NEPOOL
NEW ENGLAND POWER POOL

Sebastian Lombardi
Secretary

October 30, 2025

VIA E-MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of November 6, 2025 Participants Committee Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the November 2025 meeting of the Participants Committee will be held **in person on Thursday, November 6, 2025, at 2:00 p.m. at the Hilton Boston Logan Airport, One Hotel Drive, Boston, MA 02128** **following individual, modified Sector meetings with the ISO Board and with State Officials as follows:**

- 9:00 am – 10:15 am — Sector Meetings Session I
- 10:35 am – 11:50 am — Sector Meetings Session II
- 11:50 am – 12:30 pm — Lunch
- 12:30 pm – 1:45 pm — Sector Meetings Session III
- 2:00 pm – conclusion of business — NPC General Business

A schedule of planned Sector meetings is included with this supplemental notice.

The Participants Committee meeting, which is scheduled to begin at **2:00 p.m.** following those Sector meetings, will be held in the second floor International Ballroom for the purposes set forth on the attached agenda and posted with the meeting materials at nepool.com/meetings/.

To join the meeting using the enhanced Webex interface, please **download the Webex app** to your desktop or to your phone (whichever device you will be using) **in advance of the meeting**, and use the app to join the meeting by clicking the following link for the meeting: https://iso-newengland.webex.com/iso-newengland/j.php?MTID=m3e6801300a7cfec6fffff7c39e9e224d. You may also access the meeting through the ISO's Webex meetings page by clicking https://iso-newengland.webex.com/webappng/sites/iso-newengland/meeting/home and selecting the meeting (event password = **nepool**).

Please also note that the ISO Board will conduct a public meeting the day before, on November 5, 2025, from 1:00 p.m. to approximately 4:30 p.m., at the same venue (the Hilton Boston Logan Airport Hotel). For your convenience, we have included with this package the ISO's Notice of its Open Board Meeting, which also can be downloaded at https://www.iso-ne.com/static-assets/documents/100028/iso-ne-rsp-public-meeting-open-board-meeting-initial-notice-nov-5-2025.pdf. If you wish to participate in or listen to the Board meeting, you should review the notice. Advanced registration is required for in-person attendance and is available via the ISO New England Calendar at https://www.iso-ne.com/event-details?eventId=159951.

Looking forward, please make sure that your calendars reflect the upcoming NEPOOL Annual Meeting, which will be on Thursday, December 4, 2025 at the Colonnade Hotel in Boston.

Respectfully yours,

/s/
Sebastian Lombardi, Secretary

FINAL AGENDA

1. To approve the draft minutes of the October 9, 2025 Participants Committee Meeting. A copy of the draft minutes, marked to show the changes since the minutes were circulated with the initial notice, are included with this supplemental notice and posted with the meeting materials.

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

3. To receive an ISO Chief Executive Officer report. The November CEO report is included and posted with this supplemental notice.

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

5. To consider, and take action, as appropriate, on changes to Appendix A (Transmission Formula Rate Template) ~~and Appendix D (Depreciation/Amortization Rates)~~ to OATT Attachment F (Annual Transmission Revenue Requirements) in response to the requirements of *Order 898* ("Accounting and Reporting Treatment of Certain Renewable Energy Assets"). Background materials and a draft resolution are included and posted with this supplemental notice.

6. To consider, and take action, as appropriate, on changes to the NEPOOL Generation Information System (GIS) to allow a NEPOOL GIS login to be linked and have access to multiple GIS Accounts. Background materials and draft resolutions are included and posted with this supplemental notice.

6A. To receive background and an overview on a proposed NEPOOL Policy Statement regarding GIS Waiver Requests. While no action is to be taken at this meeting, the expectation is that the Committee will be asked to take action to adopt the Policy Statement at the December 2025 Annual Meeting. A draft of that proposed Policy Statement is included with this supplemental notice.

7. To receive a report on current contested matters before the FERC and the Federal Courts. The litigation report will be circulated and posted in advance of the meeting.

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

9. Administrative matters.

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

Protocols. The NEPOOL general business portions and plenary sessions of the meeting will be recorded, as are all the NEPOOL Participants Committee meetings. NEPOOL meetings, while not public, are open to all NEPOOL Participants, their authorized representatives and, except as otherwise limited for discussions in executive session, consumer advocates that are not members, federal and state officials and guests whose attendance has been cleared with the Committee Chair. All those participating in this meeting must 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.

2025 Regional System Plan Public Meeting
and Open Meeting of the ISO New England Board of Directors
November 5, 2025
Boston, Massachusetts

The ISO New England Board of Directors will conduct an open meeting in Boston on Wednesday, November 5, 2025 from 1:00 p.m. to approximately 4:30 p.m.

Location: The meeting will take place in-person at the Hilton Boston Logan Airport Hotel (1 Hotel Drive, Boston, MA 02128). A virtual attendance option will also be available.

Preliminary Agenda: The program will begin with opening remarks from the chair of the ISO New England Board of Directors, Cheryl LaFleur. Following opening remarks, ISO New England Board of Directors member, Caren Anders, will introduce the Regional System Plan. ISO New England leadership will provide a presentation outlining highlights and key takeaways from the 2025 Regional System Plan (RSP25). The Board will then conduct its regular business, which will include a management update from ISO New England CEO and President, Gordon van Welie, and an update on the ISO's Multi-Year Roadmap from Executive Vice President and COO, Vamsi Chadalavada. A listening session will follow. The ISO will post a final agenda prior to the meeting.

Written Comments: The public can submit written comments to the ISO Board of Directors either in advance of or after the meeting. Please submit written comments by email to the following email address: BoardofDirectors@iso-ne.com. Written comments provided by December 31 will be compiled and posted to the ISO website.

Listening Session: The Board is conducting this open session to give the public an opportunity to observe the Board's discussions firsthand. The format of this meeting is not a public hearing. A limited number of timeslots will be available for those who want to address the Board directly. Meeting details, including how to sign up for the listening session, are available on the ISO Calendar Event Page. The meeting additionally provides the opportunity for public review and comment on the 2025 draft Regional System Plan (RSP). Additional information on the RSP is available on the ISO website.

Registration: The public will have options to attend in-person and virtually. Virtual attendance is not limited and virtual meeting information is available on the ISO event page. The meeting space can accommodate approximately 150 in-person attendees. Because in-person space is limited, we urge people to register early. Advanced registration is required to attend in-person and is available on the ISO New England Calendar: https://www.iso-ne.com/event-details?eventId=159951

Recording: After the meeting, ISO-NE will post a video recording for the benefit of members of the public who are not able to attend the meeting live.

Accessibility: If you have requests for accommodations, you may reach out to Melissa Winne (mwinne@iso-ne.com) and we will do our best to meet requests for reasonable accommodations.

About ISO New England: ISO New England is the independent, private, nonprofit entity that serves as the Regional Transmission Organization ("RTO") for New England. The ISO operates the New England bulk power system and administers New England's organized wholesale electricity market pursuant to the Tariff and the Transmission Operating Agreement ("TOA") with the New England Participating Transmission Owners ("PTO"). As the RTO, the ISO has the responsibility to protect the short-term reliability of the New England Control Area and to plan and operate the system according to reliability standards established by the ISO, the Northeast Power Coordinating Council, Inc. ("NPCC") and the North American Electric Reliability Corporation ("NERC").

For more information about ISO New England, please visit www.iso-ne.com, or www.ISONewswire.com.

About the ISO New England Board of Directors: An independent Board of Directors oversees the management of ISO New England. For information on ISO governance, including profiles of the individual members of the ISO New England Board of Directors, please visit: https://www.iso-ne.com/about/corporate-governance.

2025 Regional System Plan Public Meeting & Open Meeting of the ISO New England Board of Directors

November 5, 2025
1:00 – 4:30 p.m.

Hilton Boston Logan Airport Hotel
1 Hotel Drive, Boston, Massachusetts
and virtually via WebEx

Preliminary Agenda:

1. Chair's Opening Remarks and Agenda Review
2. 2025 Regional System Plan
3. Management Reports
    a. CEO Report
    b. ISO's Multiyear Roadmap
4. Listening Session
5. Chair's Closing Remarks and Adjournment

NEPOOL
NEW ENGLAND POWER POOL

PARTICIPANTS COMMITTEE NOVEMBER 6, 2025 MEETING
Hilton Boston Logan Airport, Boston, MA
MEETING SCHEDULE**

SECTOR/GROUP	Session I 9:00 – 10:15 a.m.	Session II 10:30 – 11:45 a.m.	Lunch 11:45 – 12:30 p.m.	Session III 12:30 – 1:45 p.m.	General Business 2:00 p.m. - adjournment
Generation / Long	State Officials Panel 1 ***(Dartmouth)***	ISO Board Panel 2 ***(Wellesley)***	Lunch (*Ballroom*)	*Open*	**General Business 2:00 p.m. - adjournment** Participants Committee General Business *(International Ballroom)*
Transmission	State Officials Panel 2 ***(Conf. Suite 208)***	ISO Board Panel 1 ***(Middlebury)***	Lunch (*Ballroom*)	*Open*	
Supplier / Short (LSE)	*Open*	State Officials Panel 2 ***(Conf. Suite 208)***	Lunch (*Ballroom*)	ISO Board Panel 1 ***(Middlebury)***	
Publicly Owned Entity	ISO Board Panel 1 ***(Middlebury)***	*Open*	Lunch (*Ballroom*)	State Officials Panel 2 ***(Conf. Suite 208))***	
AR	ISO Board Panel 2 ***(Wellesley)***	*Open*	Lunch (*Ballroom*)	State Officials Panel 1 ***(Dartmouth)***	
End User	*Open*	State Officials Panel 1 ***(Dartmouth)***	Lunch (*Ballroom*)	ISO Board Panel 2 ***(Wellesley)***	
ISO Board Panel 1	Publicly Owned Entity ***(Middlebury)***	Transmission ***(Middlebury)***	Lunch (*Ballroom*)	Supplier / Short (LSE) ***(Middlebury)***	
ISO Board Panel 2	AR ***(Wellesley)***	Generation / Long ***(Wellesley)***	Lunch (*Ballroom*)	End User ***(Wellesley)***	
State Officials Panel 1**	Generation / Long ***(Dartmouth)***	End User ***(Dartmouth)***	Lunch (*Ballroom*)	AR ***(Dartmouth)***	
State Officials Panel 2**	Transmission ***(Conf. Suite 208)***	Supplier / Short (LSE) ***(Conf. Suite 208)***	Lunch (*Ballroom*)	Publicly Owned Entity ***(Conf. Suite 208)***	

ISO Board Panel 1: Brook Colangelo, Steve Corneli, Catherine Flax, Cheryl LaFleur, and Mel Williams

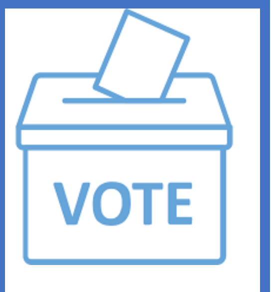
ISO Board Panel 2: Caren Anders, Mike Curran, Craig Ivey, Mark Vannoy, and Gordon van Welie

State Officials Panel 1: CT DEEP Staff Eric Annes, ME PUC Commissioner Carolyn Gilbert, ME PUC Commissioner Patrick Scully, MPUC Staff Michael Haskell, MA DPU Commissioner Liz Anderson, MA DPU Commissioner Staci Rubin, MA EOEEA Assistant Secretary Weezie Nuara, NH DOE Staff Bruce Blair, VT PUC Staff Mary Jo Krolewski, NESCOE Staff Jeff Bentz, NESCOE Staff Shannon Beale, and NECPUC Exec. Dir. George Twigg

State Officials Panel 2: CT DEEP Staff Josh Walters, ME PUC Chair Phil Bartlett, MA EOEEA Staff Ashley Gagnon, MA DPU Staff Gregg Wade, NH PUC Chairman Mark Dell'Orfano, NH DOE Staff Dan Phelan, NH DOE Staff Matt Young, VT PUC Commissioner Riley Allen, VT DPS Commissioner Kerrick Johnson, NESCOE Staff Sheila Keane, NESCOE Staff Nathan Forster, and NESCOE Exec. Dir. Heather Hunt

**** Subject to Change**

1 October 9, 2025 Minutes



66.67%

RESOLVED, that the Participants Committee approves the preliminary minutes of the October 9, 2025 meeting, as circulated in advance of this meeting, with additional non-material clarifications, as the final minutes of the October 9, 2025 meeting.

PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held beginning at 10:00 a.m. on Thursday, October 9, 2025 at the Delamar West Hartford, in West Hartford, CT. 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 Webex.

Ms. Sarah Bresolin, Chair, presided, and Mr. Sebastian Lombardi, Secretary, recorded. Ms. Bresolin welcomed the members, alternates, ISO and State officials, and guests who were present.

APPROVAL OF SEPTEMBER 4, 2025 MEETING MINUTES

Ms. Bresolin referred the Committee to the preliminary minutes of the September 4, 2025 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 in advance of the meeting, with an abstention by Mr. Jon Lamson noted.

CONSENT AGENDA

Ms. Bresolin then referred the Committee to the Consent Agenda that was circulated and posted in advance of the meeting. Following motion duly made and seconded, the Consent Agenda was unanimously approved, with an abstention by Mr. Lamson noted.

Transmission Sector representatives then addressed their support for the revisions to Operating Procedure (OP) No. 17 (OP-17) (Revisions). They conveyed their appreciation to the ISO for the time, efforts and refinements that resulted in the Transmission Sector's support for the Revisions. A few expressed a lingering concern regarding the potential impacts of the Revisions on distribution companies, including the time for and costs of compliance, but also optimism that the five-year implementation timeline was workable. They asked that the ISO continue to work with the TOs to educate stakeholders and state officials about the importance of the Revisions. To better understand the need for the Revisions and for changes to OP-22, the Versant representative commended to Participants the reports from Red Eléctrica (the Spanish System Operator) and the Spanish government, and the factual report from ENTSO-E (an association of European TOs) issued the week before the meeting, that discuss the blackout that affected the Iberian Peninsula on April 28, 2025.

OP-2 REVISIONS

Mr. Nicholas Gangi, Reliability Committee (RC) Chair, referred the Committee to the materials circulated in advance of the meeting related to proposed revisions to OP-2. He explained that, as part of its biannual review process, the ISO introduced minor revisions to OP-2, associated with the scheduling of planned maintenance, that remove outdated steps and add new steps to verify resource outage submission requirements. Those revisions, together with certain revisions to Appendix A to OP-2 (OP-2A Revisions), had been unanimously recommended for Participants Committee support by the RC at its August 19, 2025 meeting. Following that recommendation, the ISO, in response to stakeholder feedback, had (i) made a further substantive (though relatively minor) change to OP-2 (to remove Dynamic Data Recorders from the scope of OP-2), and (ii) determined that action on the OP-2A Revisions should be deferred and taken up at a later Participants Committee meeting in connection with complementary revisions to OP-22 then under discussion at the RC. Accordingly, only the modified version of OP-2 ~~only~~ was being presented for Participants Committee action.

Following a clarifying question and comments, the following motion was duly made, seconded and unanimously approved, with an abstention by Mr. Lamson noted:

> RESOLVED, that the Participants Committee supports the OP-2 Revisions, as proposed by the ISO and as circulated to the Participants Committee in advance of its October 9, 2025 meeting, together with such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), referred the Committee to October CEO Report, which had been circulated and posted with the materials for the meeting. In response to a question, Mr. van Welie provided additional information and context regarding the annual conference of ISO/RTO Council (IRC) which, because Mr. van Welie was the IRC's Chairman for 2025, ISO New England had hosted in 2025.

ISO COO REPORT

Operations Report

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), began 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 for the full month of September 2025, unless otherwise noted. The October report highlighted: (i) that the Peak Hour for September, with 17,226 MW of Revenue Quality Metered (RQM) Data (including settlement-only generation), occurred on September 6, 2025 during the hour ending 4:00 p.m.; (ii) September averages for Day-Ahead Hub LMP ($34.21/MWh), Real-Time Hub LMP ($33.90/MWh), and natural gas prices ($2.02/MMBtu); (iii) Energy Market value for September 2025 was $358 million, up from $321 million in September 2024 and down from the updated

August Energy Market value of $603 million; (iv) Ancillary Services Markets value ($7 million) was down from September 2024 ($8.5 million); (v) average Day-Ahead cleared physical energy during the peak hours as a percentage of forecasted load was 98.6% during September (down from 100.3% reported for August 2025); (vi) Daily Net Commitment Period Compensation (NCPC) payments for September totaled $1.8 million (representing just 0.5% of September's monthly Energy Market value), comprised of (a) $1.6 million in First Contingency payments (including $300,000 in Dispatch Lost Opportunity Costs, $174,000 in Rapid Response Pricing Opportunity Costs, and $72,000 paid to resources at external locations), (b) $29,000 in Second Contingency and no voltage payments, and (c) $136,000 in Distribution payments; and (vii) a Forward Capacity Market (FCM) value of $88.6 million.

Dr. Chadalavada summarized information he had provided to a Participant representative in response to a question received following the September Participants Committee meeting regarding load forecasts on June 10, 2025. He explained that the weather models for that day were calling for significant cloud cover throughout the~~at~~ day, but the region actually experienced unexpectedly clear skies by mid-day, resulting in a 2 gigawatt (GW) difference between the ISO's photovoltaic (PV) forecast and PV production. He said that the June 10 experience illustrated the risks to load forecasting associated with weather forecasts (including cloud cover and storm intensity and timing). He added that, through load reconstitution with actual weather data, the ISO had confirmed that almost the entirety of the June 10 deviation was attributable to the error in the weather models.

Turning to outages, he noted that the region was in its peak season for maintenance and he highlighted the October 22 to November 21 outage of Line 398 (Long Mountain to Cricket

Valley), which would limit imports to from New York to New England to 1,000 MW. He said that exports from New England to New York would also be limited, by roughly 500-600 MW.

Dr. Chadalavada then highlighted results from the Day-Ahead Ancillary Services (DAAS) market. He said that the ISO continued to study and hoped to provide further insight into the performance of the DAAS market through reports to be submitted to the Principal Committees in 2026. Members expressed their thanks for the continued information on the DAAS market.

He concluded his Operations Report highlights by reporting on the submissions received in response to the Long-Term Transmission Planning (LTTP) request for proposals (RFP). He reported that six proposals were submitted from four different Qualified Transmission Project Sponsors (QTPS), with three of the project designs primarily alternating current (AC) transmission and three primarily high voltage direct current (HVDC) transmission. All six of the proposals claimed that they meet the conditions of the RFP in terms of supporting the integration of wind in Northern Maine as well as the Surowiec-South limits and the Maine-New Hampshire limits. Installed costs ranged from a low of $0.96 billion to a high of $4.04 billion (though some, contrary to RFP instructions, included estimates for corollary upgrades). "In Service" dates ranged from the fourth quarter of 2032 to the third quarter of 2035.

In response to questions, Dr. Chadalavada stated that there was much work to be completed on the LTTP proposals received, including accounting and adjusting for the corollary upgrades. He said that, in light of the number of RFP responses received, it would be reasonable to expect that the proposed evaluation timeline would be accelerated, but it was too early at that time to estimate by how much or when the evaluations might be available. A high-level summary of the LTTP Proposals would be provided by November 30, and likely presented at the November Planning Advisory Committee (PAC) meeting.

When asked about expectations for the upcoming winter months, Dr. Chadalavada confirmed that there would likely be an overall reduction in the volume of imports from Hydro-Quebec, though the ties would likely continue to be fully utilized during peak hours under cold winter conditions. With respect to DAAS market prices, he said that, while there was no specific forecast for such prices expected for Winter 2025/26, it would be fair to surmise that, on colder days, especially when gas prices are high, prices for the products cleared in the DAAS market would be higher.

Related to forecasting, Dr. Chadalavada agreed in response to a comment to consider further and address how the ISO might improve the ease of accessing load forecast information already available through the ISO website and identifying the impact of load forecast errors on the DAAS market. Referring to the new updated load forecasts being published by the ISO, a member expressed his company's appreciation for the information and the ISO's response to the request for that information.

2026 Annual Work Plan

Turning to the ISO's draft 2026 Annual Work Plan (AWP), which had been circulated in advance of the meeting and posted with the meeting materials, Dr. Chadalavada highlighted and discussed the following anchor projects: Capacity Auction Reforms (CAR), Asset Condition Reviewer (ACR), LTTP Implementation, *Order 1920* compliance, Dynamic Operating Reserves, and Information Technology (IT) implementation of major initiatives. With respect to IT initiatives more generally, Dr. Chadalavada suggested that the Committee might benefit from a focused update on the ISO's cyber security and generative artificial intelligence (AI) efforts, and committed to work with the Committee officers to identify an appropriate time for that update. He also identified notable initiatives related to: (i) operations (a first run of the formalized Probabilistic Energy Adequacy Tool (PEAT)/Regional Energy Shortfall Threshold (REST) processes); (ii) planning (*Order 2023* implementation and the evaluation of surplus capacity interconnection service rules (a NEPOOL priority request for the 2026 AWP)); (iii) markets (including Pay-for-Performance (PFP) revisions depending on FERC action on NEPGA's pending Balancing Ratio and Stop Loss Allocation Methodology complaint, and continued assessment and future steps on the DAAS market); and (iv) IT/security (inverter-based resource (IBR) integration and modeling and enhancements to synchrophasor infrastructure and the Integrated Market Simulator). He invited questions and comments from members.

In response to questions on markets initiatives, Dr. Chadalavada suggested that the ISO planned to wait for a limited, but as-yet-undetermined, period of time to allow for FERC action on the NEPGA Complaint. Absent such action, he anticipated a discussion around voluntary changes that could address the experience underlying the NEPGA Complaint and Participant concerns raised in connection therewith. With respect to the treatment of exports during PFP or Capacity Scarcity Condition events, Dr. Chadalavada noted that export-related recommendations were at or near the top of the list in both the EMM and IMM Annual Markets Reports. Dr. Chadalavada said that the ISO would respond to those recommendations, irrespective of the NEPGA Complaint and any FERC action thereon, and the timing for that response and related efforts was under consideration. He added that any potential PFP revisions were also likely to be informed by the CAR impact analysis, which was expected to reveal insights not only on resource accreditation values, but on certain market clearing values, the seasonal breakdown of loss of load hours and their bearing on the PFP performance rate.

Addressing a question related to a planning initiative not mentioned in the AWP, Dr. Chadalavada reported on the status of the joint study by PJM, New York, and the ISO to evaluate whether the 1,200 MW minimum loss of source limit (the amount of power that can be imported into New England before an interregional reliability risk arises in PJM and New York) could be raised and any necessary transmission upgrades to support a higher limit identified. He reported that the ISO New England team had pushed this project as far as they could take their part, but other developments in PJM and New York had resulted in a lower priority for the initiative in those regions. Dr. Chadalavada suggested very modest improvements might be achievable in the short-term, but he thought the probability of a more significant increase, which would require transmission upgrades in each of the regions, was quite low. Mr. Al McBride, ISO Vice President of System Planning, offered some additional context regarding topology and load developments in New York and directed those interested in the initiative to the status report that would be provided at the December meeting of the Interregional Planning Stakeholder Advisory Committee (IPSAC).

A Publicly Owned Entity representative, otherwise satisfied with the focus and progress on anchor projects and notable initiatives, raised a continuing concern with the REST process and that potential for energy shortfall issues to arise in a shorter timeframe or on shorter notice than the two to two and one-half years it normally takes to implement market solutions. He encouraged the ISO, if at all possible, to carve out time in 2026 and early 2027 to consider potential alternatives so as to reduce implementation timeframes for solutions associated with the 2028-2029 winter delivery period. Agreeing that the ISO would prefer not to be in a "reactive mode", Dr. Chadalavada committed the ISO to doing everything within reason to avoid being in that mode~~ensure that it does not get there~~.

Another member, complimenting the ISO for the projects and initiatives identified in the AWP, commented on a few areas of specific interest to his organization and more generally thanked the ISO for its willingness to include in the AWP evaluation of surplus interconnection service rules, which had come out of the NEPOOL priority setting process. In turn, Dr. Chadalavada highlighted the value that the NEPOOL priority setting process had provided the ISO, thanking Participants for the time, attention and effort invested in the iterative process.

Dr. Chadalavada concluded by emphasizing the importance of the certainty of the capacity auction schedules under the CAR project. He noted that significant reforms would be tied to a Summer 2028 auction, would require crisply-defined timelines, and could not be allowed to slip. He said that staying the course with respect to schedules had served the region well, notwithstanding any substantive differences or disagreements, and implored the Committee, as well as state officials, to help the ISO ensure the coming capacity auctions stay on schedule.

~~that it was critical as ISO goes through the Work Plan that they make sure the one thing they should not compromise on is the timing on the. ISO will be going into the significant reform phase that has a lot of scope within that. They will tie to a specific timeline for 2028 and run a summer auction. They will be coming back to the Committee with a very crisp timeline of the next phase of auctions which cannot slip.~~

2026 ISO AND NESCOE BUDGETS

Mr. Tom Kaslow, Budget & Finance Subcommittee (B&F) Chair, referred the Committee to the materials circulated and posted in advance of the meeting related to the proposed 2026 ISO and NESCOE Budgets. He reminded the Committee that the ISO had presented its preliminary top-down 2026 Capital and Operating Budgets (ISO Budgets) at the Participants Committee June Summer Meeting. He reported that both the ISO Budgets and the 2026 NESCOE Budgets had then been reviewed and considered at the B&F's August 8, 2025 meeting. He reported that no objections or concerns had been raised with respect to either the ISO Budgets or to NESCOE's 2026 Budget~~, which had been presented~~ at that meeting. At the September 4, 2025 Participants Committee meeting, the ISO provided further explanation and review of their two budgets and NESCOE also provided and opportunity for questions on their budget as well. He said that the 2026 ISO and NESCOE Budgets were ready for Participants Committee action.

2026 ISO Budgets

Ms. Kelly Reyngold, ISO Director of Accounting, provided an update on the ISO Budgets since their presentation at the September Participants Committee meeting. She explained that ISO Budget amounts had not changed, though there had been changes to the Capital Projects plan and thus to the allocation in the Capital Budget.

In response to a question related to funds earmarked for the Asset Condition Reviewer project, Ms. Reyngold explained that the 2026 budget included $1 million to pay outside consultants that would~~ill~~ review asset condition projects during the interim phase and would~~to~~ help the ISO develop the Asset Condition Reviewer (AC Reviewer) function. She said that costs for the permanent AC Reviewer function would be reflected in the 2027 budget and any costs above 2026's budgeted $1 million amount would be funded from contingency funds and would not increase the overall 2026 ISO Operating Budget.

The following motion was then duly made, seconded and approved unanimously, with abstentions by the Maine Office of Public Advocate and Mr. Lamson noted.:

RESOLVED, that the Participants Committee supports the Year 2026 **ISO operating** budget **and capital budget** proposed by the ISO, as presented at this meeting.

2026 NESCOE Budget

Without further comment or discussion, the following motion to support the 2026 NESCOE Budget was duly made, seconded and unanimously approved, with an abstention by Mr. Lamson noted:

RESOLVED, that the Participants Committee supports the Year 2026 **NESCOE budget** proposed by the ISO, as presented at this meeting.

LITIGATION REPORT

Mr. Lombardi referred the Committee to the October 7, 2025 Litigation Report that had been circulated and posted before the meeting. He highlighted the following:

- activity in NEPGA's Balancing Ratio and Stop Loss Allocation Methodology Complaint proceeding (EL25-106), which remained pending before the FERC. As a Section 206 complaint, he noted that there was not a specific timeframe or deadline for FERC action;
- the FERC's order on the Maine Office of Public Advocate's (MOPA) formal challenge to the TO's 2023/24 annual transmission rate update informational filing, which directed certain New England TOs to provide additional information;
- a preliminary injunction issued by a judge from the U.S. District Court for the District of Columbia granting the interim relief sought by Revolution Wind regarding the stop-work order issued by the U.S. Department of Interior's Bureau of Ocean Energy Management, allowing Revolution Wind, LLC to restart impacted activities while the underlying lawsuit challenging the stop-work order progresses; and

- the Senate confirmation on October 7, 2025 of the nominations of FERC Commissioners Laura Swett and David LeCerte.

Mr. Lombardi encouraged those with questions on those or any matter in the Litigation Report to reach out to NEPOOL Counsel.

COMMITTEE REPORTS

Markets Committee (MC). Mr. Ben Griffiths, MC Vice-Chair, reported that the next MC meeting would be on October 15-16, 2025~~,~~ at the DoubleTree Hotel in Westborough, MA. Discussion on the first day would focus mostly on seasonal accreditation; the second day, on Capacity Auction Reform's prompt market design and related deactivation changes (CAR-PD). Discussion on CAR-PD would include amendments and two or three updates that had not been discussed previously.

Reliability Committee. Mr. Bob Stein, RC Vice-Chair, reported that the next RC meeting would be held on October 22, 2025 at the DoubleTree Hotel in Westborough, MA. Principal topics, in addition to the usual review of Proposed Plan Applications (PPAs) and Transmission Cost Allocations (TCAs), was expected to include how the Resource Adequacy Assessment (RAA) tool would be used to determine the accreditation level of resources and consideration of the proposed HQICCs and ICR-Related Values for the third Annual Reconfiguration Auction (ARA) for the 2026-2027 Capacity Commitment Period (CCP) and the second ARA for CCP 2027-2028.

Transmission Committee (TC). Mr. Dave Burnham, TC Vice-Chair, reported that the next TC meeting would be October 28, 2025~~,~~ and was scheduled to be held at the DoubleTree Hotel in Westborough, MA. He said that discussion could include: (i) an amendment related to

CAR-PD (which would be discussed at the October MC meeting and then noticed as a joint item at the October TC meeting if not fully covered at the October MC meeting, and most likely not noticed or discussed if fully covered). Votes would be in November; (ii) a vote on *Order 898 c*ompliance; and (iii) further discussion on additional changes related to *Order 2023* implementation.

Budget & Finance Subcommittee (B&F). Mr. Kaslow reported that the next B&F meeting was scheduled for the following day. In addition to any regular reports, the B&F would review the ISO's 2025 third quarter Capital Funding Tariff filing and address the annual process for Generation Information System (GIS) exemption requests.

Membership Subcommittee. On behalf of Mr. Brad Swalwell, Membership Subcommittee Chair, Mr. Gerity reported that the next Membership Subcommittee meeting would be held by Zoom on October 14, 2025. There would be a couple of applications to accept, no terminations, and a retrospective on the development of the provisional member arrangements. He encouraged all those interested to participate and to reach out to NEPOOL Counsel for the Zoom information.

ADMINISTRATIVE MATTERS

Ms. Anne George, ISO Vice President and Chief External Affairs and Communications Officer, informed the Committee that the registration process for the November 5 open Board Meeting/Regional System Plan public meeting was open and accessible via the ISO website. She added that anyone interested in making public comments to the Board could either sign-up to do so at that meeting or submit written comments to the Board.

Mr. Lombardi reported that the November Participants Committee meeting would be held at the Hilton Boston Logan Airport Hotel in Boston, MA (preceded the day before by the ISO Board's annual open meeting, and earlier on the morning of November 6 by Sector meetings with ISO Board and State Officials starting at 9:00 am). He directed those needing an overnight room for the November meeting to contact Pat Gerity or Jaki Sloan as soon as possible. Looking ahead, Mr. Lombardi reported that the December 4 Annual Meeting would be at the Colonnade Hotel in Boston, MA.

There being no other business, the meeting adjourned at 11:05 am.

Respectfully submitted,

____
Sebastian Lombardi, Secretary

**PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN THE OCTOBER 9, 2025 MEETING**

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Advanced Energy United	Assoc. Non-Voting		Alex Lawton (W)	
AR Large RG Group Member	AR-RG	Aidan Foley (W)		
Ashburnham Municipal Light Plant	Publicly Owned Entity	Matt Ide		
AVANGRID (CMP/UI)	Transmission	Alan Trotta	Jason Rauch (W)	Jaimie St. Pierre
Avangrid Power	Transmission	Kevin Kilgallen		
Bath Iron Works	End User			Bill Short
Belmont Municipal Light Department	Publicly Owned Entity			Brian Forshaw (W)
Block Island Utility District	Publicly Owned Entity			Brian Forshaw (W)
Boylston Municipal Light Department	Publicly Owned Entity	Matt Ide		
BP Energy Company (BP)	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity			Brian Forshaw (W)
Brookfield Energy Trading and Marketing LLC	Supplier	Aleks Mitreski		
Chester Municipal Light Department	Publicly Owned Entity			Brian Forshaw (W)
Chicopee Municipal Lighting Plant	Publicly Owned Entity	Matt Ide		
Clear River Electric	Publicly Owned Entity			Brian Forshaw (W)
Concord Municipal Light Plant	Publicly Owned Entity			Brian Forshaw (W)
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw (W)		
Connecticut Office of Consumer Counsel	End User		Jamie Talbert-Slagle	
Constellation Energy Generation (Constellation)	Supplier	Gretchen Fuhr (W)	Bill Fowler (W)	
CPV Towantic, LLC (CPV)	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity			Brian Forshaw (W)
Dominion Energy Generation Marketing, Inc.	Generation	Wes Walker (W)		
DTE Energy Trading, Inc. (DTE)	Supplier			José Rotger
ECP Companies Calpine Energy Services, LP New Leaf Energy	Generation	Andy Gillespie		Bill Fowler (W)
Elektrisola, Inc.	End User			Bill Short
Emera Energy Services	Supplier			Bill Fowler (W)
energyRe Giga-Projects USA, LLC	Provisional Member	Wayne Galli (W)		
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Eversource Energy	Transmission		Dave Burnham	
FirstLight Power Management, LLC	Generation	Tom Kaslow		
First Point Power, LLC	Supplier	Peter Schieffelin (W)	Bryan Amaral (W)	
Gabel Associates, Inc.	Supplier	Sarah Yasutake (W)		
Galt Power, Inc.	Supplier	José Rotger	Jeff Iafrati (W)	
Garland Manufacturing Company	End User			Bill Short
Generation Bridge Companies	Generation			Bill Fowler (W)
Generation Group Member	Generation		Abby Krich (W)	
Georgetown Municipal Light Department	Publicly Owned Entity			Brian Forshaw (W)
Groton Electric Light Department	Publicly Owned Entity	Matt Ide		
Granite Shore Companies	Generation			Bob Stein
Grid United LLC	Provisional Member	Mike Spector		
Groveland Electric Light Department	Publicly Owned Entity			Brian Forshaw (W)
H.Q. Energy Services (U.S.) Inc. (HQUS)	AR-RG	Louis Guilbault (W)	Bob Stein	
Hammond Lumber Company	End User			Bill Short
High Liner Foods (USA) Inc.	End User		Bill Short	
Hingham Municipal Lighting Plant	Publicly Owned Entity			Brian Forshaw (W)
Holden Municipal Light Department	Publicly Owned Entity			Brian Forshaw (W)
Holyoke Gas & Electric Department	Publicly Owned Entity	Matt Ide		
Hull Municipal Lighting Plant	Publicly Owned Entity	Matt Ide		
Icetec Energy Services, Inc.	AR-LR	Doug Hurley		

(W) = Webex

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN THE OCTOBER 9, 2025 MEETING

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Ipswich Municipal Light Department	Publicly Owned Entity	Matt Ide		
Jericho Power LLC (Jericho)	AR-RG	Ben Griffiths		
Lamson, Jon	End User	Jon Lamson		
Littleton (MA) Electric Light and Water Dept.	Publicly Owned Entity			Brian Forshaw (W)
Littleton (NH) Water & Light Department	Publicly Owned Entity		Craig Kieny (W)	
Long Island Power Authority (LIPA)	Supplier		Bill Kilgoar (W)	
Maine Power LLC	Supplier	Jeff Jones (W)		
Maine Public Advocate’s Office	End User	Drew Landry (W)		Susan Chamberlain (W)
Mansfield Municipal Electric Department	Publicly Owned Entity	Matt Ide		
Marble River, LLC	Supplier	John Brodbeck		
Marblehead Municipal Light Department	Publicly Owned Entity	Matt Ide		
Mass. Attorney General’s Office (MA AG)	End User	Jackie Bihrle		Chris Modlish
Mass. Bay Transportation Authority	Publicly Owned Entity			Brian Forshaw (W)
Mass. Climate Action Network (MCAN)	End User			Abby Krich (W)
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Matt Ide		
MDC – The (CT) Metropolitan District	Publicly Owned Entity			Brian Forshaw (W)
Mercuria Energy America, LLC	Supplier			José Rotger
Merrimac Municipal Light Department	Publicly Owned Entity			Brian Forshaw (W)
Middleborough Gas & Electric Department	Publicly Owned Entity			Brian Forshaw (W)
Middleton Municipal Electric Department	Publicly Owned Entity			Brian Forshaw (W)
Moore Company	End User			Bill Short
Nautilus Power, LLC	Generation		Bill Fowler (W)	
New England Power (d/b/a National Grid)	Transmission		Tim Martin	
New England Power Gens. Assoc. (NEPGA)	Assoc. Non-Voting	Bruce Anderson	Dan Dolan	Molly Connors (W)
New Hampshire Electric Cooperative	Publicly Owned Entity			Brian Forshaw (W)
New Hampshire Office of Consumer Advocate	End User	Matthew Fossum		
NextEra Energy Resources, LLC	Generation	Michelle Gardner	Nick Hutchings	
North Attleborough Electric Department	Publicly Owned Entity			Brian Forshaw (W)
Norwood Municipal Light Department	Publicly Owned Entity			Brian Forshaw (W)
NRG Business Marketing	Supplier		Pete Fuller	
Nylon Corporation of America	End User			Bill Short
Pawtucket Power Holding Company	Generation	Dan Allegretti (W)		
Paxton Municipal Light Department	Publicly Owned Entity	Matt Ide		
Peabody Municipal Light Department	Publicly Owned Entity	Matt Ide		
Princeton Municipal Light Department	Publicly Owned Entity	Matt Ide		
Reading Municipal Light Department	Publicly Owned Entity			Brian Forshaw (W)
RENEW Northeast, Inc.	Assoc. Non-Voting	Francis Pullaro		
Rhode Island Energy (Narragansett Electric Co.)	Transmission	Brian Thomson	Robin Lafayette (W)	
Rowley Municipal Lighting Plant	Publicly Owned Entity			Brian Forshaw (W)
Russell Municipal Light Dept.	Publicly Owned Entity	Matt Ide		
Saint Anselm College	End User			Bill Short
Shell Energy North America (US), L.P.	Supplier	Jeff Dannels		
Shipyard Brewing LLC	End User			Bill Short
Shrewsbury Electric & Cable Operations	Publicly Owned Entity	Matt Ide		
South Hadley Electric Light Department	Publicly Owned Entity	Matt Ide		
Sterling Municipal Electric Light Department	Publicly Owned Entity	Matt Ide		
Stowe Electric Department	Publicly Owned Entity			Brian Forshaw (W)
Tangent Energy	AR-LR	Brad Swalwell (W)		
Taunton Municipal Lighting Plant	Publicly Owned Entity			Brian Forshaw (W)
Templeton Municipal Lighting Plant	Publicly Owned Entity	Matt Ide		
The Energy Consortium	End User		Mary Smith (W)	

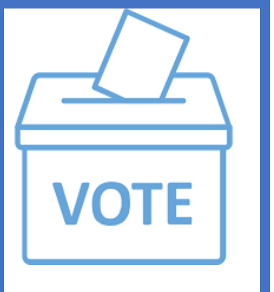
(W) = Webex

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN THE OCTOBER 9, 2025 MEETING

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Union of Concerned Scientists	End User	Susan Muller (W)		
Vermont Electric Company	Transmission	Frank Ettori		
Vermont Electric Cooperative	Publicly Owned Entity	Craig Kieny (W)		
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw (W)
Versant Power	Transmission	Dave Norman	Stephen Johnston (W)	
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity			Brian Forshaw (W)
Vistra (Dynegy Marketing and Trade, Inc.)	Supplier	Ryan McCarthy		Bill Fowler (W)
Vitol Inc.	Supplier	Seth Cochran (W)		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity	Matt Ide		
Wallingford DPU Electric Division	Publicly Owned Entity			Brian Forshaw (W)
Wellesley Municipal Light Plant	Publicly Owned Entity			Brian Forshaw (W)
West Boylston Municipal Lighting Plant	Publicly Owned Entity	Matt Ide		
Westfield Gas & Electric Department	Publicly Owned Entity			Brian Forshaw (W)
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler (W)	
ZTECH, LLC	End User			Bill Short

(W) = Webex

2 Consent Agenda



66.67%

1. Revisions to OP-4 (Revisions/Clarifications to LCC Communications)
2. Revisions to OP-5A (Biennial Review – inclusion of Maintenance Outages in the calculation of Short-Term Locational Operable Capacity Margin; minor grammatical changes)
3. HQICCs Values for the 2026-27 3rd ARA and 2027-28 2nd ARA
4. ICR and Related Values for the 2026-27 3rd ARA and 2027-28 2nd ARA

RESOLVED, that the Participants Committee approves the Consent Agenda as circulated in advance of this meeting.

