schedule 25 and Tariff § I.3.10 remain just and reasonable or (2) explain what changes to Schedule 25 and/or Tariff § I.3.10 it believes would remedy the identified concerns if the FERC were to determine that Schedule 25 and/or Tariff section I.3.10 has become unjust and unreasonable and proceeds to establish a replacement rate. On September 8, 2021, the FERC issued a notice of the proceeding and of the refund effective date, which is October 13, 2020 (the date the NECEC/Avangrid Complaint Against NextEra/Seabrook was filed). Those interested in participating in this proceeding were required to intervene on or before October 5, 2021[20] and included NEPOOL, NESCOE, Brookfield, Calpine, Dominion, Eversource, HQ US, LS Power, MA AG, MMWEC, National Grid, NECEC Transmission, NEPGA, NextEra, NRG, CT DEEP, MA DOER, Pixelle Androscoggin (out-of-time), Vistra (out-of-time), ACPA, EPSA, RENEW, and Public Citizen.

ISO-NE Answer. On November 8, 2021, ISO-NE submitted its answer explaining why Schedule 25 and Tariff § I.3.10 remain just and reasonable. ISO-NE called for the FERC to "assist Affected Parties and Interconnection Customers in resolving any disputes pertaining to upgrades on Affected Systems—such as the dispute between NECEC Transmission and NextEra Energy Seabrook, LLC in Docket No. EL21-6—as quickly as possible." Interested parties had until January 7, 2022 to address whether ISO-NE's existing Tariff remains just and reasonable and if not, what changes to ISO-NE's Tariff should be implemented as a replacement rate.

Comments. Comments were filed by the January 7, 2022 deadline by NEPOOL, NECEC/Avangrid, NEPGA, NextEra. On January 20, 2022, NextEra answered the NECEC/Avangrid comments. On January 28, 2022, NECEC answered NextEra's January 20 answer and ISO-NE answered NECEC's Jan 7 comments.

As noted, this matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

Still pending before the FERC is the October 13, 2020 complaint by NECEC and Avangrid Inc. (together, "Avangrid") requesting FERC action "to stop NextEra from unlawfully interfering with the interconnection of the NECEC Project and seeking, among other things, an initial, expedited order that would grant certain relief[21] and direct 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 (the "Complaint"). NextEra submitted an answer to the Complaint (requesting the FERC dismiss or deny the Complaint) and National Grid filed comments. Doc-less interventions only were filed by Dominion, Eversource, Calpine, Exelon, HQ US, MA AG, MMWEC, NESCOE, NRG, and Public Citizen. Avangrid answered NextEra's answer and NextEra answered Avangrid's answer ("supplemental answer"), repeating its request that the FERC dismiss or deny the Complaint. Avangrid subsequently answered the supplemental answer.

Amended Complaint. On March 26, 2021, Avangrid amended the Complaint to reflect that aspects of the relief originally requested in the Complaint were no longer feasible within the timeline previously sought. Avangrid continued to seek expeditious FERC action, requesting in its March 26 filing a FERC order on or before May 7, 2021 (which did not occur). On April 15, 2021, NextEra answered the amended Complaint. On April 20, 2021, Avangrid answered NextEra's April 15 answer. On May 6, 2021, ISO-NE submitted a letter to express importance of prompt resolution of these matters. On May 17, Avangrid submitted a letter supporting ISO-NE's May 6, 2021 letter.

[20] The *Notice* was published in the *Fed. Reg.* on Sep. 14, 2021 (Vol. 86, No. 175) p. 51,140.

[21] 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.

Additional Briefing. On September 7, 2021, the FERC issued an order establishing additional briefing in this proceeding and instituted a broader Section 206 proceeding (*see* EL21-94 above).[22] Initial briefs[23] were due on or before October 7, 2021, and were filed by ISO-NE, Avangrid, NextEra, MA AG, NEPGA/EPSA, MA DOER. Reply briefs were due on or before October 22, 2021, and were filed by Avangrid, NextEra, ISO-NE. Avangrid answered NextEra's November 4 answer, NextEra moved to lodge a letter from a Branch Chief of the Nuclear Regulatory Commission ("NRC"), including an Inspection Report for Seabrook Station for the time period from July 1, 2021 through September 30, 2021 (together, the "NRC Seabrook Report"), to directly refute a central claim of Avangrid (that Seabrook should have already replaced the Generation Breaker at issue in this proceeding). Avangrid opposed that motion to lodge (asserting that the NRC Seabrook Report is outside the scope of these proceedings and will not assist the FERC in its decision making). With briefing complete, this matter is again 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, and also still pending before the FERC, is a Petition for a Declaratory Order filed by NextEra Energy Seabrook, LLC ("Seabrook") a week earlier than the Avangrid Complaint that seeks clarity on the scope of Seabrook's "FERC-jurisdictional regulatory obligations with respect to the project ("NECEC Elective Upgrade"), and to resolve its dispute with NECEC" (the "Seabrook Petition"). Specifically, Seabrook asked the FERC to declare that: (1) Seabrook is not required to incur a financial loss to upgrade, for NECEC's sole benefit, a 24.5 kV generator circuit breaker and ancillary equipment ("Generation Breaker") at Seabrook Station; (2) "Good Utility Practice" for replacement of the nuclear plant Generation Breaker is defined in terms of the practices of the nuclear power industry, such that Seabrook's proposed definition of that term is appropriate for use in a facilities agreement with NECEC; and (3) Seabrook will not be liable for consequential damages for the service it provides to NECEC under a facilities agreement (collectively, the "Requested Declarations"). Alternatively, Seabrook asked that the FERC declare that nothing in ISO-NE's Tariff requires Seabrook to enter into an agreement to replace the Generation Breaker, and therefore, Seabrook and the Joint Owners are entitled to bargain for appropriate terms and conditions to recover their costs, to define Good Utility Practice, and to limit liability associated with providing the service ("Alternative Declaration").

Comments on the Seabrook Petition were filed by Eversource, MMWEC and NEPGA. Avangrid and NECEC Transmission (together, "Avangrid") protested the Seabrook Petition. Doc-less interventions only were filed by Dominion, Eversource, Calpine, Exelon, HQ US, National Grid, NESCOE, NRG, and Public Citizen. NextEra answered Avangrid's protest and Avangrid answered NextEra's answer. On May 6, 2021, ISO-NE submitted a letter in this proceeding, as well as in EL21-6, to express importance of prompt resolution of these matters. NextEra moved to lodge both an August 29, 2021 filing containing an executed Engineering and Procurement Agreement ("E&P Agreement") between Seabrook and NECEC that was filed with the FERC on August 19, 2021 and the NRC Seabrook Report. Avangrid answered that motion, asserting that the NRC Seabrook Report was outside the scope of the proceeding and the motion to lodge should be denied. This matter remains pending before the FERC. If

[22] *NECEC Transmission LLC and Avangrid, Inc. v. NextEra Energy Resources, LLC et al. and ISO New England Inc.*, 176 FERC ¶ 61,148 (Sep. 7, 2021).

[23] The FERC requested additional briefing from the Parties, as well as from ISO-NE, on the following issues: (i) whether or not Seabrook's breaker is properly identified as a part of Seabrook's generating facility; (ii) if Seabrook's breaker is part of Seabrook's generating facility, under what authority, if any, Seabrook may be subject to the upgrade obligations imposed on Affected Parties under the ISO-NE Tariff; (iii) if Seabrook's breaker is part of Seabrook's generating facility, what obligations, if any, Seabrook has under its LGIA with respect to replacement of the breaker and whether or not ISO New England Operating Documents and Applicable Reliability Standards impose an obligation to replace the breaker. If Seabrook's breaker is appropriately classified as a system protection facility, what obligations Seabrook has to replace the breaker. If the Seabrook LGIA obligates Seabrook to act, a description of the scope of Seabrook's obligation under the LGIA; (iv) whether there exists any solution for the interconnection of the NECEC Project that may be implemented without the replacement of Seabrook's breaker; and (v) If replacement of Seabrook's breaker is necessary for the interconnection of the NECEC Project, whether there exists any interim solution for the interconnection of the NECEC Project that would allow energization of the NECEC Project prior to the replacement of Seabrook's breaker.

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

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

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

- ***Base ROE Complaint I (EL11-66)***. In the first Base ROE Complaint proceeding, the FERC concluded that the TOs' ROE had become unjust and unreasonable,[24] 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*).[25] However, the FERC's orders were challenged, and in *Emera Maine,*[26] the U.S. Court of Appeals for the D.C. Circuit ("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)[27] and third (EL14-86)[28] 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.[29] 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[30] also went to hearing before an Administrative Law Judge ("ALJ"), Judge Glazer, who issued his initial decision on March

[24] 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*")).

[25] *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*").

[26] *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).

[27] 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%.

[28] 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.

[29] *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*").

[30] 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,

27, 2017.[31] The *Base ROE IV Initial Decision* concluded that the currently-filed base ROE of 10.57%, which may reach a maximum ROE of 11.74% with incentive adders, was ***not*** unjust and unreasonable for the Complaint IV period, and hence was not unlawful under Section 206 of the FPA.[32] 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.[33] 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*[34] (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.[35]

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

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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 XVI below, have been appealed to, and are pending before, the DC Circuit.

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

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

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

[34] *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*.

[35] *Id.* at P 19.

unreasonable. The FERC suggested that it would adopt a 10.41% Base ROE and cap any preexisting incentive-based total ROE at 13.08%.[36] The new ROE would be effective as of the date of *Opinion 531-A*, or October 16, 2014. Accordingly, the issue to be addressed in the Base ROE Complaint II proceeding is whether the ROE established on remand in the first complaint proceeding remained just and reasonable based on financial data for the six-month period September 2013 through February 2014 addressed by the evidence presented by the participants in the second proceeding. Similarly, briefing in the third and fourth complaints will have to address whether whatever ROE is in effect as a result of the immediately preceding complaint proceeding continues to be just and reasonable.

The FERC directed participants in the four proceedings to submit briefs regarding the proposed approaches to the FPA section 206 inquiry and how to apply them to the complaints (separate briefs for each proceeding). Additional financial data or evidence concerning economic conditions in any proceeding must relate to periods before the conclusion of the hearings in the relevant complaint proceeding. Following a FERC notice granting a request by the TOs and Customers[37] 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, Edison Electric Institute ("EEI"), Louisiana PSC, Southern California Edison, and AEP. As part of their initial briefs, each of the Louisiana PSC, SEC and AEP also moved to intervene out-of-time. Those interventions were opposed by the TOs on January 24, 2019. The Louisiana PSC answered the TOs' January 24 motion on February 12. Reply briefs were due March 8, 2019 and were submitted by the TOs, Complainant-Aligned Parties, EMCOS, and 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*[38] 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

- **ICR-Related Values and HQICCs – Annual Reconfiguration Auctions (ER23-)**

On November 30, 2022, 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 2023-24 Capability Year, the second ARA for the 2024-25 Capability Year, and the first ARA for the 2025-26 Capability Year. The ICR-Related Values were supported by the Participants Committee at its November 2, 2022 meeting (Consent Agenda Items 1 and 2). A January 29, 2023 effective date was requested. Comments on this filing are due on or before ***December 21, 2022***. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

[36] *Id.* at P 59.

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

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

- **ICR-Related Values and HQICCs – FCA17 (2026-27) Capacity Commitment Period (ER23-405)**

On November 8, 2022, 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 "2026-27 ICR-Related Values") for the 2026-27 Capacity Commitment Period ("CCP"). The 2026-27 ICR will be 31,306 MW (reflecting tie benefits of 2,100 MW) and HQICCs of 1,001 MW/mo., the net amount of capacity to be purchased in FCA17 to meet the ICR will be 30,305 MW. The MCL for the Maine Capacity Zone is 4,065 MW. The MCL for the NNE Capacity Zone is 8,595 MW. (For FCA17, there are no import-constrained Capacity Zones and, accordingly, ISO-NE did not have to calculate a LSR for any Capacity Zone.) The Participants Committee supported the FAC17 ICR-Related Values at its October 6, 2022 meeting. Comments on this filing were due November 29, 2022; none were filed. Doc-less interventions were filed by Calpine, Dominion, Eversource, National Grid, and NESCOE. 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).

- **2023 NESCOE Budget (ER23-100)**

This proceeding was initiated by ISO-NE's October 14, 2022 filing of the budget for funding NESCOE's 2023 operations. The 2023 Operating Expense Budget for NESCOE is $2,691,505. The amount to be recovered reflects true-ups from 2022 (over-collections of $1,108,802). Accordingly, if accepted, the NESCOE budget will result in a charge of $0.00701 per kilowatt ("kW") of Monthly Network Load (a $0.00035/kW decrease from 2022). The 2023 NESCOE budget was supported by the Participants Committee at its October 6, 2022 meeting. Comments and any interventions were due on or before November 4. On NEPOOL 4, NEPOOL filed comments supporting the 2023 NESCOE Budget. Doc-less interventions only were filed by Calpine, Eversource, NESCOE, National Grid, and Rhode Island Energy. This matter is pending before the FERC. If there are any questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **2023 ISO-NE Administrative Costs and Capital Budgets (ER23-94)**

Also on October 14, 2022, ISO-NE filed for recovery of its 2023 administrative costs (the "2023 Revenue Requirement") and submitted its capital budget and supporting materials for calendar year 2023 ("2023 Capital Budget", and together with the 2023 Revenue Requirement, the "2023 ISO Budgets"). The 2023 ISO-NE Budgets were filed together pursuant to the Settlement Agreement entered into to resolve challenges to the 2013 ISO-NE Budgets. In the October 14 filing, ISO-NE reported that the 2023 Revenue Requirement is $240.2 million (a $25.1 million or 11.7% increase over 2022), which decreases to $225.6 million after the over-collection for 2021 is subtracted. Of that total, ISO-NE's administrative costs (i.e., the 2023 Core Operating Budget) comprise $209.2 million; depreciation and amortization of regulatory assets, $31 million; and a $14.6 million true-up decrease for 2021 over-collections.

ISO-NE further reported that the 2023 Capital Budget is $33.5 million, a $1.5 million increase over 2022, and is comprised of the following (with 2023 projected costs and target completion dates, if available, in parentheses):

nGem Market Clearing Engine Implementation (Mar 2023)	($1.3 million)	IT Asset Workflow Integration and Updates (Mar 2022)	($800,000)
FCTS Infrastructure Conversion Part III ($700,000) (Apr 2023)	($700,000)	PI Historian for Short-Term Phasor Measurement Units Data Repository (Sep 2023)	($500,000)
FCM Order 2222 (Nov 2023)	($600,000)	Forecast Enhancements (Jul 2023)	($600,000)
PI Historian for Short-Term Phasor Measurement Units Data Repository (Jul 2023)	($500,000)	Physical Security Improvement Project (Sep 2023)	($400,000)

- E-mail List Server Technology Refresh (Jan 2023) ($100,000)
- Day-Ahead Ancillary Services Improvements (Oct 2024) ($3.5 million)
- CIP Electronic Security Perimeter Redesign Phase II (Jan 2024) ($2 million)
- Privileged Account Management Security Enhancements 2023 (Sep 2023) ($1.3 million)
- Integrated Market Simulator Phase I (Jun 2022) ($400,000)
- Inventoried Energy Program (Sep 2023) ($1 million)
- 2023 Issue Resolution Project ($400,000)
- Microsoft 365 Service Adoption (Jun 2024) ($500,000)
- Identity and Access Management Phase III (Dec 2023) ($500,000)
- MIS Reporting by Sub Accounts (Mar 2023) ($200,000)
- Control Room Voice Recorder Upgrade (Mar 2023) ($100,000)
- LMP Monitor Replacement (Apr 2022) ($100,000)
- Replace Messaging Software (Mar 2023) ($100,000)
- nGem Real-Time Market Clearing Engine Implementation (Jun 2025) ($3 million)
- nGem Software Development Part III (Dec 2023) ($1.5 million)
- Web to Cloud Migration
  Phase I (Nov 2023) ($800,000)
  Phase I (Dec 2023) ($1.2 million)
- External Website Migration to Cloud (Oct 2022) ($400,000)
- Solar Do Not Exceed Dispatch Phase II (Dec 2023) ($1 million)
- MOPR Elimination ($650,000) (Dec 2024) ($650,000)
- Windows Server 2019R2 (Oct 2023) ($500,000)
- FERC Order 2222 (Dec 2026) ($400,000)
- Enterprise Resource Planning System Replacement (Sep 2026) ($100,000)
- Capitalized Interest ($600,000)
- Non-Project Capital Expenditures ($4.8 million)
- Other Emerging Work ($3.4 million)

The 2023 ISO-NE Budgets were supported by the Participants Committee at its October 6, 2022 meeting. Comments on this filing were due November 4, 2022. On October 31, 2022, NEPOOL filed comments supporting the 2023 Budgets. Doc-less interventions only were filed by Calpine, Eversource, National Grid, and RI Energy. This matter is pending before the FERC. If there are any questions on this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **FirstLight CIP IROL (Schedule 17) Cost Recovery Schedule Filing (ER22-2876)**

On November 15, 2022, the FERC accepted FirstLight Power Management LLC's ("FirstLight") rate schedule that will allow FirstLight to begin the recovery period for certain Interconnection Reliability Operating Limits Critical Infrastructure Protection costs ("CIP-IROL Costs") of its affiliated generation facilities under Schedule 17 of the ISO-NE Tariff.[39] As previously reported, FirstLight stated that the rate schedule will provide interested parties notice of FirstLight'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. FirstLight's rate schedule was accepted effective as of September 16, 2022, as requested. Unless the November 15 order is challenged, this proceeding will be

[39] *FirstLight Power Management LLC*, Docket No. ER22-2876-000 (Nov. 15, 2022) (unpublished letter order).

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

- **NESCOE 5-year (2023-2027) *Pro Forma* Budget (ER22-2812)**

On September 6, 2022, NESCOE filed its fourth 5-year *pro forma* budget covering years 2023 - 2027 (the "5-year *Pro Forma* Budget") in accordance with the Memorandum of Understanding ("MOU") among ISO-NE, NEPOOL and NESCOE. The 5-year *Pro Forma* Budget was supported by the Participants Committee at its September meeting. Comments on this filing were due on or before September 27. NEPOOL filed comments supporting the 5-year *Pro Forma* Budget on September 27. National Grid and Eversource filed doc-less interventions. This matter remains pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Mystic COS Agreement Updates to Reflect Constellation Spin Transaction[40] (ER22-1192)**

As previously reported, on May 2, 2022, the FERC accepted and suspended in part Constellation Mystic Power, LLC's ("Mystic's") changes to its Amended and Restated Cost-of-Service Agreement ("COS Agreement") to reflect Mystic's current upstream ownership.[41] The changes were accepted effective as of Jun 1, 2022, but subject to refund. Specifically, the FERC accepted (i) Mystic's changes throughout the COS Agreement to replace the term "Exelon Generation Company, LLC" with "Constellation Energy Generation, LLC"; and (ii) the addition of language to the true-up methodology that provides that the values included in the true-up methodology exclude costs associated with the Spin Transaction. However, noting that Mystic's contested proposal on the issue of capital structure and cost of debt raises issues of material fact that cannot be resolved based on the record, the FERC accepted and suspended this portion of the COS Agreement for a nominal period, to become effective June 1, 2022, subject to refund and to the outcome of paper hearing procedures. The FERC also directed the appointment of a settlement judge, holding its paper hearing in abeyance so as to provide the participants an opportunity for settlement discussions.[42]

Settlement Agreement (-001) and Interim Implementation of Settlement Rate (-002). On September 8, 2022, Mystic filed an offer of settlement and related materials ("Offer of Settlement") to resolve all issues set for hearing in this proceeding. Comments supporting the Offer of Settlement were filed by FERC Trial Staff on September 22, 2022. No reply comments were filed. Judge French certified the uncontested Settlement to the Commission on October 4, 2022. The FERC accepted the Offer of Settlement on November 2, 2022,[43] directing Mystic to make a compliance filing within 30 days in this proceeding with revised tariff records in eTariff format reflecting the FERC's action in the November 2 order.

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).

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

Mystic I Remand. As previously reported, the DC Circuit issued a decision on August 23, 2022[44] that, among other things: (i) granted State Petitioners' petitions for review on the cost allocation issue; (ii) vacated the clawback portions excluding Everett costs and the challenged delay provision of the orders under review; and (iii) remanded the cases to the FERC to address NESCOE's request for clarification about revenue credits

[40] In the Spin Transaction, Constellation's and Mystic's corporate parent changed from Exelon Corporation to a newly-created holding company, Constellation Energy Corporation ("Constellation Corporation"). Mystic continues to be an indirect wholly-owned subsidiary of Constellation Energy Generation, LLC, which in turn is a direct, wholly-owned subsidiary of Constellation Corporation.

[41] *Constellation Mystic Power, LLC*, 179 FERC ¶ 61,081 (May 2, 2022) ("*May 2, 2022 Order*").

[42] *Id.* at P 24.

[43] *Constellation Mystic Power, LLC*, 181 FERC ¶ 61,099 (Nov. 2, 2022).

[44] *Constellation Mystic Power, LLC v. FERC*, 45 F.4th 1028 (D.C.Cir. 2022) ("*Mystic I Remand Order*").

and for clarification of the apparent contradictions in the FERC's *December 2020 Rehearing Order*. Since the last Report, Mystic and Constellation filed an emergency motion requesting expedited action by ***January 9, 2022***, on the Cost Allocation and Clawback issues remanded to the FERC in the *Mystic I Remand Order*, asserting that expedited FERC action on remand is needed given the implications for sales of gas from the Everett facility during the term of the COSA and the future of the Everett facility post-COSA. The FERC's Remand Order has not yet been issued.

(-000) First CapEx Info. Filing. On September 15, 2021, Mystic submitted, as required by orders in this proceeding and Sections I.B.1.i. and II.6. of Schedule 3A of the COSA ("Protocols"), its informational filing to provide support for the capital expenditures and related costs that Mystic projects will be collected as an expense between June 1, 2022 to December 31, 2022 ("First CapEx Projects Info. Filing"). Formal challenges to the September 15 filing were submitted by the Eastern New England Customer-Owned Systems ("ENECOS") and NESCOE. Mystic responded to the formal challenges on November 17, 2021 asserting that that the challenges should be rejected without further procedures. ENECOS and NESCOE replied to Mystic's November 17 reply on December 2 and December 6, 2021, respectively.

On April 28, 2022, the FERC issued an order granting in part, and denying in part, ENECOS' and NESCOE's formal challenges, subject to refund, and established hearing and settlement judge procedures.[45] The FERC summarily denied NESCOE's challenge regarding the update to the AFRR and ENECOS' challenge with regard to the improper booking of items. Those items, and challenges to other underlying projected costs, may be challenged in connection with Mystic's Second Informational Filing (where the informal challenge process begins on April 1, 2022 and the formal challenge process begins on September 15, 202).[46] The FERC reiterated that all items except return on equity and depreciation are subject to the true-up process described in Schedule 3A of the COS Agreement, not just projected capital expenditures. However, with respect to NESCOE's and ENECOS' allegations that Mystic failed to support all of its projected capital expenditures, the FERC found that the First CapEx Projects Info. Filing raised issues of material fact that could not be resolved based on the record and would be more appropriately addressed under hearing and settlement judge procedures.[47] Accordingly, the FERC set these matters for a trial-type evidentiary hearing. The FERC encouraged the parties to make every effort to settle their disputes before hearing procedures are commenced, and to that end, will hold the hearing in abeyance pending the appointment of a settlement judge and completion of settlement judge procedures.[48]

(-000) Second CapEx Info Filing. On September 15, 2022, Mystic submitted, as required by orders in this proceeding and Sections I.B.1.i. and II.6.of Schedule 3A of the COS Agreement ("Protocols") its "Second CapEx Info Filing" to provide support for the capital expenditures and related costs that Mystic projects will be collected as an expense between January 1, 2023 to December 31, 2023 ("2023 CapEx Projects"). Formal challenges to the Second CapEx Info Filing were submitted by NESCOE and ENECOS. Comments on NESCOE's and ENECOS' challenges were due on or before November 16, 2022 and November 17, 2022, respectively. Mystic responded separately to NESCOE's and ENECOS' challenges. MMWEC/NHEC filed comments supporting ENECOS' formal challenge, emphasizing its support for formal challenge to the pass through of charges incurred by Everett for pipeline transportation reservations (*see* ENECOS Mystic COSA Complaint (EL23-4) above). The Second CapEx Info Filing, including the formal challenges, and the responses/comments thereon, are now pending before the FERC.

(-014) Revised ROE (Sixth) Compliance Filing. Still pending is Mystic's December 20, 2021 filing in response to the requirements of the *Mystic ROE Allegheny Order*. The sixth compliance filing revised (i) the Cost of Common Equity figures from 9.33% to 9.19%, for both Mystic 8&9 and Everett Marine Terminal ("Everett"), and

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[45] *Constellation Mystic Power, LLC*, 179 FERC ¶ 61,011 (Apr. 28, 2022) ("*Mystic First CapEx Info. Filing Order*").

[46] *Id.* at PP 23-24.

[47] *Id.* at P 26.

[48] *Id.* at P 27.

(ii) the stated Annual Fixed Revenue Requirements for both the 2022/23 and 2023/24 Capacity Commitment Periods. Comments on the sixth compliance filing were due on or before January 10, 2022; none were filed. The Sixth Compliance Filing remains pending before the FERC.

(-015) First CapEx Info. Filing Settlement Judge Procedures. On May 4, Chief Judge Cintron designated Judge Andrea McBarnette as the Settlement Judge. Thus far, two settlement conferences have been held, the first on June 15 and the second on November 17, 2022. A third settlement conference is scheduled by WebEx for ***December 20, 2022***. On October 13, 2022, Settlement Judge McBarnette submitted a status report recommending the continuation of settlement judge procedures.

If you have questions on any aspect of this proceeding, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

- **Transmission Rate Annual (2022-23) Update/Informational Filing (ER09-1532; RT04-2)**

On July 29, 2022, the PTO AC submitted its 2023 annual filing identifying adjustments to Regional Transmission Service charges, Local Service charges, and Schedule 12C Costs under Section II of the Tariff. The filing reflected the charges to be assessed under annual transmission and settlement formula rates, reflecting actual 2021 cost data, plus forecasted revenue requirements associated with projected PTF, Local Service and Schedule 12C capital additions for 2022 and 2023, as well as the Annual True-up including associated interest. As prescribed in the Interim Protocols,[49] the formula rates that will be in effect for 2023 include a billing true up of seven months of 2021 (June-December). The PTO AC states that the annual updates results in a Pool "postage stamp" RNS Rate of $140.94 /kW-year effective January 1, 2023, a decrease of $1.84 /kW-year from the charges that went into effect on January 1, 2022. In addition, the filing includes updates to the revenue requirements for Scheduling, System Control and Dispatch Services (the Schedule 1 formula rate), which result in a Schedule 1 charge of $1.75 kW-year (effective June 1, 2022 through May 31, 2023), a $0.12/kW-year decrease from the Schedule 1 charge that last went into effect on June 1, 2022. This filing was not noticed for public comment.

The July 29 filing was reviewed with the Transmission Committee at its August 16, 2022 summer meeting and at an August 22, 2022 technical session for Interested Parties. The July 29 filing triggered the commencement of the Information Exchange Period and a Review Period under the Interim Protocols. Interested Parties have until September 15, 2022 to submit information and document requests, and the PTOs are required to make a good faith effort to respond to all requests within 15 days, but by no later than October 15, 2022. During the Review Period, Interested Parties have until November 15, 2022 to submit Informal Challenges to the PTOs, and the PTOs are required to make a good faith effort to respond to any Informal Challenges no later than December 15, 2022. Interested Parties have until January 31, 2023 to file a Formal Challenge with the FERC. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

- **FCM Parameters Recalculation Schedule Modification (ER23-74)**

On November 22, 2022, the FERC accepted Tariff changes that defer for two years the next recalculation of several FCM "parameters" and, going forward, modify the schedule for such updates from no less often than once every three years to no less often than once every four years.[50] The changes were accepted December 12,

[49] The Interim Formula Rate Protocols ("Interim Protocols") became effective June 15, 2021, and will be replaced by permanent Formula Rate Protocols that will become effective June 15, 2023. *See* Settlement Agreement resolving all issues in Docket No. EL16-19 ("Settlement") approved by the FERC on Dec. 28, 2020, in *ISO New England et al.*, 173 FERC ¶ 61,270 (2020) ("Settlement Order").

[50] *ISO New England Inc. and New England Power Pool Participants Comm.*, Docket No. ER23-74-000 (Nov. 22, 2022) (unpublished letter order).

2022, as requested. Unless the November 22, 2022 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **Solar DNE Dispatch Changes (ER23-517)**

On November 30, 2022, ISO-NE and NEPOOL filed revisions to the Do Not Exceed ("DNE") dispatch rules in Market Rule 1 to allow front-of-meter solar resources to become Dispatchable Resources ("Solar DNE Dispatch Changes"). The Solar DNE Dispatch Changes were supported by the Participants Committee at its September 1, 2022 meeting (Consent Agenda Item #6). A December 5, 2023 effective date was requested. Comments on the Solar DNE Dispatch Changes are due on or before December 21, 2022. If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **Waiver Request: Attachment F (NEP) (ER23-370)**

On November 2, 2022, New England Power requested limited waiver of certain provisions in the Attachment F formula rate template to ensure that, as of the date RI Energy becomes a PTO, NEP's transmission revenue requirements collected through regional and local rates will not include a forecast based on historical NEP revenue requirements that included costs of RI Energy-owned transmission facilities. Comments on New England Power's waiver request were due on or before November 23, 2022; none were filed. Eversource, NESCOE, the RI Division, and RI Energy intervened. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **FCA18 Schedule Modifications (ER23-50)**

On October 11, 2022, ISO-NE and NEPOOL jointly filed Tariff changes to modify the schedule for FCA18. The modifications compress the schedule for FCA18 in order that FCA18 can be conducted as originally scheduled (on February 5, 2024) notwithstanding delays in FA16 and FCA17 that otherwise would have caused the FCA18 auction date to slip. The Participants Committee supported the changes over two meetings – the September 1 and October 6, 2022 meetings (Consent Agenda Items #5 and 2, respectively). ISO-NE requested an effective date of December 11, 2022 for these changes. Comments on this filing were due on or before ***November 1, 2022***; none were filed. Doc-less interventions were filed by Dominion, Eversource, National Grid, NEPGA, NESCOE, and the MA DPU. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **New England's *Order 2222* Compliance Filing (ER22-983)**

New England's *Order 2222* Compliance Filing remains pending before the FERC. As previously reported, ISO-NE, NEPOOL and the PTO AC ("Filing Parties") submitted on February 2, 2022 Tariff revisions ("*Order 2222* Changes") in response to the requirements of *Order 2222*. The Filing Parties stated that the *Order 2222* Changes create a pathway for Distributed Energy Resource Aggregations ("DERAs") to participate in the New England Markets by: creating new, and modifying existing, market participation models for DERA use; establishing eligibility requirements for DERA participation (including size, location, information and data requirements); setting bidding parameters for DERAs; requiring metering and telemetry arrangements for DERAs and individual Distributed Energy Resources ("DERs"); and providing for coordination with distribution utilities and relevant electric retail regulatory authorities ("RERRAs") for DERA/DER registration, operations, and dispute resolution purposes.

Comments, following an extension of time granted by the FERC in response to a request by Advanced Energy Management Alliance ("AEMA"), were due on or before April 1, 2022. NEPOOL filed supplemental comments on March 28. Protests and comments were filed by: AEE/PowerOptions/SEIA; Environmental

Organizations;[51] MA AG; Voltus; AEMA and 4 New England US Senators.[52] Doc-less interventions were filed by: Avangrid (CMP/UI), Calpine, Centrica Business Solutions Optimize (out-of-time), Constellation, ENE, Enerwise, Eversource, FirstLight, MA AG, National Grid, NESCOE, NRG, MA DPU, MPUC (out-of-time), APPA, and EEI. ISO-NE (April 20) and National Grid/Avangrid/Eversource (April 19) filed answers to the protests and adverse comments. Since the last Report, AEE/PowerOptions/SEIA and AEMA answered the ISO-NE and National Grid/Avangrid/ Eversource answers.

(-001) Deficiency Letter. On May 18, 2022, the FERC issued a 25-page deficiency letter directing ISO-NE to provide, on or before June 17, 2022, additional information and clarifications. ISO-NE filed its 39-page response to the deficiency letter on June 17, 2022. Comments in response to ISO-NE's deficiency letter response were due on or before July 8, 2022 and a joint protest was filed by AEE, AEMA, PowerOptions, and SEIA ("Joint Protest"). The Joint Protest, while supportive of certain responses (those regarding the exemption of DERAs from the Small Generator Interconnection Procedures ("SGIP") prior to 2026, locational requirements for DER aggregation, and the role of host utilities in identifying potential conflicts with retail program participation), protested the adequacy of ISO-NE responses regarding proposed metering and telemetering requirements for behind-the-meter ("BTM") DERs. On July 25, 2022, ISO-NE answered the July 8 Joint Protest. On August 9, 2022, AEE, AEMA, PowerOptions, and SEIA answered ISO-NE's July 25 answer.

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); Eric Runge (617-345-4735; ekrunge@daypitney.com); or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **IEP Remand (ER19-1428-006)**

On November 22, 2022, ISO-NE filed Tariff provisions governing the Inventoried Energy Program ("IEP") consistent with the D.C. Circuit's *IEP Decision*.[53] ISO-NE's proposed Tariff changes remove nuclear, biomass, coal, and hydroelectric generators from the IEP. ISO-NE's Tariff changes were supported by the Participants Committee at its November 2 meeting (as were alternative Tariff changes proposed by Brookfield that explicitly allow pumped hydro resources to participate in the IEP as Electric Storage Facilities). Comments, including those by NEPOOL that will identify and advocate for the alternative Tariff changes, must be filed on or before ***December 13, 2022***. Calpine filed a doc-less intervention on November 23, 2022. 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).

IV. OATT Amendments / TOAs / Coordination Agreements

- **Attachment F Revisions Reflecting RIE Addition as PTO (ER23-299)**

On October 31, 2022, The Narragansett Electric Company d/b/a Rhode Island Energy ("RI Energy") filed revisions to Attachment F of the OATT to reflect its addition as a newly independent Participating Transmission Owner ("PTO"). A January 1, 2023 effective date was requested. Comments on the RI Energy

[51] Environmental Organizations are Acadia Center, Conservation Law Foundation ("CLF"), Environmental Defense Fund ("EDF"), Massachusetts Climate Action Network, NRDC, Sierra Club, and the Sustainable FERC Project.

[52] Senators Markey (MA), Sanders (VT), Warren (MA), and Whitehouse (RI).

[53] *Belmont Mun. Light Dept., et al., v. FERC*, 2022 WL 2182810 (June 17, 2022) (the "*IEP Decision*"). The *IEP Decision* leaves intact the FERC's *June 2020 IEP Remand Order* (*ISO New England Inc.*, 171 FERC ¶ 61,235 (June 18, 2020)) except for the inclusion of nuclear, biomass, coal, and hydroelectric generators in ISO-NE's IEP, the inclusion of which the Court found arbitrary and capricious (because those resources were unlikely to change their behavior in response to the IEP payments). Because the Court believed "there is not substantial doubt that FERC would have adopted IEP if it had not included these resources in the first place [and] IEP can function sensibly without them", the Court found that it had the authority to sever this portion from the overall program and therefore vacated that portion of IEP from the remainder of the IEP. The Court upheld the remainder of the IEP and remanded the matter to the FERC for further proceedings consistent with its opinion.

Attachment F Revisions were due on or before November 21, 2022. Comments were filed by National Grid (supporting the revisions) and the Rhode Island Division of Public Utilities and Carriers ("RI Division") (not opposing the revisions based on RI Energy's representations, the additional procures highlighted, and the RI Division's express reservation or rights set forth in the Division's comments). Eversource and NESCOE submitted doc-less interventions only. 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).

- **Attachment F Depreciation Normalization Requirement Revisions (ER23-197)**

On October 26, 2022, certain Transmission Owners[54] filed revisions to Attachment F of the OATT to apply the IRS's ADIT proration formula to their actual (true-up) revenue requirements and to thereby maintain compliance with the IRS's depreciation normalization requirements and to ensure their continued ability to use accelerated depreciation. Estimated revenue impacts were identified in the filing. A January 1, 2023 effective date was requested. Comments on these Attachment F Revisions were due on or before November 16, 2022; none were filed. Calpine and the MPUC intervened. 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).