CONSENT AGENDA

Reliability Committee (RC)

*From the previously-circulated notice of actions of the RC's **October 22, 2025** meeting, dated October 22, 2025.*[1]

1. Revisions to OP-4 (Revisions/Clarifications to LCC Communications)

Support proposed revisions to ISO-NE Operating Procedure (OP) No. 4 (Action During a Capacity Deficiency),[2] as recommended by the RC at its October 22, 2025 meeting, together with such further non-material changes as may be approved by the RC Chair and Vice-Chair.

The motion to recommend Participants Committee support was approved unanimously with one abstention (End User Sector) noted.

2. Revisions to OP-5A (Biennial Review – inclusion of Maintenance Outages in the calculation of Short-Term Locational Operable Capacity Margin; minor grammatical changes)

Support proposed revisions to Appendix A (Operable Capacity Calculations) to OP-5 (Resource Maintenance and Outage Scheduling),[3] as recommended by the RC at its October 22, 2025 meeting, together with such further non-material changes as may be approved by the RC Chair and Vice-Chair.

The motion to recommend Participants Committee support was approved unanimously with one abstention (End User Sector) noted.

3. HQICCs Values for the 2026-27 3rd ARA and 2027-28 2nd ARA

Support the following Hydro-Québec Interconnection Capability Credit (HQICC) values for the Third Annual Reconfiguration Auction (ARA) for the 2026-27 Capacity Commitment Period (CCP), Second ARA for the 2027-28 CCP, as recommended by the RC at its October 22, 2025 meeting, together with any non-substantive changes as the Chair and Vice-Chair of the RC may approve.

Month	2026-2027 HQICC Values (MW)	2027-2028 HQICC Values (MW)
June	1,009	1,041
July	1,009	1,041
August	1,009	1,041
September	1,009	1,041
October	1,009	1,041
November	1,009	1,041
December	1,009	1,041
January	1,009	1,041
February	1,009	1,041
March	1,009	1,041
April	1,009	1,041
May	1,009	1,041

The motion to recommend Participants Committee support was approved with one opposed (Supplier Sector) and 14 abstentions (4 - Generation, 7 - Supplier, 2 - AR, and 1 End User Sectors) noted.

---

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

[2] The revisions to OP-4 update language regarding ISO communications to Local Control Centers (LCCs).

[3] The revisions to Appendix A to OP-5 (i) explicitly include Maintenance Outages in the calculation of Short-Term Locational Operable Capacity Margin and (ii) make minor grammar changes.

4. ICR and Related Values for the 2026-27 3rd ARA and 2027-28 2nd ARA

3rd ARA for the 2026-27 CCP

Support, for the 3rd ARA for the 2026-27 CCP, the following New England Installed Capacity Requirement (ICR) and Net ICR, Maine (ME) Maximum Capacity Limit (MCL), Northern New England (NNE) MCL values:

	2026-2027 ARA 3 ICR values (MW)
ICR	31,059
Net ICR	30,050
ME MCL	4,230
NNE MCL	8,595

and the following Marginal Reliability Impact (MRI) Capacity Demand Curves -- System-Wide, ME Export-Constrained Capacity Zone, and NNE Export-Constrained Capacity Zone

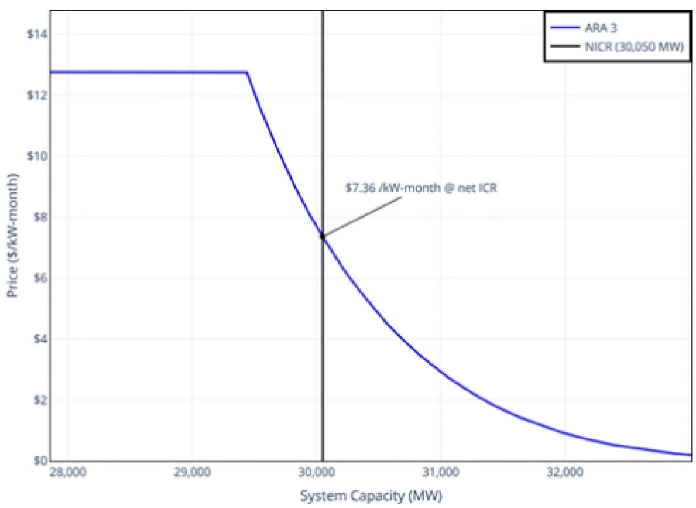


Figure 1: 2026-27 CCP ARA3 System-Wide MRI Capacity Demand Curve

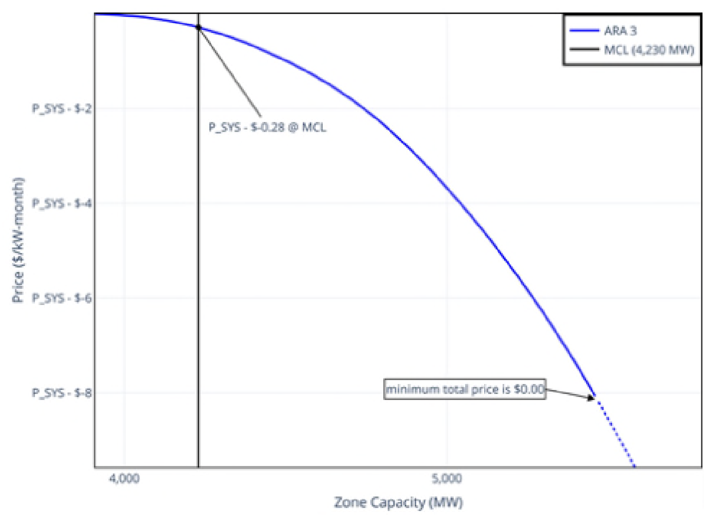


Figure 2: 2026-27 CCP ARA3 ME Export-Constrained MRI Capacity Demand Curve

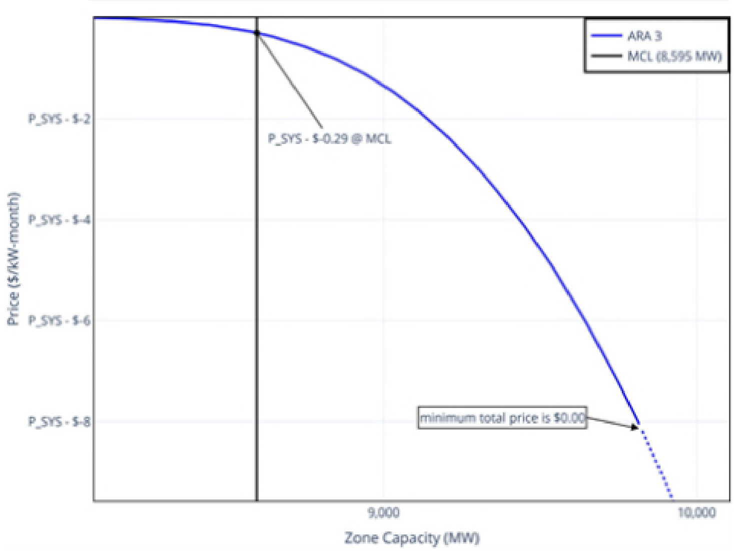


Figure 3: 2026-27 CCP ARA3 NNE Export-Constrained MRI Capacity Demand Curve

2nd ARA for the 2027-28 CCP

Support, for the 2nd ARA for the 2027-28 CCP, the following New England ICR, Net ICR, ME MCL, and NNE MCL values:

	2026-2027 ARA 2 ICR values (MW)
ICR	30,896
Net ICR	29,855
ME MCL	4,335
NNE MCL	8,625

and the following Marginal Reliability Impact (MRI) Capacity Demand Curves -- System-Wide, ME Export-Constrained Capacity Zone, and NNE Export-Constrained Capacity Zone

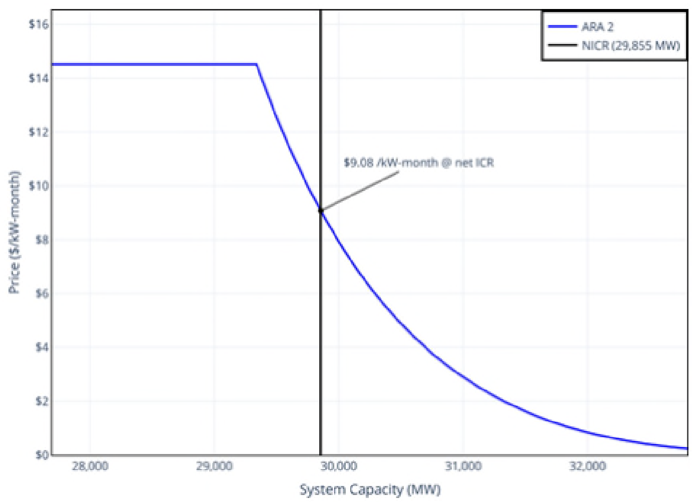


Figure 4: 2027-28 CCP ARA2 System-Wide MRI Capacity Demand Curve

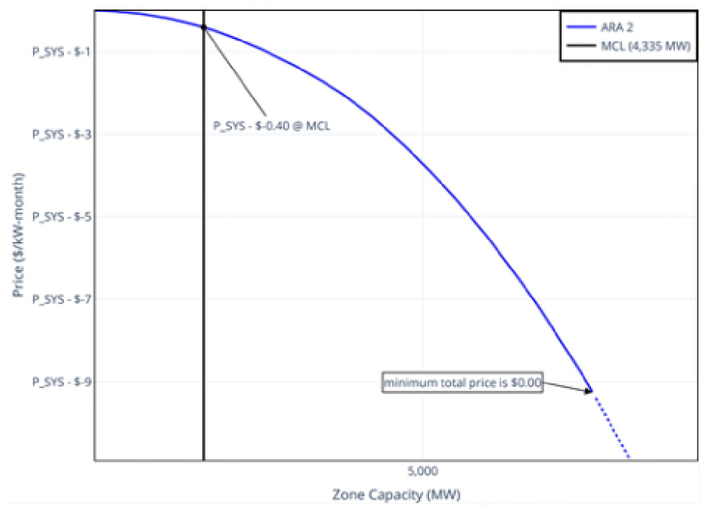


Figure 5: 2027-28 CCP ARA2 ME Export-Constrained MRI Capacity Demand Curve

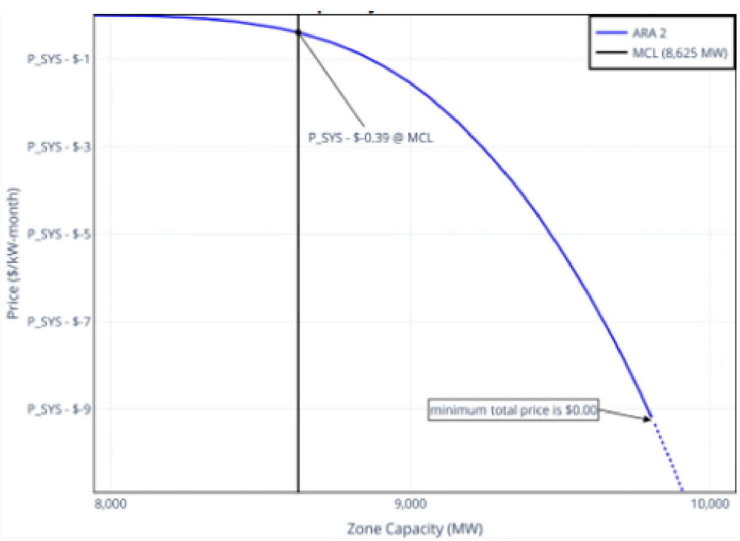


Figure 6: 2027-28 CCP ARA2 NNE Export-Constrained MRI Capacity Demand Curve

each as recommended by the RC at its October 22, 2025 meeting, with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was approved, with one opposition in the Supplier Sector and 14 abstentions (4 – Generation Sector; 7 – Supplier Sector; 2 – AR Sector; and 1 End User Sector) noted.

3 CEO Report

Nov 6, 2025
Meeting

NEPOOL
NEW ENGLAND POWER POOL
Participants Committee

Summary of ISO New England Board and Committee Meetings

November 6, 2024 Participants Committee Meeting

Since the last update, the Board of Directors met on October 7, and the Markets Committee met on October 23. Both of the meetings were held virtually.

The Board of Directors convened to review plans for the future organization of the Chief Executive Officer under Mr. Chadalavada's leadership commencing in 2026, and discussed potential shifts in responsibilities among the senior leadership team.

The Markets Committee was provided with a summary of management's responses to the recommendations included in both the External Market Monitor's and Internal Market Monitor's annual reports, and reviewed the assessment and prioritization of the various recommendations. The Committee discussed the recommendations in detail, noting that some are being addressed through current initiatives, additional recommendations are included in the 2026 work plan, and some items have been deferred to 2027 or later due to lower priority. The Committee further noted that management agreed with most, but not all, of the recommendations; and that areas that differ had been reviewed previously with the Market Monitors and the Committee.

4 COO Report

Nov 6, 2025
Meeting

NEPOOL
NEW ENGLAND POWER POOL
Participants Committee

NEPOOL Participants Committee Report

November 2025

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

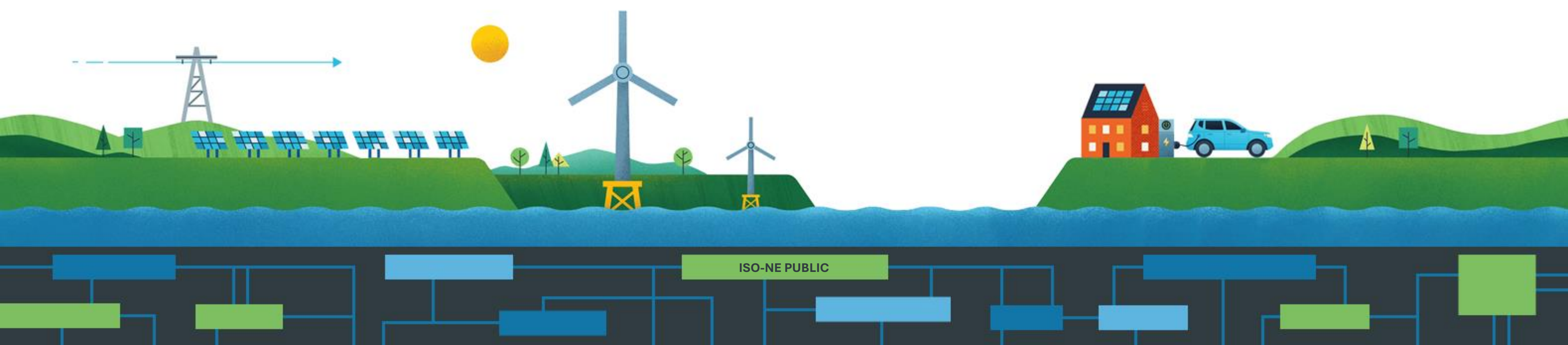


Table of Contents

Regular Operations Report - Highlights

Highlights: October 2025

Settled data through October 29th

- **Peak Hour** on October 6
  - 15,935 MW system peak (Revenue Quality Metered/RQM); hour ending 7:00 P.M.
- **Minimum Telemetered Load**
  - 7,385 MW; hour ending 01:00 P.M. on Saturday, October 18
- **Average Pricing**
  - Day-Ahead (DA) Hub Locational Marginal Price (LMP): $39.98/MWh
  - Real-Time (RT) Hub LMP: $40.38/MWh
  - Natural Gas: $2.31/Mmbtu (MA Natural Gas Avg)
- **Energy Market** value $429M up from $350M in October 2024
  - Ancillary Markets* value $16.9M up from $8M in October 2024
  - Average DA cleared physical energy** during the peak hours as percent of forecasted load was 98.3% during October, down from 98.6% during September
  - Updated September Energy Market value: $358M
- **Net Commitment Period Compensation (NCPC)** total $2.4M
  - Represents 0.6% of monthly Energy Market value
  - First Contingency $2.4M
    - Dispatch Lost Opportunity Cost (DLOC) - $414K; Rapid Response Pricing (RRP) Opportunity Cost - $250K; Posturing - $0; Generator Performance Auditing (GPA) - $177K
    - $69K paid to resources at external locations, down $2K from September
      - $57K charged to Day-Ahead Load Obligation (DALO) at external locations; $7K to Day-Ahead Generation Obligation (DAGO) at external locations; $6K to RT Deviations
  - Second Contingency $18K
  - Distribution and Voltage were zero
- **Forward Capacity Market (FCM)** market value $88.8M
  - FCM peak for 2025 is currently 26,086 MWh

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

*Ancillaries = Reserves, Regulation, NCPC, less Marginal Loss Revenue Fund **DA cleared physical energy is the sum of generation, DRR, and net imports cleared in the DA Energy Market and does not include EIR MW. Effective March 1, 2025, EIR MW obligations from physical generation and DRR are additionally procured up to (but not exceeding) 100% of the forecasted energy requirement.

Year-to-Date Peak Load* Statistics

- Telemetered System Peak Load: **26,024 MW**
  - hour ending 7:00 P.M. on Tuesday, June 24
- RQM System Peak Load: **26,586 MW**
  - hour ending 6:00 P.M. on Tuesday, June 24
- FCM Peak Load: **26,086 MW**
  - hour ending 7:00 P.M. on Tuesday, June 24
  - At this hour, the capacity zone-level FCM peak loads were 3,357 MW in Northern New England, 2,026 MW in Maine, 9,920 MW in Rest-of-Pool, and 10,783 MW in Southeast New England.

*Telemetered loads are as reported by the Control Room. RQM loads are of settlement quality and reflect the contribution of Settlement Only Resources (SOG). Due to the difference in calculation methodologies and the impact of SOGs, these values can occur on different days and/or hours. Both are 'net energy for load' concepts and include transmission losses. FCM load values reflect the sum of active, normal load assets that are non-dispatchable, are included in the FCM settlement and do not include transmission losses.

Day-Ahead Ancillary Services (DAAS) Results

- Average daily total DA E&AS Market value: **$15.2M**
- DAAS Settlements:
  - Average daily Gross (pre-closeout) DAAS Credits: **$700K**
    - Includes EIR, TMOR, TMNSR, and TMOR
  - Net (post-closeout) DAAS Credits per MWh Cleared: **$7.87/MWh**
  - Net (post-closeout) DAAS Credits as % of total DA E&AS Value: **3.0%**
- FER Credits* as % of total DA E&AS Market Value: **11.9%**
- Energy Gap:
  - Average hourly cleared EIR MWh: **209 MWh**
  - Average hourly cleared FER Price: **$6.13/MWh**

DA E&AS refers to DA Energy and Ancillary Services
*FER credits are paid to all DA cleared energy supply from physical resources (Gen, Imports, DRR)
FER credits are charged to RTLO excluding RTLO associated with RT Exports and Dispatchable Asset Related Demand (DARDs)

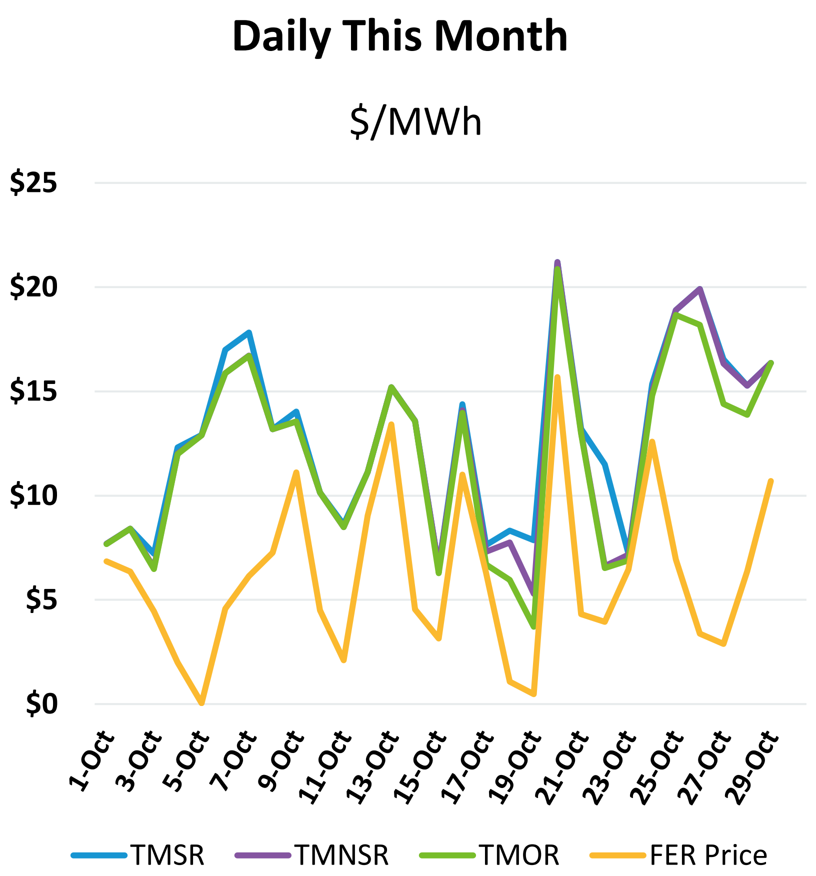
DAAS Results (continued)...

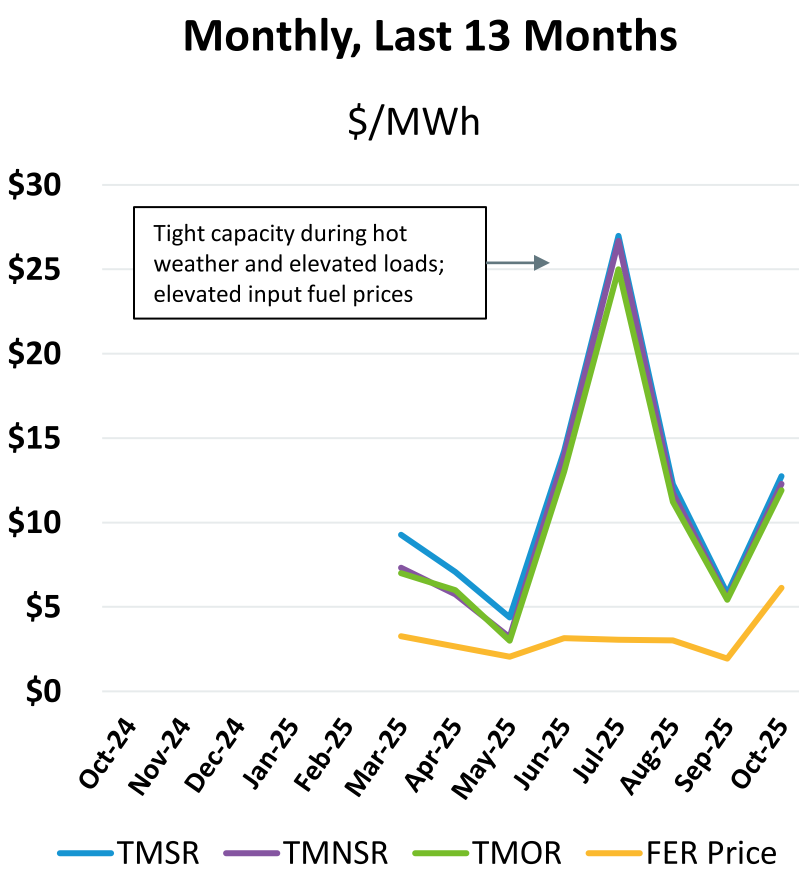
Month	Avg. Daily Total DA E&AS Credit	Avg. Daily DAAS Credit	Avg. Daily DAAS Net Credits (post-closeout)	DAAS Net Credits per MWh Cleared	DAAS Net Credits as % of Total DA E&AS Credit	Avg. Daily FER Credit	Avg Daily Energy MWh Paid FER Price*	Avg. FER Price	FER Credit as % of Total DA E&AS Credit	Avg. Hourly Cleared EIR Obligation MWh
3/1/2025	$17.3M	$466K	$202K	$3.35	1.2%	$982K	177K	$3.26	6.2%	176
4/1/2025	$13.9M	$332K	$175K	$3.23	1.3%	$760K	128K	$2.66	5.8%	97
5/1/2025	$11.0M	$190K	$52K	$0.94	0.5%	$563K	164K	$2.06	5.2%	155
6/1/2025	$20.2M	$885K	$173K	$2.97	0.9%	$1,287K	156K	$3.15	6.6%	125
7/1/2025	$35.8M	$1,704K	$1,139K	$19.53	3.2%	$1,277K	97K	$3.06	3.7%	55
8/1/2025	$20.2M	$747K	$544K	$9.57	2.7%	$1,292K	143K	$3.02	6.4%	94
9/1/2025	$12.3M	$320K	$184K	$3.21	1.5%	$587K	134K	$1.94	4.8%	104
10/1/2025	$15.2M	$700K	$457K	$7.87	3.0%	$1,812K	198K	$6.13	11.9%	209

About the Table:
- DA E&AS refers to DA Energy and Ancillary Services
- DAAS Net Credits reflect combined EIR, TMSR, TMNSR, and TMOR credits reduced by closeout costs
- FER Credits are paid to all DA cleared energy supply from physical resources (Gen, Imports, DRR) and are charged to RTLO excluding RTLO associated with RT Exports and Dispatchable Asset Related Demand (DARDs)
- *'Avg Daily Energy MWh Paid FER Price' reflects Cleared DA Physical Gen and DRR MWh during non-zero FER prices
- Data prior to August (denoted by the line) may not match settlement quality data provided in the Monthly Market Report

Additionally:
- FER Credits are included in the Monthly Market Report (see Section 7.1.1) found on the ISO Website here. Additional information, such as EIR Credits and Closeout Charges are included in the same report (see Section 9.1.1)

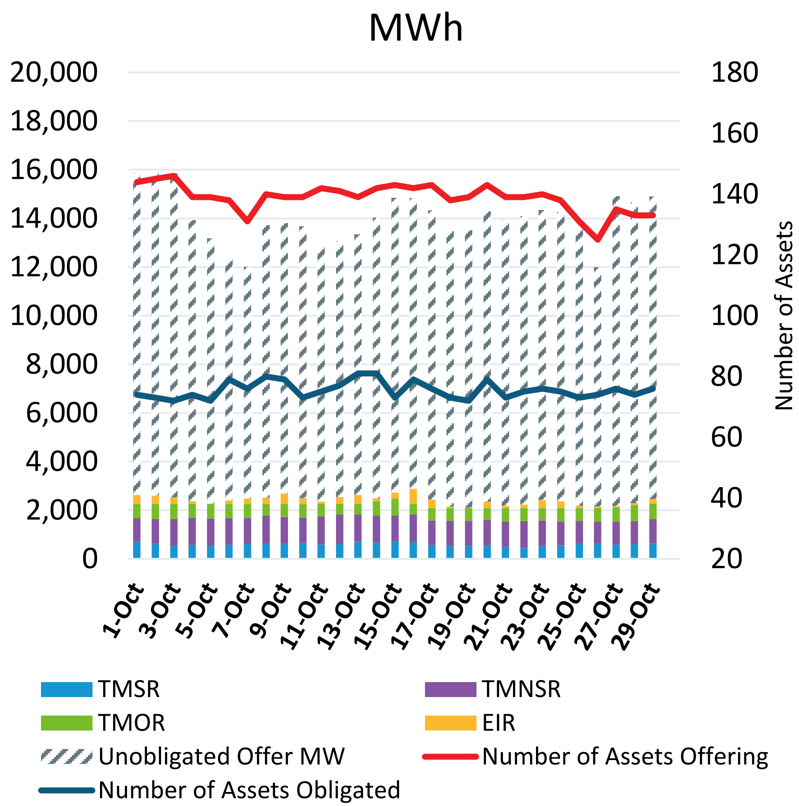
Average Hourly DAAS Prices



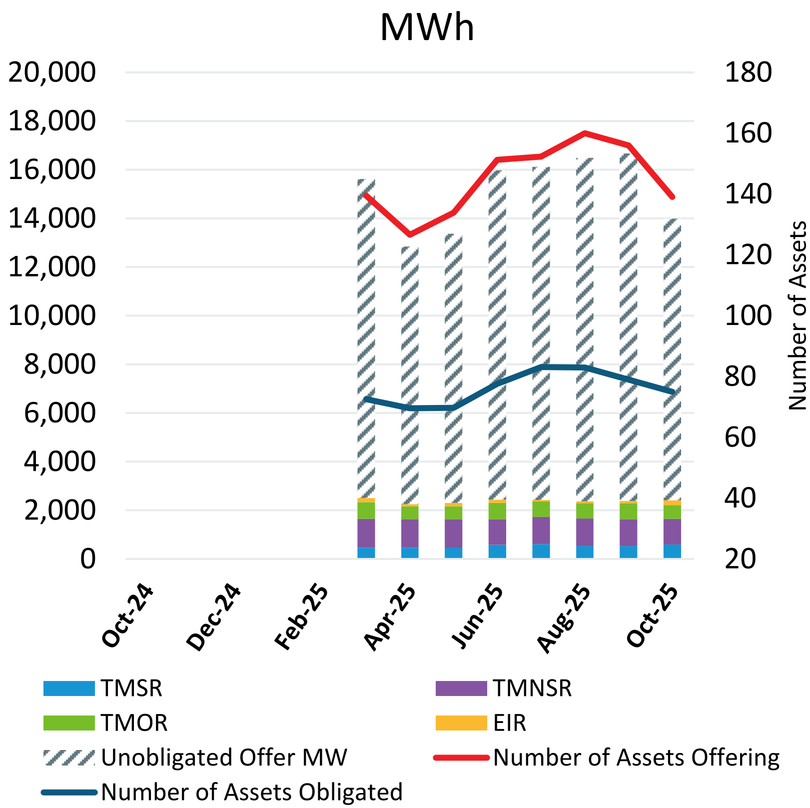


Average Hourly DAAS Offered* and Awarded Amounts

Daily This Month



Monthly, Last 13 Months



*Unobligated Offer MWh reflect the raw, as-offered DAAS MW amounts that remained unobligated (received no MW reward). This supply does not yet consider additional unit parameter constraints or dispatch constraints and should not be equated with actual capacity available in the dispatch solution.

Highlights

- The ISO is evaluating all submissions and expects to provide a high-level summary of all Longer-Term Proposals at the 11/19/25 PAC
- The 2026 Load Forecast cycle formally began in September
- Stakeholder discussions related to CELT 2026 will continue at the next Load Forecast Committee on November 7

Forward Capacity Market (FCM) Highlights

- CCP 16 (2025-2026)
  - The third annual reconfiguration auction (ARA3) was held March 3-5 and results were posted on April 1
- CCP 17 (2026-2027)
  - The second annual reconfiguration auction (ARA2) was held August 1-5 and results were posted on September 2
  - At the October 7 PSPC meeting and October 22 RC meeting, the ISO presented proposed ICR and related values for the ARA 3 that will be conducted in 2026. RC voted to approve the values.
- CCP 18 (2027-2028)
  - The first annual reconfiguration auction (ARA1) was held June 2-4 and results were posted on July 2
  - At the October 7 PSPC meeting and October 22 RC meeting, the ISO presented proposed ICR and related values for the ARA 2 that will be conducted in 2026. RC voted to approve the values.

CCP – Capacity Commitment Period

FCM Highlights, cont.