- **Attachment F, Appendix D-PSNH: Establishment of Depreciation Rate for Accounts 357 and 358 (ER22-2953)**

On September 29, 2022, PSNH proposed changes to Attachment F, Appendix D-PSNH to establish the transmission plant depreciation rates for Account 357 (Underground Conduit) and Account 358 (Underground Conductors and Devices) in PSNH's Appendix D to Attachment F of the ISO-NE OATT that will be used to calculate PSNH's annual transmission revenue requirements for transmission service under the ISO-NE OATT. On November 2, 2022, PSNH supplemented and corrected its September 29 filing by submitting substitute eTariff records with PSNH's proposed depreciation rates for Accounts 357 (1.73%) and 358 (2.19%), revised versions of supporting Exhibit Nos. PSNH-1, PSNH-2, PSNH-3, and PSNH-4, and a new Exhibit No. PSNH-5. The amended proposed depreciation rates are expected to result in a revenue rate reduction of approximately $27,314 more than proposed in the September 29 Filing. A January 1, 2023 effective date was requested for all the changes proposed in this proceeding. Comments on the November 2 amendments were due on or before November 23, 2022; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Phase I/II HVDC-TF Order 881* Compliance Filing: HVDC TOA (ER22-2467) and Sched. 20-A Common Attachment M (ER22-2468)**

On July 22, 2022, following a requested 10-day extension of time granted by the FERC, a Phase I/II HVDC-TF *Order 881* compliance filing was submitted in two parts ((i) changes to the HVDC TOA and (ii) changes to Schedule 20-Common Attachment M) by: ISO-NE, the Asset Owners,[55] and the Schedule 20A Service Providers.[56] Specifically, the Filing proposed changes to the ***HVDC TOA*** (ER22-2467) to address the Order 881 requirements related to transmission ratings and rating procedures and to ***Schedule 20A-Common*** (ER22-2468) to ensure compliance with Order 881 with respect to transmission rating transparency and transmission service (together, the "Phase I/II HVDC-TF *Order 881* Compliance Filing"). Comments on the Phase I/II HVDC-

[54] The TO filers are as follows: Central Maine Power Co. ("CMP"); Eversource Energy Service Co. ("Eversource") on behalf of The Conn. Light and Power Co. ("CL&P"), Public Service Co. of New Hampshire ("PSNH"), NSTAR Elec. Co. ("NSTAR"); Fitchburg Gas and Elec. Light Co.; Green Mountain Power Corp.; Maine Elec. Power Co.; New England Power Co. d/b/a National Grid; New Hampshire Transmission, LLC; The United Illuminating Co.; Vermont Transco, LLC; and Versant Power.

[55] The "Asset Owners" are, collectively, New England Hydro-Transmission Electric Company, New England Hydro-Transmission Corporation, New England Electric Transmission Corporation, and Vermont Electric Transmission Company ("VETCO").

[56] The "Schedule 20A Service Providers" are: Central Maine Power Co. ("CMP"); The Conn. Light and Power Co. and Public Service Co. of NH ("Eversource"); Green Mountain Power Cor. ("GMP"); New England Power Co. ("NEP"); NSTAR Electric Co.; The United Illuminating Co. ("UI"); Vermont Electric Cooperative, Inc. ("VEC"); and Versant Power.

TF *Order 881* Compliance Filing were due on or before August 12, 2022; none were filed. The IRH Management Committee submitted a doc-less intervention. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Order 881* Compliance Filing: New England (ER22-2357)**

As previously reported, ISO-NE, NEPOOL, the PTO AC, and CSC (the "Filing Parties") filed, on July 12, 2022, proposed revisions to the OATT in response to the requirements of *Order 881*[57] ("*Order 881* Compliance Changes"). Specifically, the Filing Parties proposed the addition of a new Attachment Q to the OATT, and to revise OATT Schedules 18 (MTF; MTF Service) and 21 (Local Service - Common). The *Order 881* Compliance Changes (the Attachment Q and Schedule 18 changes) were supported by the Participants Committee at its June 21-23 Summer Meeting (Consent Agenda Item No. 2). An effective date of September 10, 2022 was requested, with changes to Attachment Q and Schedule 21 to become applicable by their own terms in July 2025. Comments on the *Order 881* Compliance Changes are due on or before August 2, 2022; none were filed. Eversource, Narragansett Electric Company ("Narragansett") and National Grid filed doc-less interventions. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Order 676-J* Compliance Filing Part I (CSC-Schedule 18-Attachment Z) (ER22-1168)**

On March 2, 2022, in response to the requirements of *Order 676-J*,[58] ISO-NE and CSC filed revisions to ISO-NE Tariff Schedule 18 Attachment Z to incorporate the new cybersecurity and PFV standards contained in the North American Energy Standards Board ("NAESB") Wholesale Electric Quadrant ("WEQ") Version 003.3 Standards ("Schedule 18 Order 676-J Part I Changes").[59] An effective date as of the date of the FERC order accepting these changes was requested. Comments on this filing were due on or before March 23, 2022; none were filed. Doc-less interventions were filed by CSC and NEPOOL. There was no activity since the last Report and this matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Order 676-J* Compliance Filing Part I (TOs-Schedule 20/21-Common) (ER22-1161)**

Also on March 2, 2022, in response to the requirements of *Order 676-J*, the PTO AC, ISO-NE, and the Schedule 20A Service Providers ("S20SPs") (collectively, the "TOs") filed revisions to ISO-NE Tariff Schedules 20A-Common and 21-Common to incorporate the new cybersecurity and PFV standards contained in NAESB WEQ Version 003.3 Standards ("Schedule 20/21-Common Order 676-J Part I Changes").[59] An effective date as of the date the FERC may determine was requested. Comments on this filing were due on or before March 23, 2022; none were filed. Doc-less interventions were filed by NEPOOL and Eversource. There was no activity since the last Report and this matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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[57] *Managing Transmission Line Ratings*, Order No. 881, 177 FERC ¶ 61,179 (Dec. 16, 2021); *Managing Transmission Line Ratings*, Order No. 881-A, 179 FERC ¶ 61,125 (May 19, 2022) (together, "*Order 881*").

[58] *Standards for Business Practices and Communication Protocols for Public Utilities*, Order No. 676-J, 175 FERC ¶ 61,139 (May 20, 2021) ("*Order 676-J*"). *Order 676-J* revised FERC regulations to incorporate by reference the latest version (Version 003.3) of the Standards for Business Practices and Communication Protocols for Public Utilities adopted by NAESB's Wholesale Electric Quadrant. The WEQ Version 003.3 Standards include, in their entirety, the WEQ-023 Modeling Business Practice Standards contained in the WEQ Version 003.1 Standards, which address the technical issues affecting Available Transfer Capability ("ATC") and Available Flowgate Capability ("AFC") calculation for wholesale electric transmission services, with the addition of certain revisions and corrections. The FERC also revised its regulations to provide that transmission providers must avoid unduly discriminatory and preferential treatment in the calculation of ATC.

[59] Compliance filings for the rest of the WEQ Version 003.3 Standards (Schedule 24 Order 676-J Part II Changes) were due 12 months after implementation of the WEQ Version 003.2 Standards, or no earlier than Oct. 27, 2022.

- ***Order 676-J* Compliance Filing Part I (ISO-NE-Schedule 24) (ER22-1150)**

Again on March 2, 2022, in response to the requirements of *Order 676-J*, ISO-NE filed revisions to ISO-NE Tariff Schedule 24 (Incorporation by Reference of NAESB Standards) to incorporate the new cybersecurity and PFV standards contained in NAESB WEQ Version 003.3 Standards ("Schedule 24 Order 676-J Part I Changes").[59] An effective date no earlier than June 2, 2022 was requested. The Transmission Committee recommended that the Participants Committee support the Schedule 24 Order 676-J Part I Changes at its March 23 meeting, and the Participants Committee supported the changes at the April 7 meeting (Consent Agenda Item # 1). Comments on this filing were due on or before March 23, 2022; none were filed. NEPOOL, Eversource, MA DPU, and National Grid submitted doc-less interventions. There was no activity since the last Report and this matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes & Agreements

- **Schedule 21-NEP: Removal of References to Narragansett; Update Reference to NGrid LCC (ER23-165)**

On October 24, 2022, New England Power Company ("NEP") filed revisions to Schedule 21-NEP. The revisions remove references in Schedule 21-NEP to The Narragansett Electric Company ("Narragansett") as an affiliate of NEP and any Narragansett-specific rate provisions. NEP also proposed minor revisions to Schedule 21-NEP to update references in the local service schedule to the National Grid Local Control Center ("LCC") (f/k/a REMVEC). NEP requested a January 1, 2023 effective date for the revisions. Comments on this filing were due on or before November 14, 2022; none were filed. Narragansett filed a doc-less intervention. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-RIE (ER23-16)**

On October 4, 2022, The Narragansett Electric Company d/b/a Rhode Island Energy ("RI Energy") filed revisions to Schedule 21 and Attachment E of Section II of the OATT to establish RI Energy's rates, terms, and conditions for the provision of Local Service and to accommodate RIE as a new Participating Transmission Owner ("PTO"). Comments on this filing were due on or before October 26, 2022 and were filed by National Grid (supporting RI Energy's filing) and the Rhode Island Division of Public Utilities and Carriers ("RI Division") (expressing concern that this proceeding's record is inadequate to demonstrate the justness and reasonableness of RI Energy's filing and requesting that RI Energy (i) confirm that its filing complies with all of the commitments made by PPL in connection with approval of the Narragansett acquisition; (ii) confirm that its filing will carry forward the rate treatment of the Block Island Transmission System approved earlier in 2022;[60] and (iii) provide additional information regarding the rate impacts of the proposed changes). On November 14, 2022, RI Energy answered the October 26 comments of the RI Division. On November 21, 2022, the RI Division answered RI Energy's November 14 answer. This matter is now pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-VP: 2021 Annual Update Settlement Agreement (ER20-2119-001)**

On March 25, 2022, Versant Power submitted a joint offer of settlement between itself and the MPUC to resolve all issues raised by the MPUC in response to Versant's 2021 annual charges update filed, as

[60] *See* Filing of Third Revised Service Agreement Nos. TSA-NEP-83 and TSA-NEP86 Under Schedule 21-NEP to the ISO New England Inc. Open Access Transmission Tariff, *ISO New England Inc.*, Docket No. ER22-927 (filed Jan. 31, 2022); *ISO New England Inc.*, Docket No. ER22-927 (Mar. 31, 2022) (unpublished letter order accepting changes).

previously reported, on June 15, 2021, and as amended on June 20, 2021 and July 8, 2021 (the "Versant 2021 Annual Update Settlement Agreement"). Under Part V of Attachment P-EM to Schedule 21-VP, "Interested Parties shall have the opportunity to conduct discovery seeking any information relevant to implementation of the [Attachment P-EM] Rate Formula. . . ." and follow a dispute resolution procedure set forth there. In accordance with those provisions, the MPUC identified certain disputes with the 2021 Annual Update, all of which are resolved by the Versant 2021 Annual Update Settlement Agreement. Comments on the Versant 2021 Annual Update Settlement Agreement were due on or before April 14, 2022; none were filed. This matter remains pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-VP: 2020 Annual Update Settlement Agreement (ER15-1434-005)**

On November 19, 2021, Versant Power submitted a joint offer of settlement between itself and the MPUC to resolve all issues raised by the MPUC in response to Versant's 2020 annual charges update filed, as previously reported, on June 15, 2020 (the "Versant 2020 Annual Update Settlement Agreement"). Under Part V of Attachment P-EM to Schedule 21-VP, "Interested Parties shall have the opportunity to conduct discovery seeking any information relevant to implementation of the [Attachment P-EM] Rate Formula. . . ." and follow a dispute resolution procedure set forth there. In accordance with those provisions, the MPUC identified certain disputes with the 2020 Annual Update, all of which are resolved by the Versant 2020 Annual Update Settlement Agreement. Comments on the Versant 2020 Annual Update Settlement Agreement were due on or before December 10, 2021; reply comments, December 19, 2021; none were filed. There was no activity since the last Report and this matter remains pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

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

Fitchburg Gas & Electric's ("FG&E") 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*[61] *and 531-B*[62] also remains pending. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

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

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

The *Opinions 531-A and 531-B* refund reports filed by the following TOs for their customers taking local service during the refund period also remain pending before the FERC:

- Central Maine Power
- Emera Maine
- Eversource
- National Grid
- NHT
- NSTAR
- United Illuminating
- VTransco

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

- **Capital Projects Report - 2022 Q3 (ER23-114)**

On October 14, 2022, ISO-NE filed its Capital Projects Report and Unamortized Cost Schedule covering the third quarter ("Q3") of calendar year 2022 (the "Report").[63] Report highlights included the following new projects: (i) FCM *Order 2222* ($1.15 million); and (ii) IT Asset Workflow Integration and Updates ($1.06 million). Projects with a significant changes (with amounts returned to the Emerging Work Fund following in parentheses) were (i) 2022 Issue Resolution ($120,000); (ii) Privileged Account Management Security Enhancements ($105,900); and (iii) Packet Broker Infrastructure Replacement Project ($105,500). While comments on the 2022 Q3 Report would in due course otherwise have been due on or before November 4, 2022, the FERC did not issue a notice of this filing until November 17, 2022, and thus identified the comment date as December 8, 2022. On October 31, NEPOOL intervened doc-lessly and submitted comments supporting the Report. Other than NEPOOL, no party has yet intervened. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **Interconnection Study Metrics Processing Time Exceedance Report Q3 2022 (ER19-1951)**

On November 16, 2022, ISO-NE filed, as required,[64] public and confidential[65] versions of its Interconnection Study Metrics Processing Time Exceedance Report (the "Exceedance Report") for the Third Quarter of 2022 ("2022 Q3"). ISO-NE reported that all six of the 2022 Q3 ***Interconnection Feasibility Study ("IFS") reports*** delivered to Interconnection Customers were delivered later than the best efforts completion timeline.[66] In addition, 11 IFS Reports that are not yet completed have exceeded the 90-day completion expectation. The average mean time from ISO-NE's receipt of the executed IFS Agreement to delivery of the completed IFS report to the Interconnection Customer was 176 days (roughly 60 days longer than in 2022 Q2). All four of the ***System Impact Study ("SIS") reports*** delivered to Interconnection Customers were delivered later than the best efforts completion timeline of 270 days. In addition, 19 SIS Studies that are not yet completed have exceeded the 270-day completion expectation. The average mean time from ISO-NE's receipt of the executed SIS Agreement to delivery of the completed SIS report to the Interconnection Customer was 449 days (an decrease of roughly 75 days from 2022 Q2). There were no Interconnection Requests with projects in the Interconnection Facilities Study phase of the interconnection process. Section 4 of the Report identified steps ISO-NE has identified to remedy issues and prevent future delays, including mitigating the impact of backlogs and initiating clustering, moving to earlier in the process certain Interconnection Customer

[63] *ISO New England Inc.*, Docket No. ER21-2632 (Oct. 1, 2021) (unpublished letter order).

[64] Under section 3.5.4 of ISO-NE's Large Generator Interconnection Procedures ("LGIP"), ISO-NE must submit an informational report to the FERC describing each study that exceeds its Interconnection Study deadline, the basis for the delay, and any steps taken to remedy the issue and prevent such delays in the future. The Exceedance Report must be filed within 45 days of the end of the calendar quarter, and ISO-NE must continue to report the information until it reports four consecutive quarters where the delayed amounts do not exceed 25 percent of all the studies conducted for any study type in two consecutive quarters.

[65] ISO-NE requested that the information contained in Section 3 of the un-redacted version of the Exceedance Report, which contains detailed information regarding ongoing Interconnection Studies and if released could harm or prejudice the competitive position of the Interconnection Customer, be treated as confidential under FERC regulations.

[66] 90 days from the Interconnection Customer's execution of the study agreement.

data reviews, and enhanced information sharing and coordination efforts with Interconnecting TOs. This report was not noticed for public comment.

- **IMM Quarterly Markets Reports – Summer 2022 (ZZ22-4)**

On November 2, 2022, the IMM filed with the FERC its Summer 2022 report of "market data regularly collected by [the IMM] in the course of carrying out its functions under … Appendix A and analysis of such market data," as required pursuant to Section 12.2.2 of Appendix A to Market Rule 1. These filings are not noticed for public comment by the FERC. The Summer 2022 Report was discussed with the Markets Committee at its November 9, 2022 meeting.

- **ISO-NE FERC Form 3Q (2022/Q3) (not docketed)**

On November 28, 2022, ISO-NE submitted its 2022/Q3 FERC Form 3Q (Quarterly financial report of electric utilities, licensees, and natural gas companies). FERC Form 3-Q is a quarterly regulatory requirement which supplements the annual FERC Form 1 financial reporting requirement. These filings are not noticed for comment.

IX. Membership Filings

- **December 2022 Membership Filing (ER23-518)**

On November 30, 2022, NEPOOL requested that the FERC accept the membership of 11772244 Canada Inc. (Supplier Sector), effective as of December 1, 2022. Comments, if any, on the December membership filing are due on or before ***December 21, 2022***.

- **November 2022 Membership Filing II (ER23-402)**

On November 9, 2022, NEPOOL requested that the FERC accept the membership of Windham Energy Center (Provisional Member), effective as of November 10, 2022 (to coincide with the FCA17 qualification deadline for Market Participant status). Comments on the second of the two November membership filings were due on or before November 30, 2022; none were filed. November 2022 Membership Filing II is also pending before the FERC.

- **November 2022 Membership Filing I (ER23-310)**

On October 31, 2022, NEPOOL requested that the FERC accept (i) the memberships of: Derby Fuel Cell, LLC [Related Person to Fuel Cell Energy Companies, DFC ERG CT and Bridgeport Fuel Cell (AR Sector, RG Sub-Sector)]; KCE CT 5, KCE CT 7, KCE CT8, and KCE CT 9 [Related Persons to KCE CT 1 and 2 (Provisional Group Member); Maven Energy, LLC (Supplier Sector); Rhode Island Bioenergy, LLC [Related Person to Rhode Island Bioenergy Facility, LLC (AR Sector, RG Sub-Sector, Small RG Group Member); Rhode Island Division of Public Utilities Carriers End User Sector); Sunnova Energy Corporation (AR Sector, DG Sub-Sector); and Triolith Energy Fund, LP (Supplier Sector); (ii) the termination of the Participant status of EIP Investment, LLC (Provisional Group Member); and (iii) the name change of Stones DR, LLC (f/k/a Centrica Business Solutions Optimize, LLC). Comments on the first of the two November membership filings were due on or before November 21, 2022; none were filed. November 2022 Membership Filing I is pending before the FERC.

- **October 2022 Membership Filing (ER22-2982)**

On November 25, 2022, the FERC accepted (i) the memberships of Danske Commodities US LLC (Supplier Sector); The Massachusetts Climate Action Network (End User Sector); MFT Energy US 1 LLC (Supplier Sector); and Spotlight Power LLC (Supplier Sector); and (ii) the termination of the Participant status of IPKeys Power Partners, Inc. (Supplier Sector).[67]

[67] *New England Power Pool Participants Comm.*, Docket No. ER22-2982-000 (Nov. 25, 2022) (unpublished letter order).

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

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

- **Revised Reliability Standards: EOP-011-3 and EOP-012-1 (RD23-1)**

On October 28, 2022, NERC requested approval of proposed changes to Reliability Standards EOP-011-3 (Emergency Operations) and EOP-012-1 (Extreme Cold Weather Preparedness and Operations) (the "Cold Weather Standards"). The changes to the Cold Weather Standards, which address certain key recommendations from the *Feb 2021 Cold Weather Outages Joint Report,*[68] establish a more comprehensive framework of requirements addressing generator preparedness for cold weather operations. The Cold Weather Standards also address the use of manual load shed during Emergency conditions, requiring Transmission Operators to take steps to minimize the use of manual load shed that could further exacerbate Emergency conditions and threaten system reliability. NERC requested that these Cold Weather Standards become effective on the first day of the first calendar quarter that is 18 months after FERC approval ("Effective Date"). Generator Owners would have an additional 42 months from the Effective Date to come into compliance with new freeze protection measures and 60 months from the Effective Date to perform their first five-year update of the Extreme Cold Weather Temperature. Comments on the Cold Weather Standards are due, following a request for an extension of time filed by EPSA and partially granted by the FERC on November 29, 2022, on or before ***December 8, 2022***.

- **Revised Reliability Standards: FAC-001-4 and FAC-002-4 (RD22-5)**

On November 17, 2022, the FERC approved proposed changes to Reliability Standards FAC-001-4 (Facility Interconnection Requirements) and FCA-002-4 (Facility Interconnection Studies) (the "FAC Standards"). The changes to the FAC Standards, developed from recommendations in the NERC Inverter-Based Resource Performance Task Force's ("IRPTF") March 2020 white paper, (i) replace the term "materially modifying," which is used in FERC's interconnection process, and replace it with the term "qualified change"; and (ii) identify the planning coordinator as the entity responsible for developing a uniform definition of "qualified change" that describes the changes to interconnected Facilities that must be addressed in interconnection requirements and studies under the FAC Standards. The FERC accepted NERC's proposed implementation plan, which provides that the proposed FAC Standards would become effective on January 1, 2024, and on January 1, 2025 where the planning coordinator's definition of "qualified change" differs from what an applicable entity may have considered a "materially modifying" change in Facility interconnection requirements or studies under the current standards. Challenges, if any, to the *FAC Standards Order* are due on or before ***December 19, 2022***.

- **Inverter-Based Resource Registration (RD22-4)**

On November 17, 2022, to address FERC concerns regarding the reliability impacts of inverter-based resources ("IBRs")[69] on the Bulk-Power System ("BPS"), the FERC issued an order[70] directing NERC to submit a work plan on or before ***February 15, 2023*** describing how it plans to identify and register owners and operators of IBRs that are connected to the BPS, but that are not currently required to register with NERC under the bulk electric system ("BES") definition ("unregistered IBRs"), and that "have an aggregate, material impact on the reliable operation of the [BPS]". FERC stated that the work plan should explain how NERC will modify its processes

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68 FERC, NERC, Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States (Nov. 2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texasand-south-central-united-states-ferc-nerc-and ("*Feb 2021 Cold Weather Outages Joint Report*").

69 IBRs include all generating facilities that connect to the BPS using power electronic devices that change direct current ("DC") power produced by a resource to alternating current ("AC") power compatible with distribution and transmission systems. IBRs connected to the distribution system are not addressed in the *IBR Registration Order*.

70 *Registration of Inverter-based Resources*, 181 FERC 61,124 (Nov. 17, 2022) ("*IBR Registration Order*").

to address unregistered IBRs within 12 months of approval of the work plan. The work plan must also include implementation milestones ensuring that owners and operators meeting the new registration criteria are identified within 24 months of the approval date of the work plan, and that they are registered and required to comply with applicable Reliability Standards within 36 months of the approval date of the work plan. The FERC will notice the work plan for public comment. Once approved, NERC must file progress reports every 90 days thereafter detailing the progress towards identifying and registering owners and operators of unregistered IBRs.

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

As previously reported, NERC is required to file on an informational basis quarterly status updates regarding the development of new or modified Reliability Standards pertaining to virtualization and cloud computing services. NERC submitted its most recent informational filing regarding one active CIP standard development project (Project 2016-02 – Modifications to CIP Standards ("Project 2016-02")) on September 15, 2022.[71] Project 2016-02 focuses on modifications to the CIP Reliability Standards to incorporate applicable protections for virtualized environments. A revised schedule for Project 2016-02, which has not changed since the last (June 2022) quarterly report, calls for final balloting of revised standards in October 2022, NERC Board of Trustees Adoption in November 2022 and filing of the revised standards with the FERC in December 2022.

- **2023 NERC/NPCC Business Plans and Budgets (RR22-4)**

On November 2, 2022, the FERC accepted, subject to a 60-day compliance filing, NERC's proposed Business Plan and Budget, as well as the Business Plans and Budgets for the Regional Entities, including NPCC, for 2023.[72] As previously reported, FERC regulations[73] require NERC to file its proposed annual budget for statutory and non-statutory activities 130 days before the beginning of its fiscal year (January 1), as well as the annual budget of each Regional Entity for their statutory and non-statutory activities, including complete business plans, organization charts, and explanations of the proposed collection of all dues, fees and charges and the proposed expenditure of funds collected. NERC reported that its proposed 2023 funding requirement represents an overall increase of approximately 13.7% over NERC's 2022 funding requirement. The NPCC U.S. allocation of NERC's net funding requirement is $10.97 million. NPCC requested $18.14 million in statutory funding (a U.S. assessment per kWh (2021 NEL) of $0.0000600) and $1.07 million for non-statutory functions.

In accepting NERC's Business Plan/Budget Filing, the FERC agreed with EEI that additional transparency into certain Electricity Information Sharing and Analysis Center ("E-ISAC") costs would better allow the FERC to fulfill its oversight duties. To that end, the FERC directed NERC to submit a compliance filing providing additional information related to E-ISAC costs, the E-ISAC vendor affiliate program, and the E-ISAC and natural gas stakeholder partnership. That compliance filing is due on or before ***January 3, 2023***.

- **NPCC Bylaws Changes (RR22-2)**

As previously reported, the FERC conditionally approved, on July 8, 2022, changes to the NPCC Bylaws (the "Bylaws") designed to, among other things: (1) to improve corporate governance; (2) to ensure consistency with the Not-for-Profit Corporation Law of the State of New York ("N-PCL"), pursuant to which NPCC is organized; and (3) to remove extraneous provisions rom the Bylaws, create efficiencies, and reflect changes at NPCC since 2012 (when the last changes to the Bylaws were filed).[74] In accepting the Bylaws Changes, the FERC directed NERC/NPCC to submit in a compliance filing, due, following an extension of time requested and granted, on or before October 6, 2022, changes that (i) provide members being terminated for failure to comply with bylaw

[71] The other project which had been addressed in prior updates, Project 2019-02, has concluded, and the FERC approved in RD21-6 the Reliability Standards revised as part of that project (CIP-004-7 and CIP-011-3) on Dec. 7, 2021.

[72] *N. Am. Elec. Rel. Corp.*, 181 FERC ¶ 61,095 (Nov. 2, 2022) ("*FAC Standards Order*").

[73] 18 CFR § 39.4(b) (2022).

[74] *N. Am. Elec. Rel. Corp.*, 180 FERC ¶ 61,016 (July 8, 2022).

provisions related to qualifications, obligations, and conditions of membership (a) notice within a reasonable time period of the NPCC Board's membership termination decision and the reason(s) for the action and (b) the option to appeal the membership termination in accordance with the due process requirement in FPA Section 215; and (ii) specifically describe the method of providing public notice of member meetings. The FERC found Public Citizen's protest[75] beyond the scope of the proceeding. The Bylaws changes were accepted effective as of the date of the order, or July 8, 2022, as requested.

Compliance Filing. On October 5, 2022, NERC and NPCC submitted as directed their compliance filing in response to the July 8, 2022 order. The compliance filing revises the Bylaws to (i) require that prior to terminating any NPCC Member under section 4.6, the NPCC Board must provide the affected Member 21 days prior written notice and an opportunity to cure the problem or appeal the reason for the proposed termination; (ii) to specify that the meeting notices shall be posted on NPCC's public website in a "reasonably prominent location; and (iii) to update the NPCC Bylaws' Table of Contents. Comments on the compliance filing were due on or before October 26, 2022; none were filed. The compliance filing is pending before the FERC.

XI. Misc. - of Regional Interest

- **203 Application: Agilitas Companies / AB CarVal Funds (EC23-30)**
  On November 21, 2022, Agilitas Companies[76] requested authorization for a transaction pursuant to which the AB CarVal Funds[77] will convert their existing passive, non-voting ownership interest in Agilitas Energy, Inc., which indirectly owns all of the membership interests in the Agilitas Companies, into 21.3% of the voting interests in Agilitas Energy. Comments on the 203 application are due on or before ***December 12, 2022***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Central Rivers Power / LSPower (EC23-22)**
  On November 2, 2022, Central Rivers Power Super Holdings Holdco, LLC, an affiliate of Hull Street Energy Partners and Central Rivers Power (together, "Central Rivers Power") and Patriot Hydro, LLC, an indirect, wholly controlled subsidiary of LS Power Development, LLC and affiliate of LS Power (together, "LSPower") requested authorization for a portion of a larger transaction pursuant to which LSPower will acquire Central Rivers Power's QF assets in New England, making NEPOOL Participants Central Rivers Power MA, LLC and Central Rivers Power NH, LLC Related Persons to Jericho Power. Comments on this application were due on or before November 23, 2022; none were filed. PJM filed a doc-less intervention. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Seneca Energy II / BP (EC23-18)**
  On October 31, 2022, Seneca Energy II, LLC ("Seneca") and wholly owned subsidiaries of BP Products North America Inc. ("BP") requested authorization for a transaction pursuant to which Seneca will ultimately become a Related Person of BP. Comments on the 203 application were due on or before November 21, 2022; 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).

[75] In its protest, Public Citizen argued that the FERC should require a change to the composition of NPCC's Board of Directors, suggesting that NPCC be compelled to ensure that, of NPCC's eight board sectors and 15 voting members, "household consumer advocates" have two voting seats in Sector 7 (Sub-Regional Reliability Councils, Customers, Other Regional Entities and Interested Entities), and that regulators, reliability coordinators, and end-users compose at least half of the voting seats of the board.

[76] For purposes of this proceeding, "Agilitas Companies" are: Madison BTM LLC; Madison ESS, LLC; Rumford ESS, LLC; South Portland ESS, LLC; Sanford ESS, LLC; Ocean State BTM, LLC; and AE-ESS NWS 1, LLC. Madison BTM, Madison ESS, Rumford EES, and Ocean State BTM are each NEPOOL Participants. This transaction will not impact Agilitas' membership in the AR Sector.

[77] The "AB CarVal Funds" are CEF Master Fund IV LP, CVI CEF II Pooling Fund IV LP, and CVI CSF Master Fund II LP.

- **203 Application: ConEd / RWE (EC23-17)**

On October 28, 2022, RWE Renewables Americas, LLC ("RWE") and ConEd[78] requested authorization for a transaction pursuant to which RWE will acquire 100% of the equity interests in ConEd's Clean Energy Businesses (including NEPOOL members Consolidated Edison Energy, Inc.; Consolidated Edison Development, Inc.; and Consolidated Edison Solutions, Inc. (but not Consolidated Edison Company of New York)). Comments on the 203 application were due on or before November 28, 2022; none were filed. PJM and Public Citizen filed doc-less interventions. 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).

- **203 Application: Great River Hydro / HQI US (EC23-16)**

Also on October 28, 2022, Great River Hydro, LLC ("Great River Hydro") and HQI US Holding LLC ("HQUI US"), an indirect and wholly-owned subsidiary of Hydro-Québec ("HQ") requested authorization for a transaction pursuant to which HQI US will indirectly acquire 100% of the membership interests in Great River Hydro. Comments on this 203 application are due on or before ***December 12, 2022***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: EDF Energy / BP Retail (EC22-122)**

On November 14, 2022, the FERC authorized a transaction pursuant to which BP Retail Energy LLC ("BP Retail") will acquire 100% of the membership interests in EDF Energy Services, LLC ("EDF Energy"),[79] making EDF Energy and BP Retail Related Persons. Pursuant to the November 14 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. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Salem Harbor / Lenders (EC22-117)**

On October 31, 2022, the FERC authorized[80] as requested a transaction pursuant to which the direct and indirect equity interests in Salem Harbor that are currently directly and indirectly held by Salem Harbor Power FinCo, LP will be transferred to a newly formed Delaware limited liability company ("New HoldCo"), and (2) the equity interests of New HoldCo will be issued to Salem Harbor's lenders (the "Lenders") under a pre-petition credit facility. Among other standard conditions, the October 31 order requires that notice must be filed within 10 days of consummation of the transaction, which as of the date of this Report has not yet occurred. If you have any questions, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).If you have any questions, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Waterside Power / KKR (EC22-79)**

As previously reported, the FERC authorized on August 19, 2022 the sale of 100% of the equity interests in Applicants, including Generation Group Seat Member Waterside Power, among others,[81] to Cretaceous Bidco Limited ("Buyer"), a special purpose vehicle indirectly owned by funds, investment vehicles and/or separately managed accounts advised and/or managed by one or more subsidiaries of KKR & Co. Inc. ("KKR & Co." and, together with its subsidiaries, ("KKR")).[82] Pursuant to the *August 19 Order*, notice must be filed within 10 days of

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[78] "ConEd" includes Consolidated Edison, Inc., its wholly-owned subsidiary Con Edison Clean Energy Businesses, Inc. ("CEB"), and CEB's public utility subsidiaries (together, members of the Supplier Sector). RWE's NEPOOL Related Person (Cassadaga Wind LLC) is a member of the Supplier Sector.

[79] *BP Energy Retail et al.*, 181 FERC ¶ 62,102 (Nov. 14, 2022).

[80] *Salem Harbor Power Development LP*, 181 FERC ¶ 62,084 (Oct. 31, 2022).

[81] In addition to Waterside Power, "Applicants" are: Lea Power Partners, LLC; Badger Creek Limited; Chalk Cliff Limited; Double C Generation Limited Partnership; High Sierra Limited; Kern Front Limited; McKittrick Limited; Bear Mountain Limited; Live Oak Limited; and WGP Redwood Holdings, LLC.

[82] *Lea Power Partners, LLC*, 180 FERC ¶ 62,086 (Aug. 19, 2022) ("*August 19 Order*").

consummation of the transaction, which as of the date of this Report has not yet occurred. If you have any questions, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Stonepeak / JERA Americas (EC22-71)**
  On November 23, 2022, the FERC authorized[83] the sale by Stonepeak[84] of 100% of the interests in Canal Power Holdings LLC to a wholly-owned affiliate of JERA Americas Inc. ("JERA Americas").[85] Among other standard conditions, the November 23 order requires that notice must be filed within 10 days of consummation of the transaction, which as of the date of this Report has not yet occurred. If you have any questions, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **LGIA-ISO-NE/NSTAR/Vineyard Wind 1 (ER23-488)**
  On November 23, 2022, ISO-NE and NSTAR filed a First Revised LGIA with Vineyard Wind 1, LLC to reflect the assignment of the LGIA by Vineyard Wind, LLC to Vineyard Wind I, LLC. A November 4, 2022 effective date was requested. Comments on this filing are due on or before ***December 14, 2022***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Cost Reimbursement Agreement: NEP/Holden (ER23-396)**
  On November 9, 2022, New England Power filed a Cost Reimbursement Agreement with Holden Municipal Light Department ("Holden") pursuant to which NEP will perform work to support Holden's plan to rebuild its Chaffins Substation. An October 10, 2022 effective date was requested. Comments on this filing were due on or before November 30, 2022; 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).

- **NEP Tariff No. 1 Revisions (ER23-348)**
  On November 2, 2022, NEP filed revisions to its Tariff No. 1 (i) to remove certain language in light of PPL's acquisition of The Narragansett Electric Company d/b/a Rhode Island Energy ("RI Energy"), the subsequent transition in operational control of RI Energy's transmission facilities, and an associated change in the mechanism through which RI Energy recovers its transmission revenue requirements; and (ii) to make non-substantive edits to Tariff No. 1 to replace outdated references therein. A January 1, 2023 effective date was requested. Comments on this filing were due on or before November 23, 2022; none were filed. RI Energy filed a doc-less intervention. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **MPD OATT: Changes to Treatment of CIS Costs and Expenses (ER23-345)**
  On November 2, 2022, Versant Power filed proposed changes to the formula rate in its MPD OATT that, if accepted, will modify the treatment of costs and expenses associated with the company's Customer Information System ("CIS"). The changes : (i) eliminate the inclusion in wholesale transmission charges under the MPD OATT of costs and expenses associated with the CIS and (ii) modify the allocation of CIS costs and expenses as between transmission and distribution functions in order to align such allocation with the ISO-NE OATT. Comments on this filing were due on or before November 23; none were filed. The Maine PUC filed a notice of intervention on November 16, 2022. 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).

[83] *Canal Generating LLC et al.,* 181 FERC ¶ 61,157 (Nov. 23, 2022).

[84] "Stonepeak" includes Canal Power Holdings LLC ("Seller"), and its indirect wholly-owned, public utility subsidiaries, Canal Generating LLC ("Canal Generating"), Canal 3 Generating LLC ("Canal 3"), Bucksport Generation LLC ("Bucksport"), and Stonepeak Kestrel Energy Marketing LLC ("Stonepeak Marketing").

[85] JERA Americas Related Persons in NEPOOL include Provisional Member Cricket Valley Energy Center, LLC.

- **Service Agreement Cancellation: NEP/Pawtucket (ER23-144)**

On November 28, 2022, the FERC accepted New England Power's Notice of Cancellation of its Firm Local Generation Deliverability Service Agreement ("Service Agreement") with Pawtucket Power Associates Limited Partnership ("Pawtucket").[86] As previously reported, Pawtucket decommissioned and retired the generating facility covered by the Service Agreement effective June 1, 2022. The Notice of Cancellation was accepted effective as of December 19, 2022, as requested. Unless the November 28 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: CL&P/NY Transco (ER22-2830)**

On November 9, 2022, the FERC accepted[87] an Agreement for Engineering, Design and Procurement (the "D&E Agreement") between CL&P and New York Transco LLC ("NY Transco") that sets forth the terms and conditions under which CL&P will perform the necessary services to address the impacts of NY Transco's reinforcement of a major 345 kV transmission corridor in New York that will have reliability impacts on the New England System. The D&E Agreement was accepted for filing as of September 13, 2022, as requested. Unless the November 9 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).

- **Versant Power MPD OATT *Order 881* Compliance Filing (ER22-2358)**

On July 12, 2022, in response to the requirements of *Order 881*, Versant Power filed a proposed new Attachment T to the Versant Power Open Access Transmission Tariff for the Maine Public District ("MPD OATT"). Attachment T, Versant reported, incorporates all the contents of the *pro forma* OATT's new Attachment M. An effective date of July 12, 2025 was requested in an errata filing submitted on August 1, 2022. On August 2, 2022, MPUC submitted comments asserting that Versant's Compliance Filing, without further detail, is insufficient to meet the requirements of *Order 881* and should either (i) be rejected outright, ordering Versant to re-file with sufficient detail, or (ii) subject to a deficiency letter requiring further information with respect to the Compliance Filing. MPUC withdrew those comments on August 31, 2022 in exchange for certain understandings with Versant Power (including MPUC's attendance, as a non-voting participant, at any NMISA working group discussions on *Order 881* implementation planning and Versant Power's submission of informational compliance filings to keep the FERC apprised of versant's progress in developing its AAR implementation plan). On September 6, 2022, Versant Power supplemented its compliance filing to confirm the MPUC's understandings, as delineated in its Notice of Withdrawal. 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).