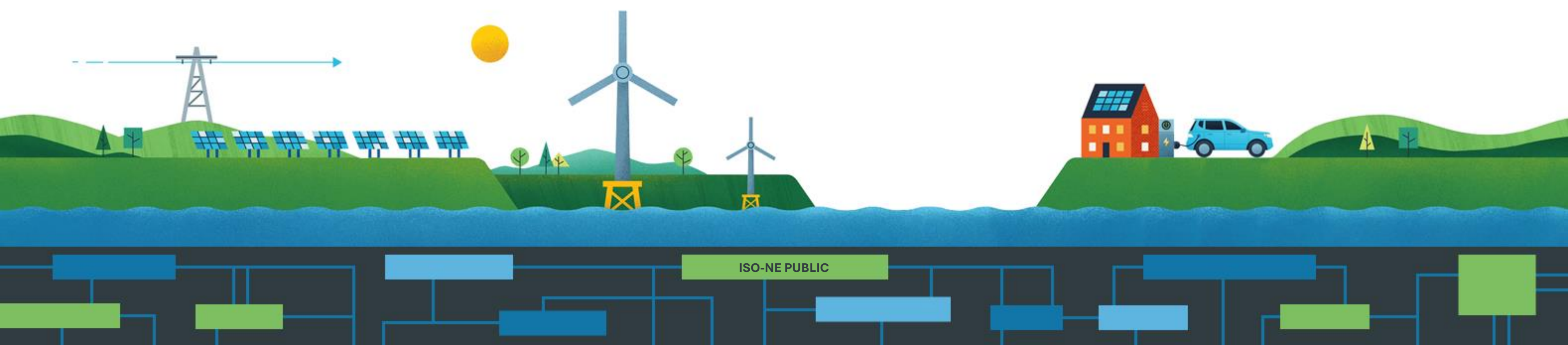
- CCP 19 (2028-2029)
  - The ISO filed market rule changes to delay FCA 19 for two additional years with FERC on April 5, 2024
    - On May 20, 2024 FERC issued an order accepting the additional delay to FCA 19
    - 2024 interim RA qualification process completed on November 1, 2024
      - A total of 1,389 MW (summer Qualified Capacity) was qualified to participate in future reconfiguration auctions
    - 2025 interim RA qualification process began in April 2025
      - The Show of Interest submission deadline was April 30, 2025
      - Qualification Determination Notifications were issued on October 17, 2025 and Qualified Capacities will be finalized on November 3, 2025.
      - In response to the April 4, 2025 order on the Order No. 2023 compliance filing, the ISO proposed narrow date changes to allow running the Transitional CNR Group Study with the 2025 interim RA qualification process. FERC accepted the proposed date changes in an order on June 30, 2025.
  - No ICR and related values will be calculated for CCP 19 until the CAR project is completed

NOVEMBER 6, 2025| BOSTON, MA

ISO New England 2024/2025 Winter Outlook

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

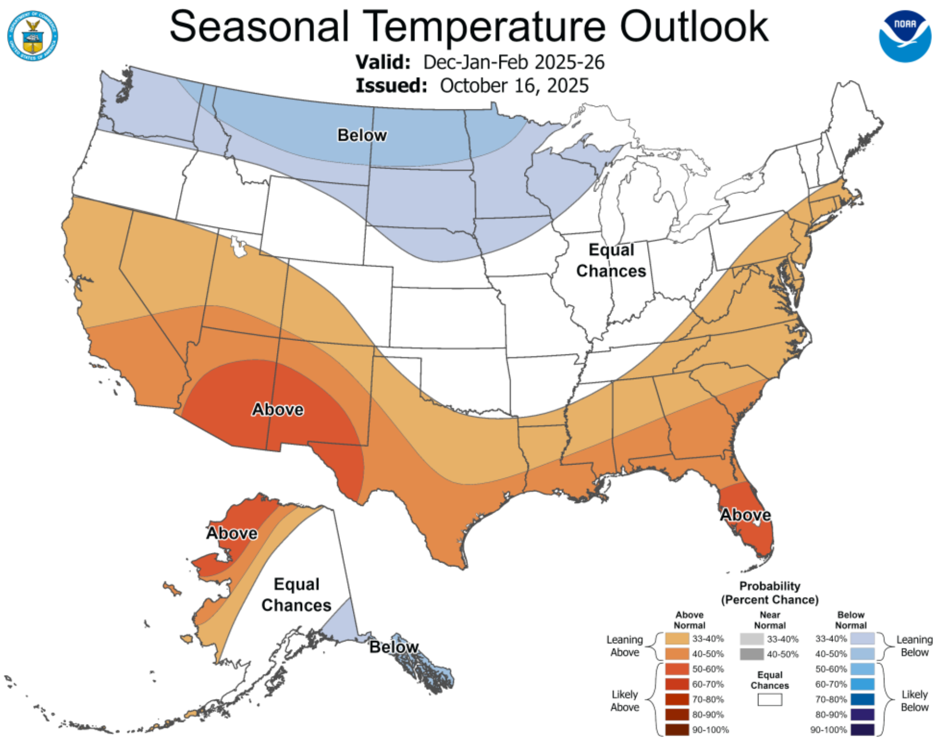


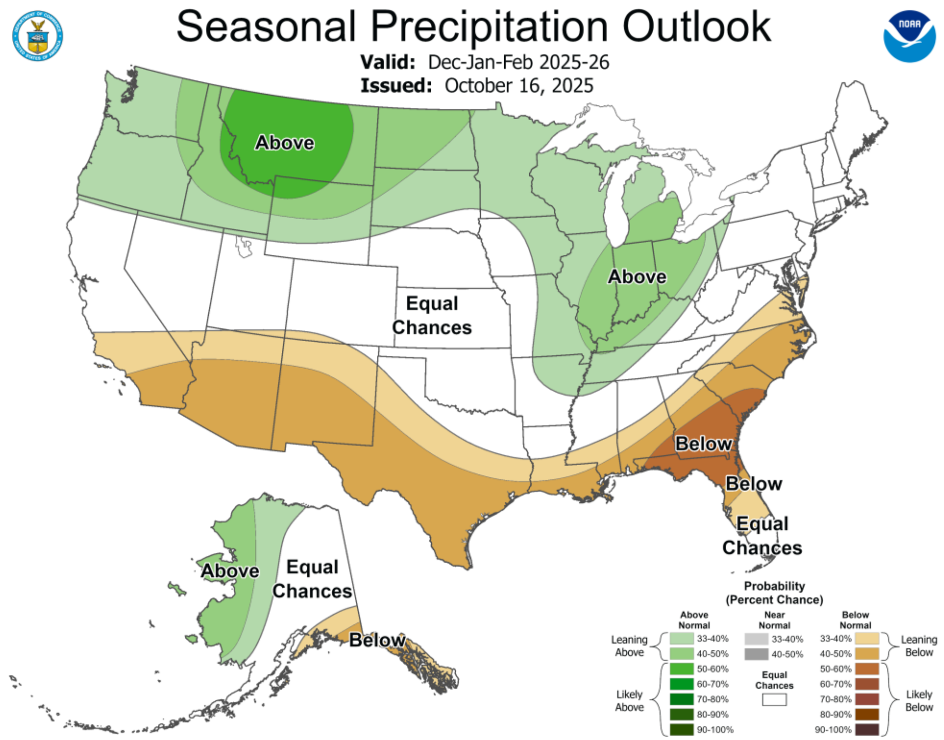
Winter Outlook Highlights

- Winter Outlook
  - The seasonal temperature outlook for the winter months of December through February indicates a 33-40% probability of above normal temperatures for southern New England, and equal chances for either above or below normal temperatures for northern New England
  - An equal chance for above normal or below normal precipitation is forecasted across New England
  - Lowest capacity margin is projected for the week beginning January 10[1]
    - Surplus capacity is projected for the 50/50 load forecast while a slightly negative capacity margin is projected for the 90/10 forecast; projections are based on conservative import and forced outage assumptions
  - Consistent with the existing resource mix and load expectations for this winter, energy shortfall risk associated with extreme winter events does not exceed the Regional Energy Shortfall Threshold (REST)

1 - Based on October 23, 2025 Annual Maintenance Schedule Capacity Analysis

Winter Temperature and Precipitation Outlook





Winter Expectations

- Demand Forecast
  - The Winter 2024/25 peak demand of 19,607 MW occurred on January 22, 2025
  - 50/50 winter peak demand forecast of 20,056 MW, which is ~252 MW (~1.2%) lower than the 2024/25 forecast
  - 90/10 winter peak demand forecast of 21,125 MW, which is ~36 MW (~0.2%) higher than the 2024/25 forecast
- Scheduled Generation and Transmission Outages
  - Generation and transmission outages have been coordinated to minimize any adverse impacts; no significant generation or transmission outages are currently scheduled
- Transfer Capability
  - Transfer capability on the New York Northern AC ties will be increased from 1,400 to 1,600 MW for the winter period

Winter Expectations, cont.

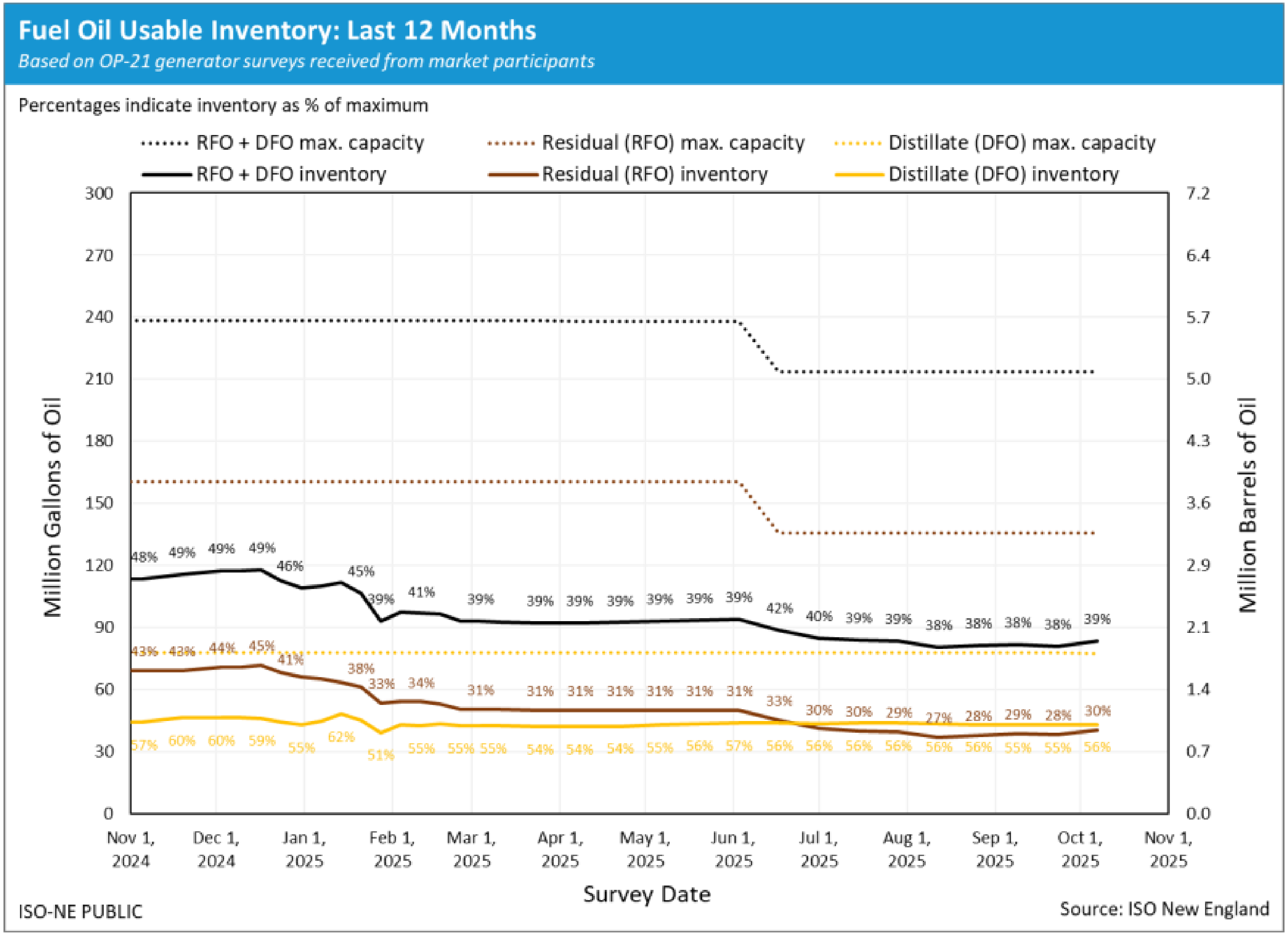
- Natural Gas Deliverability
  - ISO will continue to monitor natural gas deliverability throughout the winter
  - Consistent with past winter seasons, the ISO assumes that approximately 3,900 – 4,800 MW[1] may be at risk due to constrained natural gas pipelines
- Capacity Outlook
  - Projecting the lowest 50/50 capacity margin of ~1,793 MW and lowest 90/10 capacity margin of ~-135 MW for the week beginning January 10[1]
  - Extended periods of cold weather may rapidly deplete stored fuel inventory, and the capacity outlook will be adjusted accordingly

1 - Based on resource Winter Seasonal Claimed Capabilities and not counting OP4 actions

LNG and Fuel Oil Expectations

- Saint John LNG tanks are expected to be full (~10 Bcf) heading into the winter
- Current fuel oil inventory is ~83.6M gallons (~39% of max)
  - Recent fuel surveys and discussions with owners/operators of stations with large fuel oil storage capability indicate that pre-winter replenishment is underway and supply chains are expected to be strong with adequate supply available

Total Usable Fuel Oil in New England



Winter Energy Analysis

- 20 extreme weather events were studied to evaluate the region's energy shortfall risk this winter
  - Studies were performed using ISO's Probabilistic Energy Adequacy Tool (PEAT) and results were compared to the recently developed Regional Energy Shortfall Threshold (REST)
- Similar to the methodology employed for ISO's prior PEAT-based analysis the 20 weather events studied were those identified as having the most significant shortfall risk
  - Peak load across the weather events averages ~21.2 GW with a maximum peak load of 22.3 GW
- Each weather event was studied 720 times (*i.e.*, "cases"); each case represented different combinations of fuel oil inventories, LNG inventories, imports, and generator forced outages

Winter Energy Analysis, cont.

- Key Assumptions
  - Existing resource mix
  - Vineyard Wind and New England Clean Energy Connect (NECEC) in-service
  - ~8.5 GW of behind-the-meter (BTM) PV nameplate capacity
  - Up to 1.2 Bcf/d of LNG injection capability from Saint John LNG and the Everett Marine Terminal (EMT)

Energy Analysis Results Show Minimal Risk When Compared Against REST Criteria

- The recently adopted REST criteria is defined as follows:
  - acceptable shortfall **magnitude** of **3%**
  - acceptable shortfall **duration** of **18 hours**
  - magnitude and duration must **both** be exceeded for the REST to be violated
- ISO's PEAT-based evaluation of extreme events for this winter resulted in **shortfall magnitude of 0.1% and shortfall duration of 0.7 hours, both well below the established REST criteria**
  - As an extreme tail risk measure, maximum (i.e., worst-case) 21-day energy shortfall is ~168,000 MWh (equivalent to ~2% of the total 21-day energy demand)
- Study results are consistent with the existing resource mix and expectations for load this winter

Winter Energy Analysis Summary

- The worst-case 21-day energy shortfall quantities result from a low probability combination of several uncertainties (*i.e.*, low LNG, low fuel oil, low imports, high forced outages)
- In the worst cases, energy shortfall begins on day 14 or later thus allowing time for additional actions
  - ISO expects that in the event of a forecasted energy shortfall, market-based incentives will encourage relief in the form of market response, including additional fuel replenishment
- In advance of a forecasted energy shortfall, and in addition to anticipated market response, ISO would implement additional preventive measures, as necessary
  - Reducing exports and/or scheduling of additional imports
  - Posturing of generators with stored fuels in short supply
  - Seeking waivers of emissions or air permit limitations under Section 202c of the Federal Power Act
  - Coordinated conservation appeals

Winter Preparations

- ISO staff hosted the Generator Winter Readiness Seminar with Market Participants on October 29, 2025
- Will distribute a Winter Generator Readiness Survey to all generators prior to November 1, 2025 with responses due by December 1, 2025
- Completed the annual Natural Gas Critical Infrastructure Survey process to ensure critical infrastructure is not part of automatic or manual load shed schemes
- Dual fuel audits of ~30 generators totaling ~6,500 MW of capacity to be completed prior to December 1, 2025
- Generator Fuel and Emissions Surveys and 21-Day Energy Assessments will be performed weekly (or daily, if required) during the winter season
  - 21-day Energy Assessment results and summaries of generator fuel surveys are posted weekly to the ISO public website

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (1.6°F) Max: 84°F, Min: 40°F Precipitation: 4.96" – Above Normal Normal: 4.03"	Hartford	Temperature: Above Normal (1.0°F) Max: 85°F, Min: 29°F Precipitation: 4.62" - Above Normal Normal: 4.52"

Peak Load:	15,482 MW	October 06, 2025	19:00 (ending)
Mid-Day Minimum Load - Month:	7,385 MW	October 18, 2025	13:00 (ending)
Mid-Day Minimum Load - Historical:	5,318 MW	April 20, 2025	14:00 (ending)

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

Procedure	Declared	Cancelled	Note
NONE			

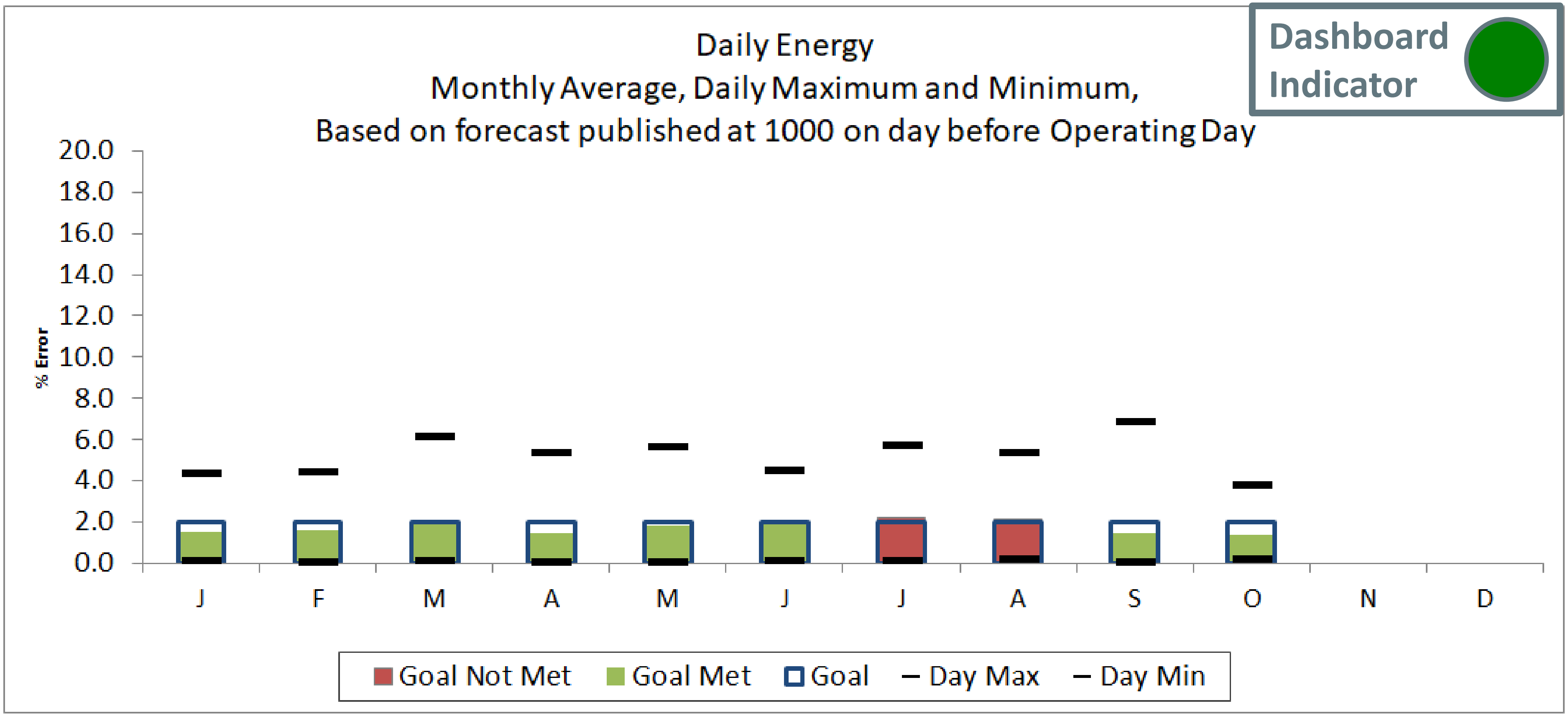
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
10/27/2025	ISO-NE	690

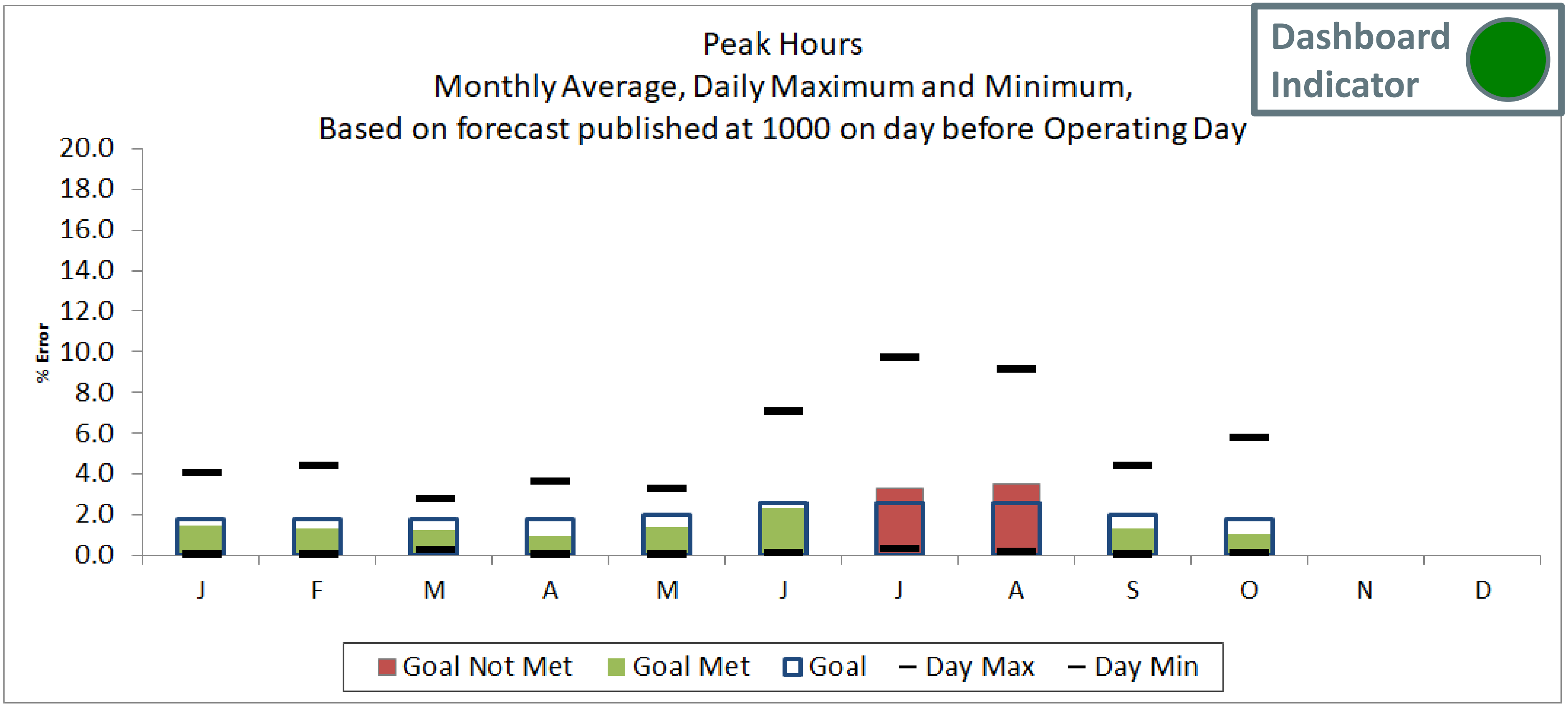
2025 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.31	4.44	6.10	5.36	5.61	4.48	5.70	5.34	6.81	3.73			6.81
Day Min	0.12	0.04	0.12	0.05	0.06	0.08	0.11	0.16	0.05	0.18			0.04
MAPE	1.54	1.62	1.89	1.45	1.80	1.98	2.24	2.12	1.46	1.39			1.75
Goal	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00			

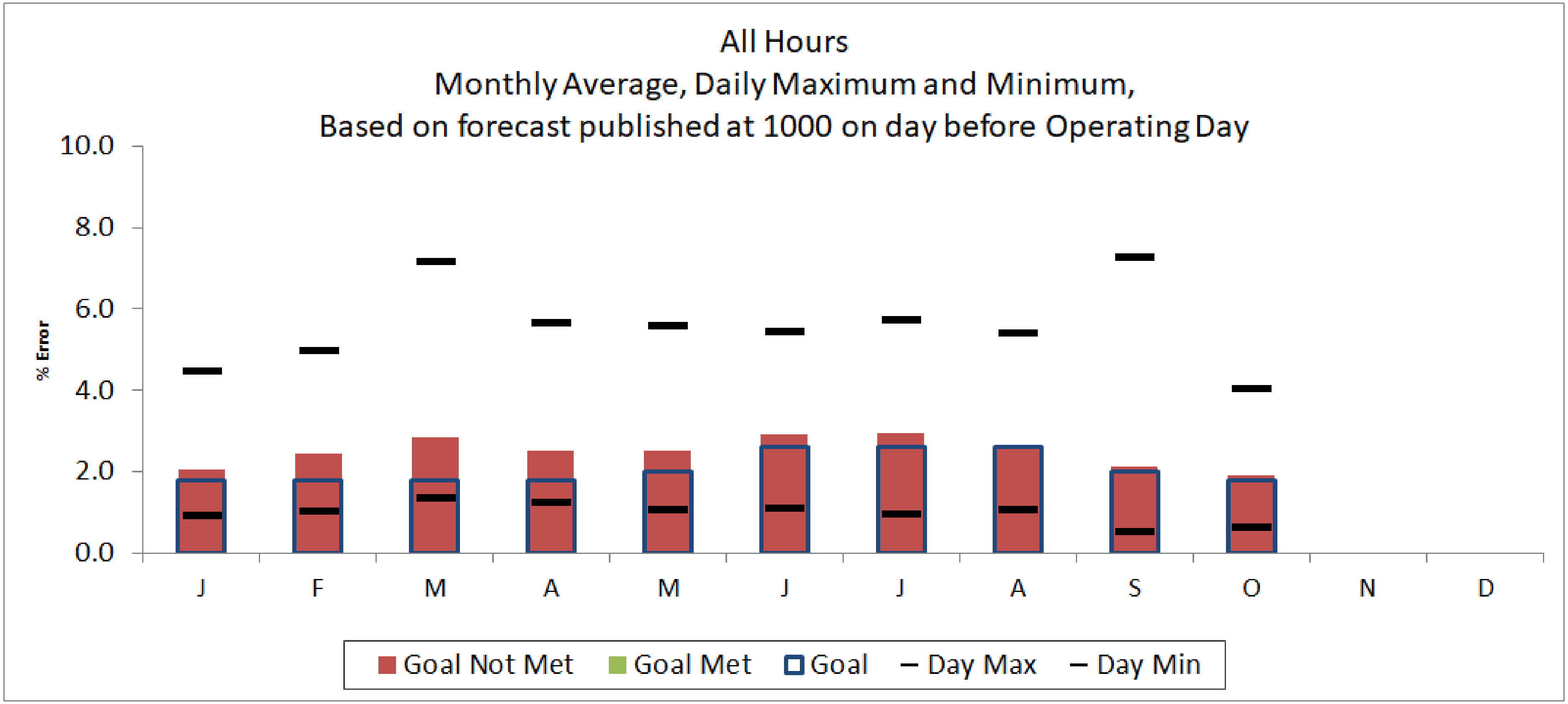
2025 System Operations - Load Forecast Accuracy cont.



Dashboard Indicator

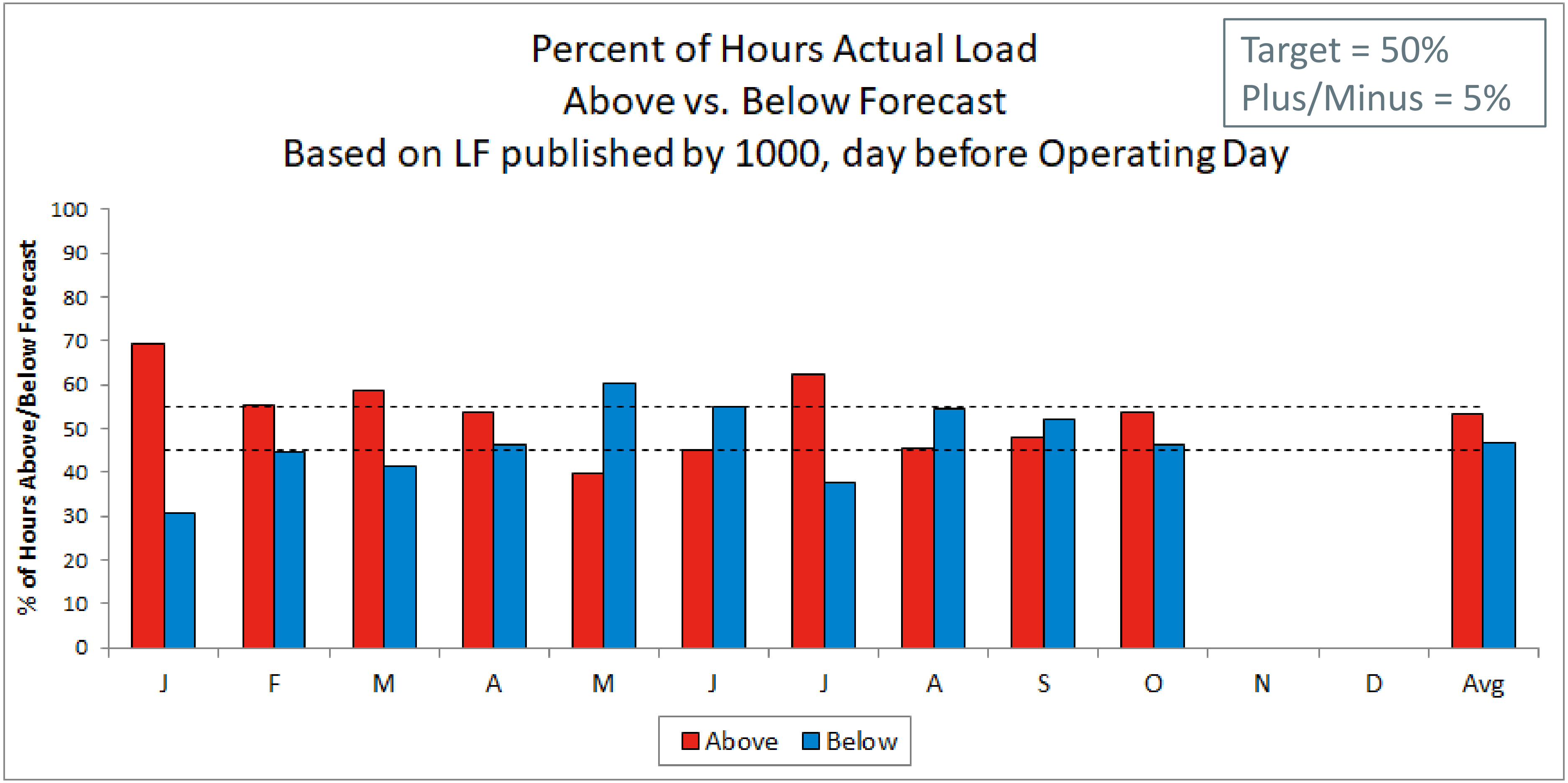
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.04	4.41	2.77	3.63	3.29	7.08	9.71	9.15	4.43	5.77			9.71
Day Min	0.03	0.06	0.24	0.03	0.06	0.11	0.34	0.15	0.05	0.12			0.03
MAPE	1.48	1.34	1.29	1.00	1.41	2.30	3.28	3.48	1.30	1.02			1.80
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80			

2025 System Operations - Load Forecast Accuracy cont.



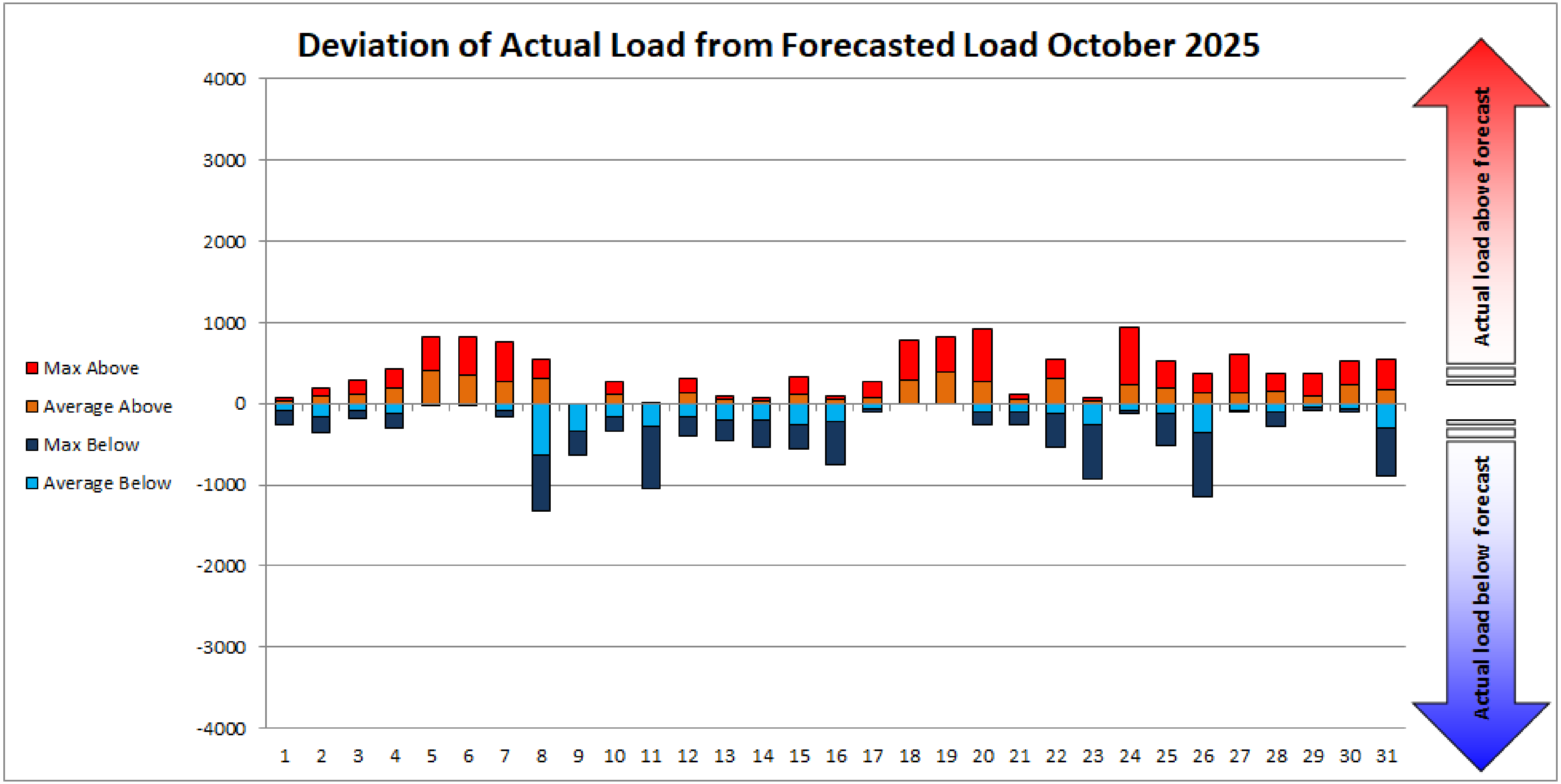
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.46	4.98	7.13	5.65	5.57	5.44	5.72	5.41	7.24	4.01			7.24
Day Min	0.90	1.02	1.33	1.23	1.07	1.11	0.95	1.07	0.52	0.64			0.52
MAPE	2.07	2.47	2.83	2.53	2.53	2.93	2.94	2.68	2.13	1.92			2.50
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80			

2025 System Operations - Load Forecast Accuracy cont.



	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	69.2	55.2	58.5	53.5	39.8	45.1	62.5	45.3	48.1	53.5			53
Below %	30.8	44.8	41.5	46.5	60.2	54.9	37.5	54.7	51.9	46.5			47
Avg Above	280.5	282.1	246.5	255.8	164.5	307.8	397.3	225.4	213.7	161.8			397
Avg Below	-178.6	-287.9	-273.2	-190.7	-254.1	-310.2	-270.0	-308.7	-179.5	-157.1			-310
Avg All	138	24	12	49	-82	-24	145	-81	1	12			19

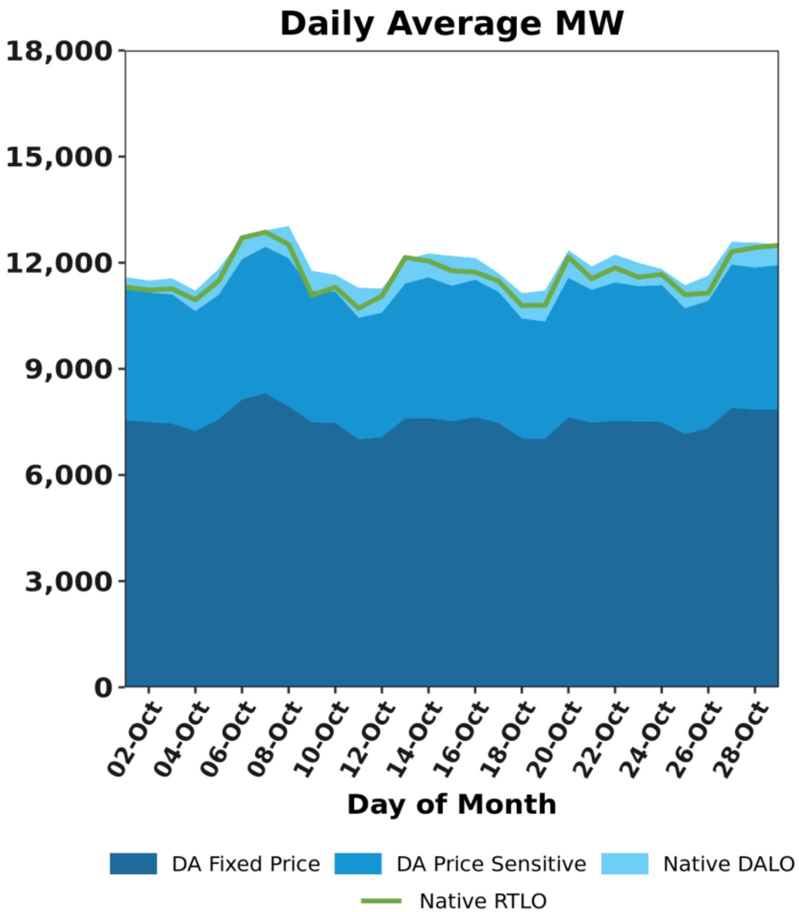
2025 System Operations - Load Forecast Accuracy