- **Versant Power MPD OATT *Order 676-J* Compliance Filing Part I (ER22-1142)**

As previously reported, Versant Power filed revisions to Section 4 of the Versant OATT for the Maine Public District ("MPD OATT") to incorporate the new cybersecurity and PFV standards contained in NAESB WEQ Version 003.3 Standards in response to the requirements of *Order 676-J*, ("Versant MPD OATT *Order 676-J* Part I Changes").[59] A placeholder effective date was submitted. Comments on this filing were due on or before March 23, 2022; none were filed. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

[86] *New England Power Co.*, Docket No. ER23-144-000 (Nov. 28, 2022) (unpublished letter order).

[87] *Connecticut Light & Power*, Docket No. ER22-2830-000 (Nov. 9, 2022) (unpublished letter order).

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

All but one of the region's *Order 864*[88] and *Order 864-A*[89] compliance filings (UI's May 10, 2022 filing, Docket No. ER22-1850) have been accepted. Reporting here will continue until that filing is accepted.

XII. Misc. - Administrative & Rulemaking Proceedings[90]

- **Interregional HVDC Merchant Transmission (AD22-13)**

As previously reported, Invenergy Transmission ("Invenergy") filed a petition, on July 19, 2022, requesting that the FERC hold a technical conference to explore ways to potentially make available and compensate certain grid reliability and resilience benefits associated with interregional high voltage direct current ("HVDC") merchant transmission. Any comments to be considered by the FERC in its determination of any action to be taken were due on or before August 26, 2022. Comments were filed by 13 parties and included, among others, CSC, ENGIE, Invenergy, Phase I/II Asset Owners and IRH, Joint Consumer Advocates, MISO, ACORE, ACPA, SEIA, and Neptune and Hudson. Invenergy answered the comments filed by MISO. Since the last Report, on November 10, 202, Invenergy again urged the FERC to "hold a technical conference to examine and to improve the policy and processes relating to the interconnection of interregional MHVDC systems. This matter is pending before the FERC.

- **Reliability Technical Conference (Nov 10) (AD22-10)**

On November 10, 2022, the FERC held its annual Commissioner-led technical conference to discuss policy issues related to the reliability of the BPS. The conference's two panels were: (I) "Managing the Electric Grid to Advance Reliability" (to explore the current state of grid reliability and efforts that can be undertaken to improve it); and (II) "Managing Cyber Security Threats, the CIP Reliability Standards, and Best Practices for the Bulk-Power System" (to discuss how cyber security governance encompasses the CIP Reliability Standards and compliance as well as best practices; the challenges of implementing appropriate oversight; and ways in which industry can address these challenges to improve its response to evolving vulnerabilities and threats to reduce the risk to the BPS). On November 22, 2022, the FERC invited all those interested to file post-technical conference comments to address issues raised during the technical conference identified in the Supplemental Notice of Technical Conference issued on November 3, 2022. Comments are due on or before ***January 9, 2023***.

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[88] *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 Accumulated Deferred Income Taxes ("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 ("ADIT Worksheet"). The ***ADIT Worksheet*** must contain the following five specific categories of information: (i) how any ADIT accounts were re-measured and the excess or deficient ADIT contained therein ("***Category 1 Information***"); (ii) is the accounting for any excess or deficient amounts in Accounts 254 (Other Regulatory Liabilities) and 182.3 (Other Regulatory Assets) ("***Category 2 Information***"); (iii) whether the excess or deficient ADIT is protected (and thus subject to the Tax Cuts and Jobs Act's normalization requirements) or unprotected ("***Category 3 Information***"); (iv) the accounts to which the excess or deficient ADIT are amortized ("***Category 4 Information***"); and (v) the amortization period of the excess or deficient ADIT being returned or recovered through the rates ("***Category 5 Information***"). In addition, the FERC stated that it expects public utilities to identify each specific source of the excess and deficient ADIT, classify the excess or deficient ADIT as protected or unprotected, and list the proposed amortization period associated with each classification or source.

[89] *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*").

[90] Reporting on the following Administrative & Rulemaking proceedings has been suspended since the last Report and will be continued if and when there is new activity to report: Improving Generating Units Winter Readiness (AD22-4); NOI: Rate Recovery, Reporting, and Accounting Treatment of Industry Association Dues and Certain Civic, Political, and Related Expenses (RM22-5); NOI: Reactive Power Capability Compensation (RM22-2); NOI: Removing the DR Opt-Out in ISO/RTO Markets (RM21-14).

- **New England Gas-Electric Forum (AD22-9)**

The FERC held a New England Gas-Electric Forum on September 8, 2022 in Burlington, VT. The purpose of the Forum was to discuss and achieve a greater understanding among stakeholders in defining the electric and natural gas system challenges in the New England Region. Topics discussed included the historical context of New England winter gas-electric challenges, concerns and considerations for upcoming winters such as reliability of gas and electric systems and fuel procurement issues, and whether additional information or modeling exercises are needed to inform the development of solutions to these challenges. On September 21, 2022, the FERC invited parties wishing to submit comments regarding the topics discussed at the Forum to do so on or before November 7, 2022. Post-Forum Comments were submitted by: ISO-NE, Acadia, AEE, AIM, Calpine, Constellation, Excelerate, FirstLight, LS Power, NECOS, NEPGA, NESCOE, Public Systems, Repsol, TOs, VELCO, Vistra, Potomac Economics, CT DEEP, AEMA, APGA, EPSA, INGA, NE LDCs, NGSA, New England Council, NEPPA, NH BIA, PIOs, RENEW/ACPA, Berkshire Action Team, Greater Concord Chamber of Comm., Mass. Alliance for Econ. Dev., Mass. Business Roundtable, Mass. Coalition for Sustainable Energy, Mass. United Assoc. of Journeymen, Middlesex County Chamber of Commerce, Public Citizen, Western Mass. Economic Dev. Council, and Individual Citizens (M. Axner, E. Blank, S. Botkin, D. Heimann, J. Krieger, B. Little, I. McDonald, J. Neville, W. Persons, R. Spector). On November 22, National Grid filed reply comments.

- **Transmission Planning and Cost Management Technical Conference (AD22-8)**

On October 6, 2022, the FERC convened a Commissioner-led technical conference regarding transmission planning and cost management for transmission facilities developed through local or regional transmission planning processes. The 5 panels throughout the day addressed: (1) the processes by which transmission providers develop local transmission planning criteria, identify local transmission needs using those criteria, and evaluate and choose local transmission facilities to address those needs; (2) whether local transmission facility costs are adequately scrutinized; (3) the processes by which transmission providers evaluate, select, and develop regional transmission facilities for reliability; (4) whether regional transmission facilities for reliability costs are adequately scrutinized; and (5) cross-cutting themes and potential best practices for both local transmission facilities and regional reliability transmission planning and cost management, in addition to innovative approaches that could be explored further, including the possibility of establishing a role for an Independent Transmission Monitor, and mechanisms to support enhanced transparency. Advance materials were submitted by representatives on behalf of: ISO-NE, CA PUC, KY PSC, NC Utils. Comm. Public Staff, NV PUC, RI PUC, AEE, AEP, Ameren, AMP/APPA, Ari Peskoe, L. Azar, Clean Energy Buyers Assoc., Coalition of MISO Customers, Harvard Electricity Law Initiative, ITC Holdings, LPPC, IA Consumer Advocate, J. Macey, NESCOE, Northern California Power Agency, Northwest & Intermountain Power Producers Coalition, OH Consumers' Counsel, OH PUC, Old Dominion Elec. Coop., PJM, G. Poulus, SPP, Potomac Economics, Southern California Edison, Southern Environmental Law Center, and TAPS/FMPA and WIRES.

On September 30 and October 4, the FERC issued supplemental notices that included a final agenda, including further details regarding the agenda and speakers, for this technical conference. An additional supplemental notice identifying the opportunity for interested parties to submit post-technical conference comments has yet to be issued. On November 1, 2022, a transcript of the technical conference was posted in the FERC's eLibrary. There was no material activity since the last Report and this matter is pending before the FERC.

- **NOI: Dynamic Line Ratings (AD22-5)**

On February 17, 2022, the FERC issued a notice of inquiry ("NOI")[91] seeking comments on (i) whether and how the required use of dynamic line ratings ("DLR") is needed to ensure just and reasonable wholesale rates; (ii) whether the lack of DLR requirements renders current wholesale rates unjust and unreasonable; (iii) potential criteria for DLR requirements; (iv) the benefits, costs, and challenges of implementing DLRs; (v) the nature of potential DLR requirements; and (vi) potential timeframes for implementing DLR requirements. This NOI represents the first step in the FERC's effort to gather more information about the costs and benefits, and

[91] *Implementation of Dynamic Line Ratings*, 178 FERC ¶ 61,110 (Feb. 17, 2022) ("*Dynamic Line Ratings NOI*").

potentially mandating the use, of DLRs. A more detailed summary was provided to the Transmission Committee and is posted on the Transmission Committee's webpage.

Initial comments were due April 25, 2022 and filed by: ISO-NE; DC Energy; Eversource; Clean Energy Parties; Potomac Economics; CT DEEP; NERC; US DOE; CAISO; MISO; NYISO; Org of MISO States; PJM, SPP; SPP MMU; AEP; Alliant; APPA; APS; AZ PUC; Clean Energy Entities; Dayton Power; EEI; ELCON; Entergy; IN Util. Reg. Comm.; ITC; LA DPW; MISO TOs; NRECA; NYISO TOs; PPL; R Street Institute; Southern Co.; TAPS; Tri-State; Electricity Canada; Electric Grid Monitoring; Line Vision; Idaho Power.

Reply comments were due on or before May 25, 2022[92] and were filed by: AEP, Clean Energy Entities,[93] EEI, Joint Consumer Advocates, MISO TOs, and the R Street Institute. This matter is pending before the FERC.

- **Joint Federal-State Task Force on Electric Transmission (AD21-15)**

A fifth meeting of the FERC-established Joint Federal-State Task Force on Electric Transmission ("Transmission Task Force")[94] was held on November 15, 2022, in New Orleans, LA. Discussion addressed regulatory gaps/challenges in the oversight of transmission development.[95]

- **Modernizing Electricity Market Design - Resource Adequacy (AD21-10)**

ISO/RTO Reports. On April 21, 2022, the FERC issued an order[96] directing each independent system operator ("ISO") and regional transmission organization ("RTO"), including ISO-NE, to submit on or before October 18, 2022 a report that describes: (1) current system needs given changing resource mixes and load profiles; (2) how it expects its system needs to change over the next five and 10 years; (3) whether and how it plans to reform its energy and ancillary services ("EAS") markets to meet expected system needs over the next five and 10 years; and (4) information about any other reforms, including capacity market reforms and any other resource adequacy reforms that would help it meet changes in system needs. The *Order Directing Reports* follows a series of staff-led technical conferences, convened in 2021 and summarized in previous Reports, addressing ISO/RTO resource adequacy[97] and energy and ancillary services markets.[98]

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[92] The *Dynamic Line Ratings NOI* was published in the Fed. Reg. on Feb. 24, 2022 (Vol. 87, No. 37) pp. 10,349-10,354.

[93] The "Clean Energy Entities" are the Working for Advanced Transmission Technologies Coalition ("WATT"), ACPA, AEE, and SEIA.

[94] *Joint Federal-State Task Force on Electric Transmission*, 175 FERC ¶ 61,224 (June 18, 2021). The Transmission Task Force is comprised of all FERC Commissioners as well as representatives from 10 state commissions (two from each NARUC region). State commission representatives will serve one-year terms from the date of appointment by FERC and in no event will serve on the Task Force for more than three consecutive terms. The Transmission Task Force will convene multiple formal meetings annually, with FERC issuing orders fixing the time and place and agenda for each meeting, and the meetings will be open to the public for listening and observing and on the record. The Transmission Task Force will focus on "topics related to efficiently and fairly planning and paying for transmission, including transmission to facilitate generator interconnection, that provides benefits from a federal and state perspective." New England is represented by Commissioners Riley Allen (VT PUC) and Matt Nelson (Chair, MA DPU), each of whom will be serving a second term during the Sept. 1, 2022 – Aug. 31, 2023 term. *See* Order on Nominations, *Joint Federal-State Task Force on Elec. Trans.*, 180 FERC ¶ 61,030 (July 15, 2022).

[95] Summaries of the first – fourth meetings of the Transmission Task Force can be found in previous Reports.

[96] *Modernizing Wholesale Electricity Market Design*, 179 FERC ¶ 61,029 (Apr. 21, 2022) ("*Order Directing Reports*").

[97] The FERC held two staff-led technical conferences addressing resource adequacy, one on Mar. 23, 2021 (with post-conference comments focused on PJM-specific issues) and the other on May 25, 2021 (focused on the wholesale markets administered by ISO-NE). Following the Mar. 23 conference, more than 45 sets of initial comments were filed, including by: AEE, Calpine, Cogentrix, Dominion, Exelon, FirstLight, LS Power, NESCOE, NEPGA, NRG, PSEG, Shell, Vistra, CT DEEP, EEI, EPSA, and NRECA/APPA. Reply comments were filed by ACPA, AEP, EPSA, Exelon, Joint Consumer Advocates, LS Power, Old Dominion Electric Cooperative ("ODEC"), PJM Power Providers ("P3"), Public Interest Organizations ("PIOs"), and the Retail Electric Supply Association ("RESA"). Following the May 25 conference, comments were filed by: AEE, Calpine, CT Parties, Dominion, Eversource, MMWEC, NESCOE, NEPGA, NextEra, NRG, Public Interest Orgs, Vistra, AEMA, EPSA, RENEW.

[98] The FERC held two staff-led technical conferences addressing ISO/RTO EAS markets, one on Sept. 14, 2021; the second on Oct. 12, 2021. Transcripts of both technical conferences are posted in eLibrary. In advance of the EAS technical conferences, FERC staff issued

ISO-NE Report. On October 18, 2022, ISO-NE (as well as the other ISO/RTOs) filed its report in response to the *Order Directing Reports.* The FERC will review the RTO/ISO reports and comments related thereto to determine whether further action is appropriate. Thus far, one set of comments was filed, by America's Power, addressing coal retirements. Unless extended, comments in response to the RTO/ISO reports are due on or before ***December 19, 2022***. However, on November 30, 2022, EEI requested an additional 30 days, until January 18, 2023, to submit comments on the ISO/RTO reports. EEI's request for a 30-day extension of time to comment is pending before the FERC.

- **NOPR: Duty of Candor (RM22-20)**

On July 28, 2022, the FERC issued a NOPR[99] proposing to add a new section to its regulations to require that any entity communicating with the FERC or other specified organizations (e.g. ISO/RTOs, FERC-approved market monitors, NERC and its Regional Entities, or transmission providers) related to a matter subject to FERC jurisdiction submit accurate and factual information and not submit false or misleading information, or omit material information ("Duty of Candor Requirements"). An entity would be shielded from violation of the new regulation if it has exercised due diligence to prevent such occurrences. The FERC's current regulations prohibit, in defined circumstances, inaccurate communications to the FERC and other organizations upon which the FERC relies to carry out its statutory obligations. However, because those requirements cover only certain communications and impose a patchwork of different standards of care for such communications, the FERC believes that a broadly applicable duty of candor will improve its ability to effectively oversee jurisdictional markets. It further indicated that its proposed due 'diligence standard' and other limitations are intended to minimize the additional burdens to industry that come with the new Duty of Candor Requirements.

On September 1, 2022, Joint Associations[100] requested an additional month to submit comments.[101] On September 14, 2022, the FERC granted that request. Accordingly, initial comments were due November 11, 2022 and over 30 sets of comments were filed, including by: ISO-NE, ISO-NE IMM, ISO-NE EMM, PJM IMM, ABA, AGA, APGA, APPA, EEI, Energy Trade Associations, INGA, NGSA, Nodal Exchange, NRECA, State Agencies, US Chamber of Commerce, DE Riverkeeper Network, New Civil Liberties Alliance, and Nodal Exchange.

- **NOPR: Advanced Cybersecurity Investment (RM22-19)**

On September 22, 2022, the FERC issued a NOPR[102] proposing to provide incentive-based rate treatments for the transmission of electric energy in interstate commerce and the sale of electric energy at wholesale in interstate commerce by utilities for the purpose of benefitting consumers by encouraging investments by utilities in advanced cybersecurity technology and participation by utilities in cybersecurity threat information sharing programs, as directed by the Infrastructure Investment and Jobs Act of 2021 ("Infrastructure and Jobs Act"). This

on Sept. 7, 2021 a White Paper entitled "Energy and Ancillary Services Market Reforms to Address Changing System Needs" summarizing recent EAS markets reforms as well as reforms then under consideration. Initial comments on the topics discussed during the EAS technical conferences were filed by: ISO-NE, Appian Way Energy Partners, Constellation, Dominion, Envir. Defense Fund, FirstLight, LS Power, CAISO, MISO, NYISO, PJM, SPP MMU, ACPA, Clean Energy Organizations, EEI, Energy Trading Institute, EPRI, EPSA, Middle River Power, National Hydropower Assoc., NYSERDA, PJM Providers Group, and Public Citizen. Reply comments were filed by EPRI, NERC and its Regional Entities and Vistra.

[99] *Duty of Candor*, 180 FERC ¶ 61,052 (July 28, 2022) ("*Duty of Candor NOPR*").

[100] "Joint Associations" included the following trade associations on behalf of their respective members: the American Gas Association ("AGA"), American Public Gas Association ("APGA"), Interstate Natural Gas Association of America ("INGA"), Edison Electric Institute ("EEI"), Electric Power Supply Association ("EPSA"), Energy Trading Institute ("ETI"), Natural Gas Supply Association ("NGA"), and Process Gas Consumers Group ("PGCG").

[101] The *Duty of Candor NOPR* was published in the *Fed. Reg.* on Aug. 12, 2022 (Vol. 87, No. 155) pp. 49,784-49,793.

[102] *Incentives for Advanced Cybersecurity Investment; Cybersecurity Incentives*, 180 FERC ¶ 61,189 (Sep. 22, 2022) ("*Advanced Cybersecurity Investment NOPR*").

NOPR also terminated the NOPR proceeding in Docket RM21-3 (*Dec 2020 Cybersecurity Incentives NOPR*)[103] described in previous Reports.

Initial comments on the *Advanced Cybersecurity Investment NOPR* were due on or before November 7, 2022 and reply comments were due November 21, 2022.[104] Nearly 30 sets of initial comments were filed, including by: Avangrid, APPA, EEI, EPSA, INGA, Joint Consumer Advocates, Microsoft, MISO TOs, PJM TOs, NERC, NRECA, TAPS, and the Operational Technology Cybersecurity Coalition. Reply comments were filed by DOE, EEI, ELCON, CA PUC, AEP, and Anterix. This matter is pending before the FERC.

- **NOPR: Extreme Weather Vulnerability Assessments (RM22-16; AD21-13)**

On June 16, 2022, as corrected on July 12, 2022, the FERC issued a notice[105] proposing to require transmission providers to submit one-time informational reports describing their current or planned policies and processes for conducting extreme weather vulnerability assessments[106] (how they establish a scope for their extreme weather vulnerability assessments, develop inputs, identify vulnerabilities and determine exposure to extreme weather hazards, estimate the costs of impacts, and develop mitigation measures to address extreme weather risks). Initial comments were due August 30, 2022[107] and were filed by over 13 parties, including among others, Eversource, NRDC, NERC, MISO, PJM, and EPSA. This matter is pending before the FERC.

- **NOPR: Interconnection Reforms (RM22-14)**

On June 16, 2022, the FERC issued a notice of proposed rulemaking ("NOPR"),[108] more than 400 pages long, that proposes reforms to the *pro forma* Large Generator Interconnection Procedures ("LGIP"), *pro forma* Small Generator Interconnection Procedures ("SGIP"), *pro forma* Large Generator Interconnection Agreement ("LGIA"), and *pro forma* Small Generator Interconnection Agreement ("SGIA") to address interconnection queue backlogs, improve certainty, and prevent undue discrimination for new technologies.

Initial Comments. Initial comments were due October 13, 2022[109] and over 130 sets of comments were filed, including: NEPOOL, ISO-NE, NESCOE, AEE, Anbaric, Avangrid, Cypress Creek Renewables, Dominion, EDF Renewables, ENGIE, Envir. Defense Fund, Longroad, National Grid, NextEra, PPL, RWE, Shell, VELCO, Vistra, ACPA, ACRE, APPA, US DOE, EEI, ELCON, EPRI, EPSA, IRC, NARUC, NERC, NRECA, PIOs, R Street Institute, SEIA, State Agencies, and WIRES.

Reply Comments. Following a request by EEI for a 30-day extension of time to submit reply comments, supported by AAE, ACPA, ACRE, and SEI, and granted by the FERC on October 28, 2022, reply comments are now

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[103] *Cybersecurity Incentives*, 173 FERC ¶ 61,240 (Dec. 17, 2020) ("*Dec 2022 Cybersecurity Incentives NOPR*"). As described in previous Reports, the *Dec 2022 Cybersecurity Incentives NOPR* proposed to establish rules for incentive-based rate treatment for voluntary cybersecurity investments by a public utility for or in connection with the transmission or sale of electric energy subject to FERC jurisdiction, and rates or practices affecting or pertaining to such rates for the purpose of ensuring the reliability of the Bulk Power System.

[104] The *Advanced Cybersecurity Investment NOPR* was published in the *Fed. Reg.* on Oct. 6, 2022 (Vol. 87, No. 193) pp. 60,567-60,580.

[105] *One-Time Informational Reports on Extreme Weather Vulnerability Assessments; Climate Change, Extreme Weather, and Elec. Sys. Rel.*, 179 FERC ¶ 61,196 (June 16, 2022) ("*Extreme Weather Vulnerability Assessments NOPR*").

[106] "Extreme weather vulnerability assessments" are proposed to be defined as "analyses that identify where and under what conditions jurisdictional transmission assets and operations are at risk from the impacts of extreme weather events, how those risks will manifest themselves, and what the consequences will be for system operations".

[107] The *Extreme Weather Vulnerability Assessments NOPR* was published in the *Fed. Reg.* on July 1, 2022 (Vol. 87, No. 126) pp. 39,414-39,426.

[108] *Improvements to Generator Interconnection Procedures and Agreements*, 179 FERC ¶ 61,194 (June 16, 2022) ("*Interconnection* Reforms *NOPR*").

[109] The *Interconnection Reforms NOPR* was published in the *Fed. Reg.* on July 5, 2022 (Vol. 87, No. 127) pp. 39,934-40,032.

due ***December 14, 2022***. Thus far, reply comments have been filed by two individuals -- R. Shanker and R. Lathrop.

As previously reported, the proposed reforms fall into three main categories: (1) reforms to implement a first-ready, first-served cluster study process; (2) reforms to increase the speed of interconnection queue processing; and (3) reforms to incorporate technological advancements to the interconnection process. Within each of these categories, the FERC proposes a wide array of reforms, and requests comment.

To implement the **first-ready, first-served cluster study process**, the FERC proposes to:

- Require transmission providers offer an alternative option for an informational interconnection study that would not require a project enter the interconnection queue;
- Make cluster studies the required interconnection study method under the *pro forma* LGIP;
- Allocate the shared costs of the cluster studies so that 90% of the applicable study costs are allocated to interconnection customers on a pro rate basis based on the requested MWs included in the applicable cluster, and 10% of the applicable study costs are allocated to interconnection customers on a per capita basis based on the number of interconnection requests in the applicable cluster;
- Require transmission providers to allocate network upgrade costs to interconnection customers within a cluster using a proportional impact method, in which the transmission provider will determine the degree to which each generating facility in the cluster contributes to the need for a specific network upgrade;
- Allow interconnection customers in an earlier-in-time cluster to share the costs of network upgrades with interconnection customers who will significantly benefit from those upgrades but would not share the cost of the network upgrades solely by virtue of being in a later cluster;
- Increase study deposits based on the size of the generating facility from $35,000 to $250,000;
- Require more stringent site control requirements, and proposes to require an interconnection customer to demonstrate 100% site control for a proposed generating facility when they submit the interconnection request;[110]
- Implement a commercial readiness framework whereby interconnection customers must show demonstrable milestones towards commercial readiness in order to enter the cluster, such as an executed term sheet, reasonable evidence the project was selected in a resource plan, or a provisional LGIA;[111] and
- Impose withdrawal penalties when the interconnection customer withdraws from the interconnection queue.[112]

To **increase the speed of the interconnection queue process**, the FERC proposes to:

- Eliminate the "reasonable efforts" standard for transmission providers completing interconnection studies and instead impose firm study deadlines and establish penalties that would apply when transmission providers fail to meet these deadlines. The penalty imposed would be $500 per day that the study is late and would be distributed to interconnection customers on a pro rata basis;

[110] The FERC proposes to limit the option to provide a financial deposit in lieu of site control and would only allow this option when regulatory limitations prohibit the interconnection customer from obtaining site control. In such instances, the interconnection customer would submit a deposit of $10,000 per MW, subject to a floor of $500,000 and a ceiling of $2 million.

[111] *Id.* at P 128.

[112] The proposed withdrawal penalty will increase as the interconnection customer moves through the interconnection queue and proposes a chart demonstrating the possible penalties at P 144.

- Add an entirely *pro forma* affected system study process to address the current lack of uniformity in the study of affected systems, which results in late-stage withdrawals, re-studies and increased costs to remaining interconnection customers;
- Establish two new *pro forma* agreements, a *pro forma* Affected System Study Agreement (new Appendix 15) and a *pro forma* Affected Systems Facilities Construction Agreement (new Appendix 16); and
- Implement an optional resource solicitation study that can be performed by entities required to conduct a resource plan or solicitation. Under this proposed study process, a resource planning agency (such as a state agency or load-serving entity implementing a state mandate) would facilitate a study to group together interconnection requests associated with the qualifying resource solicitation process, and the resources vying for selection in a qualifying state resource solicitation process would be studied together for the purposes of informational interconnection studies.

Finally, as **technological advances to the interconnection process**, the FERC proposes to:

- Require transmission providers to allow more than one resource to co-locate on a shared site behind a single point of interconnection and share a single interconnection request;
- Change the way in which transmission providers assess an addition of a generating facility to an interconnection request, requiring that transmission providers evaluate a proposed addition as long as the addition does not change the requested interconnection service level;
- Enable customers with unused interconnection capacity share that surplus capacity with other resources as long as the original interconnection customer executes an LGIA or requests filing of an unexecuted LGIA;
- Require transmission providers, at the request of the interconnection customer to use operating assumptions for interconnection studies that reflect the proposed operation of an electric storage resource or co-located storage resource; and
- Require transmission providers to evaluate grid-enhancing solutions and file an annual informational report on their use of grid-enhancing technologies.

The FERC proposes to require compliance within 180 days of a final rule in this proceeding. Compliance would require transmission providers to file updates to their *pro forma* LGIA, LGIP, SGIA and SGIP, as applicable. If you have any questions concerning the *Interconnection Reforms NOPR*, please contact Margaret Czepiel (202-218-3906; mczepiel@daypitney.com) or Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **NOPR: ISO/RTO Credit Information Sharing (RM22-13)**

On July 28, 2022, the FERC issued a NOPR[113] proposing to revise its regulations to permit ISO/RTOs to share among themselves[114] credit-related information regarding market participants.[115] The FERC believes that

[113] *Credit-Related Information Sharing in Organized Wholesale Electric Markets*, 180 FERC ¶ 61,048 (July 28, 2022) ("*ISO/RTO Credit-Related Info Sharing NOPR*").

[114] The *ISO/RTO Credit-Related Info Sharing NOPR* does propose credit-related information sharing with markets that are not Commission-jurisdictional (i.e. ERCOT, AESO, IESO or commodities and derivative markets that are subject to the jurisdiction of other regulators, including the Commodity Futures Trading Commission).

[115] Revisions would be to 18 CFR § 35.47(h). The changes would "[p]ermit the sharing of market participant credit-related information with, and receipt of market participant credit-related information from, other organized wholesale electric markets for the purpose of credit risk management and mitigation, provided such market participant credit-related information is treated upon receipt as confidential under the terms for the confidential treatment of market participant information set forth in the tariff or other governing document of the receiving organized wholesale electric market; and permit the receiving organized wholesale electric market to use market participant credit-related information received from another organized wholesale electric market to the same extent and for the same purposes that the receiving organized wholesale electric market may use credit-related information collected from its own market participants.

the proposed credit information sharing could improve ISO/RTOs' ability to accurately assess market participants' credit exposure and risks and enable ISO/RTOs to respond to credit events more quickly and effectively (minimizing the overall credit-related risks, including risks of unexpected defaults by market participants, in organized wholesale electric markets). The FERC proposal would not permit the information sharing to be conditioned on the specific consent of the market participant, would permit the receiving ISO/RTO to use market participant credit-related information received from another ISO/RTO to the same extent and for the same purposes that the receiving ISO/RTO may use credit-related information collected from its own market participants, and would not change the existing discretion an ISO/RTO has to act on credit-related information, regardless of the source of that information. The FERC seeks comment on whether ISO/RTOs' credit-related information sharing discretion should be limited in any specific ways or to any specific circumstances.

Initial Comments. Initial comments were due October 7, 2022[116] and were filed by, among others: NEPOOL, Dominion, EEI, Energy Trading Institute, EPSA, and the IRC.

Reply Comments. Reply comments were due November 7, 2022 and were filed by the ISO/RTO Council ("IRC") and a couple of persons from Augusta University.

- **NOPR: Transmission System Planning Performance Requirements for Extreme Weather (RM22-10)**

On June 16, 2022, the FERC issued a notice[117] proposing to require that NERC modify Reliability Standard TPL-001-5.1 (Transmission System Planning Performance Requirements) within one year of the effective date of a final rule in this proceeding to address reliability concerns pertaining to transmission system planning for extreme heat and cold weather events that impact the reliable operations of the Bulk-Power System. Specifically, the FERC proposed modifications to TPL-001-5.1 to require: (i) development of benchmark planning cases; (ii) planning for extreme heat and cold events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios; and (iii) corrective action plans that include mitigation for any instances where performance requirements for extreme heat and cold events are not met. Initial comments were due August 26, 2022[118] and were filed by over 37 parties, including, among others, ISO-NE, Eversource, NESCOE, NRDC, UCS, NERC, ERCOT, MISO, NYISO, PJM, ACPA, EPRI, EPSA, NARUC, and Trade Associations. This matter is pending before the FERC.

- **NOPR: Internal Network Security Monitoring for High and Medium Impact BES Cyber Systems (RM22-3)**

On January 20, 2022, the FERC issued a NOPR[119] proposing to direct NERC to develop and submit for FERC approval new or modified Reliability Standards that require internal network security monitoring ("INSM")[120] within a trusted Critical Infrastructure Protection networked environment for high and medium impact Bulk Electric System ("BES") Cyber Systems. The FERC stated that "including INSM requirements in the CIP Reliability Standards would ensure that responsible entities maintain visibility over communications between networked devices within a trust zone (i.e., within an ESP), not simply monitor communications at the network perimeter access point(s), i.e., at the boundary of an ESP as required by the current CIP requirements. In the event of a

[116] The *ISO/RTO Credit-Related Info Sharing NOPR* was published in the *Fed. Reg.* on Aug. 8, 2022 (Vol. 87, No. 151) pp. 48,118-48,125.

[117] *Transmission System Planning Performance Requirements for Extreme Weather*, 179 FERC ¶ 61,195 (June 16, 2022) ("*Extreme Weather Transmission System Planning NOPR*").

[118] The *Extreme Weather Transmission System Planning NOPR* was published in the *Fed. Reg.* on June 27, 2022 (Vol. 87, No. 122) pp. 38,021-38,044.

[119] *Internal Network Security Monitoring for High and Medium Impact Bulk Electric System Cyber Systems*, 178 FERC ¶ 61,038 (Jan. 20, 2022) ("*Internal Network Security Monitoring NOPR*").

[120] INSM is a subset of network security monitoring that is applied within a "trust zone," such as an Electronic Security Perimeter ("ESP"), and is designed to address situations where vendors or individuals with authorized access are considered secure and trustworthy but could still introduce a cybersecurity risk to a high or medium impact BES Cyber System.

compromised ESP, improving visibility within a network would increase the probability of early detection of malicious activities and would allow for quicker mitigation and recovery from an attack."[121]

Comments on the *Internal Network Security Monitoring NOPR* were due on or before March 28, 2022.[122] Comments were filed by: the IRC, NERC, EEI, EPSA, TAPS, Bonneville Power Admin., Consumers Energy, Cynalytica, CA Department of Water Resources, Electricity Canada, Entergy, Idaho Power, Juniper Networks, ITC, Microsoft, North American Generator Forum, Nozomi Networks, Operational Technology Cybersecurity Coalition, the US Bureau of Reclamation, and T. Conway. This matter is pending before the FERC.

- ***Transmission NOPR* (RM21-17)**

Following its ANOPR process,[123] the FERC issued on April 21, 2022 a NOPR[124] that would require public utility transmission providers to:

(i) conduct long-term regional transmission planning on a sufficiently forward-looking basis to meet transmission needs driven by changes in the resource mix and demand;

(ii) more fully consider dynamic line ratings and advanced power flow control devices in regional transmission planning processes;

(iii) seek the agreement of relevant state entities within the transmission planning region regarding the cost allocation method or methods that will apply to transmission facilities selected in the regional transmission plan for purposes of cost allocation through long-term regional transmission planning;

(iv) adopt enhanced transparency requirements for local transmission planning processes and improve coordination between regional and local transmission planning with the aim of identifying potential opportunities to "right-size" replacement transmission facilities; and

(v) revise their existing interregional transmission coordination procedures to reflect the long-term regional transmission planning reforms proposed in this NOPR.

In addition, the *Transmission NOPR* would not permit public utility transmission providers to take advantage of the construction-work-in-progress ("CWIP") incentive for regional transmission facilities selected for purposes of cost allocation through long-term regional transmission planning and would permit the exercise of federal rights of first refusal ("ROFR") for transmission facilities selected in a regional transmission plan for purposes of cost allocation, conditioned on the incumbent transmission provider with the federal ROFR for such regional transmission facilities establishing joint ownership of the transmission facilities. While the ANOPR sought

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121 *Id.* at P 2.

122 The *Internal Network Security Monitoring NOPR* was published in the *Fed. Reg.* on Jan. 27, 2022 (Vol. 87, No. 18) pp. 4,173-4,180.

123 *See Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 176 FERC ¶ 61,024 (July 15, 2021) ("*Transmission Planning & Allocation/Generation Interconnection ANOPR*"). The FERC convened a tech. conf. on Nov. 15, 2021, to examine in detail the issues and potential reforms described in the *ANOPR*. Speaker materials and a transcript of the tech. conf. are posted in FERC's eLibrary. Pre-technical conference comments were submitted by over 175 parties, including by: NEPOOL, ISO-NE, AEE, Anbaric, Avangrid, BP, CPV, Dominion, EDF, EDP, Enel, EPSA, Eversource, Exelon, LS Power, MA AG, MMWEC, National Grid, NECOS, NESCOE, NextEra, NRDC, Orsted, Shell, UCS, VELCO, Vistra, Potomac Economics, ACORE, ACPA/ESA, APPA, EEI, ELCON, Industrial Customer Orgs, LPPC, MA DOER, NARUC, NASUCA, NASEO, NERC, NRECA, SEIA, State Agencies, TAPS, WIRES, Harvard Electric Law Initiative; NYU Institute for Policy Integrity, New England for Offshore Wind Coalition, and the R Street Institute. *ANOPR* reply comments and post-technical conference comments were filed by over 100 parties, including: by: CT AG, Acadia Center/CLF, CT AG, Dominion, Enel, Eversource, LS Power, MA AG, MMWEC, NESCOE, NextEra, Shell, UCS, Vistra, ACPA/ESA, AEE, APPA, EEI, ELCON, Environmental and Renewable Energy Advocates, EPSA, Harvard ELI, NRECA, Potomac Economics, and SEIA. Supplemental reply comments were filed by WIRES, and a group of former military leaders and former Department of Defense officials, and ACPA/AEE/SEIA.

124 *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 179 FERC ¶ 61,028 (Apr. 21, 2022) ("*Transmission NOPR*").

comment on reforms related to cost allocation for interconnection-related network upgrades, interconnection queue processes, interregional transmission coordination and planning, and oversight of transmission planning and costs, the *Transmission NOPR* does not propose broad or comprehensive reforms directly related to these topics. The FERC indicated that it would continue to review the record developed to date and expects to address possible inadequacies through subsequent proceedings that propose reforms, as warranted, related to these topics.

A number of the elements of the *Transmission NOPR*, if adopted as part of a final rule, would result in some significant changes to how the region's transmission needs are identified, solutions are evaluated and selected, and costs recovered and allocated. A more fulsome high-level summary from NEPOOL Counsel of the *Transmission NOPR* was distributed to, and was reviewed with, the Transmission Committee, which will recommend whether NEPOOL should submit comments on the *Transmission NOPR*.

Comments. Following a number of requests for extensions of time, comments on the *Transmission NOPR* were due August 17, 2022.[125] Nearly 200 sets of comments were filed, including comments by NEPOOL , ISO-NE, Acadia/CLF, Anbaric, AEE, Avangrid, BP, Dominion, Enel, Engie, Eversource, Invenergy, LSP Power, MOPA, MMWEC/CMEEC/NHEC/VPPSA, National Grid, NECOES, NESCOE, NextEra, NRG, Onward Energy, Orsted, PPL, Shell, Transource, VELCO, Vistra, ISO/RTO Council, NERC, US DOJ/FTC, MA AG, State Agencies, VT PUC/DPS, Potomac Economics, ACPA, ACRE, APPA, EEI, EPSA, Industrial Customer Organizations, LPPC, NASUCA, NRECA, Public Interest Organizations, SEIA, TAPS, WIRES, Harvard Electricity Law Initiative, New England for Offshore Wind, and the R Street Institute.