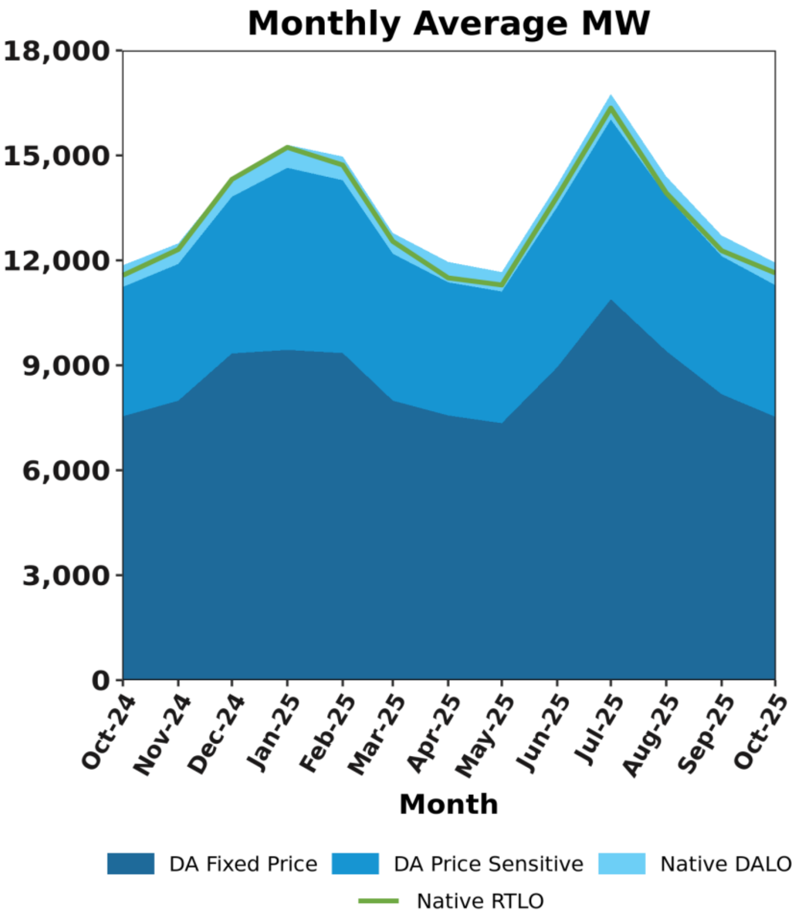


MARKET OPERATIONS

SUPPLY AND DEMAND VOLUMES

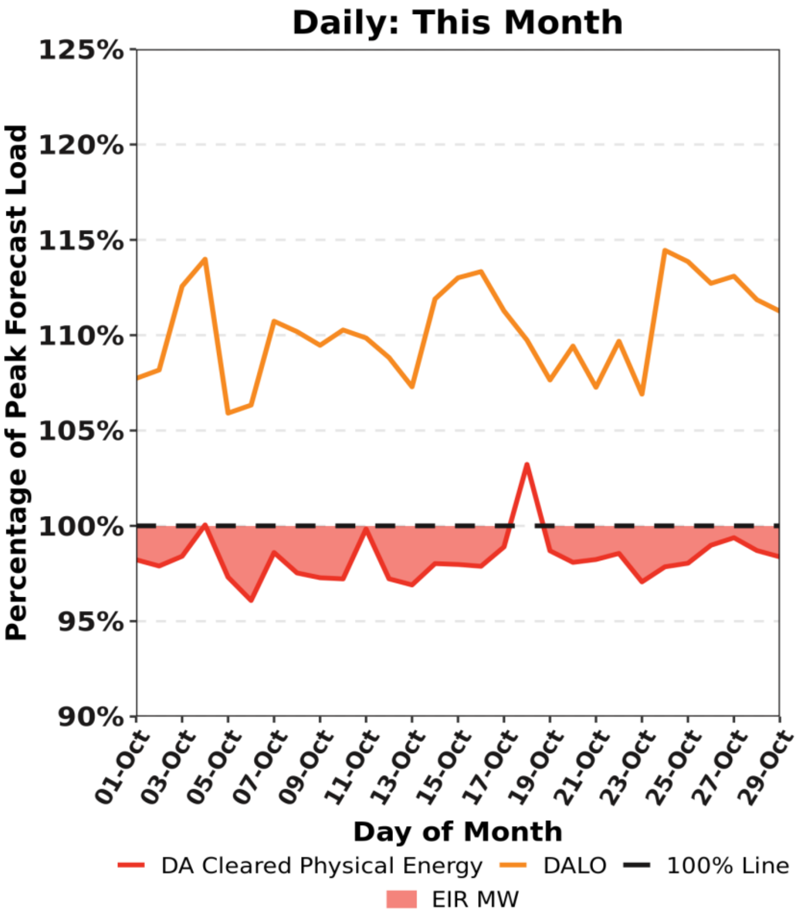
DA Cleared Native Load by Composition Compared to Native RT Load

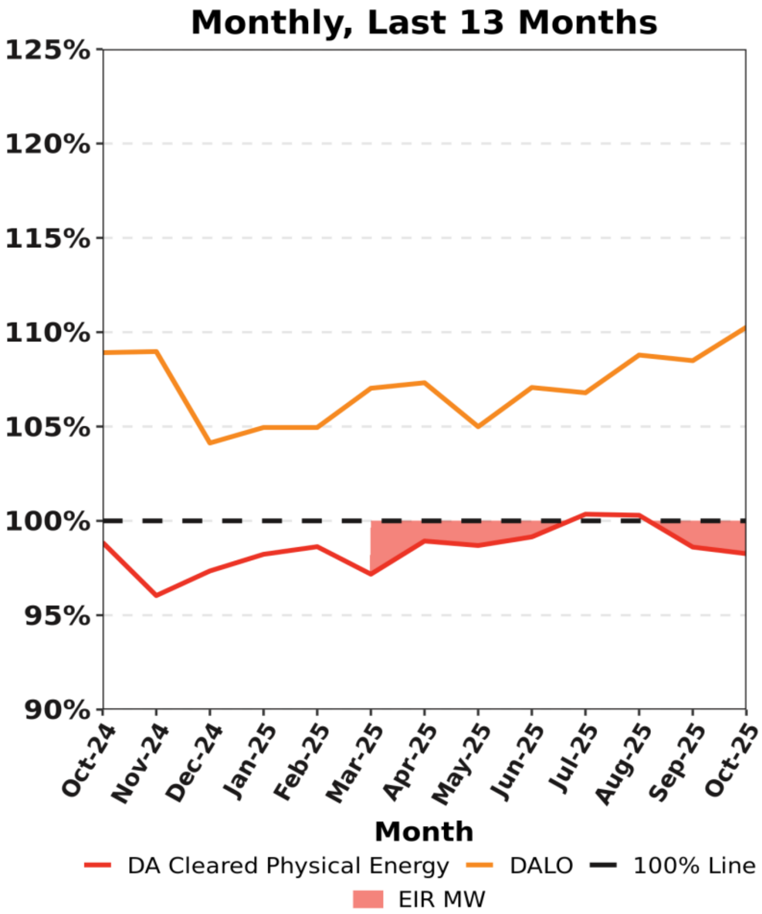




Native Day-Ahead Load Obligation (DALO) is the sum of all internal DA cleared load obligation, including internally cleared decrement bids (DECs). Native Real-Time Load Obligation (RTLO) is the sum of all internal real-time load obligation. Modeled transmission losses and exports are excluded in these charts.

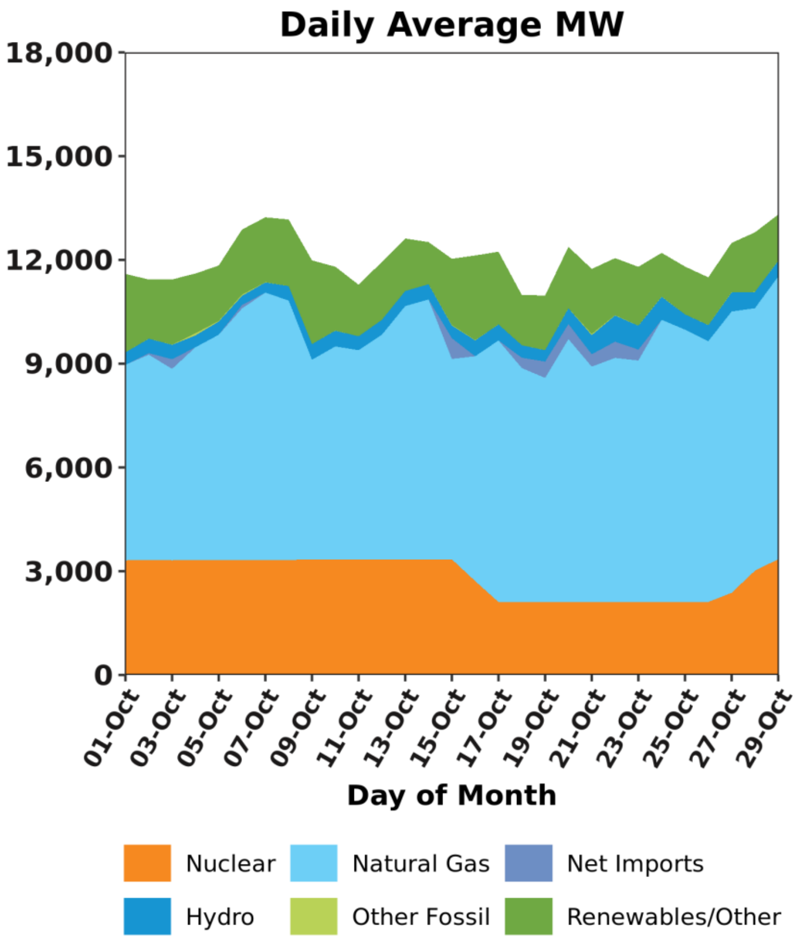
DA Volumes as % of Forecast in Peak Hour

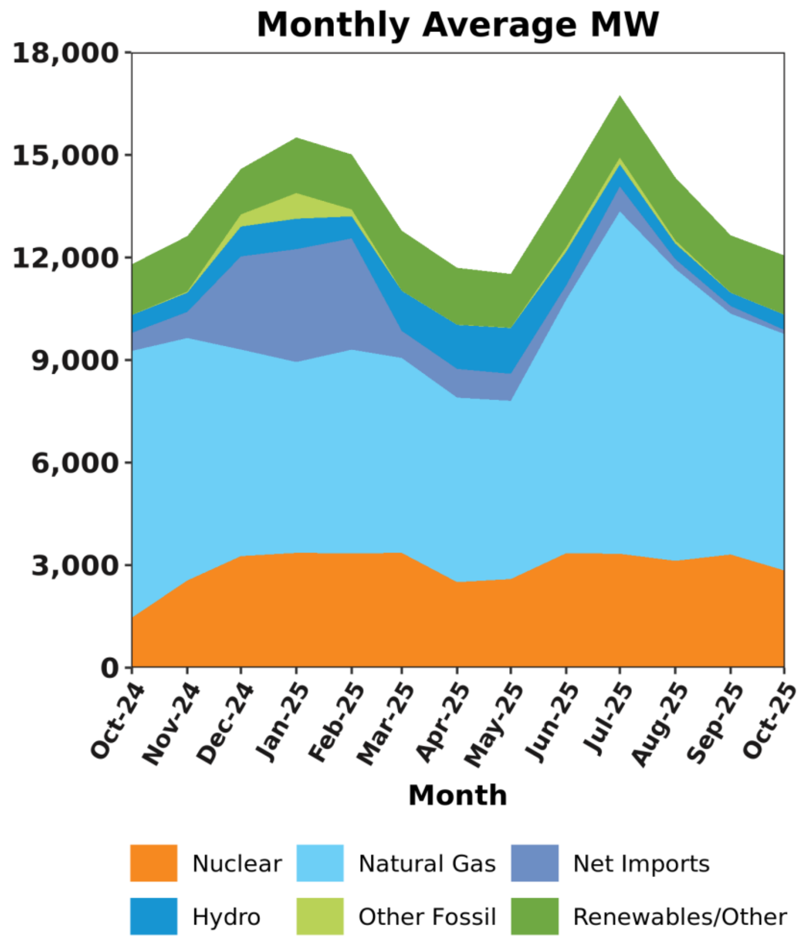




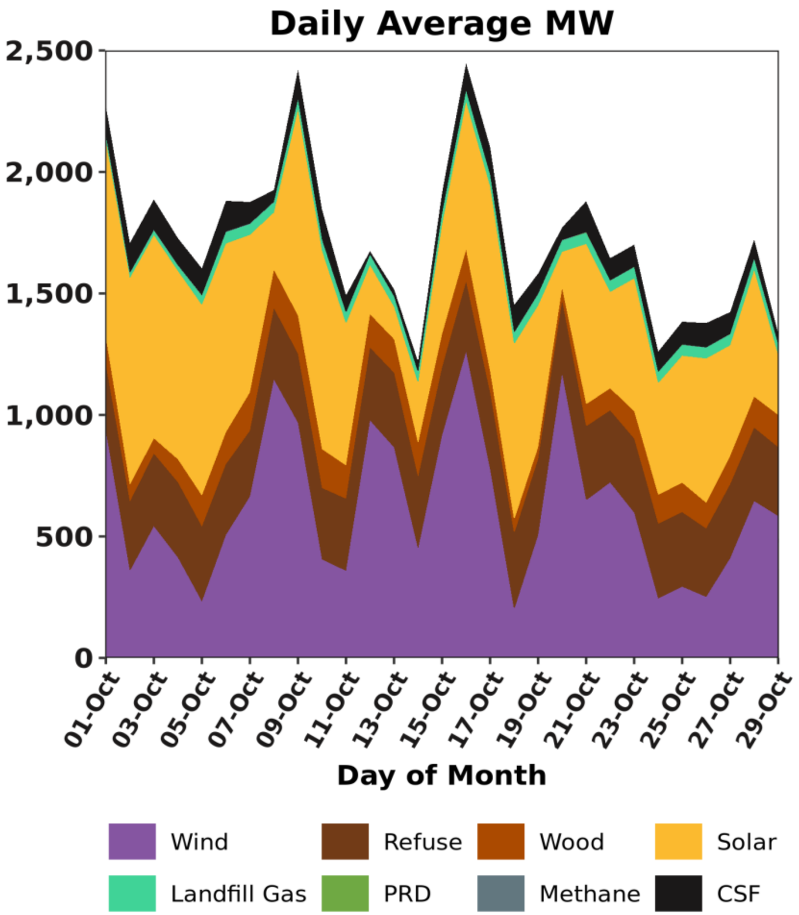
*DA cleared physical energy is the sum of generation, DRR and net imports cleared in the DA Energy Market and does not include EIR MW. Effective March 1, 2025, EIR MW obligations from physical generation and DRR are additionally procured up to (but not exceeding) 100% of the forecasted energy requirement.

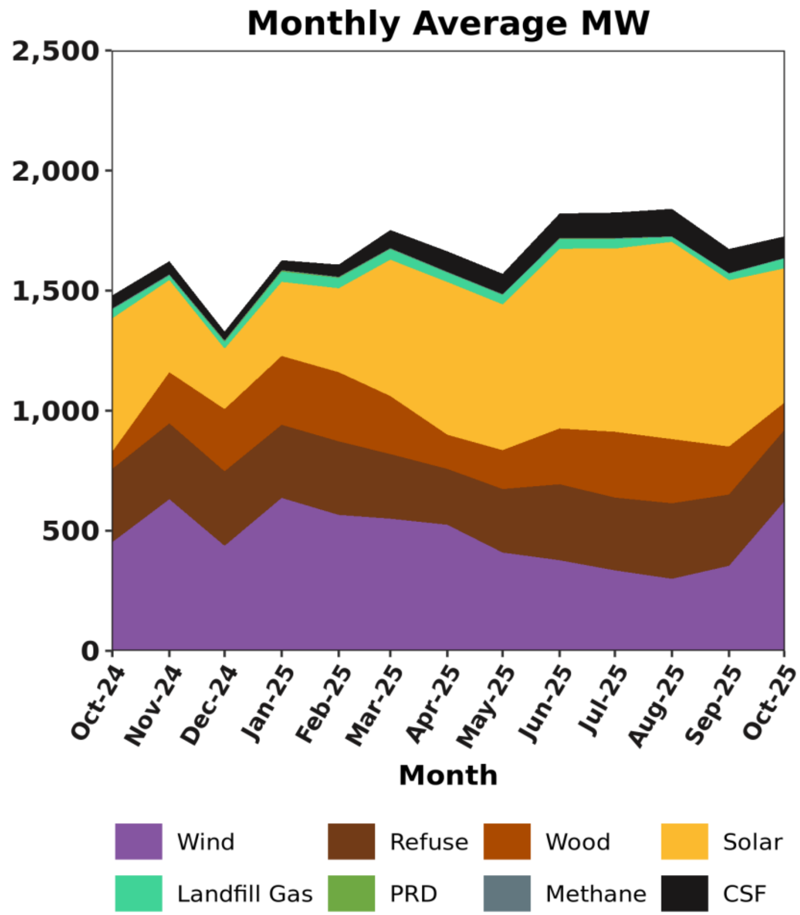
Resource Mix





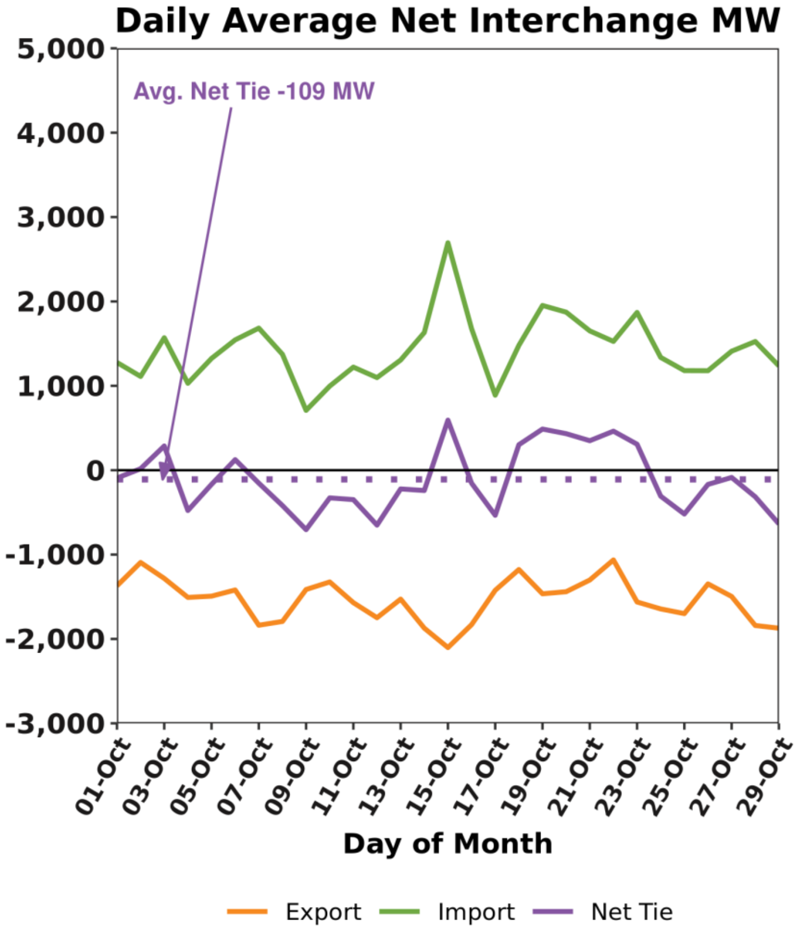
Renewable Generation by Fuel Type

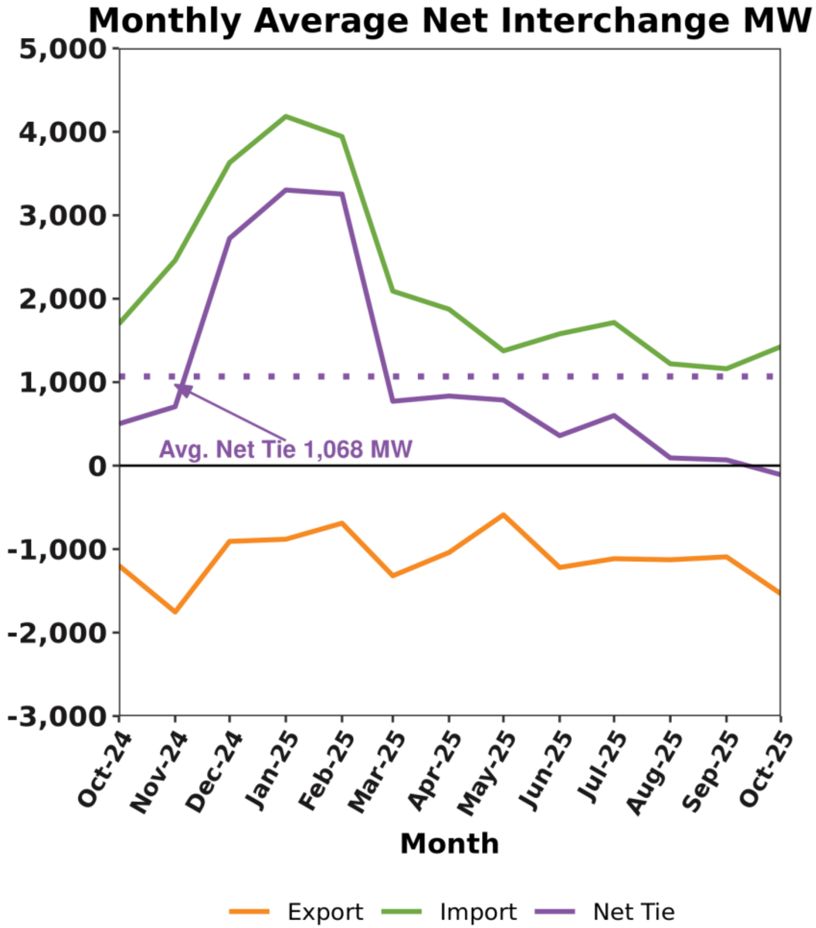




CSF = Continuous Storage Facilities (a.k.a. Batteries); PRD=Demand Response Resources (DRR)

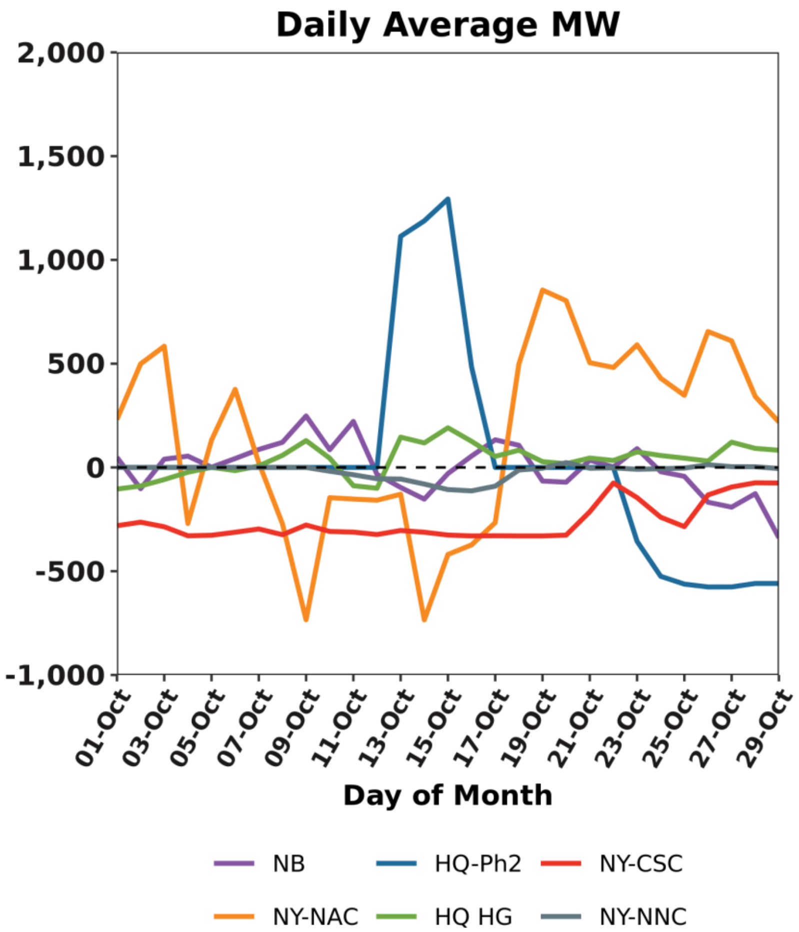
RT Net Interchange

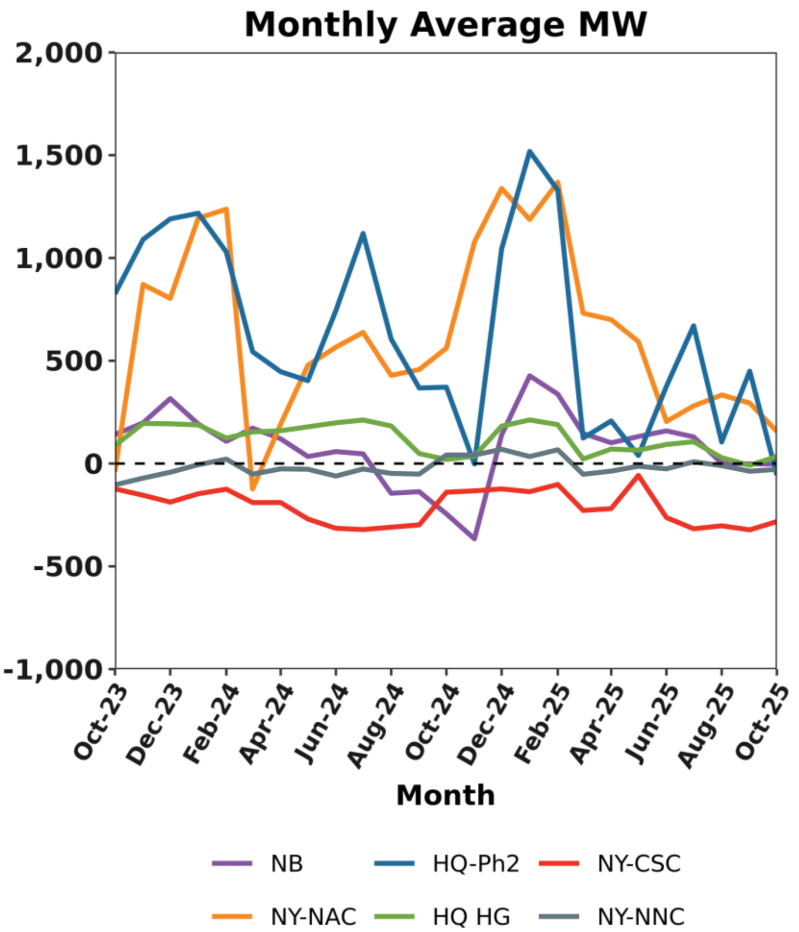




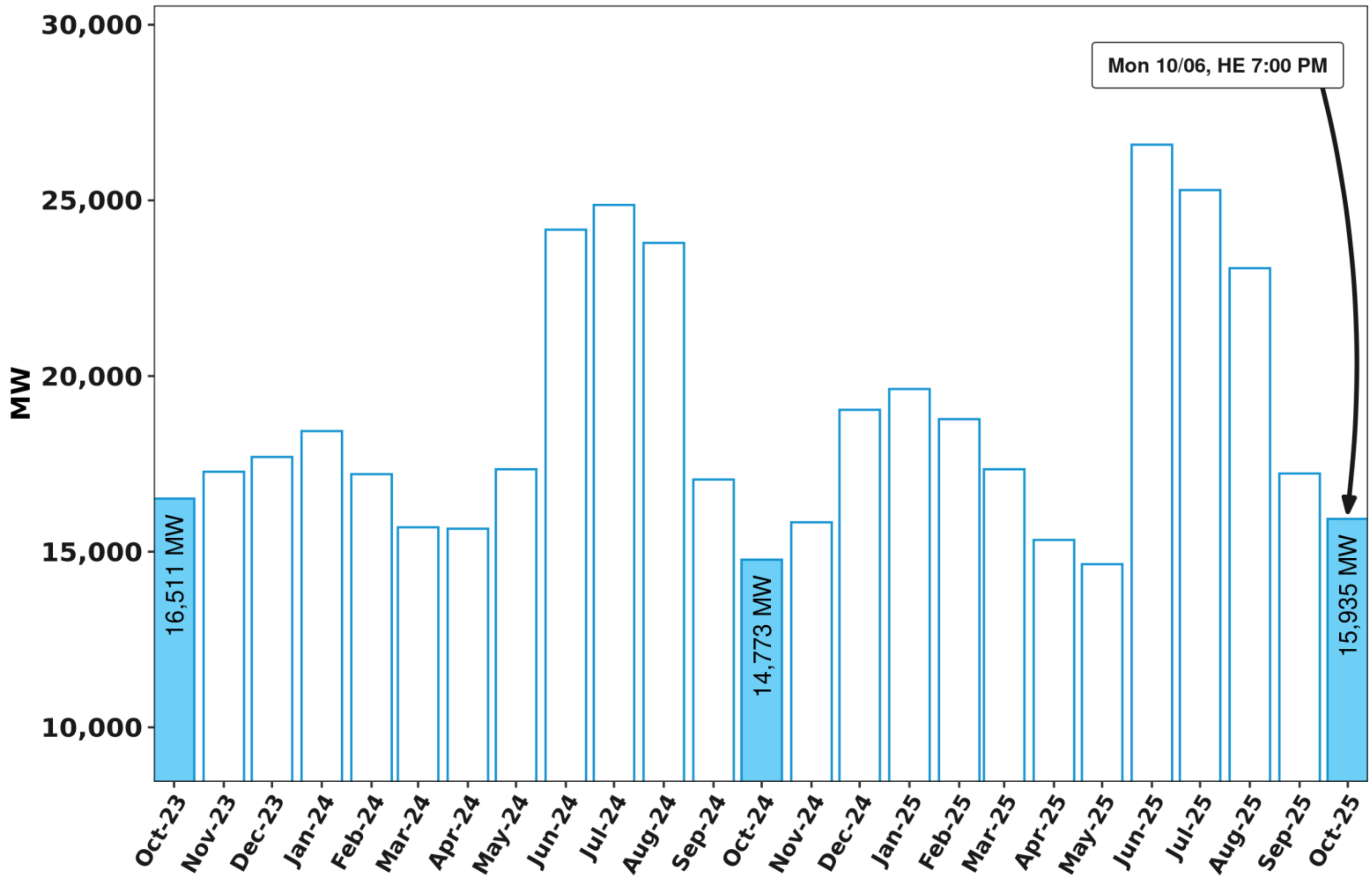
Net Interchange is the net of Participant scheduled imports (+) and exports (-). Inadvertent flows are not reflected.

RT Net Interchange by External Interface



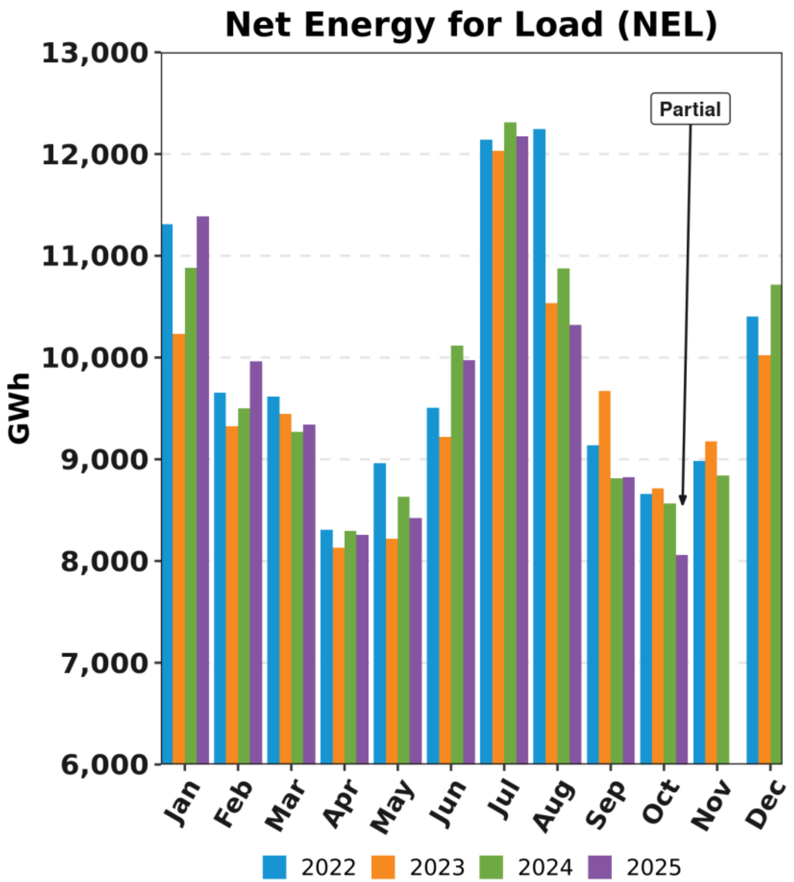


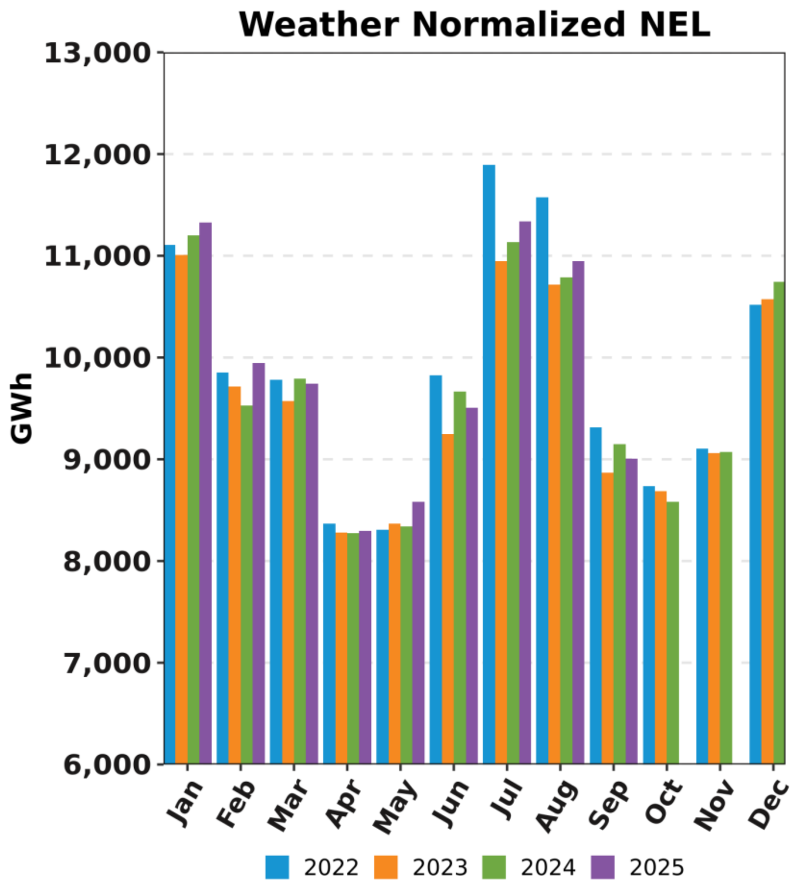
RQM System Peak Load MW by Month



Shaded columns highlight current month and the same month over the prior two years

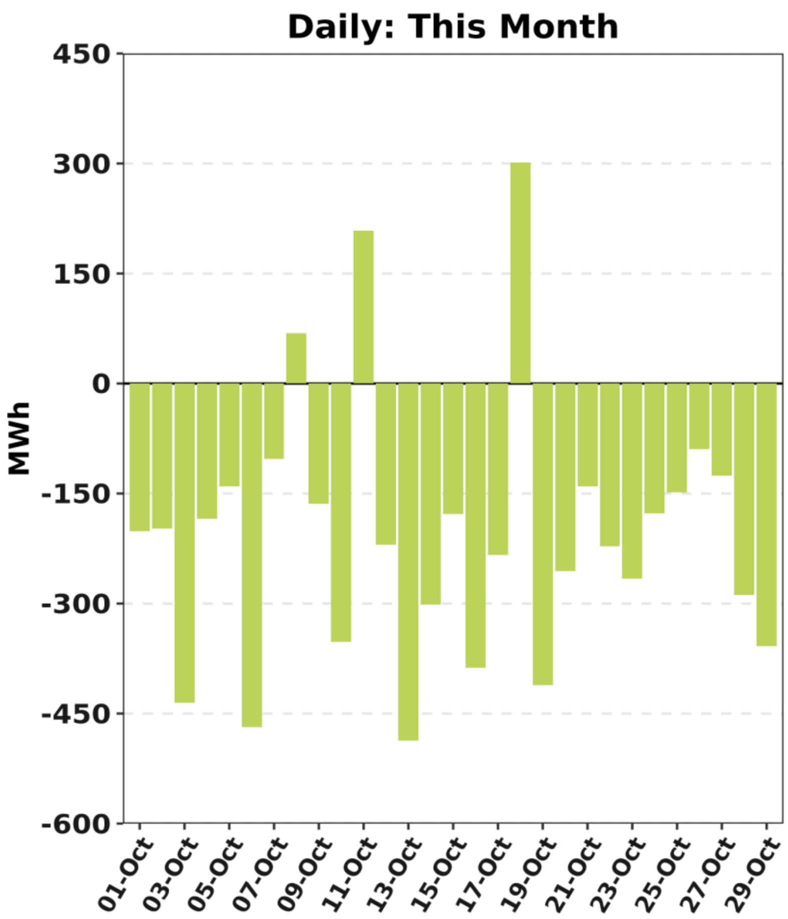
Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL

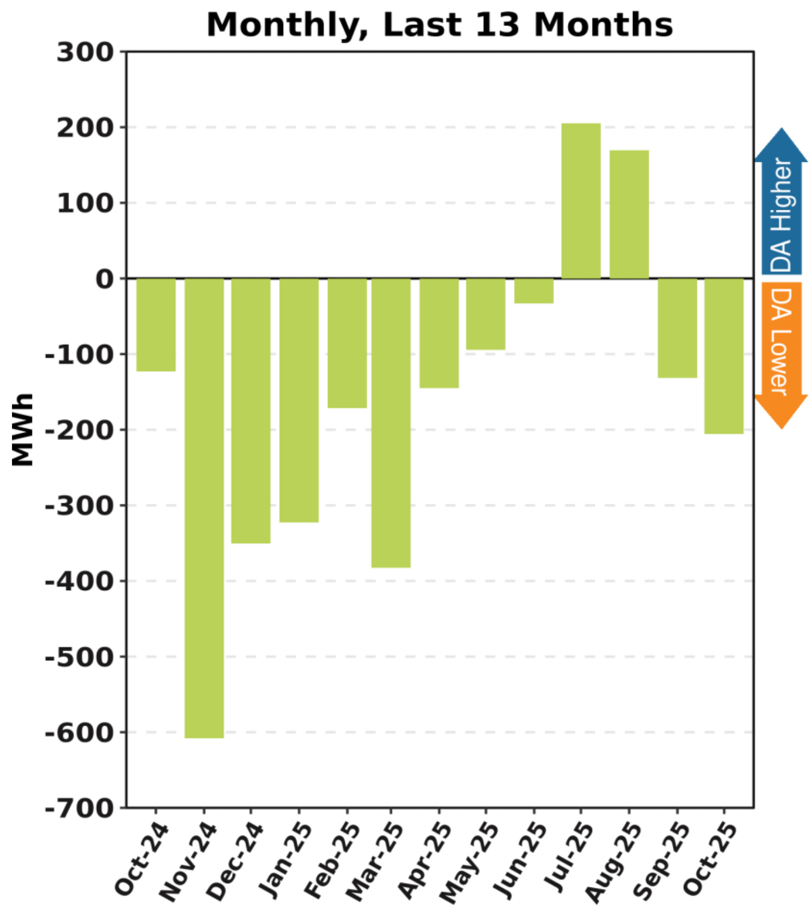




NEPOOL NEL is the total net revenue quality metered energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation + Demand Response Resource output - pumping load + net interchange where imports are positively signed. Current month's data may be preliminary. Weather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

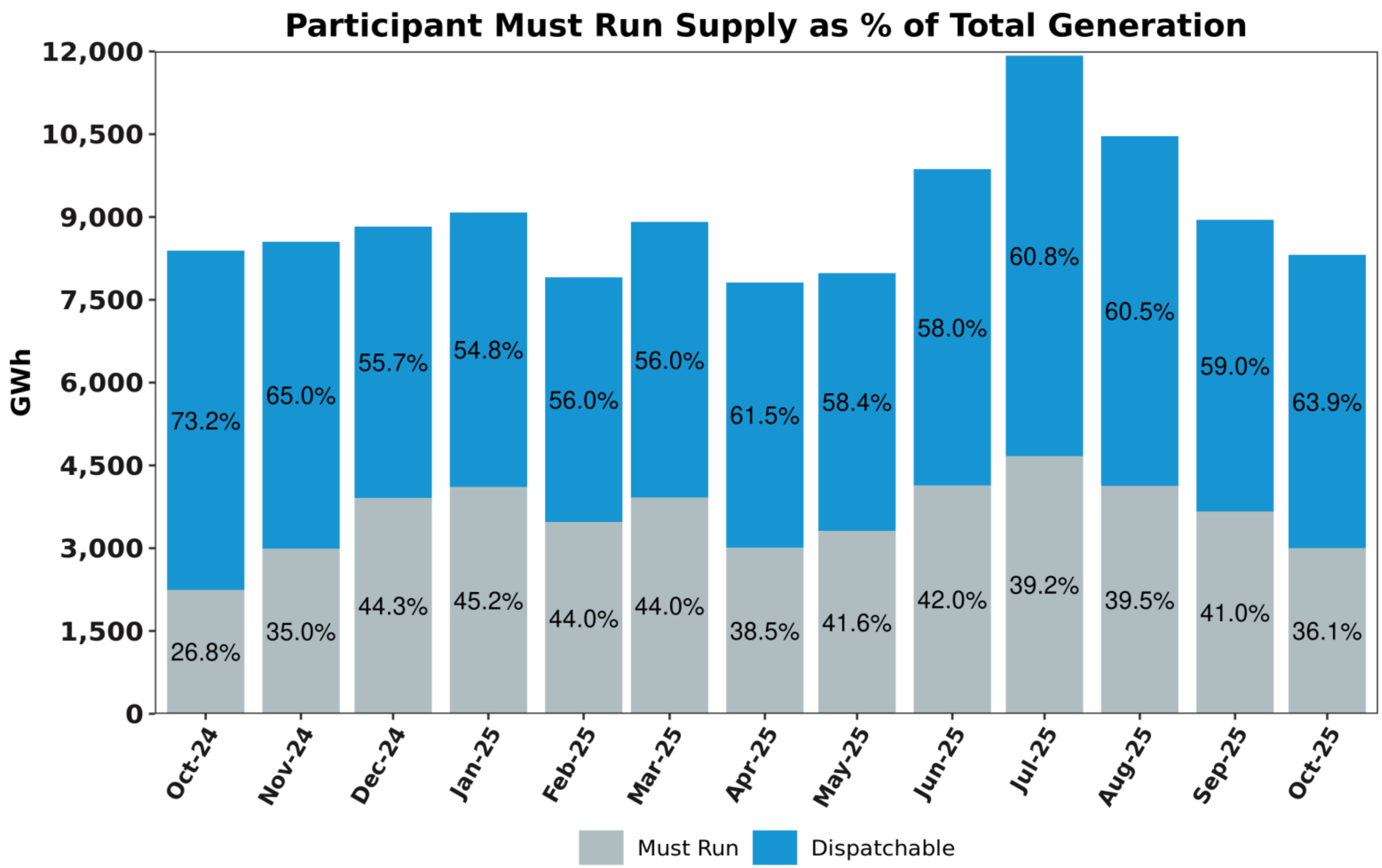
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour





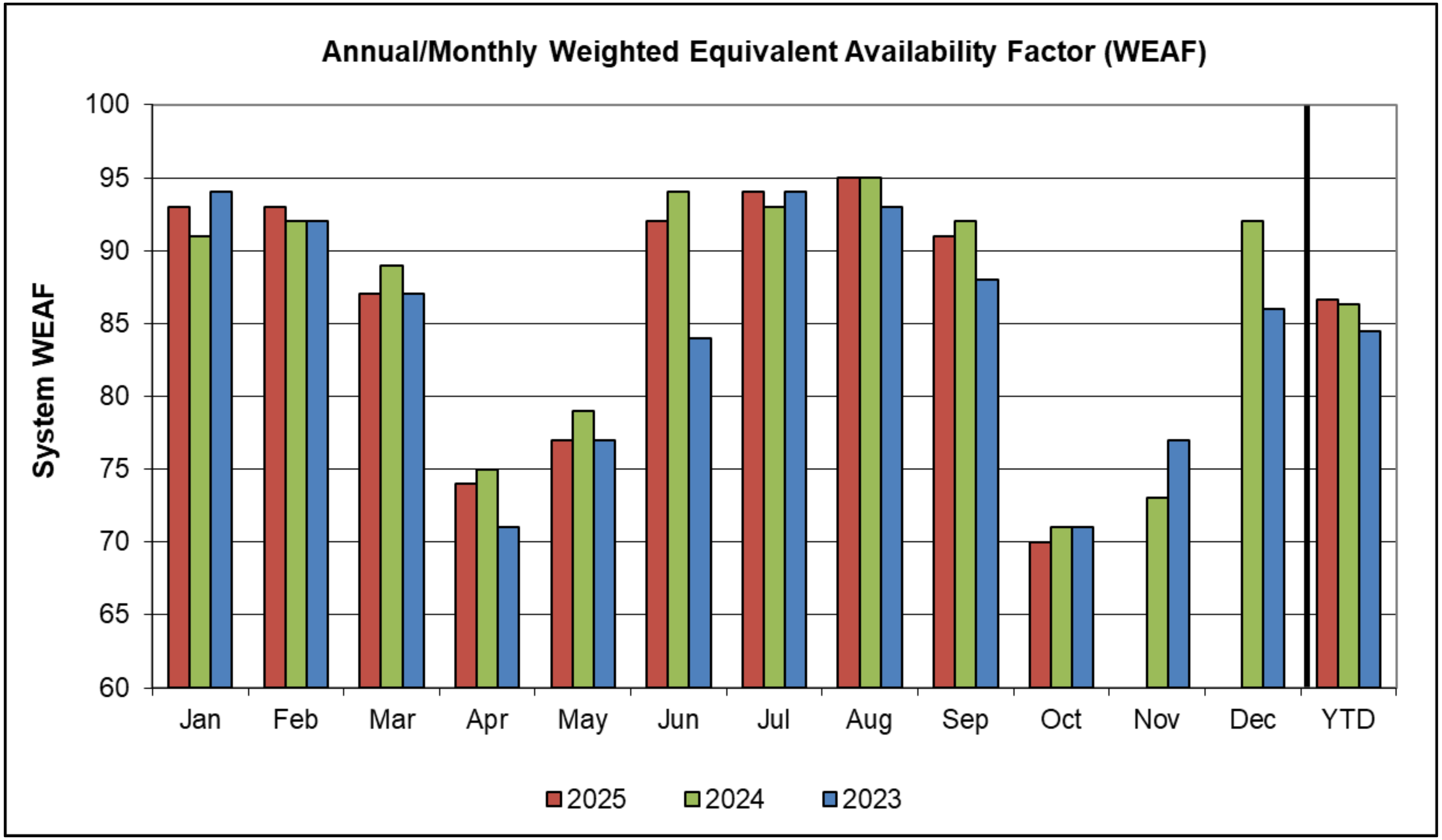
Negative values indicate DA Cleared Physical Energy value below its RT counterpart. EIR MW are not included in DA Physical Energy.

RT Generation Output Offered as Must Run vs Dispatchable



Includes generation and DRR. Must Run (non-dispatchable) category reflects full output of Settlement Only Resources (SOG) as well as must run offers from modeled units

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2025	93	93	87	74	77	92	94	95	91	70			87
2024	91	92	89	75	79	94	93	95	92	71	73	92	86
2023	94	92	87	71	77	84	94	93	88	71	77	86	85

Data as of 10/27/25

MARKET PRICING

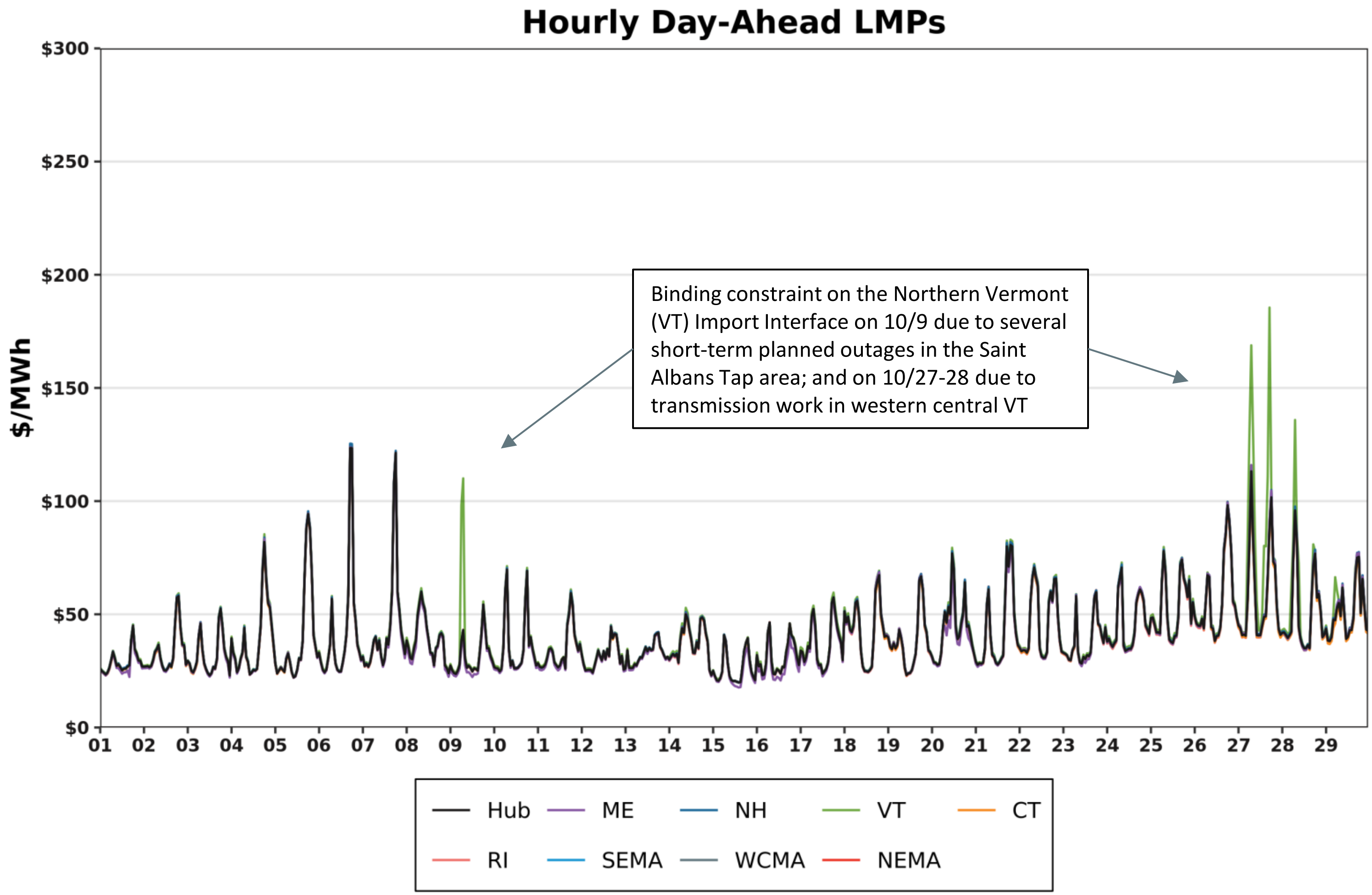
DA vs. RT LMPs ($/MWh)

Arithmetic Average

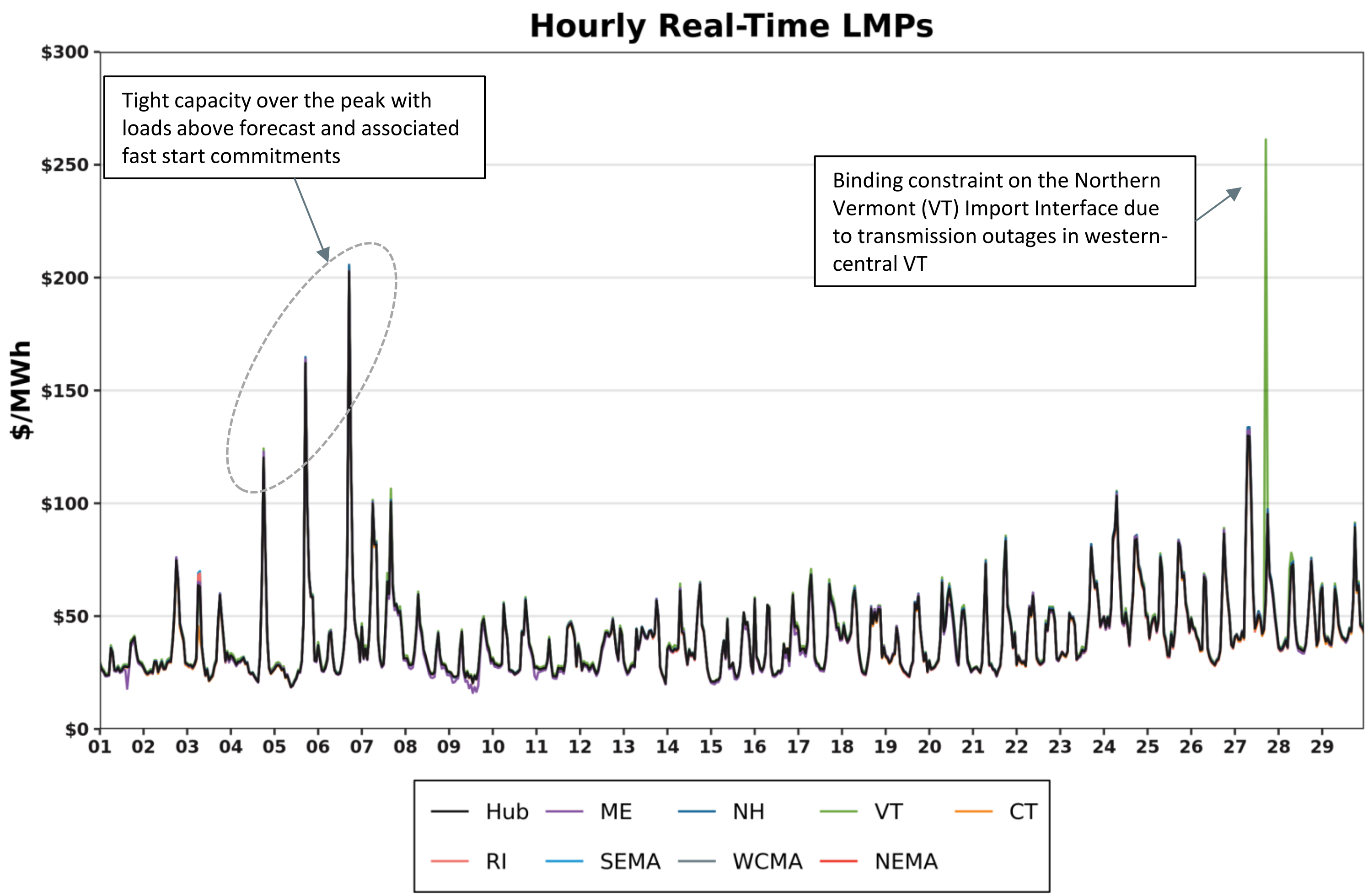
Year 2023	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$37.04	$36.59	$37.22	$36.78	$36.25	$36.89	$37.34	$37.07	$37.35
Real-Time	$35.91	$35.36	$36.05	$35.55	$35.26	$35.71	$36.17	$35.92	$36.21
RT Delta %	-3.05%	-3.36%	-3.14%	-3.34%	-2.73%	-3.20%	-3.13%	-3.10%	-3.05%
Year 2024	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$41.35	$41.07	$41.72	$41.11	$40.17	$41.28	$41.70	$41.37	$41.91
Real-Time	$39.37	$38.79	$39.65	$39.23	$38.46	$39.17	$39.62	$39.37	$39.77
RT Delta %	-3.05%	-3.36%	-3.14%	-3.34%	-2.73%	-3.20%	-3.13%	-3.10%	-3.05%

October-24	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$35.97	$36.25	$36.54	$36.41	$34.96	$35.29	$35.99	$35.99	$36.40
Real-Time	$34.84	$35.14	$35.42	$35.29	$34.00	$34.22	$34.78	$34.84	$35.25
RT Delta %	-3.14%	-3.06%	-3.07%	-3.08%	-2.75%	-3.03%	-3.36%	-3.20%	-3.16%
October-25	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$39.98	$39.27	$40.32	$41.75	$39.56	$39.39	$40.04	$40.06	$40.29
Real-Time	$40.38	$39.81	$40.78	$41.66	$39.98	$39.76	$40.31	$40.46	$40.66
RT Delta %	1.00%	1.38%	1.14%	-0.22%	1.06%	0.94%	0.67%	1.00%	0.92%
Annual Diff.	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Yr over Yr DA	11.15%	8.33%	10.34%	14.67%	13.16%	11.62%	11.25%	11.31%	10.69%
Yr over Yr RT	15.90%	13.29%	15.13%	18.05%	17.59%	16.19%	15.90%	16.13%	15.35%

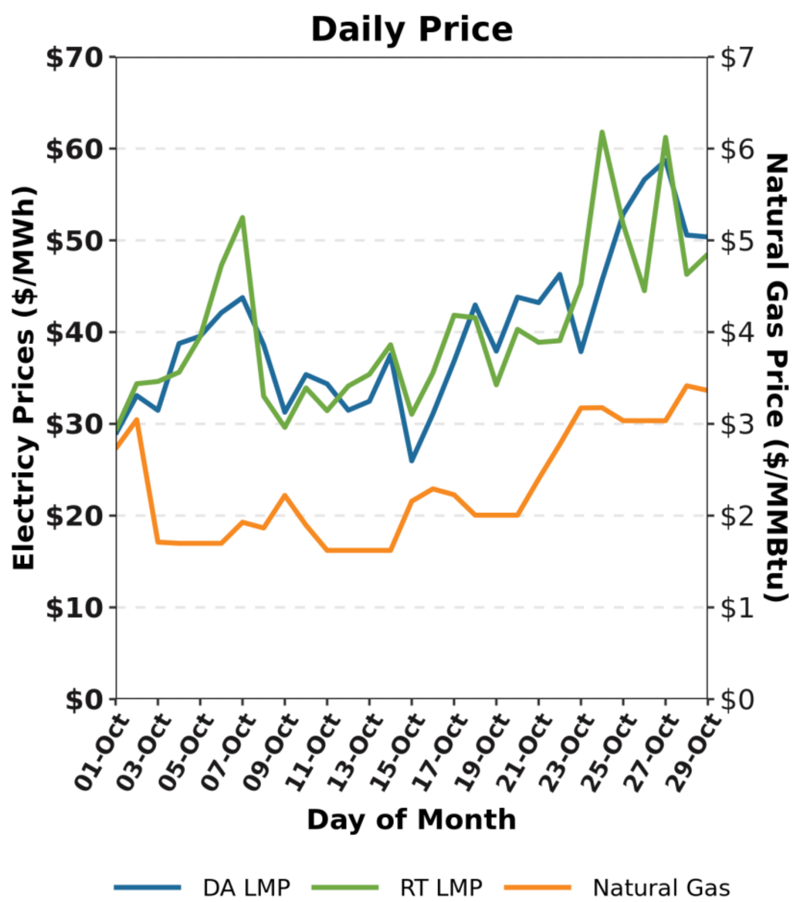
Hourly DA LMPs, October 1-29, 2025

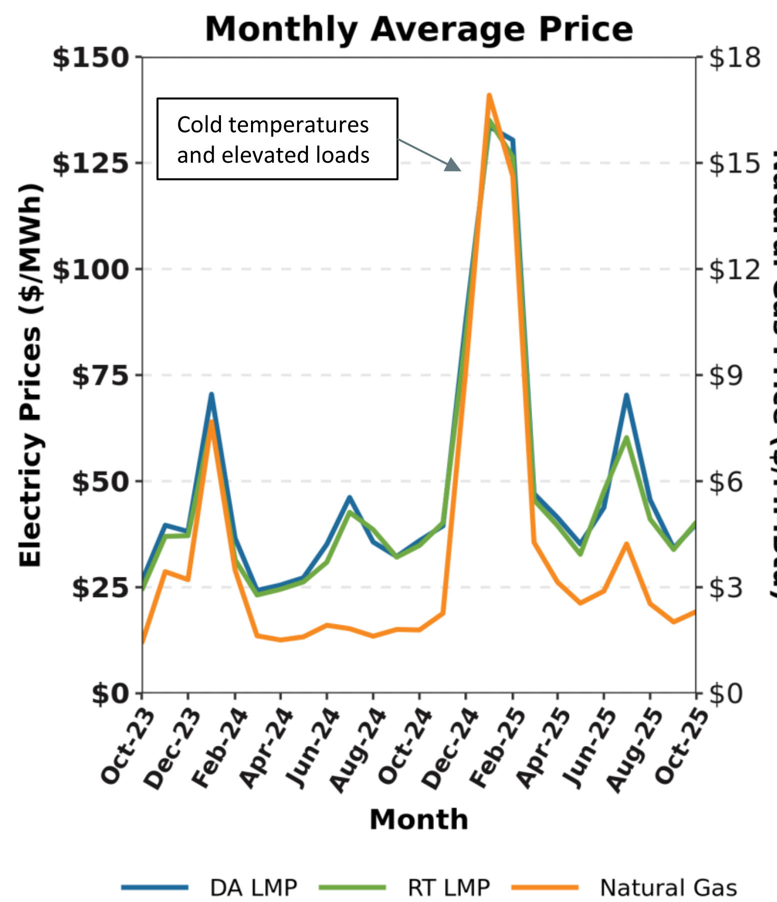


Hourly RT LMPs, October 1-29, 2025



Wholesale Electricity vs Natural Gas Price by Month

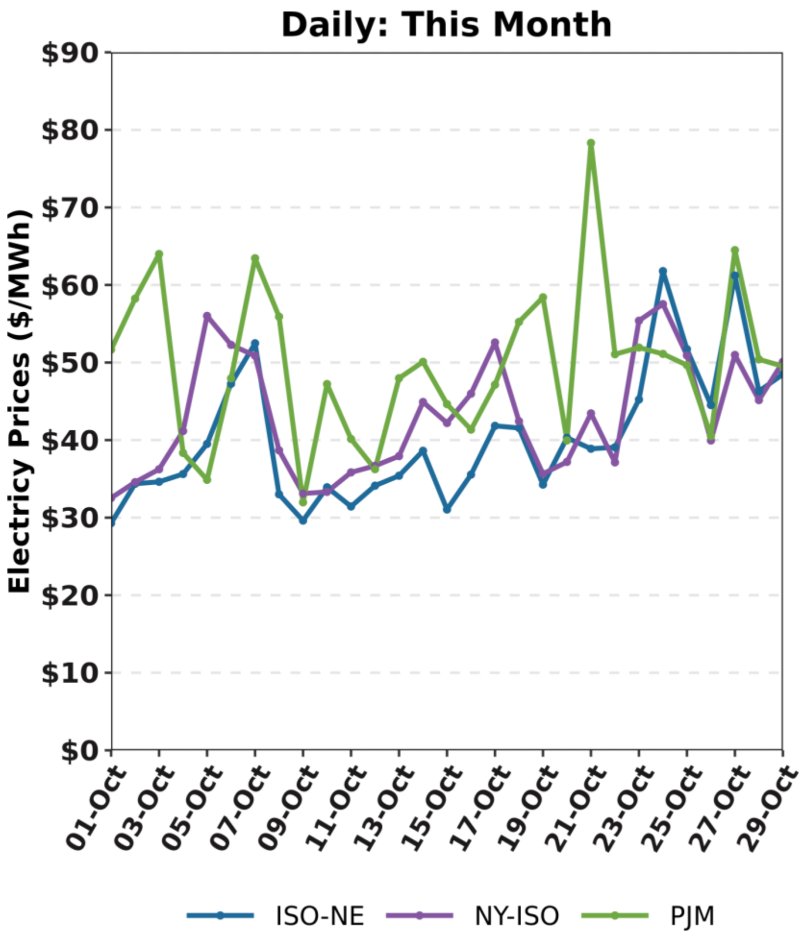


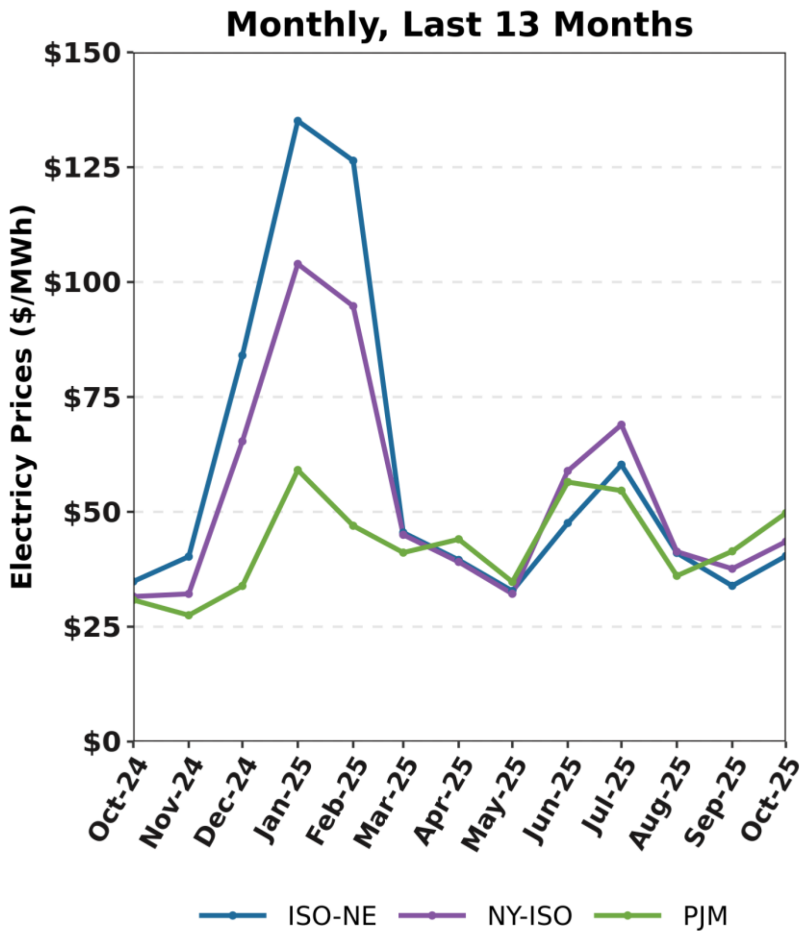


Underlying natural gas data furnished by: ICE Global markets in clear view

Gas price is average of Massachusetts delivery points

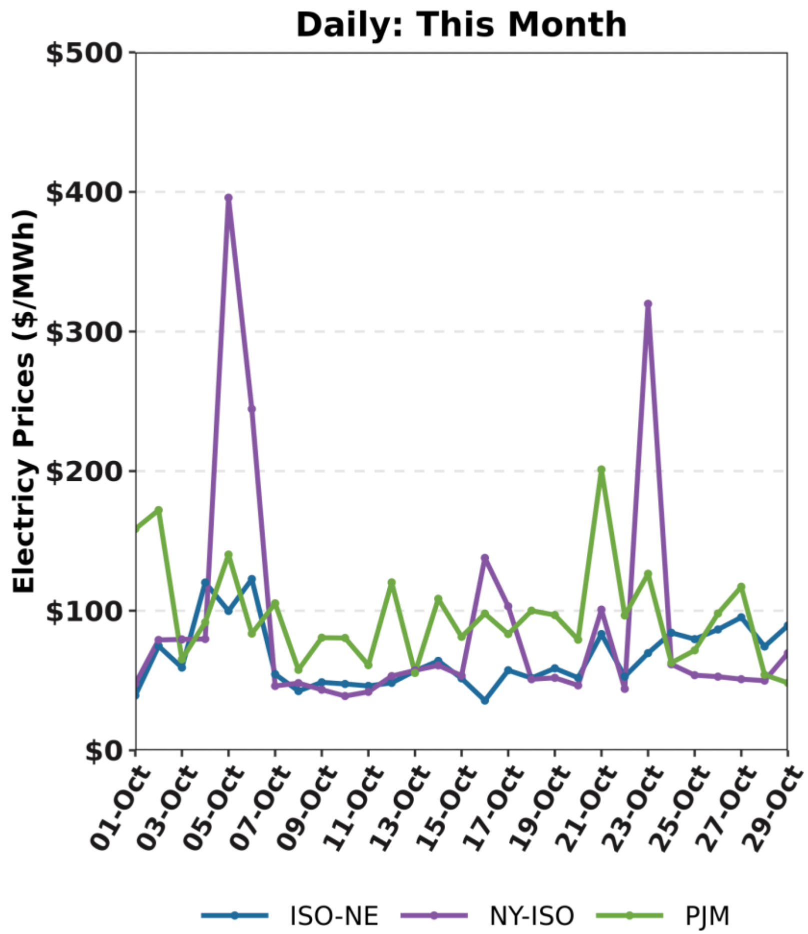
New England, NY, and PJM Hourly Average RT Prices by Month