Reply Comments. Reply comments were due ***September 19, 2022***. Nearly 100 sets of reply comments were filed, including by: ISO-NE, AEE, Anbaric, Avangrid, CT DEEP, Cypress Creek, Dominion, ENGIE, Eversource, Invenergy, LS Power, MA AG, NECOS, NESCOE, NextEra, Shell, Transource, UCS, ACPA, ACRE, APPA, EEI, Industrial Customer Organizations, LPPA, NRECA, Public Interest Organizations, R Street, and SEIA. Since the last Report, the New Jersey BPU moved to lodge its recently issued Board Order selecting transmission projects to be built pursuant to PJM's State Agreement Approach ("SAA") for the purpose of supporting New Jersey's offshore wind ("OSW") goals, the Brattle Group's SAA Evaluation Report, and PJM's SAA Economic Analysis Report, which it stated demonstrates that competitive transmission solicitations can provide significant value to consumers.

This matter is pending before the FERC. If you have any questions concerning the *Transmission NOPR*, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

- **NOPR: Accounting and Reporting Treatment of Certain Renewable Energy Assets (RM21-11)**

On July 28, 2022, the FERC issued a NOPR[126] proposing reforms to the accounting and reporting treatment of certain renewable energy assets. Specifically, the FERC proposes changes to the Uniform System of Accounts ("USofA") and relevant FERC forms to: (i) include new accounts for wind, solar, and other non-hydro renewable assets; (ii) create a new functional class for energy storage accounts; (iii) codify the accounting treatment of renewable energy credits; and (iv) create new accounts within existing functions for hardware, software, and communication equipment. The FERC also seeks comment on whether the Chief Accountant should issue guidance on the accounting for hydrogen. Comments on the *Renewable Energy Assets USofA and Reporting NOPR* were due November 17, 2022.[127] Seven sets of comments were filed by: Dominion, ACPA/SEIA, EEI, Liquid Energy Pipeline Assoc., RESA, PG&E/SDG&E, C. Pechman. This matter is pending before the FERC.

[125] A July 27, 2022, request by the Georgia Public Service Commission ("GA PUC") for an additional 30 days of time to submit comments and reply comments was denied on Aug. 9, 2022.

[126] *Accounting and Reporting Treatment of Certain Renewable Energy Assets*, 180 FERC ¶ 61,050 (July 28, 2022) ("*Renewable Energy Assets USofA and Reporting NOPR*").

[127] The *Renewable Energy Assets USofA and Reporting NOPR* was published in the *Fed. Reg.* on Oct. 3, 2022 (Vol. 87, No. 190) pp. 59,870-59,963.

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

Supplemental NOPR. In light of comments already received in this proceeding,[128] the FERC issued on April 15, 2021 a *Supplemental NOPR*[129] to propose and seek comment on a revised incentive for transmitting and electric utilities that join Transmission Organizations ("Transmission Organization Incentive"). The Incentive would be reduced from 100 to 50 basis points and would be available only for three years. The FERC sought comment on whether voluntary participation should be a requirement, and if so, how "voluntary" should be determined. In addition, the FERC now proposes to require each utility that has received a Transmission Organization Incentive for three or more years to submit a compliance filing revising its tariff to remove the incentive from its transmission tariff. The *Supplemental NOPR* did not address the other proposals contained in the *March NOPR*.[130] A more detailed summary of the NOPR was distributed to the Transmission Committee and discussed at the TC's March 25, 2020 meeting.

Comments on the *Supplemental NOPR* were due on or before June 25, 2021. Over 60 sets of comments were filed, including by the New England TOs, MMWEC/NHEC/CMMEC, NECOS, NESCOE, Potomac Economics, and CT PURA. Reply comments were due on or before July 26, 2021, with 28 sets of comments received, including by the New England TOs, NECOS, NESCOE, CT PURA/CT DEEP/MA AG, CT AG, and Public Interest Groups.[131] Reply comments were also posted from New England State Parties,[132] Alliant/Consumers/DTE, AEP, Pacific Gas & Electric, Joint Consumer Advocates, and the ACPA.

September 10, 2021 Workshop. The FERC convened a workshop on September 10, 2021[133] to discuss certain performance-based ratemaking approaches, particularly shared savings, that may foster deployment of

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128 Over 80 sets of comments on the *March NOPR* were filed on or before the July 1, 2020 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.

129 *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, 175 FERC ¶ 61,035 (Apr. 15, 2021) ("*Supplemental NOPR*").

130 As previously reported, the *March NOPR* proposed revisions to the FERCs existing transmission incentives policy and corresponding regulations, including 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***.
- ***Transmission Organization Incentive.*** A *50-basis-point increase* for transmitting utilities that turn over their wholesale facilities to a Transmission Organization and *only for the first three years after transferring operational control of its facilities.* The FERC seeks comment as to whether participation must be voluntary to receive the incentive, and if so, how the CFERC should determine whether the decision to join 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.

131 "Public Interest Groups" are NRDC, Sierra Club, Sustainable FERC Project, and Western Grid Group.

132 "New England State Parties" are CT PURA, CT DEEP and the MA AG.

133 Notice of Workshop, *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, Docket Nos. RM20-10 and AD19-19 (Apr. 15, 2021).

transmission technologies. The notice states that the workshop will explore: the maturity of the modeling approaches for various transmission technologies; the data needed to study the benefits/costs of such technologies; issues pertaining to access to or confidentiality of this data; the time horizons that should be considered for such studies; and other issues related to verifying forecasted benefits. The workshop also discussed whether and how to account for circumstances in which benefits do not materialize as anticipated and may explore other performance-based ratemaking approaches for transmission technologies seeking incentives under FPA section 219, particularly market-based incentives. The FERC issued an agenda for the workshop, which included the final workshop program and expected speakers, on August 23, 2021. The FERC supplemented that notice on September 9, 2021. On October 13, 2021, the FERC posted a transcript of the workshop in eLibrary.

Notice Inviting Post-Workshop Comments. On October 18, 2021, the FERC issued a notice inviting those interested to file post-workshop comments to address the issues raised during the workshop concerning incentives and shared savings. Comments were due on or before January 14, 2022 and were filed by APPA, CAISO, Clean Energy Parties,[134] EDF Renewables, EEI, the Industrial Energy Consumers of America ("IECA"), National Grid, PJM IMM, TAPS.

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

- ***Voltus Petition for a FERC Technical Conference on Order 2222*** **(RM18-9)**

On December 22, 2021, Voltus, Inc. ("Voltus") requested that the FERC convene a technical conference regarding *Order 2222*-related issues sometime in the months of February or March, 2022. Specifically, Voltus requested the technical conference to allow for a collective discussion of key issues arising from the ISO/RTO *Order 2222* compliance proposals, including certain regional variability, roles of industry participants, narrowing perceived knowledge gaps, and subsequent FERC guidance, all of which Voltus asserts supports the request for a technical conference. On January 7, 2022, the FERC issued a notice of Voltus' request, inviting comments on Voltus' request on or before February 7, 2022. Comments supporting Voltus' request were filed by: AEE, AEMA, APPA/NRECA, EEI, ISO-RTO Council, MISO, SPP, Sunrun, Ameren, Camus Energy, Energy Web Foundation, Entegrity Energy Partners, Environmental Law and Policy Center, Fermata LLC, Google, Leapfrog Power, Nuvve Holding, Tesla, U Delaware EV Research and Development Group, and Utilidata. Voltus' request remains pending before the FERC.

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

- **PacifiCorp (IN21-6)**

On April 15, 2021, in the FERC's first-ever Show Cause Order addressing alleged violations of NERC Reliability Standards,[135] the FERC directed PacifiCorp to show cause why it should not be found to have violated FPA section 215(b)(1) and section 39.2 of the FERC's regulations by failing to comply with Reliability Standard FAC 009-1 (Establish and Communicate Facility Ratings), Requirement R1, and the successor Reliability Standard FAC-008-3 (Facility Ratings), Requirement R6 (collectively, "FAC-009-1 R1"), which requires a transmission owner to establish and have facility ratings that are consistent with its Facility Ratings Methodology ("FRM"). An Enforcement investigation found that clearance measurements on a majority of PacifiCorp's transmission lines were incorrect under the National Electric Safety Code, which were used to calculate PacifiCorp's facility ratings, thus making PacifiCorp's facility ratings inconsistent with its FRM. Enforcement alleges that PacifiCorp was aware of incorrect clearances on its system since at least 2007 when FAC-009-1 R1 became mandatory, but failed to identify and remedy them in a timely manner, and PacifiCorp's

[134] The "Clean Energy Parties" are: Working for Advanced Transmission Technologies ("WATT Coalition"), ACPA, AEE, American Council on Renewable Energy ("ACORE"), NRDC, and the Sustainable FERC Project.

[135] *PacifiCorp,* 175 FERC ¶ 61,039 (Apr. 15, 2021) ("*PacifiCorp Show Cause Order*").

violations began on August 31, 2009, when it implemented its FRM policy, and at least some of the violations continued until August 2017 when PacifiCorp completed remediation of all of its incorrect clearances to make them consistent with its FRM. Enforcement also pointed to the role of the violations in the Wood Hollow, Utah wildfire that lasted from June 23 to July 1, 2012. In light of these alleged violations, the FERC directed PacifiCorp to show cause why it should not be assessed civil penalties in the amount of ***$42 million***.

On July 16, 2021, PacifiCorp answered the PacifiCorp Show Cause Order, denying the alleged violations of FAC-009. Enforcement filed its reply on September 14, 2021. This matter remains pending before the FERC. (Should the FERC choose to pursue a civil penalty against PacifiCorp for the alleged violations, PacifiCorp has already exercised its right to adjudicate these allegations in federal district court.) If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

Natural Gas-Related Enforcement Actions

- **Rover Pipeline, LLC and Energy Transfer Partners, L.P. (CPCN Show Cause Order) (IN19-4)**

On January 20, 2022, the FERC issued an order establishing a hearing to determine whether Rover Pipeline, LLC ("Rover") and its parent company Energy Transfer Partners, L.P. ("ETP" and collectively with Rover, "Respondents") violated section 157.5 of the FERC's regulations and to ascertain certain facts relevant for any application of the FERC's Penalty Guidelines.[136]

As previously reported, on March 18, 2021, the FERC issued a show cause order[137] in which it directed Rover Pipeline, LLC ("Rover") and Energy Transfer Partners, L.P. ("ETP" and together with Rover, "Respondents") to show cause why they should not be found to have violated Section 157.5 of the FERC's regulations by misleading the FERC in its Application for Certificate of Public Convenience and Necessity ("CPCN") under NGA section 7(c).[138] The FERC directed Respondents to show cause why they should not be assessed civil penalties in the amount of ***$20.16 million***. On April 5, 2021, the FERC extended by 60 days, to June 18, 2021, the deadline for Respondents' answer. On June 18, 2021, Rover and ETP answered the *Rover/ETP Show CPCN Cause Order*, asserting that the FERC should dismiss this matter and decline to initiate an enforcement action. On July 21, 2021, Enforcement Staff answered Rover/ETP's answer, stating the evidence supports a finding that Rover violated the FERC's Regulations and should be assessed the civil penalty identified in the *Rover/ETP Show Cause Order*. Rover answered the July 21 answer on September 15, 2021.

Procedural Schedule Suspended. As previously reported, ALJ Joel DeJesus will be the presiding judge for hearings in this matter. On May 24, 2022, the Honorable Judge Karen Gren Scholer of the U.S. District Court for the Northern District of Texas issued an order staying this proceeding. Consistent with that order and out of an abundance of caution, Judge DeJesus suspended the procedural schedule until such time as the Court's stay is lifted and the parties provide jointly a proposed amended procedural schedule.

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[136] *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.*, 178 FERC ¶ 61,028 (Jan. 20, 2022) ("*Rover/ETP Hearings Order*").

[137] *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.,* 174 FERC ¶ 61,208 (Mar. 18, 2021) ("*Rover/ETP CPCN Show Cause Order*").

[138] Specifically, Rover stated that it was "committed to a solution that results in no adverse effects" to the Stoneman House, an 1843 farmstead located near Rover's largest proposed compressor station. In truth, the OE Staff Report alleges, Rover was simultaneously planning to purchase the house with the intent to demolish it, if necessary, to complete its pipeline. The OE Staff Report alleges that Rover purchased the house in May 2015 and demolished the house in May 2016. The OE Staff Report further finds that despite taking these actions during the year and a half that Rover's application was pending before the FERC, Rover did not notify the FERC that it purchased the Stoneman House, intended to destroy the Stoneman House, and did destroy the Stoneman House. The OE Staff Report therefore concludes that Rover violated section 157.5's requirement for full, complete and forthright applications, through its misrepresentations and omissions, when it decided not to tell FERC that it had purchased the house and was considering demolishing it, and when Rover demolished it in May 2016 without notifying FERC.

- **Rover and ETP (Tuscarawas River HDD Show Cause Order) (IN17-4)**

On December 16, 2021, the FERC issued a show cause order[139] in which it directed Rover and ETP (together, "Respondents") to show cause why they should not be found to have violated NGA section 7(e), FERC Regulations (18 C.F.R. § 157.20); and the FERC's Certificate Order,[140] by: (i) intentionally including diesel fuel and other toxic substances and unapproved additives in the drilling mud during its horizontal directional drilling ("HDD") operations under the Tuscarawas River in Stark County, Ohio, in connection with the Rover Pipeline Project;[141] (ii) failing to adequately monitor the right-of-way at the site of the Tuscarawas River HDD operation; and (iii) improperly disposing of inadvertently released drilling mud that was contaminated with diesel fuel and hydraulic oil. The FERC directed Respondents to show why they should not be assessed civil penalties in the amount of ***$40 million***.

On March 21, 2022, Respondents answered and denied the allegations in the *Rover/ETP CPCN Show Cause Order*. On April 20, 2022, OE Staff answered Respondents' March 21 answer. On May 13, Respondents submitted a surreply, reinforcing their position that "there is no factual or legal basis to hold either [Respondent] liable for the intentional wrongdoing of others that is alleged in the Staff Report." The FERC denied Respondents' request for rehearing of the FERC's January 21, 2022 designation notice.[142] This matter is pending before the FERC.

- **BP (IN13-15)**

On December 17, 2020, the FERC issued *Opinion 549-A*,[143] a 159-page decision addressing arguments raised on rehearing requested of *Opinion 549.*[144] *Opinion 549-A* modifies the discussion in *Opinion 549*, but reaches the same the result (ultimately requiring BP to pay a ***$20.16 million civil penalty (roughly $24.4 million with accrued interest) and disgorge $207,169***). Of note, *Opinion 549-A* denied BP's motion to dismiss this enforcement action as time barred (by the five-year statute of limitations set forth in 28 U.S.C. § 2462), finding BP waived any statute of limitations defense by failing to raise it earlier in this proceeding.[145] 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.[146]

On December 29, 2020, BP filed a notice that it intends to appeal *Opinion 549-A* to the Fifth Circuit Court of Appeals and paid the civil penalty amount on December 28, 2020, under protest and with full reservation of rights pending the outcome of judicial review of that Opinion. On January 19, BP filed a notice that it disgorged $250,295 ($207,169 principal plus interest), divided equally ($83,431.67) among the following 3 entities identified in the "2016 Comprehensive Energy Assistance Program Subrecipient List": Dallas County Dept. of Health and Human Services (serving Dallas); El Paso Community Action, Project Bravo (Serving El Paso); and Panhandle

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[139] *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.,* 177 FERC ¶ 61,182 (Dec. 16, 2021) ("*Rover/ETP Tuscarawas River HDD Show Cause Order*").

[140] *Rover Pipeline LLC,* 158 FERC ¶ 61,109 (2017), *order on clarification & reh'g*, 161 FERC ¶ 61,244 (2017), *Petition for Rev*., *Rover Pipeline LLC v. FERC*, No. 18-1032 (D.C. Cir. Jan. 29, 2018) ("Certificate or Certificate Order").

[141] The Rover Pipeline Project is an approximately 711 mile long interstate natural gas pipeline designed to transport gas from the Marcellus and Utica shale supply areas through West Virginia, Pennsylvania, Ohio, and Michigan to outlets in the Midwest and elsewhere.

[142] *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.,* 179 FERC ¶ 61,090 (May 11, 2022) ("*Designation Notice Rehearing Order*"). The "Designation Notice" provided updated notice of designation of the staff of the FERC's Office of Enforcement ("OE") as non-decisional in deliberations by the FERC in this docket, with the exception of certain staff named in that notice.

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

[144] *BP America Inc.*, Opinion No. 549, 156 FERC ¶ 61,031 (July 11, 2016) ("*BP Penalties Order*") (affirming Judge Cintron's Aug. 13, 2015 Initial Decision finding that BP America Inc., BP Corporation North America Inc., BP America Production Company, and BP Energy Company (collectively, "BP") violated Section 1c.1 of the FERC's regulations ("Anti-Manipulation Rule") and NGA Section 4A (*BP America Inc.et al,* 152 FERC ¶ 63,016 (Aug. 13, 2015) ("*BP Initial Decision*")).

[145] *BP Penalties Allegheny Order* at P 1.

[146] *Id*. at P 319.

Community Services (serving Armstrong and numerous other counties), again under protest and with full reservation of rights pending the outcome of judicial review of *Opinion 549/549-A*.

- **Total Gas & Power North America, Inc. et al. (IN12-17)**

On April 28, 2016, the FERC issued a show cause order[147] 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.[148]

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.

Hearing Procedures. On July 15, 2021, the FERC issued and order establishing hearing procedures to determine whether Respondents violated the FERC's Anti-Manipulation Rule, and to ascertain certain facts relevant for any application of the FERC's Penalty Guidelines.[149] On July 27, Chief Judge Cintron designated Judge Suzanne Krolikowski as the Presiding ALJ and established an extended Track III Schedule[150] for the proceeding.

Discovery in this case is ongoing and is now scheduled to close on December 2, 2022. Further, pursuant to an August 30, 2022 order of the Chief Judge, hearings (estimated to last 3-4 weeks) are scheduled to begin ***January 23, 2023*** and an initial decision is thereafter due ***July 10, 2023***. Several procedural deadlines in support of that schedule were adjusted for a third time by Judge Krolikowski in an order issued on September 9, 2022.

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

[148] 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 NGA section 4A 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.

[149] *Total Gas & Power North America, Inc. et al.,* 176 FERC ¶ 61,026 (July 15, 2021).

[150] The hearing in this proceeding will be convened within 55 weeks (Aug. 15, 2022) and the initial decision issued within 76 weeks (January 9, 2023) of the issuance of the Chief Judge's order.

XIV. Natural Gas Proceedings

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

New England Pipeline Proceedings
The following New England pipeline projects are currently under construction or before the FERC:

- **Iroquois ExC Project (CP20-48)**
  - 125,000 Dth/d of incremental firm transportation service to ConEd and KeySpan by building and operating new natural gas compression and cooling facilities at the sites of four existing Iroquois compressor stations in Connecticut (Brookfield and Milford) and New York (Athens and Dover).
  - Three-year construction project; service request by November 1, 2023.
  - On March 25, 2022, after procedural developments summarized in previous Reports, the FERC issued to Iroquois a certificate of public convenience and necessity, authorizing it to construct and operate the proposed facilities.[151] The certificate was conditioned on: (i) Iroquois' completion of construction of the proposed facilities and making them available for service within ***three years*** of the date of the; (ii) Iroquois' compliance with all applicable FERC regulations under the NGA; (iii) Iroquois' compliance with the environmental conditions listed in the appendix to the order; and (iv) Iroquois' filing written statements affirming that it has executed firm service agreements for volumes and service terms equivalent to those in its precedent agreements, prior to commencing construction. The March 25, 2022 order also approved, as modified, Iroquois' proposed incremental recourse rate and incremental fuel retention percentages as the initial rates for transportation on the Enhancement by Compression Project.
  - On April 18, 2022, Iroquois accepted the certificate issued in the *Iroquois Certificate Order*.
  - On June 17, 2022, in accordance with the *Iroquois Certificate Order,* Iroquois submitted its Implementation Plan, documenting how it will comply with the FERC's Certificate conditions.
  - The Project is targeted for a 4th quarter, 2023 in-service date.

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.[152] 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*.[153] 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

[151] *Iroquois Gas Transmission Sys., L.P.*, 178 FERC ¶ 61,200 (2022) (*Iroquois Certificate Order*).

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

[153] *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).

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,[154] 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.[155] 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.[156] On February 2, 2019, the 2nd Circuit vacated the decision of the NY DEC and remanded the case with instructions for the NY DEC to more clearly articulate its basis for the denial and how that basis is connected to information in the existing administrative record. The matter is again before the NY DEC.
- On November 26, 2018, the Applicants filed a request at FERC for a 3-year extension of time, until February 3, 2022, to complete construction and to place the certificated facilities into service. The Applicants cited the fact that they "do not anticipate commencement of Project construction until early 2021 due to New York's continued legal actions and to time lines required for procurement of necessary pipe and compressor facility materials." The extension request was granted on January 31, 2019.
- On August 8, 2019, the NY DEC again denied Applicants request for a Water Quality Certification, and as directed by the Second Circuit,[157] 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.[158]
- 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, [159] finding the request premature. The FERC reiterated its encouragement that pipeline applicants requesting extensions "file their requests no more than 120 days before the deadline to complete construction",

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[154] 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).

[155] *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*").

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

[157] 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).

[158] *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).

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

so that the FERC has the relevant information available to determine whether good cause exists to grant an extension of time and whether the FERC's prior findings remain valid.[160]

- On January 28, 2022, Applicants again requested an additional extension of time, this time until December 31, 2024, to complete construction of the Project and enter service. Comments on that request were due on or before February 16, 2022. Many individual comments and protests were received.
- On June 29, 2022, the FERC granted Applicants' request for an additional extension of time. Applicants now have until December 31, 2024 to construct and place the Project into service.[161]
- A request for rehearing of the *Northern Access Project Add'l Extension Order* was denied by operation of law.[162]
- On September 6, 2022, the Sierra Club petitioned the DC Circuit for review of the *Northern Access Project Add'l Extension Order* (*see* Section XVI below).

XV. State Proceedings & Federal Legislative Proceedings

- **Maine - NECEC Transmission LLC et al. v. Bureau of Parks and Lands et al. (BCD-21-416)**

On August 30, 2022, the Maine Supreme Judicial Court concluded that the legislation enacted as a result of the passage of Maine's November 2, 2021 ballot question,[163] and that effectively halted construction of the NECEC Project,[164] was unconstitutional to the extent it required the legislation to be applied retroactively to the certificate of public convenience and necessity ("CPCN") issued for the Project if NECEC had acquired vested rights to proceed with Project construction (by undertaking substantial construction consistent with and in good-faith reliance on the CPCN before the Initiative was enacted). The Court remanded to the Business and Consumer Docket the factual question of whether NECEC performed substantial construction in good faith according to a schedule that was not created or expedited for the purpose of generating a vested rights claim (which it suggested appeared to be the case from the limited record developed in connection with the request for preliminary injunctive relief in this matter).

XVI. Federal Courts

The following are matters of interest, including petitions for review of FERC decisions in NEPOOL-related proceedings, that are currently pending before the federal courts (unless otherwise noted, the cases are before the U.S. Court of Appeals for the District of Columbia Circuit ("DC 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

[160] *Id.* at P 10.

[161] *National Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 179 FERC ¶ 61,226 (June 29, 2022) ("*Northern Access Project Add'l Extension Order*").

[162] *National Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 180 FERC ¶ 62,099 (Aug. 30, 2022).

[163] The ballot question, approved by 59% of Maine voters, which summarized the citizen's initiative pursued under Maine's constitutional provision for direct initiative of legislation (ME. Const. Art. IV, pt. 3, § 18), read: "Do you want to ban the construction of high-impact electric transmission lines in the Upper Kennebec Region and to require the Legislature to approve all other such projects anywhere in Maine, both retroactively to 2020, and to require the Legislature, retroactively to 2014, to approve by a two-thirds vote such projects using public land?"

[164] The New England Clean Energy Connect ("NECEC") project (the "NECEC Project") is designed to transmit power generated in Québec through Maine and into Massachusetts. The Project includes a new 145.3-mile, high-voltage direct current ("HVDC") transmission line, proposed to run from the Maine-Québec border in Beattie Township, ME to a new converter station in Lewiston, ME and from there to an existing substation by a new 1.2-mile, high-voltage alternating current transmission line.

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).

- ***2nd Revised Narragansett LSA Orders* (22-1161, 22-1108) (consolidated)**
Underlying FERC *Proceeding*: ER22-707[165]
Petitioner: Green Development
Status: Briefing Underway

On June 15, 2022, Green Development petitioned the DC Circuit for review of the FERC's *2nd Revised Narragansett LSA Orders*.[166] On June 17, 2022, the Court directed Green Development to file, and Green Development filed, a Docketing Statement, Statement of Issues, any Procedural Motions, and the underlying decisions from which the appeal arises. The FERC filed the Certified Index to the Record on July 28, 2022.

Green Development filed, on August 15, 2022, a Statement of Issues and Docketing Statement. Green Development filed Petitioner's Brief on October 11, 2022. The briefing schedule calls for the following: Respondent's Brief (December 12, 2022); Intervenor for Respondent's Brief (December 19, 2022); Petitioner's Reply Brief (January 9, 2023); Deferred Appendix (January 17, 2023); and Final Briefs (January 31, 2023).

- **Mystic II (ROE & *True*-Up)**
(21-1198; 21-1222, 21-1223, 21-1224, 22-1001, 22-1008, 22-1026) (consolidated)
Underlying FERC Proceeding: EL18-1639-010, -011,[167] -013[168] -017[169]
Petitioners: Mystic, CT Parties,[170] MA AG, ENECOS
Status: Being Held in Abeyance; Motions to Govern Future Proceedings Due Jan 24, 2023

As previously reported, this case was initiated when, on October 8, 2021, Mystic petitioned the DC Circuit Court of Appeals for review of the FERC's orders setting the base ROE for the Mystic COS Agreement at 9.33%. The *Mystic ROE Order* and subsequent FERC orders addressing the Mystic ROE issues have all also been appealed by various parties and consolidated under 21-1198. Docketing Statements and Statements of Issues to be Raised, and the Underlying Decision from which the various appeals arise have been filed as new dockets have been opened and then consolidated with 21-1198. As previously reported, the Certified Index to the Record was due, and filed by the FERC, on February 22, 2022. On March 10, 2022, MMWEC and NHEC filed a notice of intent to participate in support of FERC in Case Nos. 21-1198, 22-1008, and 22-1026 and in support of Petitioners in the

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[165] *ISO New England Inc. and New England Power Co. d/b/a National Grid*, 178 FERC ¶ 61,115 (Feb. 18, 2022) ("*2nd Rev Narragansett LSA Order*"). *ISO New England Inc. and New England Power Co. d/b/a National Grid*, 179 FERC ¶ 62,035 (Apr. 18, 2022) (notice of denial of rehearing by operation of law and providing for further consideration). Together, these orders referred to as the "*2nd Revised Narragansett LSA Orders*".

[166] The 2nd Revised Narragansett LSA is a Local Service Agreement ("LSA") among New England Power, Narragansett and ISO-NE. The LSA reflects the construction of the new Iron Mine Hill Road Substation and related transmission modifications, and the assessment to Narragansett of a Direct Assignment Facilities Charge ("DAF Charge") associated with the facilities. The Iron Mine Hill Road Substation, a new 115 kV/34.5 kV substation (including modifications necessary to loop Narragansett's existing 115 kV H17 transmission line through the new substation) will connect to a new 34.5 kV distribution feeder, which will serve as the point of interconnection for several distributed generation projects being developed by Green Development, LLC ("Green Development"), located in North Smithfield, Rhode Island.

[167] *Constellation Mystic Power, LLC,* 176 FERC ¶ 61,019 (July 15, 2021) ("*Mystic ROE Order*")*; Constellation Mystic Power, LLC*, 176 FERC ¶ 62,127 (Sep. 13, 2021) ("*September 13 Notice*") (Notice of Denial By Operation of Law of Rehearings of Mystic ROE Order).

[168] *Constellation Mystic Power, LLC,* 178 FERC ¶ 61,116 (Feb. 18, 2022) ("*Mystic ROE Second Allegheny Order*")*; Constellation Mystic Power, LLC,* 178 FERC ¶ 62,028 (Jan. 18, 2022) ("*January 18 Notice*") (Notice of Denial By Operation of Law of Rehearings of Mystic ROE Second Allegheny Order).

[169] *Constellation Mystic Power, LLC*, 179 FERC ¶ 61,011 (Apr. 28, 2022) ("*Mystic First CapEx Info. Filing Order*"); *Constellation Mystic Power, LLC*, 179 FERC ¶ 62,179 (June 27, 2022) ("*June 27 Notice*") (Notice of Denial By Operation of Law of Rehearings of *Mystic First CapEx Info. Filing Order*).

[170] In this appeal, "CT Parties" are the CT PURA CT PURA, Connecticut Department of Energy and Environmental Protection ("CT DEEP"), and the CT OCC.

remaining consolidated cases, and filed a statement of issues. On March 17, 2022, CT Parties moved to intervene, and those interventions were granted on May 4, 2022.

As previously reported, on July 8, 2022, Connecticut Parties and ENECOS jointly moved to hold these proceedings in abeyance until 30 days after the DC Circuit issued an opinion in *MISO Transmission Owners v. FERC*, 16-1325 ("*MISO TOs"*). They requested abeyance on the basis that the consolidated petitions in this proceeding and *MISO TOs* both involve challenges to the FERC's ROE methodology (the FERC set the ROE used in calculating Constellation's rates using the methodology challenged in *MISO TOs*). Although Constellation opposed the abeyance request, the Court granted the abeyance request on July 27, 2022, directing the Parties to file motions to govern future proceedings within 30 days of the court's disposition of *MISO TOs*.

As previously reported, the Court has since decided *MISO TOs*. However, the parties continue to agree that this case should remain in abeyance pending further proceedings in MISO TOs, now on remand at the Commission. Accordingly, on October 25, 2022, Mystic, without opposition, asked the Court for an order keeping these proceedings in abeyance and directing that motions to govern future proceedings be filed within 90 days. On October 26, 2022, the Court effectively granted Mystic's request, ordering that the proceedings remain in abeyance pending further order of the court and directing the parties to file motions to govern future proceedings by ***January 24, 2023***.

- ***CASPR* (20-1333, 21-1031) (consolidated)****
  Underlying FERC Proceeding: ER18-619[171]
  Petitioners: Sierra Club, NRDC, RENEW Northeast, and CLF
  Status: Being Held in Abeyance (until March 1, 2024)

As previously reported, the Sierra Club, NRDC, RENEW Northeast, and CLF petitioned the DC Circuit Court of Appeals on August 31, 2020 for review of the FERC's order accepting ISO-NE's CASPR revisions and the FERC's subsequent *CASPR Allegheny Order*. Appearances, docketing statements, a statement of issues to be raised, and a statement of intent to utilize deferred joint appendix were filed. A motion by the FERC to dismiss the case was dismissed as moot by the Court, referred to the merits panel (Judges Pillard, Katsas and Walker), and is to be addressed by the parties in their briefs.

Petitioners have moved to hold this matter in abeyance three times. The Court has granted each request. The most recent request was submitted on July 22, 2022 (third abeyance request) and moved the Court to hold this matter in abeyance until March 1, 2024, the date on which the elimination of MOPR is to be implemented, with motions to govern due 30 days thereafter. The Court granted the third abeyance request on July 25, 2022.

- ***Opinion 531-A* Compliance Filing Undo (20-1329)**
  Underlying FERC Proceeding: ER15-414[172]
  Petitioners: TOs' (CMP et al.)
  Status: Being Held in Abeyance

On August 28, 2020, the TOs[173] 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*[174] 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

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

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

[173] 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.

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

proceeding in which the challenged order was issued remains ongoing before the Commission." On October 2, 2020, the Court granted the FERC's motion, and directed the parties to file motions to govern future proceedings in this case by February 2, 2021. On January 25, 2021, the FERC requested that the Court continue to hold this petition for review in abeyance for an additional three months, with parties to file motions to govern future proceedings at the end of that period. The FERC requested continued abeyance because of its intention to issue a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the FERC. Petitioners consented to the requested abeyance. On February 11, 2021, the Court issued an order that that this case remain in abeyance pending further order of the court. On April 21, 2021, the FERC filed an unopposed motion for continued abeyance of this case *because* the Commission intends to issue a future order on Petitioners' request for rehearing of the challenged Order Rejecting Compliance Filing, and because the remand proceeding in which the challenged order was issued remains ongoing.

On May 4, 2021, the Court ordered that this case remain in abeyance pending further order of the Court, directing the FERC to file a status report by September 1, 2021 and at 120-day intervals thereafter. The parties were directed to file motions to govern future proceedings in this case within 30 days of the completion of agency proceedings. The FERC's last status report, indicating that the proceedings before the Commission remain ongoing and that this appeal should continue to remain in abeyance, was filed on August 11, 2022. The next status report is due on or before ***December 9, 2022***.

Other Federal Court Activity of Interest

- ***Northern* Access *Project (22-1233)***
  Underlying FERC Proceeding: *CP15-115*[175]
  Petitioners: Sierra Club
  Status: Filing of Initial Submissions Underway

On September 6, 2022, the Sierra Club petitioned the DC Circuit for review of *Northern Access Project Add'l Extension Order*. On October 11, 2022, Sierra Club filed a Docketing Statement, a Statement of Issues, and the underlying decision from which the appeal arises. Also on October 11, the FERC moved to hold this proceeding in abeyance. Sierra Club opposed that motion on October 21, 2022. Having issued its further order on rehearing on October 14, 2022,[176] the FERC, on November 4, 2022, withdrew its 's motion to hold this proceeding in abeyance and asked the Court to issue a scheduling order in this proceeding. The Court issued that schedule on November, which calls for submission of a Certified Index to the Record by November 16, 2022; Petitioner's Brief, December 16, 2022; Respondent's Brief, February 14, 2023; Brief for Respondent-Intervenors, February 21, 2023; Petitioner's Reply Brief, March 14, 2023; Joint Deferred Appendix, March 21, 2023; and Final Briefs, April 4, 2023. Consistent with that schedule, the FERC filed, on November 16, 2022, a Certified Index to the Record. Next up is Petitioner's Brief.

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[175] *National Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 179 FERC ¶ 61,226 (June 29, 2022) ("*Northern Access Project Add'l Extension Order*").

[176] *Corpus Christi Liquefaction Stage III, LLC*, 181 FERC ¶ 61,033 (Oct. 14, 2022).

- ***Order 872* (20-72788,* 21-70113; 20-73375, 21-70113) (consol.) (9th Cir.)**
  Underlying FERC Proceeding: RM19-15[177]
  Petitioners: SEIA et al.
  Status: Oral Argument Held March 8, 2022; Awaiting Decision

On September 17, 2020, SEIA petitioned the 9th Circuit Court of Appeals for review of *Order 872*.[178] Briefing is complete and oral argument was held March 8, 2022 before Judges Nguyen, Miller and Bumatay. This matter remains pending before the Court.

- **Algonquin Atlantic Bridge Project Orders (21-1115*, 21-1138, 21-1153, 21-1155 consol.) and (22-1146, 22-1147 consol.)**
  Underlying FERC Proceeding: CP16-9-012[179]
  Petitioners: LS Power, Algonquin, INGA
  Status: Cases 22-1146/47 Deconsolidated and Briefing Schedule Set; Remaining Cases (21-1115 et al.) Being Held in Abeyance Pending Disposition of 22-1146/47

On May 3, 2021, Algonquin petitioned the DC Circuit Court of Appeals for review of the *Briefing Order* and the *April 19 Notice of Denial of Rehearings by Operation of Law*. Appearances, docketing statements and a statement of issues were due and filed June 4, 2021. Also on June 4, 2021, the FERC filed an unopposed motion to hold this proceeding in temporary abeyance, until August 2, 2021, including the fling of the certified index to the record, because "the May 3 petition for review no longer reflects the [FERC]'s latest determination in this matter." The Court granted the first abeyance motion. On November 15, 2021, the Court granted a third abeyance motion by the FERC, directing the parties to file motions to govern future proceedings by January 31, 2022. On January 31, 2022, Algonquin and INGA asked the Court to extend the abeyance by an additional 120 days (to May 31, 2022). On February 15, 2022, the Court issued an order extending the abeyance and directing the Petitioners to file motions to govern future proceedings by May 31, 2022. On May 31, 2022, Petitioners asked the Court to continue to hold this proceeding in abeyance pending the First Circuit's disposition of Algonquin's pending motions to transfer that Court's cases 20-1458 and 22-1201 (which also challenge the FERC's authorization of the "Atlantic Bridge Project").

On June 30, the First Circuit transferred cases 20-1458 and 22-1201 to the DC Circuit. The DC Circuit docketed those cases as 22-1146 and 22-1147, consolidated them with its cases challenging the Atlantic Bridge Project orders (with 21-1115 remaining the lead case), and directed the parties to file a proposed briefing schedule. On July 19, the parties filed a proposal that cases 22-1146 and 22-1147 be severed, proposed a revised briefing format and schedule for those cases, and asked the Court to continue to hold the remaining cases in abeyance (asserting that abeyance may avoid the need for briefing and adjudication of the issues that Algonquin and INGAA would press).

On August 16, 2022, the Court deconsolidated 22-1146 and 22-1147 from 21-1115 et al., which is to remain in abeyance pending a further order of the Court. The Court consolidated Cases 22-1146 and 22-1147 together and issued a briefing schedule that calls for the remaining submissions: Respondent Brief by January 12, 2023, Joint Brief of Intervenors by January 26, 2023, Joint Reply Brief of Petitioners by February 16, 2023, Deferred Joint Appendix by March 2, 2023, and Final Briefs by March 9, 2023. The date of oral argument and the composition of the merits panel will be provided at a later date. Next up, Respondent (FERC) Brief.

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[177] *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).

[178] *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.

[179] *Briefing Order*; *April 19 Notice of Denial of Rehearings by Operation of Law.*

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