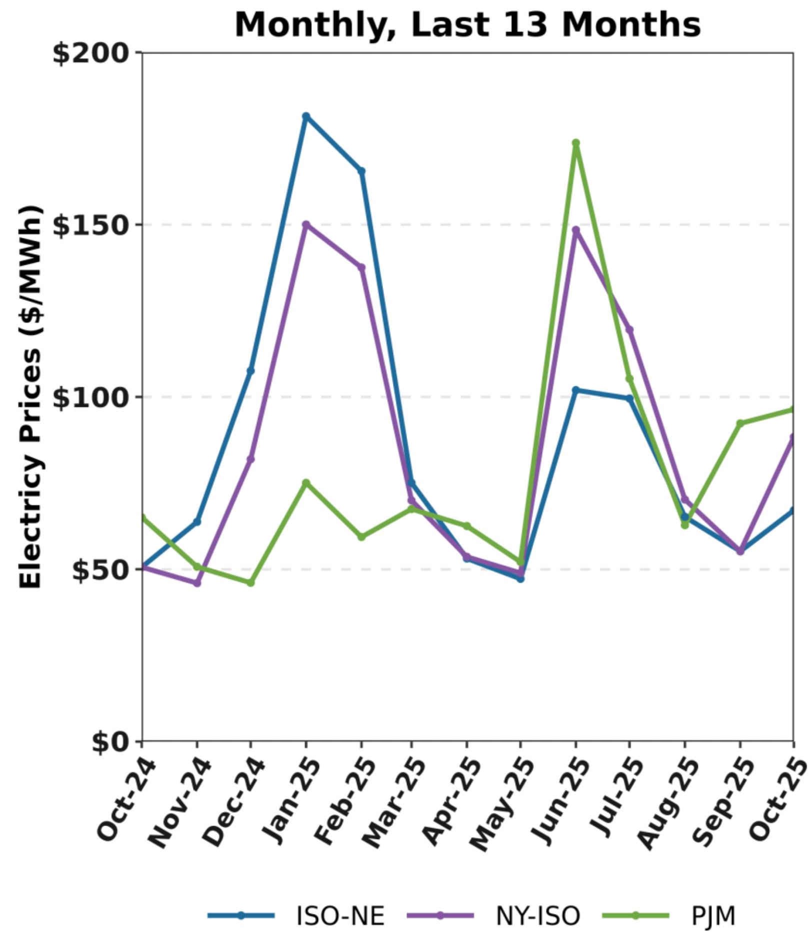




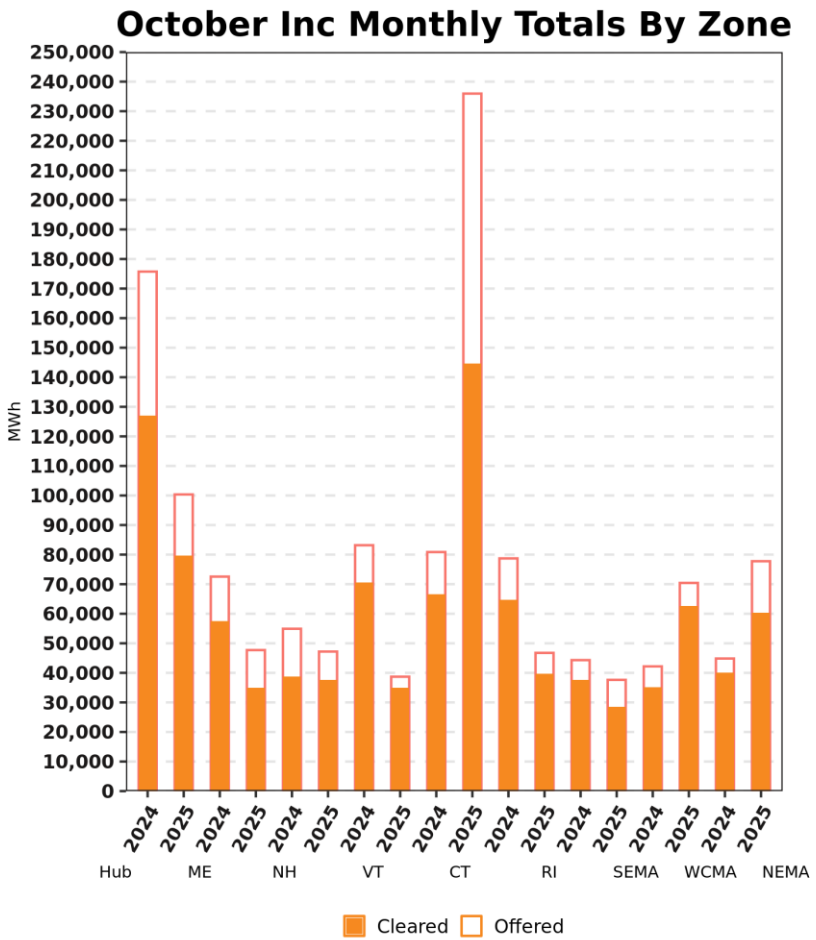
Hourly average prices are shown

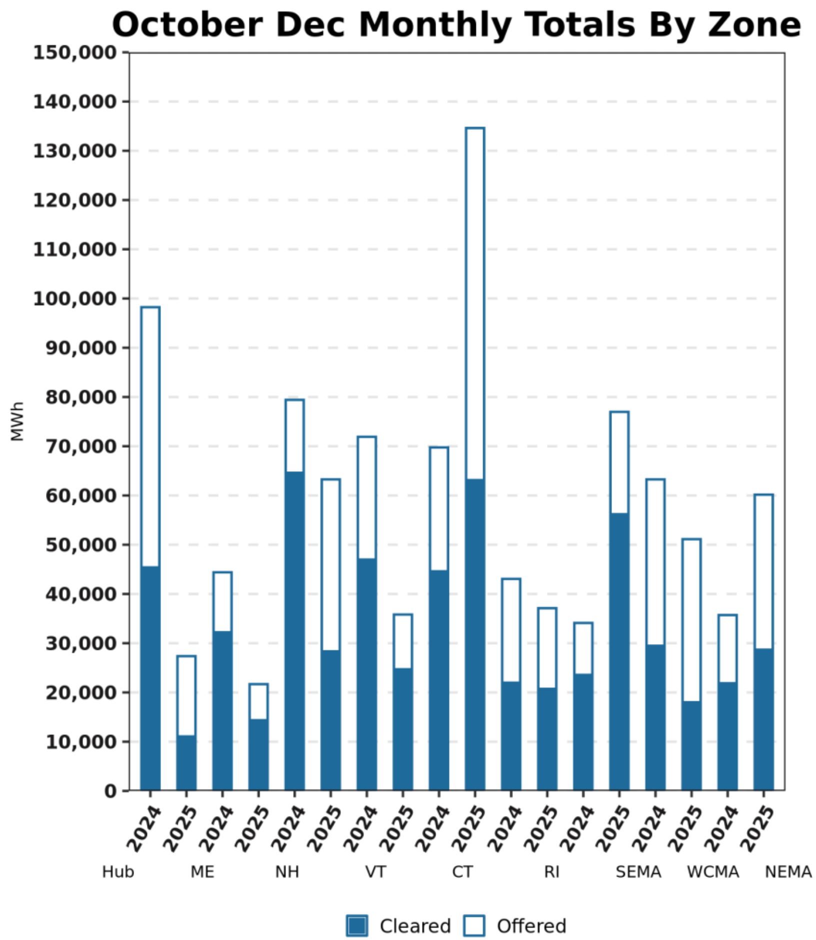
New England, NY, and PJM RT Pricing during New England's Forecasted Daily Peak Hours





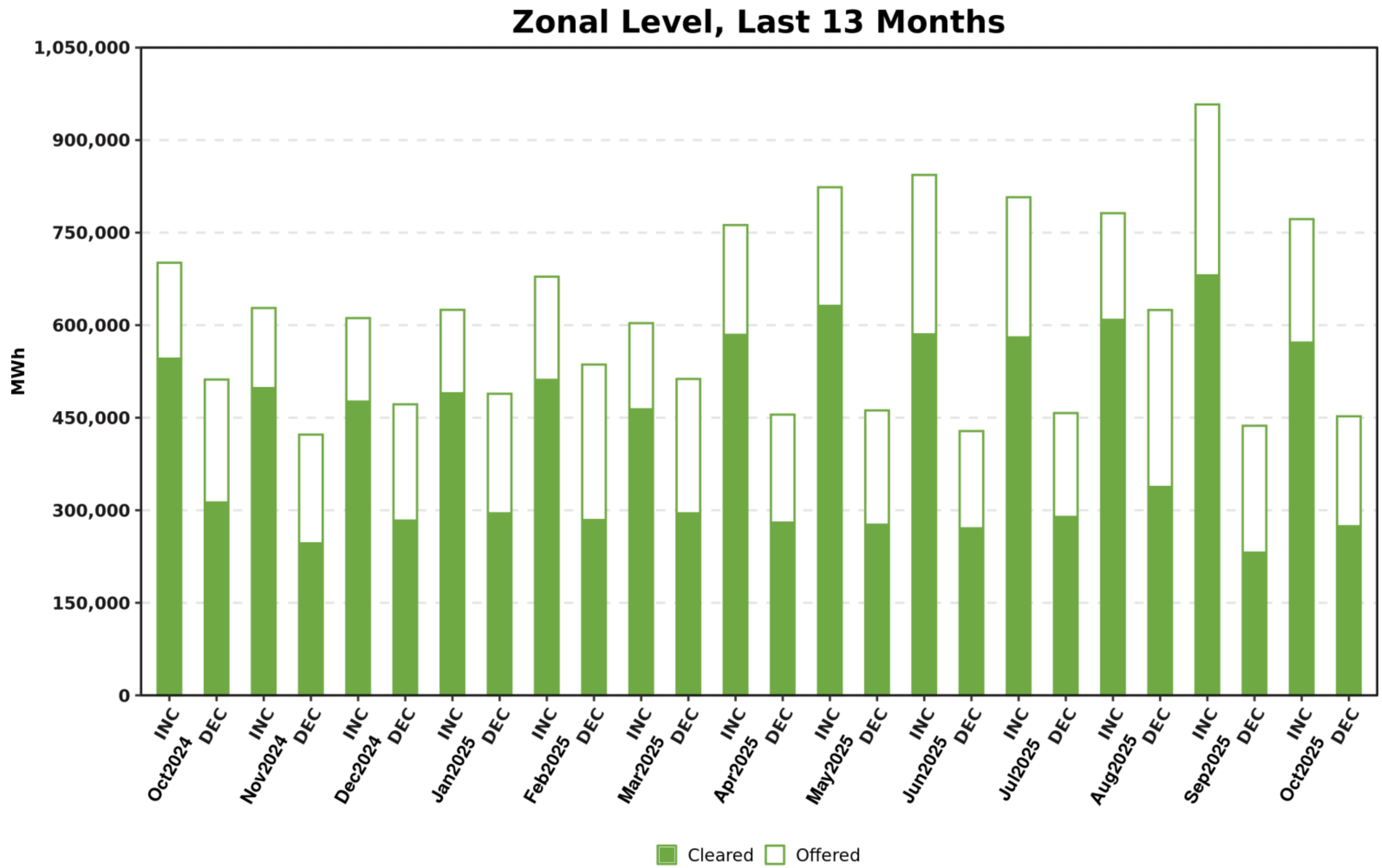
Zonal Increment Offers and Decrement Bid Amounts





Includes nodal activity within the zone; excludes external nodes

Total Increment Offers and Decrement Bids

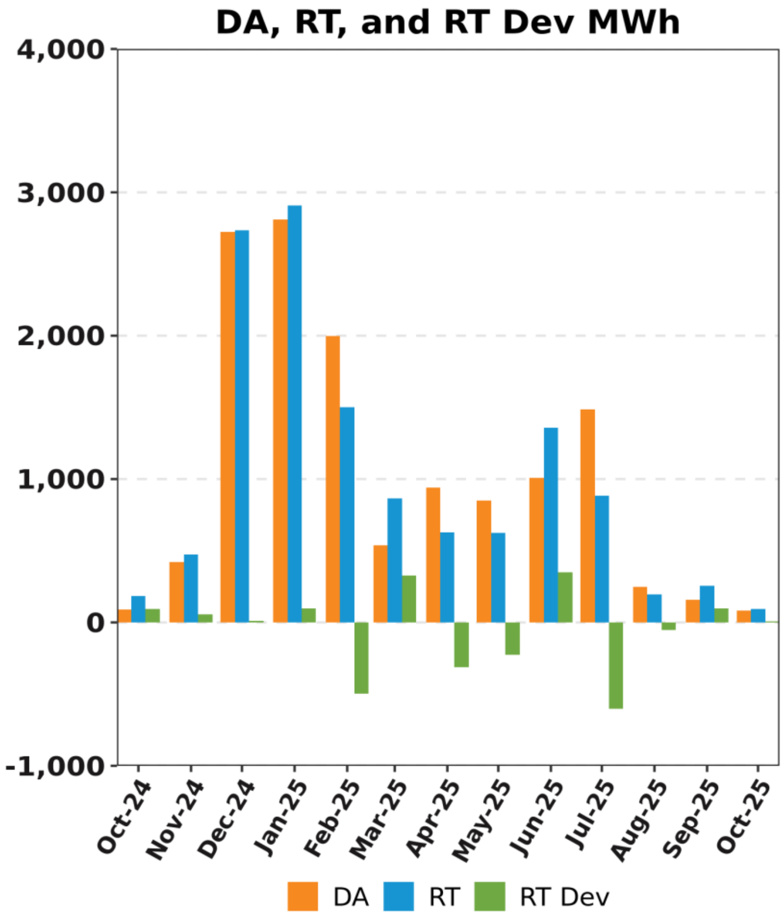


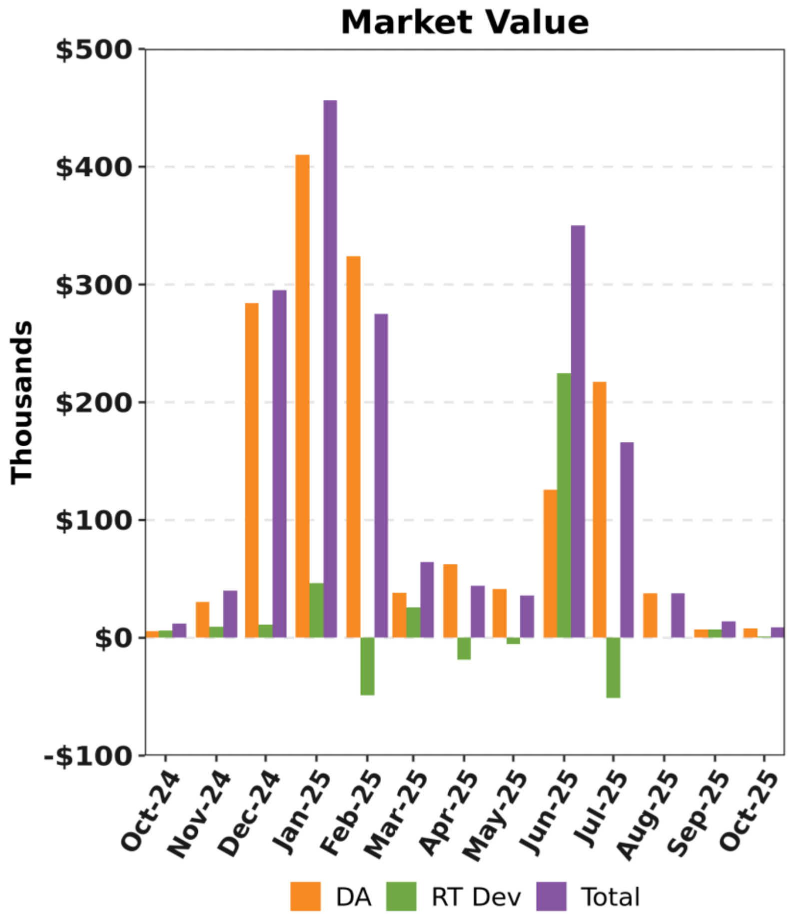
Includes nodal activity within the zone; excludes external nodes

BACK-UP DETAIL

DEMAND RESPONSE

Demand Response Resource (DRR) Energy Market Activity by Month





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

NEW GENERATION

New Generation Update

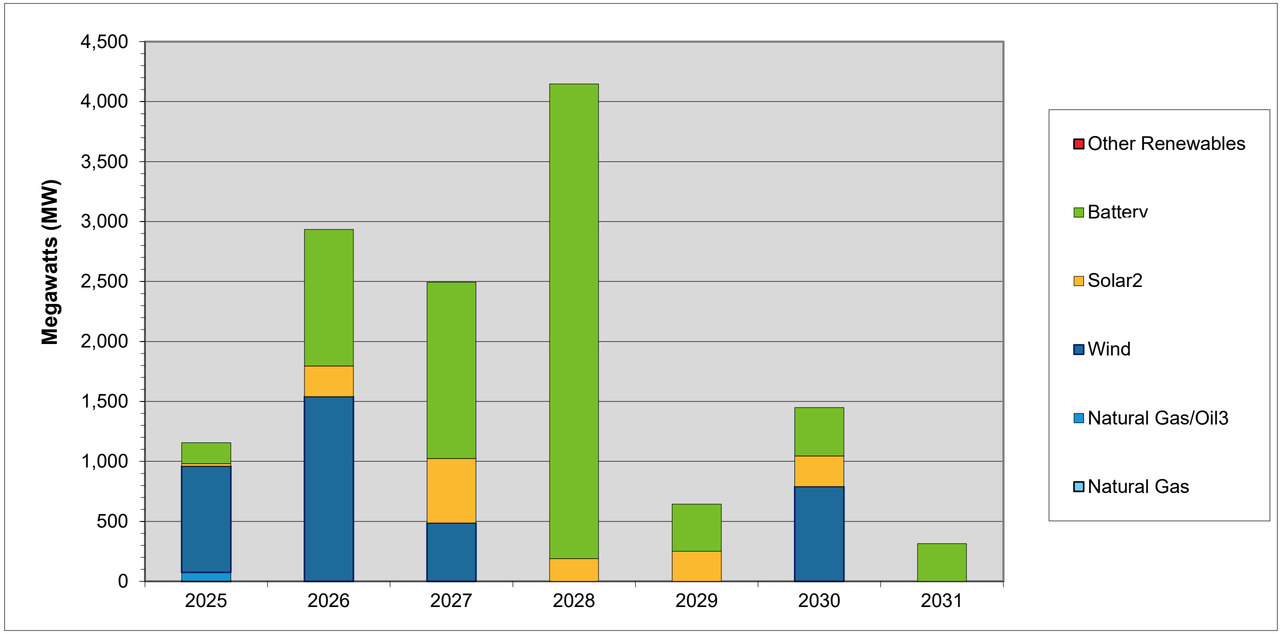
Based on Queue as of 10/28/25

- The interconnection queue has been updated to reflect the projects that have submitted the required materials to participate in the Order No. 2023 Transitional Cluster Study
- In total, 69* generation projects are currently being tracked by the ISO, totaling approximately 15,559 MW

* Total does not include CNR Only requests

Projected Annual Capacity Additions

By Supply Fuel Type



	2025	2026	2027	2028	2029	2030	2031	Total MW	% of Total[1]
Other Renewables	0	0	0	0	0	0	0	0	0.0
Battery	175	1,140	1,471	3,957	392	404	315	7,854	59.8
Solar[2]	20	255	537	190	252	254	0	1,508	11.5
Wind	886	1,540	487	0	0	791	0	3,704	28.2
Natural Gas/Oil[3]	73	0	0	0	0	0	0	73	0.6
Natural Gas	0	0	0	0	0	0	0	0	0.0
Totals	1,154	2,935	2,495	4,147	644	1,449	315	13,139	100.0

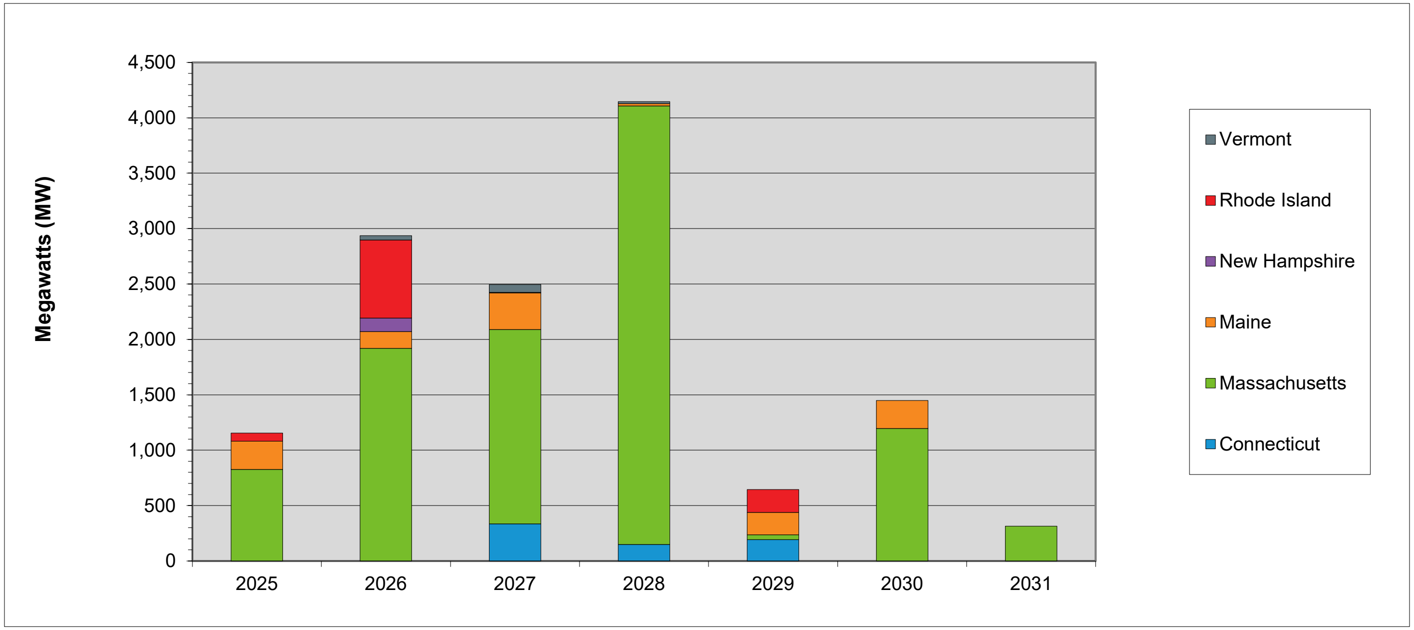
[1] Sum may not equal 100% due to rounding

[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

Chart is based on the dates listed in the interconnection queue and in many cases does not reflect accurately achievable dates for proposed projects

Projected Annual Generator Capacity Additions
By State



	2025	2026	2027	2028	2029	2030	2031	Total MW	% of Total[1]
Vermont	0	38	70	20	0	0	0	128	1.0
Rhode Island	73	704	0	0	205	0	0	982	7.5
New Hampshire	0	122	5	0	0	0	0	127	1.0
Maine	254	151	331	20	202	254	0	1,212	9.2
Massachusetts	827	1,920	1,753	3,957	45	1,195	315	10,012	76.2
Connecticut	0	0	336	150	192	0	0	678	5.2
Totals	**1,154**	**2,935**	**2,495**	**4,147**	**644**	**1,449**	**315**	**13,139**	**100.0**

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

Chart is based on the dates listed in the interconnection queue and in many cases does not reflect accurately achievable dates for proposed projects

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	31	7,854	2	425	29	7,429
Fuel Cell	0	0	0	0	0	0
Hydro	0	0	0	0	0	0
Natural Gas	0	0	0	0	0	0
Natural Gas/Oil	1	73	0	0	1	73
Nuclear	0	0	0	0	0	0
Solar	27	1,528	4	76	23	1,452
Wind	10	6,104	3	877	7	5,227
Total	69	15,559	9	1,378	60	14,181

- 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 within the next 12 months
- 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	0	0	0	0	0	0
Intermediate	1	73	0	0	1	73
Peaker	58	9,382	6	501	52	8,881
Wind Turbine	10	6,104	3	877	7	5,227
Total	69	15,559	9	1,378	60	14,181

- Green denotes projects with a high probability of going into service within the next 12 months
- 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	31	7,854	0	0	0	0	31	7,854	0	0
Fuel Cell	0	0	0	0	0	0	0	0	0	0
Hydro	0	0	0	0	0	0	0	0	0	0
Natural Gas	0	0	0	0	0	0	0	0	0	0
Natural Gas/Oil	1	73	0	0	1	73	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0
Solar	27	1,528	0	0	0	0	27	1,528	0	0
Wind	10	6,104	0	0	0	0	0	0	10	6,104
Total	69	15,559	0	0	1	73	58	9,382	10	6,104

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

FORWARD CAPACITY MARKET

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	579.692	-93.709	461.416	-118.276
Demand	*Passive Demand*	3,212.865	3,211.403	-1.462	3,134.652	-76.751	3,113.332	-21.32
Demand Total		**3,890.538**	**3,884.804**	**-5.734**	**3,714.344**	**-170.460**	**3,574.748**	**-139.596**
Generator	*Non-Intermittent*	28,154.203	27,714.778	-439.425	27,081.653	-633.125	27,132.413	50.76
Generator	*Intermittent*	1,089.265	1,073.794	-15.471	1,056.601	-17.193	865.694	-190.907
Generator Total		**29,243.468**	**28,788.572**	**-454.896**	**28,138.254**	**-650.318**	**27,998.107**	**-140.147**
Import Total		**1,487.059**	**1297.132**	**-189.927**	**1,249.545**	**-47.587**	**1,193.583**	**-55.962**
Grand Total*		**34,621.065**	**33,970.508**	**-650.557**	**33,102.143**	**-868.365**	**32,766.438**	**-335.705**
Net ICR (NICR)		**33,270**	**31,775**	**-1,495**	**31,545**	**-230**	**31,380**	**-165**

* 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 reconfiguration auctions 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 2024-2028 CCP Month 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	589.882	-175.468	504.466	-85.416	437.780	-66.686
	Passive Demand	2,557.256	2,579.120	21.864	2,574.367	-4.753	2,568.703	-5.664
Demand Total		**3,322.606**	**3,169.002**	**-153.604**	**3,078.833**	**-90.169**	**3,006.483**	**-72.350**
Generator	*Non-Intermittent*	26,805.003	26,643.379	-161.624	26,503.730	-139.649	26,049.059	-454.671
	Intermittent	1,178.933	1,146.783	-32.15	989.265	-157.518	912.376	-76.889
Generator Total		**27,983.936**	**27,790.162**	**-193.774**	**27,492.995**	**-297.167**	**26,961.435**	**-531.560**
Import Total		**1,503.842**	**1,247.601**	**-256.241**	**1,244.601**	**-3.000**	**1,234.800**	**-9.801**
Grand Total*		**32,810.384**	**32,206.765**	**-603.619**	**31,816.429**	**-390.336**	**31,202.718**	**-613.711**
Net ICR (NICR)		**31,645**	**30,585**	**-1,060**	**30,775**	**190**	**30,300**	**-475**

* 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 reconfiguration auctions 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 2024-2028 CCP Month Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 17

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*	622.854	584.913	-37.941	492.363	-92.550		
Demand	*Passive Demand*	2,316.815	2,314.068	-2.747	2,314.705	0.637		
Demand Total		**2,939.669**	**2,898.981**	**-40.688**	**2,807.068**	**-91.913**		
Generator	*Non-Intermittent*	26,507.420	26,715.489	208.069	26,271.866	-443.623		
Generator	*Intermittent*	1,356.084	1,286.589	-69.495	1,310.622	24.033		
Generator Total		**27,863.504**	**28,002.078**	**138.574**	**27,582.488**	**-419.59**		
Import Total		**566.998**	**564.079**	**-2.919**	**636.310**	**72.231**		
Grand Total*		**31,370.171**	**31,465.138**	**94.967**	**31,025.866**	**-439.272**		
Net ICR (NICR)		**30,305**	**30,395**	**90**	**30,600**	**205**		

* 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 reconfiguration auctions 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 2024-2028 CCP Month Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 18

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*	543.580	403.884	-139.696				
Demand	*Passive Demand*	2,070.498	2,851.331	780.833				
Demand Total		**2,614.078**	**3,255.215**	**641.137**				
Generator	*Non-Intermittent*	27,026.635	25,822.288	-1,204.347				
Generator	*Intermittent*	1,450.872	890.415	-560.457				
Generator Total		**28,477.507**	**26,712.703**	**-1,764.804**				
Import Total		**464.835**	**1,234.800**	**769.965**				
Grand Total*		**31,556.420**	**31,202.718**	**-353.702**				
Net ICR (NICR)		**30,550.000**	**30,415.000**	**-135.000**				

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

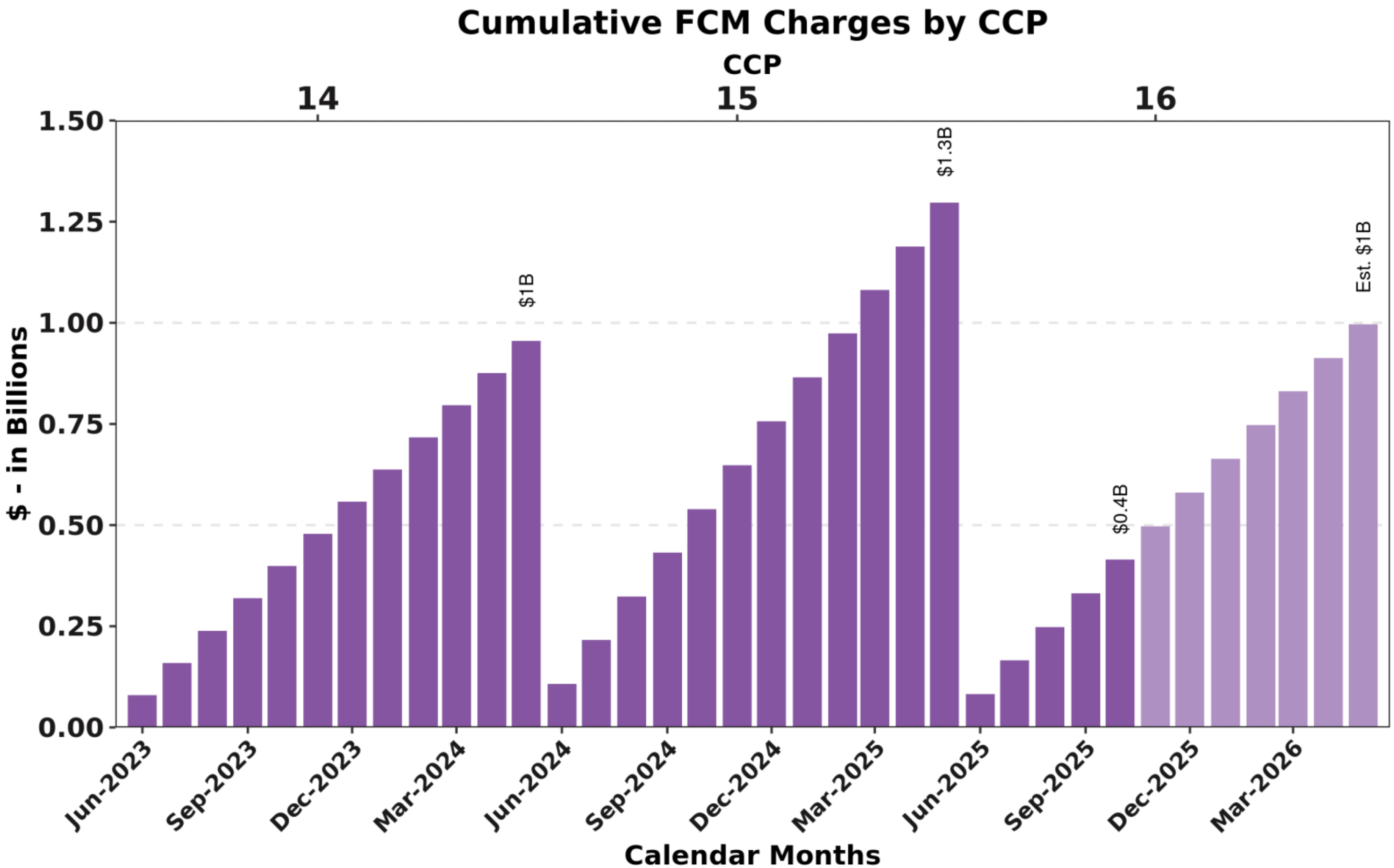
Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2024-2028 CCP Month 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
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**
2026-27	Active	615.369	7.485	622.854
	Passive	2,194.172	122.643	2,316.815
	Grand Total	**2,809.541**	**130.128**	**2,939.669**
2027-28	Active	543.58	0.0	543.58
	Passive	1,965.515	104.983	2070.498
	Grand Total	**2,509.095**	**104.983**	**2,614.498**

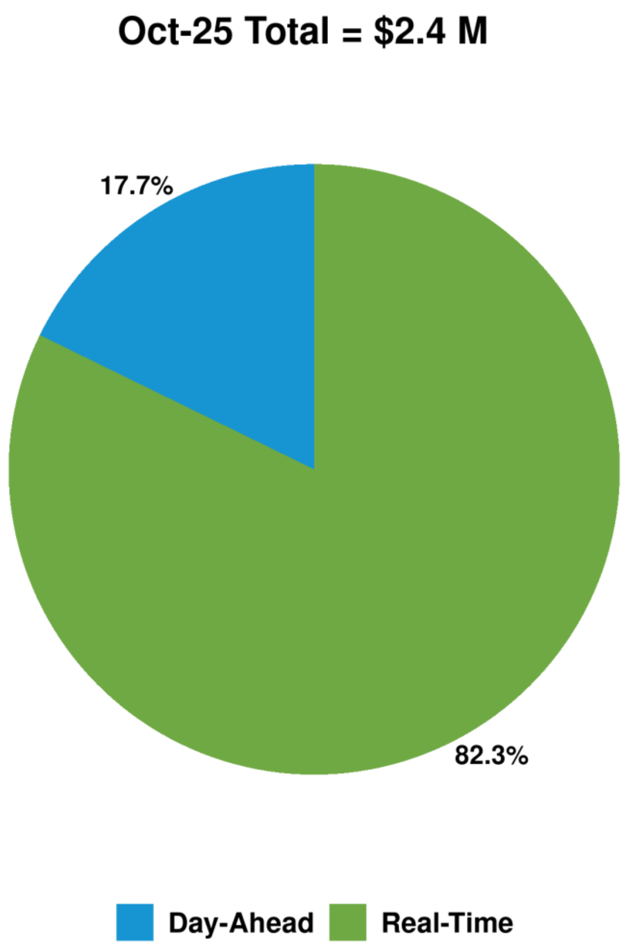
Forward Capacity Market Auctions

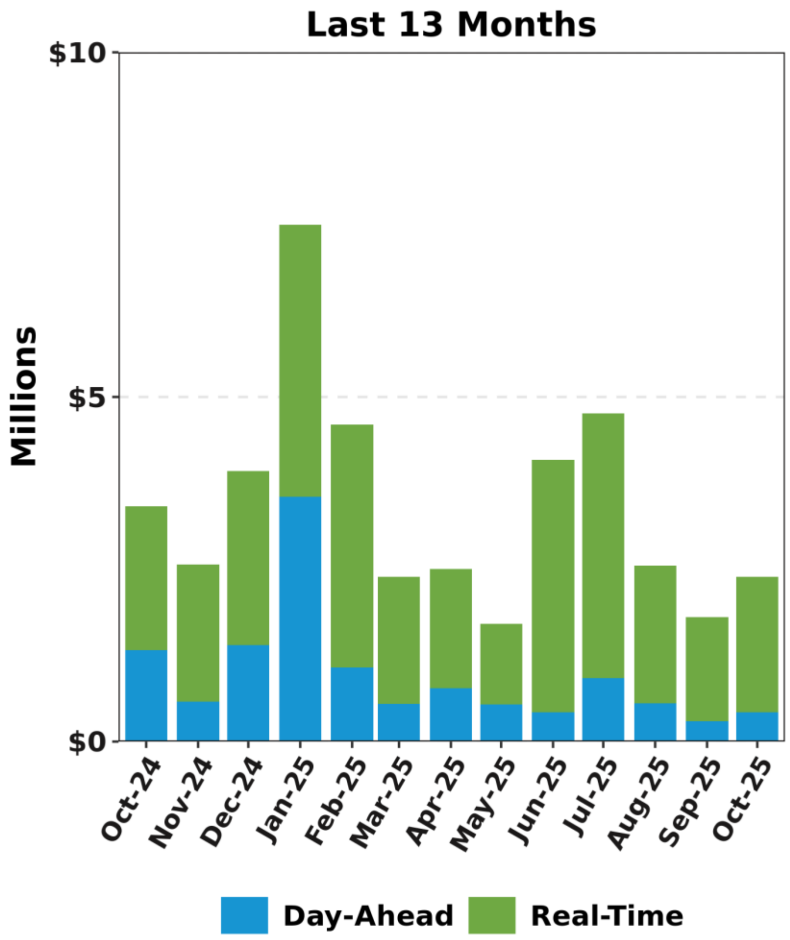


The items in the graph shaded in a lighter color represent the forecast for future months in the Capacity Commitment Period (CCP)

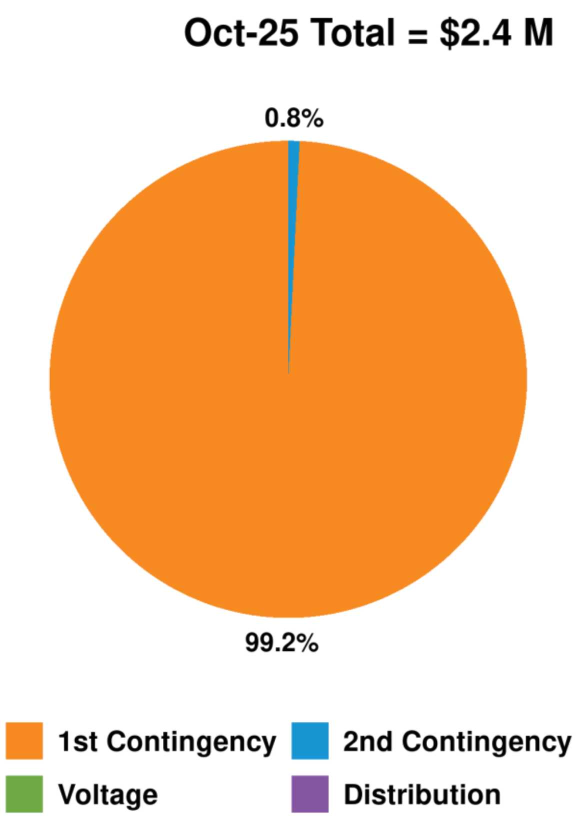
NET COMMITMENT PERIOD COMPENSATION

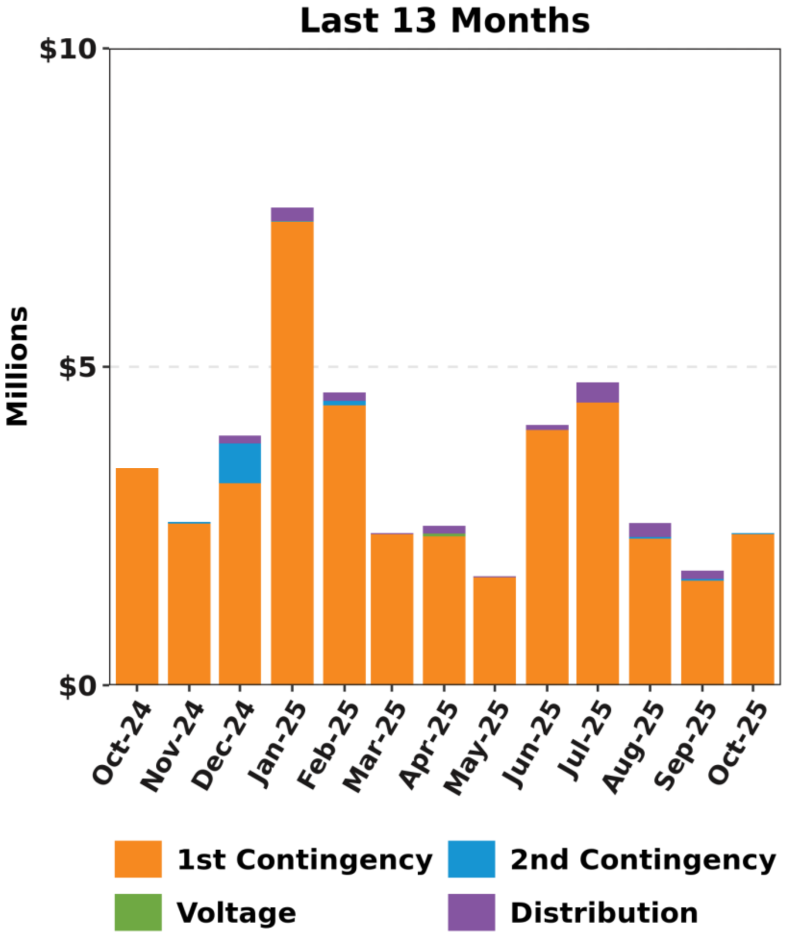
DA and RT NCPC Charges



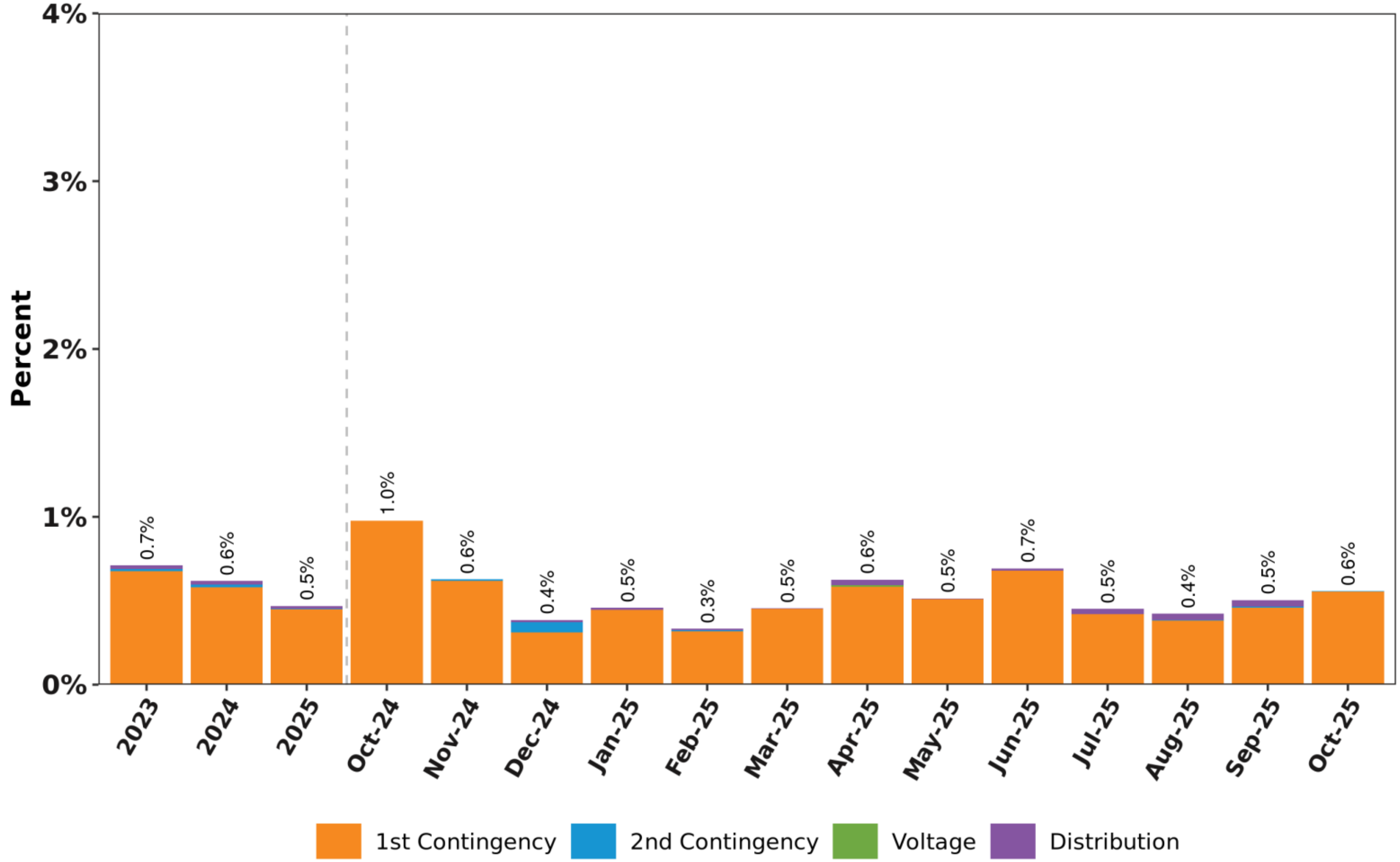


NCPC Charges by Type

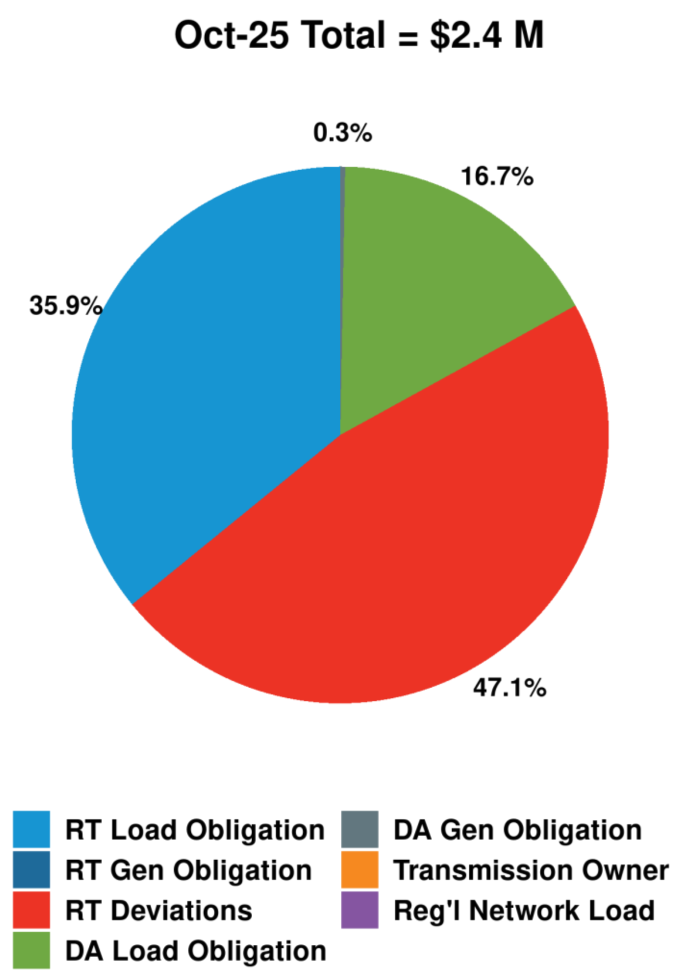


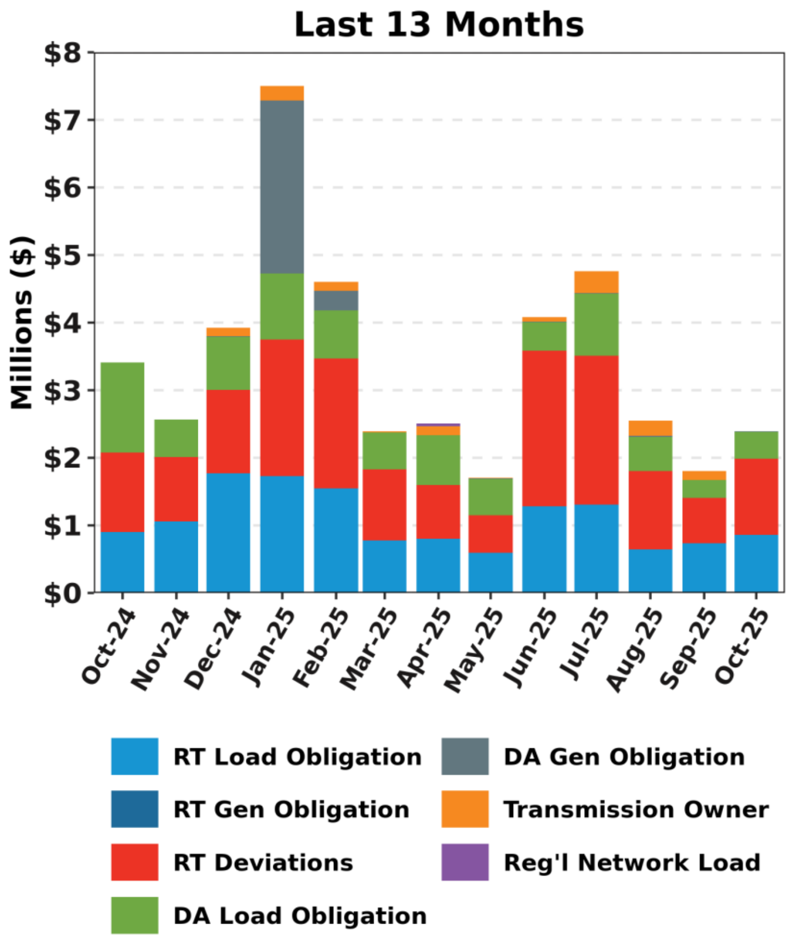


NCPC Charges by Type as Percent of Energy Market Value

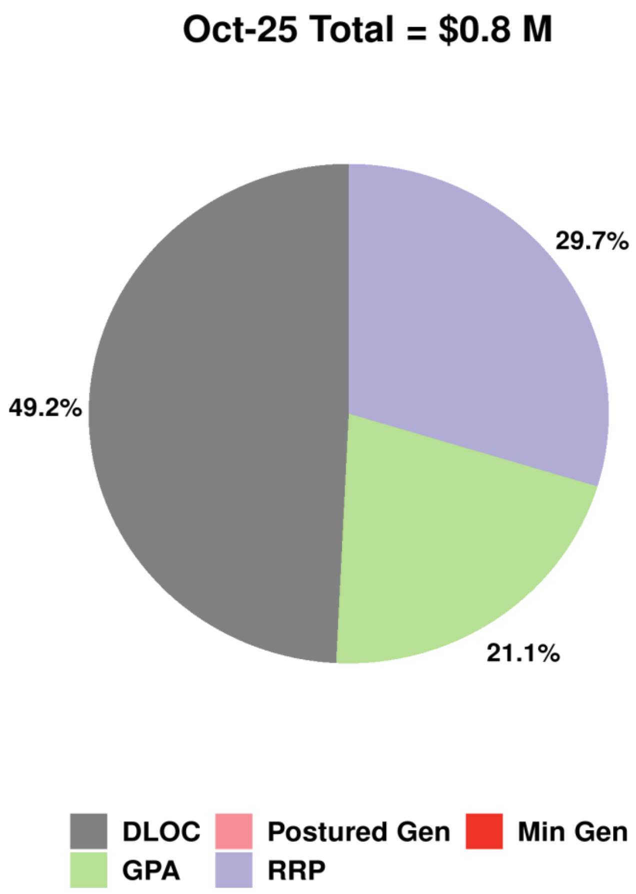


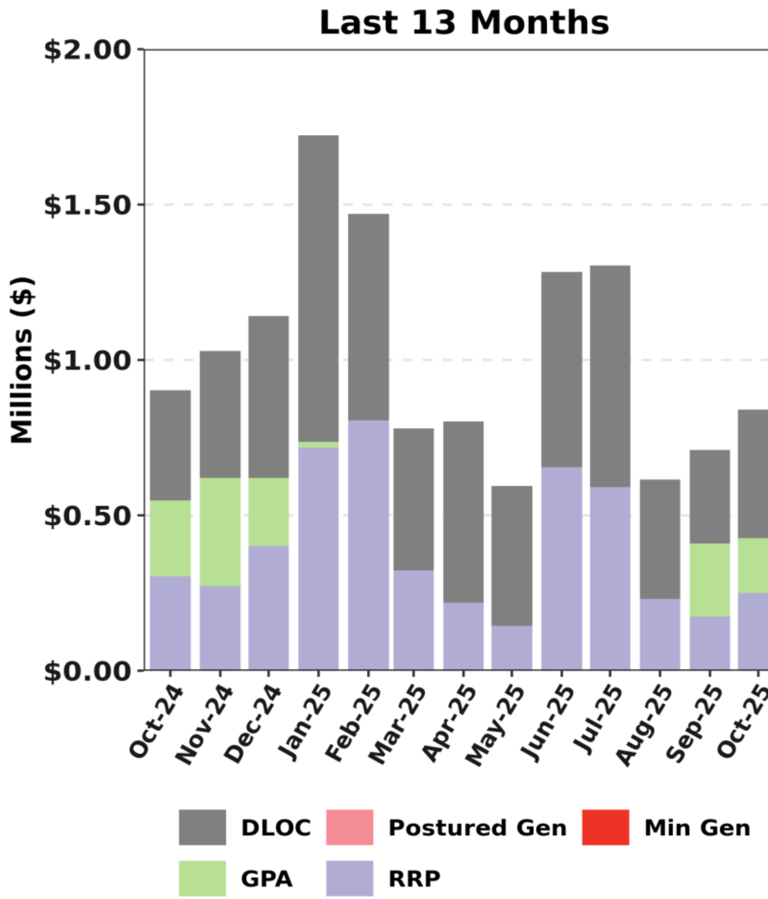
NCPC Charge Allocations





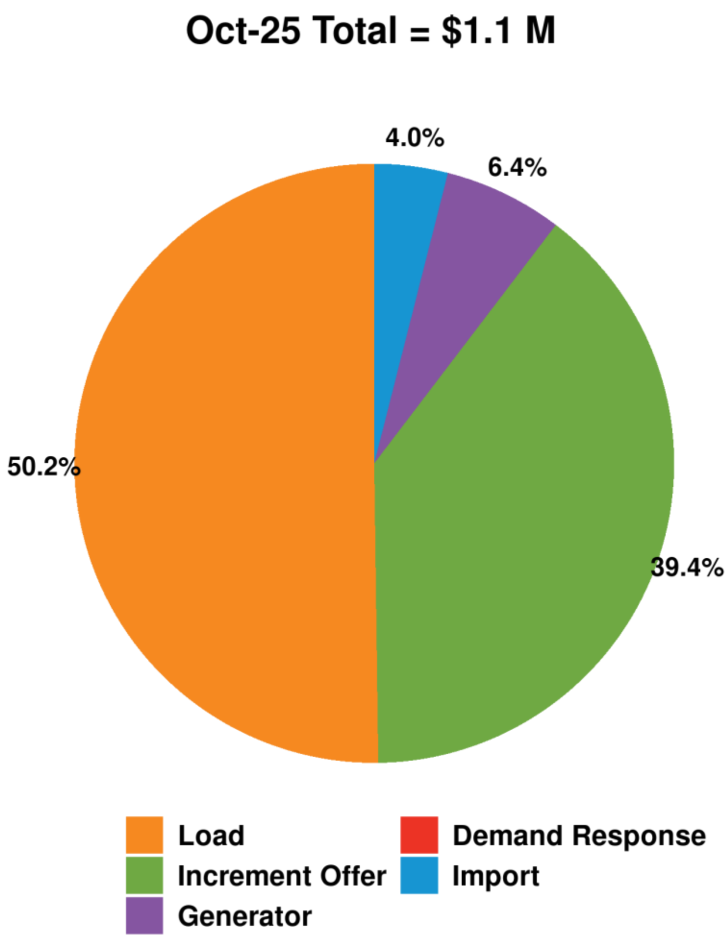
RT First Contingency NCPC Paid to Units and Allocated to RTLO and/or RTGO

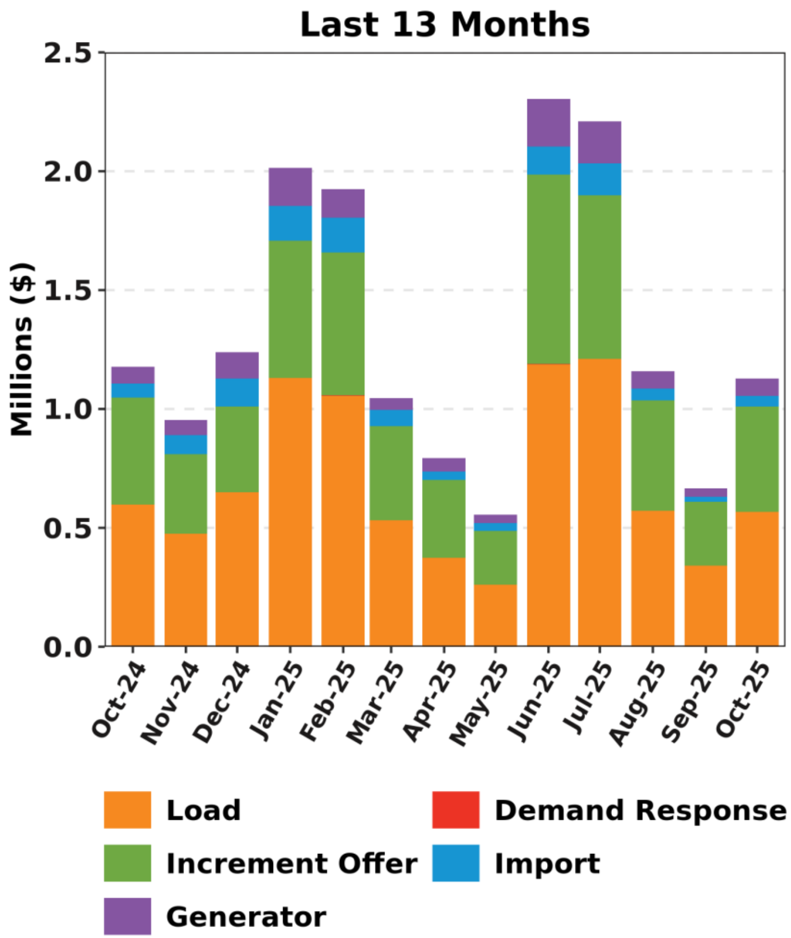




The categories shown above are a subset of those reflected in First Contingency NCPC throughout this report. The above categories are allocated to RTLO, except for Min Gen Emergency credits, which are allocated to RTGO.

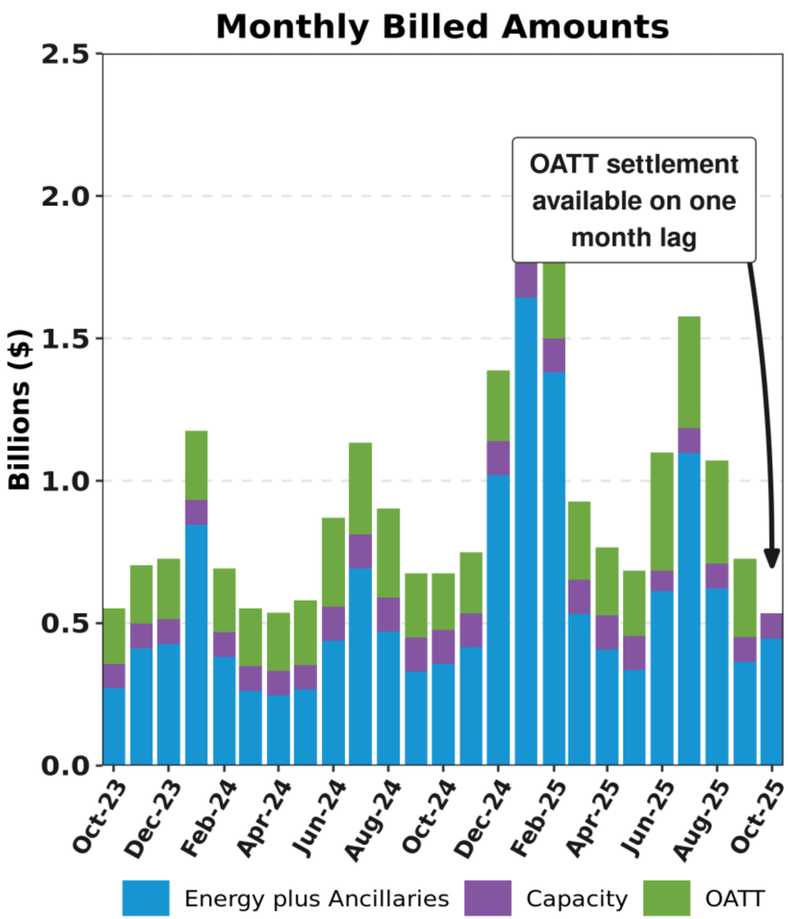
RT First Contingency Charges by Deviation Type

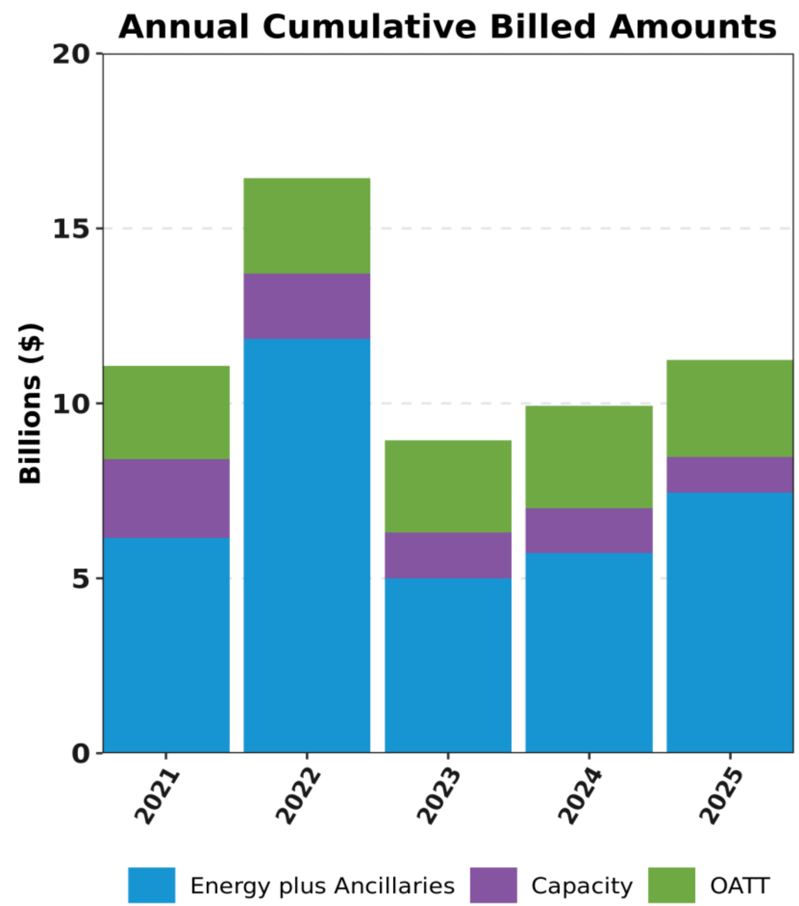




ISO BILLINGS

Total ISO Billings





Ancillaries = Reserves, Regulation, NCPC, minus Marginal Loss Revenue Fund. OATT = RNS, Through and Out, Schedule 9

REGIONAL SYSTEM PLAN (RSP)

Planning Advisory Committee (PAC)

- November 19 PAC Meeting Agenda Topics*
  - Asset Condition Projects
    - 1870S Wood River-Shunock Line Rebuild (RIE)
    - 323 345 kV Line Asset Condition Refurbishment (NGRID)
    - 394/397 345 kV Lines Asset Condition Refurbishment (NGRID)
    - Overview of Proposed Updates to New England Transmission Owner (NETO) PAC Presentation Template and Asset Condition Process Guide (Eversource)
  - 2025 LTTP RFP: Longer-Term Proposal Overview

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

2025 Longer-Term Transmission Planning (LTTP) RFP

- On 12/13/24, NESCOE provided its LTTP RFP request describing the needs to be addressed by 2035:*
  - Increase the Maine-New Hampshire interface capacity to at least 3,000 MW
  - Increase the Surowiec-South interface capacity to at least 3,200 MW
  - Develop new infrastructure (e.g., substation) at Pittsfield, Maine that can accommodate the interconnection of at least 1,200 MW (nameplate) of onshore wind**
- The ISO issued the RFP on 3/31/25, with proposals due by 9/30/25
- The ISO is evaluating all submissions and expects to provide a high-level summary of all Longer-Term Proposals at the 11/19/25 PAC

* Unless a bidder can demonstrate supply chain issues that warrant a later in-service date
** Bidders may propose alternate locations which would be more efficient and cost-effective

2025 Longer-Term Transmission Planning (LTTP) RFP, cont.

- Total of 6 Longer-Term Proposals submitted
  - 4 are joint proposals
- Total of 4 different lead QTPSs (3 non-incumbents, 1 incumbent)
  - 4 additional QTPSs are participating as part of joint proposals (all are incumbents)
- Project Designs
  - 3 primarily AC transmission
  - 3 primarily HVDC transmission
  - All designs claim they support 1200 MW of northern ME wind
  - Claimed Surowiec-South Limits: 3200-3800 MW (3200 MW target)
  - Claimed Maine-New Hampshire Limits: 3000-3600 MW (3000 MW target)
- Project Installed Costs*
  - Low of $0.96B
  - High of $4.04B
- In-Service Dates: Q4 2032 to Q3 2035 (12/31/2035 target)

* Costs may include estimates for corollary upgrades

Economic Studies: 2024 Study

- 2024 Economic Study
  - This study is the first use of new Economic Study Process Tariff language
    - The study was initiated at the January 2024 PAC meeting and will be completed this year unless a Request for Proposal is triggered
  - Benchmark, Policy and Stakeholder-Requested Scenarios are complete and the report and factsheet were issued in September
    - There was also a public webinar in September
  - System Efficiency Needs Scenario is being analyzed between now and Q4 2025
    - Economic Study Phase 2 Tariff changes were accepted by FERC on 6/20/25, with an effective date of 6/23/25

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.

SEMA/RI Reliability Projects

Status as of 10/27/2025

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 10/27/2025

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	Jun-28	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	Aug-23	4
1722	Extend the Line 114 from the Dartmouth town line (Eversource-National Grid border) to Bell Rock substation	Dec-26	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 10/27/2025

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	4
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	Aug-23	4
1729	Install a new bay position at Kingston substation to accommodate new 115 kV line	Aug-23	4
1730	Extend the 114 line from the Eversource/National Grid border to the Industrial Park Tap	Dec-26	2

SEMA/RI Reliability Projects, cont.

Status as of 10/27/2025

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 10/27/2025

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

Upper Maine Solution Projects

Status as of 10/27/2025

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	Aug-24	4
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	Jul-28	1
1884	Install a 15 MVAR capacitor at Belfast 115 kV substation	Jul-28	1
1885	Install a +50/-25 MVAR synchronous condenser at Highland 115 kV substation	Jul-28	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	Aug-25	4

Upper Maine Solution Projects, cont.

Status as of 10/27/2025

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	Nov-24	4
1888	Install 10 MVAR reactor at Keene Road 115 kV substation	Jul-24	4
1889	Install three remotely monitored and controlled switches to split the existing Orrington reactors between the two Orrington 345/115 kV autotransformers	Cancelled *	N/A
1914	Install a new 80 MVAR reactor, reconfigure the existing two reactors at the 345 kV Orrington substation	Jun-26	2

* Cancelled per the Upper Maine Solutions Study Addendum that was published on January 11, 2024

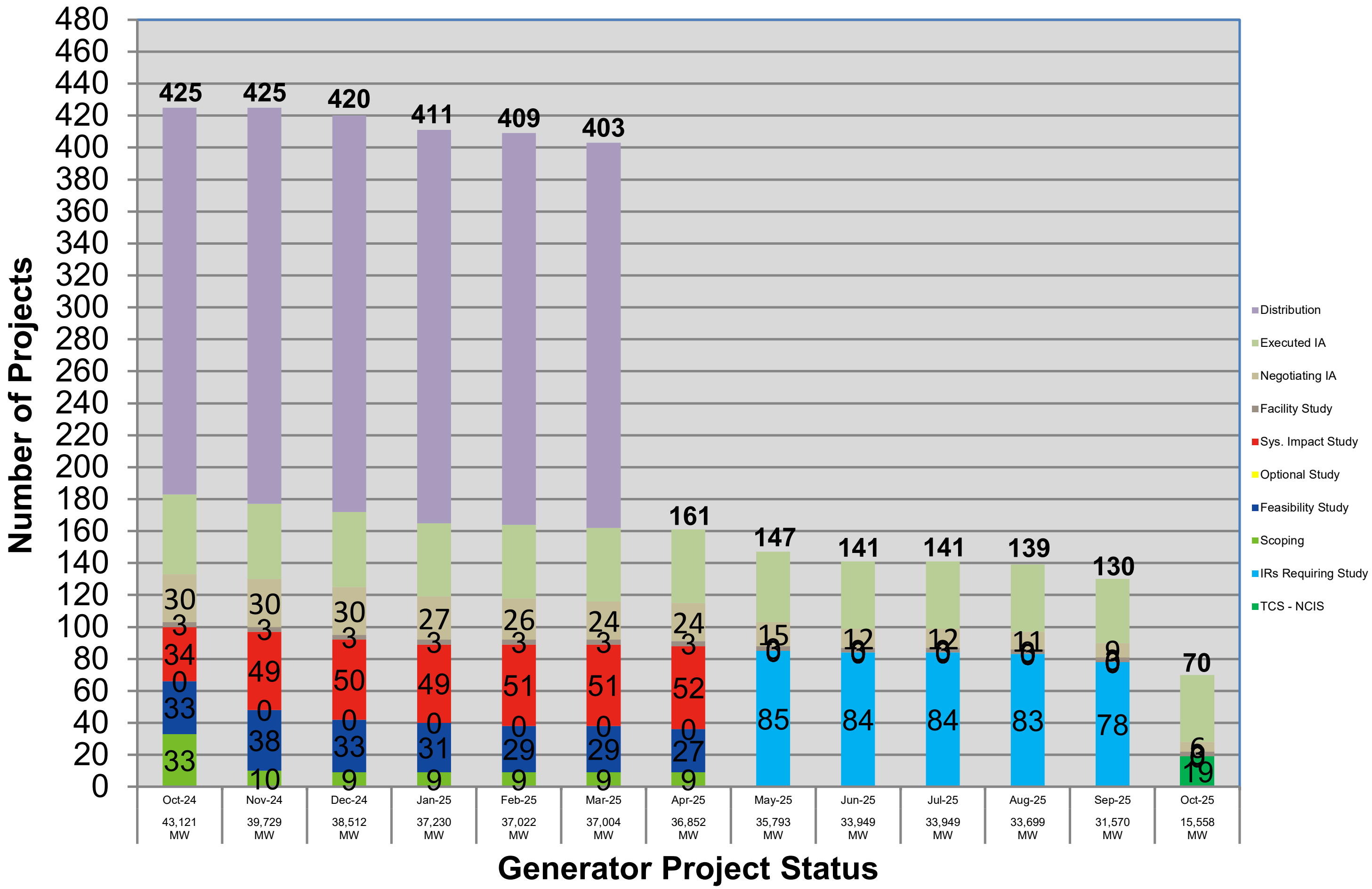
Boston 2033 Solutions Study

Status as of 10/27/2025

Project Benefit: Addresses system needs in the Boston area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1933	Install one 80 MVAR shunt reactor at the 115 kV Electric Avenue Substation	Dec-28	1
1934	Protection systems modification associated with the Stoughton RAS at three 345 kV substations (Stoughton, West Walpole and Holbrook) and two 115 kV substations (Hyde Park and K-Street)	May-26	1

Status of Tariff Studies as of October 28, 2025



ETUs: 0 in TCS – NCIS, 0 in OIS, 0 in FAC, 0 Negotiating IA, and 4 with Executed IA

Transmission Service Requests needing study: 0

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

Additional Notes provided on next slide

Status of Tariff Studies as of October 28, 2025, cont.

Additional Notes:

- *As of April 2025, the ISO is no longer tracking Distribution Projects in its interconnection queue.*
- *The values starting in May 2025 reflect that, as a result of the Order No. 2023 response from FERC, the ISO is no longer performing serial interconnection studies.*
- *The "TCS – NCIS" category represents projects that did not complete a system impact study before April 4, 2025 and require study in the Transitional Cluster Study (TCS) according to the Network Capability Interconnection Standard (NCIS). Such projects may also be studied in the TCS according to the Capacity Capability Interconnection Standard (CCIS). There are additional projects in the TCS that are seeking to augment their Network Resource Interconnection Service (NRIS) to Capacity Network Resource Interconnection Service (CNRIS) (and thus will only be studied in the TCS according to the CCIS), but are included in the Executed IA/Negotiating IA totals.*

Note on Air Emissions Slides

- For more timely reporting and stakeholder convenience, the data and information included in this report on air emissions can now be found by visiting the ISO website, under System Planning > Plans and Studies > Environmental and Emissions Reports
  - https://www.iso-ne.com/system-planning/system-plans-studies/emissions
- Monthly and year-to-date emissions by fuel type are reported in the ISO Newswire article series, Monthly Wholesale Electricity Prices and Demand in New England (link can be found on the page above)

OPERABLE CAPACITY ANALYSIS

Fall 2025 Analysis

Fall 2025 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Nov - 2025[2] CSO (MW)	Nov - 2025[2] SCC (MW)
Operable Capacity MW [1]	26,436	29,806
Active Demand Capacity Resource (+) [5]	340	305
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,198	1,198
Non Commercial Capacity (+)	189	189
Non Gas-fired Planned Outage MW (-)	1,242	2,486
Gas Generator Outages MW (-)	2,796	3,562
Allowance for Unplanned Outages (-) [4]	3,600	3,600
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	20,525	21,850
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	18,233	18,233
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	20,358	20,358
Operable Capacity Margin	167	1,492

[1]Operable Capacity is based on data as of **October 23, 2025** 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 **October 23, 2025.**

[2] Load forecast that is based on the 2025 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **November 15, 2025.**

[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.

Fall 2025 Operable Capacity Analysis

90/10 Load Forecast	Nov - 2025[2] CSO (MW)	Nov - 2025[2] SCC (MW)
Operable Capacity MW [1]	26,436	29,806
Active Demand Capacity Resource (+) [5]	340	305
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,198	1,198
Non Commercial Capacity (+)	189	189
Non Gas-fired Planned Outage MW (-)	1,242	2,486
Gas Generator Outages MW (-)	2,796	3,562
Allowance for Unplanned Outages (-) [4]	3,600	3,600
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	20,525	21,850
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	19,205	19,205
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	21,330	21,330
Operable Capacity Margin	-805	520

[1]Operable Capacity is based on data as of **October 23, 2025** 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 **October 23, 2025.**

[2] Load forecast that is based on the 2025 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **November 15, 2025.**

[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.

Fall 2025 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

October 23, 2025 - 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 in November.

FALSE

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
11/8/2025	26436	340	1198	189	1417	3079	3600	0	20067	17567	2125	19692	375	N	Fall 2025
11/15/2025	26436	340	1198	189	1242	2796	3600	0	20525	18233	2125	20358	167	Y	Fall 2025
11/22/2025	26436	340	1198	189	593	1917	3600	0	22053	18883	2125	21008	1045	N	Fall 2025

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 2025 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.

Fall 2025 Operable Capacity Analysis

90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

October 23, 2025 - 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: 10/23/2025

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
11/8/2025	26436	340	1198	189	1417	3079	3600	0	20067	18504	2125	20629	-562	N	Fall 2025
11/15/2025	26436	340	1198	189	1242	2796	3600	0	20525	19205	2125	21330	-805	Y	Fall 2025
11/22/2025	26436	340	1198	189	601	1370	3600	1206	21386	19890	2125	22015	-629	N	Fall 2025

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 2025 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**

OPERABLE CAPACITY ANALYSIS

Winter 2025/26 Analysis

Winter 2025/26 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Jan - 2026[2] CSO (MW)	Jan - 2026[2] SCC (MW)
Operable Capacity MW [1]	26,390	29,806
Active Demand Capacity Resource (+) [5]	403	305
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,235	1,235
Non Commercial Capacity (+)	568	568
Non Gas-fired Planned Outage MW (-)	43	1,171
Gas Generator Outages MW (-)	0	33
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	3,583	3,936
Net Capacity (NET OPCAP SUPPLY MW)	22,170	23,974
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,056	20,056
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,181	22,181
Operable Capacity Margin	-11	1,793

[1]Operable Capacity is based on data as of **October 23, 2025** 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 **October 23, 2025.**

[2] Load forecast that is based on the 2025 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 10, 2026.**

[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 2025/26 Operable Capacity Analysis

90/10 Load Forecast	Jan - 2026[2] CSO (MW)	Jan - 2026[2] SCC (MW)
Operable Capacity MW [1]	26,390	29,806
Active Demand Capacity Resource (+) [5]	403	305
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,235	1,235
Non Commercial Capacity (+)	568	568
Non Gas-fired Planned Outage MW (-)	43	1,171
Gas Generator Outages MW (-)	0	33
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	4,331	4,795
Net Capacity (NET OPCAP SUPPLY MW)	21,422	23,115
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	21,125	21,125
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,250	23,250
Operable Capacity Margin	-1,828	-135

[1]Operable Capacity is based on data as of **October 23, 2025** 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 **October 23, 2025.**

[2] Load forecast that is based on the 2025 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 10, 2026.**

[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 2025/26 Operable Capacity Analysis
50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

October 23, 2025 - 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 in December through March.

FALSE

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
11/29/2025	26640	403	1235	318	601	1108	3200	507	23180	19063	2125	21188	1992	N	Winter 2025/2026
12/6/2025	26640	403	1235	318	84	608	3200	1760	22944	19324	2125	21449	1495	N	Winter 2025/2026
12/13/2025	26640	403	1235	318	55	0	3200	2745	22596	19334	2125	21459	1137	N	Winter 2025/2026
12/20/2025	26640	403	1235	318	45	0	3200	3134	22217	19390	2125	21515	702	N	Winter 2025/2026
12/27/2025	26640	403	1235	318	45	0	3200	3733	21618	19390	2125	21515	103	N	Winter 2025/2026
1/3/2026	26390	403	1235	568	22	0	2800	3728	22046	19637	2125	21762	284	N	Winter 2025/2026
1/10/2026	26390	403	1235	568	43	0	2800	3583	22170	20056	2125	22181	-11	Y	Winter 2025/2026
1/17/2026	26390	403	1235	568	116	0	2800	3134	22546	20056	2125	22181	365	N	Winter 2025/2026
1/24/2026	26390	403	1235	568	49	0	2800	2835	22912	20056	2125	22181	731	N	Winter 2025/2026
1/31/2026	26390	403	1235	568	23	0	3100	2536	22937	19855	2125	21980	957	N	Winter 2025/2026
2/7/2026	26390	403	1235	568	20	0	3100	2237	23239	19615	2125	21740	1499	N	Winter 2025/2026
2/14/2026	26390	403	1235	568	20	0	3100	1788	23688	19589	2125	21714	1974	N	Winter 2025/2026
2/21/2026	26390	403	1235	568	56	0	3100	1489	23951	19352	2125	21477	2474	N	Winter 2025/2026
2/28/2026	26390	403	1235	568	203	167	2200	247	25779	18461	2125	20586	5193	N	Winter 2025/2026
3/7/2026	26390	403	1235	568	184	413	2200	0	25799	18147	2125	20272	5527	N	Winter 2025/2026
3/14/2026	26390	403	1235	568	174	594	2200	0	25628	17970	2125	20095	5533	N	Winter 2025/2026
3/21/2026	26390	403	1235	568	236	594	2200	0	25566	17641	2125	19766	5800	N	Winter 2025/2026
3/28/2026	26233	404	1235	568	262	1002	2700	0	24476	17132	2125	19257	5219	N	Winter 2025/2026

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 2025 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 2025/26 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

October 23, 2025 - 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 December through March.

Report created: 10/23/2025

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
11/29/2025	26640	403	1235	318	601	1108	3200	1684	22003	20080	2125	22205	-202	N	Winter 2025/2026
12/6/2025	26640	403	1235	318	84	608	3200	2747	21957	20354	2125	22479	-522	N	Winter 2025/2026
12/13/2025	26640	403	1235	318	55	0	3200	3864	21477	20365	2125	22490	-1013	N	Winter 2025/2026
12/20/2025	26640	403	1235	318	45	0	3200	4280	21071	20424	2125	22549	-1478	N	Winter 2025/2026
12/27/2025	26640	403	1235	318	45	0	3200	4408	20943	20424	2125	22549	-1606	N	Winter 2025/2026
1/3/2026	26390	403	1235	568	22	0	2800	4539	21235	20684	2125	22809	-1574	N	Winter 2025/2026
1/10/2026	26390	403	1235	568	43	0	2800	4331	21422	21125	2125	23250	-1828	Y	Winter 2025/2026
1/17/2026	26390	403	1235	568	116	0	2800	4032	21648	21125	2125	23250	-1602	N	Winter 2025/2026
1/24/2026	26390	403	1235	568	49	0	2800	4032	21715	21125	2125	23250	-1535	N	Winter 2025/2026
1/31/2026	26390	403	1235	568	23	0	3100	3583	21890	20914	2125	23039	-1149	N	Winter 2025/2026
2/7/2026	26390	403	1235	568	20	0	3100	3284	22192	20661	2125	22786	-594	N	Winter 2025/2026
2/14/2026	26390	403	1235	568	20	0	3100	2686	22790	20633	2125	22758	32	N	Winter 2025/2026
2/21/2026	26390	403	1235	568	56	0	3100	2237	23203	20384	2125	22509	694	N	Winter 2025/2026
2/28/2026	26390	403	1235	568	203	167	2200	1144	24882	19446	2125	21571	3311	N	Winter 2025/2026
3/7/2026	26390	403	1235	568	185	167	2200	1039	25005	19114	2125	21239	3766	N	Winter 2025/2026
3/14/2026	26390	403	1235	568	174	594	2200	0	25628	18928	2125	21053	4575	N	Winter 2025/2026
3/21/2026	26390	403	1235	568	236	594	2200	0	25566	18582	2125	20707	4859	N	Winter 2025/2026
3/28/2026	26233	404	1235	568	262	1002	2700	0	24476	18045	2125	20170	4306	N	Winter 2025/2026

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 2025 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**

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]

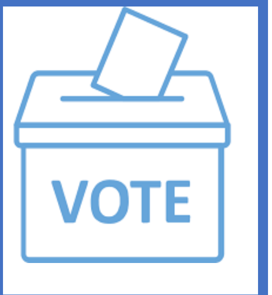
NOTES:
1. Based on Summer Ratings. Assumes 25% of total MW Settlement Only resources <5 MW will be available and respond.
2. The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
3. The MW values 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

5 *Order 898* Revisions



66.67%

To consider, and take action, as appropriate, on changes to Appendix A (Transmission Formula Rate Template) to OATT Attachment F (Annual Transmission Revenue Requirements) in response to the requirements of *Order 898* ("Accounting and Reporting Treatment of Certain Renewable Energy Assets").

RESOLVED, that the Participants Committee supports the *Order 898* Revisions, as recommended by the Transmission Committee and as circulated to the Participants Committee in advance of its November 6, 2025, meeting, together with [any changes agreed to at the meeting and] such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Transmission Committee.

M E M O R A N D U M

FROM: Eric Runge, NEPOOL Counsel

DATE: October 30, 2025

RE: NPC Vote on Tariff Revisions in Compliance with FERC *Order 898*

At the November 6, 2025 Participants Committee meeting, you will be asked to vote on proposed revisions to Attachment F of Section II of the ISO-NE Tariff that the Participating Transmission Owners are planning to file in compliance with FERC *Order 898* ("*Order 898* Revisions").[1] The Transmission Committee has unanimously recommended Participants Committee support for the *Order 898* revisions. This item would have been on the Consent Agenda but for the timing of the meetings.

By way of brief background, *Order 898* amends the Uniform System of Accounts for public utilities and licensees to: create new accounts for wind, solar, and other renewable generating assets; create a new functional class for energy storage accounts; codify the accounting treatment of environmental credits; and create new accounts within existing functions for computer hardware, software, and communication equipment. *Order 898* also amends the relevant FERC forms to accommodate these changes. The *Order 898* Revisions revise the transmission formula rate in Attachment F of Section II of the ISO-NE Tariff to comply with *Order 898*. More specifically, the filing will include minor revisions to Appendix A to Attachment F (transmission formula rate template), including minor reference revisions due to new FERC forms. Background materials are included with this memorandum.[2]

The Transmission Committee reviewed the *Order 898* Revisions at its September and October meetings. At its October 28 meeting, the Transmission Committee unanimously recommended Participants Committee support for the *Order 898* Revisions.

The following resolution could be used for Participants Committee action on the *Order 898* Revisions:

> RESOLVED, that the Participants Committee supports the Order 898 Revisions, as recommended by the Transmission Committee and as circulated to the Participants Committee in advance of its November 6, 2025, meeting, together with [any changes agreed to at the meeting and] such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Transmission Committee.

---

[1] *Order 898* is available here: https://www.ferc.gov/media/order-no-898.

[2] The Participating Transmission Owners' presentation on this item at the October 28 Transmission Committee is available here: https://www.iso-ne.com/static-assets/documents/100028/a02_neto_order_898_compliance_presentation.pdf.

PTOs' Order No. 898 Compliance Filing

Transmission Committee Meeting
October 28, 2025

(No Changes Since September TC Presentation)

FERC Order No. 898

<u>Background</u>

- Order No. 898 – titled "Accounting and Reporting Treatment of Certain Renewable Energy Assets" was issued on June 29, 2023, and became effective January 1, 2025

- Order No. 898 includes the following changes that impact the Att. F transmission formula rate:
  - Introduced new FERC accounts for wind, solar, energy storage and other renewable generating assets, including Asset Retirement Cost (ARC) accounts
  - Created new FERC Plant accounts for general plant and transmission plant related to computer hardware, software and communications equipment
  - The creation of these new accounts resulted in changes to the FERC Form 1 and Form 3Q, effective January 1, 2025

- Allows public utilities to submit a single-issue Federal Power Act Section 205 filing to comply with final rule

- Link to Order No. 898 -

Order No. 898

Order No. 898 Compliance Filing

- The PTOs[1] plan to submit a joint FERC filing in early November 2025
- The filing will be comprised of the following:
  - Minor revisions to Appendix A to Attachment F (Transmission Formula Rate Template)
    - Edits to accommodate new FERC plant accounts
    - Minor reference revisions due to the new FERC Form 1 and Form 3Q line items
  - Associated updates to Appendix D to Attachment F (Depreciation/Amortization Rates)

1 PTOs: Central Maine Power Company; Eversource Energy Service Company on behalf of The Connecticut Light and Power Company, NSTAR Electric Company and Public Service Company of New Hampshire; Fitchburg Gas & Electric Light Company; Green Mountain Power Corporation; Maine Electric Power Company; The Narragansett Electric Company d/b/a Rhode Island Energy; New England Power Company d/b/a National Grid; New Hampshire Transmission, LLC; The United Illuminating Company; Vermont Transco LLC; Versant Power

PTO AC Presentation – September 25, 2025

Tariff Changes – Appendix A, WS 3

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Transmission Investment Base Detail
Worksheet 3
For Costs in 20__

Line No.	Description	FERC Account No.		(A) 20__ Year End	(B) 20__ Year End	(C) = Avg[(A),(B)] Average		(D) Factors		(E) = (C) x (D) Transmission (m)	(F) Reference
	Input Cells are Shaded Yellow										
	Transmission Plant										
1	Transmission Plant	350-359	(b)			#DIV/0!		100.0000%		#DIV/0!	W/S 3a, Line 17(F) ~~13(F)~~
	Transmission Related Intangible and General Plant										
2	Intangible Plant	301-303	(i)			#DIV/0!	(e), (h)	0.0000%	(g)	#DIV/0!	FF1 Page 205.5g
3	General Plant	389-399	(i)			#DIV/0!	(e), (h)	0.0000%	(g)	#DIV/0!	FF1 Page 207.99g - Page 207.98g
4	Total Transmission Related Intangible and General Plant (Line 2 + Line 3)			$ -	$ -	#DIV/0!				#DIV/0!	
5	**Transmission Plant/Land Held For Future Use**	105	(d)			#DIV/0!		100.0000%		#DIV/0!	FF1 Page 214._
	Transmission Related Depreciation & Amortization Reserve										
6	Transmission Depreciation Reserve (Enter Credit)	108	(b)			#DIV/0!		100.0000%		#DIV/0!	W/S 3a, Line 21(F) ~~17(F)~~
7	Transmission Related Intangible Plant Amortization Reserve (Enter Credit)	111				#DIV/0!	(e), (h)	0.0000%	(g), (l)	#DIV/0!	FF1 Page 200.21c FN
8	Transmission Related General Plant Depreciation Reserve (Enter Credit)	108				#DIV/0!	(e), (h)	0.0000%	(g)	#DIV/0!	FF1 Page 219.28c
9	Transmission Related General Plant Amortization Reserve (Enter Credit)	111				#DIV/0!	(e), (h)	0.0000%	(l)	#DIV/0!	FF1 Page 200.21c FN
10	Total Transmission Related Depreciation & Amortization Reserve (Sum Lines 6 thru 9)			$ -	$ -	#DIV/0!				#DIV/0!	
	Transmission Related Accumulated Deferred Income Tax										
11	Accumulated Deferred Income Taxes (Enter Credit)	281				#DIV/0!	(f), (j)	0.0000%		#DIV/0!	FF1 Page 273._
12	Accumulated Deferred Income Taxes (Enter Credit)	282				-		100.0000%		-	W/S 11, Line 5(A)
13	Accumulated Deferred Income Taxes (Enter Credit)	283				#DIV/0!	(f), (j)	0.0000%		#DIV/0!	FF1 Page 277._
14	Accumulated Deferred Income Taxes	190				#DIV/0!	(f), (j)	0.0000%		#DIV/0!	FF1 Page 234._
15	Reserve for Disputed Transactions per FIN 48	190				#DIV/0!	(f), (j)	0.0000%		#DIV/0!	Attachment _
16	FAS 109 (Enter Credit)	282/283/190				#DIV/0!	(f), (j)	0.0000%		#DIV/0!	Attachment _
17	16)			$ -	$ -	#DIV/0!				#DIV/0!	
	Other Regulatory Assets/(Liabilities)										
18	Regulatory Asset for MA State Tax Rate Change	182.3				#DIV/0!		0.0000%		#DIV/0!	FF1 Page 232._
19	Deficient/(Excess) Deferred Income Tax Regulatory Asset/(Liability)	182.3/254				#DIV/0!		100.0000%		#DIV/0!	Deficient/(Excess) ADIT Worksheet, W/S 10
20	Total Other Regulatory Assets/(Liabilities)			$ -	$ -	#DIV/0!				#DIV/0!	
21	**Transmission Prepayments**	165				#DIV/0!	(e)	0.0000%		#DIV/0!	W/S 3b, Line 1(F)
22	**Transmission Materials and Supplies**	154				#DIV/0!		100.0000%	(i)	#DIV/0!	W/S 3b, Line 2(F)
23	**Transmission Unfunded Reserves (Enter Credit)**	Various	(k)			$ -		100.0000%		$ -	Appendix A, ATT 1
	Transmission Related Cash Working Capital										
24	Transmission Related Operation & Maintenance Expense				$ -						W/S 1, Line 18

Table of Contents | WS 0 Total RR Summary | WS 1 Base and RR | WS 3 Inv Base Detail | WS 3a 5-Qtr Avg. Inv. Base | WS 5 Allocation Factors | ATT CMP-2, WS 1 | ATT ES-1

PTO AC Presentation – September 25, 2025

Tariff Changes (Cont.) – Appendix A, WS 3a

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Transmission Investment Base Detail - Transmission Plant and Accumulated Depreciation
Worksheet 3a
For Costs in 20__

Line No.	Description	FERC Account No.	(A) 20__ Year End	(B) 1st Qtr 20__	(C) 2nd Qtr 20__	(D) 3rd Qtr 20__	(E) 20__ Year End	(F) = Avg[(A) thru (E)] Average	(e)	(G) Reference
	Input Cells are Shaded Yellow									
	Investment Base									
1	Total Transmission Plant	350-359.1	$ -				$ -	$ -	(b)	W/S 7, Line 7(A) and (F) or FF3Q Page 208.10b ~~7b~~
2	Total Plant	301-399.1						#DIV/0!		FF1 Page 206.104g or FF3Q Page 208.15b ~~11b~~
	Asset Retirement Costs ("ARCs"):									
3	ARCs for Steam Production	317						#DIV/0!		FF1 Page 207.15g or FF3Q Page 208.2 FN
4	ARCs for Nuclear Production	326						#DIV/0!		FF1 Page 207.24g or FF3Q Page 208.3 FN
5	ARCs for Hydraulic Production	337						#DIV/0!		FF1 Page 207.34g or FF3Q Page 208.4 FN and 208.5 FN
6	ARCs for Solar Production	338.13						#DIV/0!		FF1 Page 207.35.14g or FF3Q Page 208.6 FN
7	ARCs for Wind Production	338.34						#DIV/0!		FF1 Page 207.35.31g or FF3Q Page 208.7 FN
8	ARCs for Other Renewable Production	339.13						#DIV/0!		FF1 Page 207.35.46g or FF3Q Page 208.8 FN
9 ~~6~~	ARCs for Other Production	347						#DIV/0!		FF1 Page 207.44g or FF3Q Page 208.9 ~~6~~ FN
10 ~~7~~	ARCs for Transmission Plant	359.1						#DIV/0!		FF1 Page 207.57g or FF3Q Page 208.10 ~~7~~ FN
11 ~~8~~	ARCs for Distribution Plant	374						#DIV/0!		FF1 Page 207.74g or FF3Q Page 208.11 ~~8~~ FN
12 ~~9~~	ARCs for Regional Transmission and Market Operation	386						#DIV/0!		FF1 Page 207.83g or FF3Q Page 208.12 ~~9~~ FN
13	ARCs for Energy Storage Plant	387.12						#DIV/0!		FF1 Page 207.84.13g or FF3Q Page 208.13 FN
14 ~~10~~	ARCs for General Plant	399.1						#DIV/0!		FF1 Page 207.98g or FF3Q Page 208.14 ~~10~~ FN
15 ~~11~~	Subtotal ARCs (Sum Lines 3 thru 14 ~~10~~)		$ -	$ -	$ -	$ -	$ -	#DIV/0!		
16 ~~12~~	Phase I/II HVDC-TF Leases	(c)						#DIV/0!		Appendix A, ATT NEP-2
17 ~~13~~	Transmission Plant Net of ARCs and Leases (Line 1 - Line 10 ~~7~~ - Line 16 ~~12~~)		$ -	$ -	$ -	$ -	$ -	#DIV/0!		
18 ~~14~~	Total Plant Net of ARCs and Leases (Line 2 - Line 15 ~~11~~ - Line 16 ~~12~~)		$ -	$ -	$ -	$ -	$ -	#DIV/0!		
19 ~~15~~	Transmission Accumulated Depreciation (Enter Credit)	108						#DIV/0!	(b)	FF1 Page 219.25c or FF3Q Page 208.10c ~~7e~~
20 ~~16~~	A/D related to ARCs (Enter Credit)							#DIV/0!		
21 ~~17~~	Total Transmission Accumulated Depreciation (Line 19 ~~15~~ - Line 20 ~~16~~)		$ -	$ -	$ -	$ -	$ -	#DIV/0!	(d)	

Notes:
(a) Enter credit balances as negatives.
(b) For CMP, see Appendix A, ATT CMP-2, W/S 1; For NHT, see Attachment _ instead of FF1 reference.
(c) In addition to Phase I/II HVDC-TF Leases, include on this line the portion of any facilities, the cost of which is directly assigned under Schedule 11 to the OATT, to the Transmission Customer or a Generator Owner or Interconnection Requester and the PTF gross plant investment associated with leased facilities occupied by the Phase II section of the Phase I/II HVDC-TF.
(d) All VP figures derived from FERC Form No. 1 reflect costs of Bangor Hydro District (BHD) only. VP to provide workpaper showing reconciliation of BHD figures to FERC Form No. 1 with annual update.
(e) For Section 201(f) PTOs only, FERC Form 1 references will be replaced with references from the Section 201(f) PTOs audited financial statements or other Applicable Forms.

Table of Contents | WS 0 Total RR Summary | WS 1 Base and RR | WS 3 Inv Base Detail ER25-1699 | WS 3a 5-Qtr Avg. Inv. Base | WS 5 Allocation Factors | ATT CMP-2, WS 1 ER25-3067 | ATT ES-1

PTO AC Presentation – September 25, 2025

Tariff Changes (Cont.) – Appendix A, WS 5

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Transmission Allocation Factors
Worksheet 5
For Costs in 20__

Line No.	Description		(A) Total	(d)	(B) Reference
	Input Cells are Shaded Yellow				
	Transmission Wages and Salaries Allocation Factor "W&S"				
1	Direct Transmission Wages and Salaries			(b)	FF1 Page 354.21b
2	Total Transmission Wages and Salaries (Line 1)		-		
3	Total Wages and Salaries				FF1 Page 354.28b
4	Administrative and General Wages and Salaries				FF1 Page 354.27b
5	Total Wages and Salaries net of A&G (Line 3 - Line 4)		-		
6	Wages and Salaries Percent Allocation (Line 2 / Line 5)	(c)	0.0000%		
	Transmission Plant Allocation Factor "PL"				
7	Total Transmission Investment Excluding Phase I/II HVDC-TF Leases		$ -		Average of (W/S 3a, Line 17(A) and 17(E)) ~~13(A) and 13(E))~~
8	Transmission-related Intangible Plant		#DIV/0!		W/S 3, Line 2(E)
9	Transmission-related General Plant		#DIV/0!		W/S 3, Line 3(E)
10	Total Transmission Related Plant (Sum Lines 7 thru 9)		#DIV/0!		
11	Total Plant in Service Excluding ARCs and Phase I/II HVDC-TF Leases		$ -		Average of (W/S 3a, Line 18(A) and 18(E)) ~~14(A) and 14(E))~~
12	Plant Percent Allocation (Line 10 / Line 11)		0.0000%		

Notes:
(a) Enter credit balances as negatives.
(b) See Appendix A, ATT CMP-2, W/S 3.
(c) CTMEEC (Transco), MEPCO and NHT will enter 100% as costs designed to use W&S allocator are 100% Transmission.
(d) For Section 201(f) PTOs only, FERC Form 1 references will be replaced with references from the Section 201(f) PTOs audited financial statements or other Applicable Forms.

Table of Contents | WS 0 Total RR Summary | WS 1 Base and RR | WS 3 Inv Base Detail | WS 3a 5-Qtr Avg. Inv. Base | WS 5 Allocation Factors

PTO AC Presentation – September 25, 2025

Tariff Changes (Cont.) – Appendix A, Appendix A, ATT CMP-2, WS 1

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Transmission Investment Base Detail
Attachment CMP-2
Worksheet 1
For Costs in 20__

	Input Cells are Shaded Yellow		(A)	(B)	(C)	(D)	(E)	(F) = Avg[(A),(E)]	(G)
Line	**Description** (c)		**20_ Year End**	**1st Qtr 20__**	**2nd Qtr 20__**	**3rd Qtr 20__**	**20_ Year End**	**Average**	**Reference**
1	Total Transmission Plant as reported on FF1 or FF3Q	(c)							FF1 Page 206.58g or FF3Q Page 208.10b ~~7b~~
2	Schedule 1 related	(b)		-	-	-			Schedule 1
3	Total Transmission Plant (Line 1 - Line 2)		$ -	$ -	$ -	$ -	$ -		
4	Total Transmission Accumulated Depreciation as reported on FF1 or FF3Q (Enter Credit)	(c)							FF1 Page 219.25 or FF3Q Page 208.10c ~~7e~~
5	Schedule 1 related (Enter Credit)	(b)		-	-	-			Schedule 1
6	Transmission Accumulated Depreciation (Line 4 - Line 5)		$ -	$ -	$ -	$ -	$ -		
7	Total General Plant							#DIV/0!	FF1 Page 207.99g
8	General Plant Asset Retirement Costs (ARC)							#DIV/0!	FF1 Page 207.98g
9	Schedule 1 related	(b)						#DIV/0!	Schedule 1
10	General Plant 100% Allocated to Distribution	(d)						#DIV/0!	Internal Records
11	General Plant 100% Allocated to Transmission	(d)						#DIV/0!	Internal Records
12	General Plant (Line 7 - Line 8 - Line 9 - Line 10 - Line 11)		$ -				$ -	#DIV/0!	
13	Wages and Salaries Percent Allocation							#DIV/0!	W/S 5, Line 6(A)
14	General Plant Allocated to Transmission (Line 12 * Line 13)							#DIV/0!	
15	General Plant 100% Allocated to Transmission	(d)						#DIV/0!	Line 11
16	General Plant (Line 14 + Line 15)							#DIV/0!	
17	Total Intangible Plant	(c)						#DIV/0!	FF1 Page 205.5g
18	Schedule 1 related	(b)						#DIV/0!	Schedule 1
19	Intangible Plant 100% Allocated to Distribution	(d)						#DIV/0!	Internal Records
20	Intangible Plant 100% Allocated to Transmission	(d)						#DIV/0!	Internal Records
21	Intangible Plant (Line 17 - Line 18 - Line 19 - Line 20)		$ -				$ -	#DIV/0!	
22	Wages and Salaries Percent Allocation							#DIV/0!	W/S 5, Line 6(A)
23	Intangible Plant Allocated to Transmission							#DIV/0!	
24	Intangible Plant 100% Allocated to Transmission	(d)						#DIV/0!	Line 11
25	Intangible Plant (Line 23 + Line 24)							#DIV/0!	
26	Total Transmission Related Intangible Plant Amortization Reserve (Enter Credit)	(c)						#DIV/0!	FF1 Page 200.21c
27	Schedule 1 related (Enter Credit)	(b)						#DIV/0!	Schedule 1
28	Transmission Related Intangible Plant Amortization Reserve 100% Allocated to Distribution (Enter Cred	(d)						#DIV/0!	Internal Records
29	Transmission Related Intangible Plant Amortization Reserve 100% Allocated to Transmission (Enter Cr	(d)						#DIV/0!	Internal Records
30	Transmission Related Intangible Plant Amortization Reserve (Line 26 - Line 27 - Line 28 - Line 29)		$ -				$ -	#DIV/0!	
31	Wages and Salaries Percent Allocation							#DIV/0!	W/S 5, Line 6(A)
32	Transmission Related Intangible Plant Amortization Reserve Allocated to Transmission (Enter Credit)							#DIV/0!	
33	Transmission Related Intangible Plant Amortization Reserve 100% Allocated to Transmission (Enter Cr	(d)						#DIV/0!	Line 29
34	Transmission Related Intangible Plant Amortization Reserve (Line 32 + Line 33)							#DIV/0!	
35	Total Transmission Related General Plant Depreciation Reserve (Enter Credit)	(c)						#DIV/0!	FF1 Page 219.28c
36	Schedule 1 related (Enter Credit)	(b)						#DIV/0!	Schedule 1
37	Transmission Related General Plant Depreciation Reserve 100% Allocated to Distribution (Enter Credit)	(d)						#DIV/0!	Internal Records
38	Transmission Related General Plant Depreciation Reserve 100% Allocated to Transmission (Enter Crec	(d)						#DIV/0!	Internal Records
39	Transmission Related General Plant Depreciation Reserve (Line 35 - Line 36 - Line 37 - Line 38)		$ -				$ -	#DIV/0!	
40	Wages and Salaries Percent Allocation							#DIV/0!	W/S 5, Line 6(A)
41	Transmission Related General Plant Depreciation Reserve Allocated to Transmission (Enter Credit)							#DIV/0!	
42	Transmission Related General Plant Depreciation Reserve 100% Allocated to Transmission (Enter Crec	(d)						#DIV/0!	Line 29
43	Transmission Related General Plant Depreciation Reserve (Line 41 + Line 42)							#DIV/0!	

Notes:
(a) Enter credit balances as negatives.
(b) Scheduling, System Control, and Dispatch Service provided by CMP's Local Control Center is recovered pursuant to Schedule 1 of Schedule 21-CMP.
(c) There are no Asset Retirement Costs (ARCs) associated with Load Control Center plant or depreciation.
(d) FERC has authorized CMP to directly assign to either transmission or distribution General and Intangible Plant investment made October 1, 2025 or later.

WS 3 Inv Base Detail ER25-1699 | WS 3a 5-Qtr Avg. Inv. Base | WS 5 Allocation Factors | ATT CMP-2, WS 1 ER25-3067 | ATT ES-1

PTO AC Presentation – September 25, 2025

Tariff Changes (Cont.) – Appendix A, ATT ES-1 (1 of 2)

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A To Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Intangible & General Plant; Amortization & Depreciation Reserve; Depreciation & Amortization Expense
Attachment ES-1
For Costs in 20__

	Input Cells are Shaded Yellow		(A)	(B)	(C)	(D)	(E) = (C) - (G)	(F) = (D) - (H)	(G)	(H)	(I) = Avg[(G),(H)]	(J)
					20__ Year End	20__ Year End	20__ Year End	20__ Year End	20__ Year End	20__ Year End		
Line No.	Line Item		FF1 Reference	FF1 Footnote Reference for Columns (G) & (H)	Total	Total	Distribution Segment	Distribution Segment	Transmission Segment (b)	Transmission Segment (b)	Average Transmission Balance	Notes
1	**Intangible Plant**											
2a	FERC Account No. 301		FF1 Page 204.2				-	-			-	
2[]	FERC Account No. 302		FF1 Page 204.3				-	-			-	
2[]	FERC Account No. 303		FF1 Page 204.4				-	-			-	
3	**Total Intangible Plant** (d)				-	-	-	-	-	-	-	
4	FF1 Balance		FF1 Page 204.5									
5	**General Plant**											
6a	FERC Account No. 389		FF1 Page 204.86				-	-			-	
6[]	FERC Account No. 390		FF1 Page 204.87				-	-			-	
6[]	FERC Account No. 391		FF1 Page 204.88				-	-			-	
6[]	FERC Account No. 392		FF1 Page 204.89				-	-			-	
6[]	FERC Account No. 393		FF1 Page 204.90				-	-			-	
6[]	FERC Account No. 394		FF1 Page 204.91				-	-			-	
6[]	FERC Account No. 395		FF1 Page 204.92				-	-			-	
6[]	FERC Account No. 396		FF1 Page 204.93				-	-			-	
6[]	FERC Account No. 397.1		FF1 Page 204.94				-	-			-	
6[]	FERC Account No. 397.2		FF1 Page 204.94.1				-	-			-	
6[]	FERC Account No. 397.3		FF1 Page 204.94.2				-	-			-	
6[]	FERC Account No. 398		FF1 Page 204.95				-	-			-	
6[]	FERC Account No. 399		FF1 Page 204.97				-	-			-	
6[]	FERC Account No. 399.1		FF1 Page 204.98				-	-			-	
7	**Total General Plant** (d)				-	-	-	-	-	-	-	
8	FF1 Balance		FF1 Page 204.99									
9	**Total Transmission Related Intangible & General Plant (Line 3 + Line 7)**										-	
10	**Intangible Plant Amortization Reserve**											
11a	FERC Account No. 111	(c)	FF1 Page 200.21c				-	-			-	Follows the classification of the underlying assets as transmission
12	**General Plant Amortization Reserve**											
13a	FERC Account No. 111	(c)	FF1 Page 200.21c				-	-			-	Follows the classification of the underlying assets as transmission
14	**General Plant Depreciation Reserve**											
15a	FERC Account No. 108	(c)	FF1 Page 219.28c				-	-			-	Follows the classification of the underlying assets as transmission
											Transmission Segment of	

Table of Contents | WS 0 Total RR Summary | WS 1 Base and RR | WS 3 Inv Base Detail | WS 3a 5-Qtr Avg. Inv. Base | WS 5 Allocation Factors | ATT CMP-2, WS 1 | ATT ES-1

PTO AC Presentation – September 25, 2025

Tariff Changes (Cont.) – Appendix A, ATT ES-1 (2 of 2)

Utility Name
Annual Transmission Revenue Requirements (ATRR)
Per Appendix A To Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Intangible & General Plant; Amortization & Depreciation Reserve; Depreciation & Amortization Expense
Attachment ES-1
For Costs in 20__

				Amortization	Amortization	
16	**Intangible Plant Depreciation & Amortization Expense**					
17a	FERC Account No. 404	FF1 Page 336.1d				Follows the classification of the underlying assets as transmission
17[]	FERC Account No. 405	FF1 Page 336.1e				Follows the classification of the underlying assets as transmission
18	**Total Intangible Plant Depreciation & Amortization Expense** (d)			-	-	
19	**General Plant Depreciation & Amortization Expense**					
20a	FERC Account No. 403	FF1 Page 336.10b				Follows the classification of the underlying assets as transmission
20[]	FERC Account No. 404	FF1 Page 336.10d				Follows the classification of the underlying assets as transmission
21	**Total General Plant Depreciation & Amortization Expense** (d)			-	-	

Notes:

(a) Enter credit balances as negatives.

(b) Eversource Energy electric utility subsidiaries, CL&P, PSNH and NSTAR West, accounting system accommodates directly assigning costs to the distribution or transmission business segments. Costs are assigned to the appropriate business segment through the use of an "Entity" code (previously called a Charge Accounting Unit") at the transactional level in the source accounting systems (i.e., payroll system, accounts payable system, etc.).
The transmission segment "Entity" codes are identified below:
- CL&P = 1T
- NSTAR West = 4T
- PSNH = 6T

(c) Column (C) inputs are derived from the prior year FERC Form 1 and Column (D) inputs are derived from the current year FERC Form 1.

(d) Total equals the sum of sublines a through [], where [] is the last subline denoted by a letter. The PTO may add or remove sublines without a FPA Section 205 filing.

Table of Contents | WS 0 Total RR Summary | WS 1 Base and RR | WS 3 Inv Base Detail | WS 3a 5-Qtr Avg. Inv. Base | WS 5 Allocation Factors | ATT CMP-2, WS 1 | ATT ES-1

Next Steps

- Transmission Committee advisory vote = October 28, 2025
- Participants Committee meeting and advisory vote = November 6, 2025
- Filing with FERC = November 6 or 7, 2025

6 NEPOOL GIS Account-Linking Enhancement

VOTE

66.67%

To consider, and take action, as appropriate, on changes to the NEPOOL Generation Information System (GIS) to allow a NEPOOL GIS login to be linked and have access to multiple GIS Accounts.

RESOLVED, that the Participants Committee refers to the NEPOOL Generation Information System (GIS) Operating Rules Working Group for further consideration of the request by Vistra Corp. to change the NEPOOL GIS to allow a NEPOOL GIS login to be linked and have access to multiple NEPOOL accounts and to report back to this Committee on the outcome of that consideration.

OR

RESOLVED, that the Participants Committee approves the changes to the NEPOOL Generation Information System (GIS) to allow a GIS login to be linked and have access to multiple GIS accounts, as recommended by the Markets Committee at its October 15-16, 2025 meeting, together with [such changes as agreed to at this meeting and with] such non-material changes thereto as may be approved after the meeting by the Chair of the Participants Committee.

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: NEPOOL Counsel

DATE: October 30, 2025

RE: Consideration of Vistra Request for NEPOOL GIS Account-Linking Enhancement

At its November 6, 2025 meeting, the Participants Committee will be asked to consider an enhancement to the NEPOOL Generation Information System (GIS) that would allow a single NEPOOL GIS login to be linked to and access multiple GIS accounts. This change would not require revisions to the GIS Operating Rules.

Vistra Corp. (whose Related Person, Dynegy Marketing and Trade, LLC, is a NEPOOL Participant) requested the enhancement, which would require software modifications to and testing of the GIS platform. At its January 2025 meeting, the NEPOOL Markets Committee referred Vistra's request to the GIS Operating Rules Working Group (Working Group) for further review.

The Working Group met in September 2025 to discuss the request. As detailed in Attachment A, APX, Inc. (the GIS Administrator) estimated that implementing the requested enhancement would require more than 1,000 development hours at a total cost of $186,660 if completed in 2025. If the work were deferred to 2026 and all 500 GIS development hours budgeted for that year were allocated to this project, the cost would be reduced by nearly $90,000, to a total of $98,660.[1] During discussion, a member of the Working Group inquired about the number of account holders that would benefit from Vistra's requested enhancement. APX responded that it would be difficult to determine that figure with precision. Vistra indicated that its request is not time-sensitive and that it does not object to deferring the work to 2026.

At its October 2025 meeting, the Markets Committee considered the Working Group's report. Following discussion and responses to several questions, the Markets Committee voted by voice vote to recommend that the Participants Committee approve the requested enhancement.[2] Since that recommendation, however, several additional questions have been raised regarding Vistra's request, which may warrant further discussion at the Working Group level. Accordingly, although the Participants Committee may act on the Markets Committee's recommendation, it may also find it desirable to allow for that further discussion before taking

[1] Because Vistra's requested GIS enhancement would require at least 50 hours of development work and exceed $30,000 in cost—each of which independently requires Participants Committee approval under Rule 1.3(a)(iv) of the GIS Operating Rules—Participants Committee approval is required.

[2] Two oppositions in the End User Sector were recorded as were (54) abstentions in the following Sectors, (3) in Transmission, (48) Publicly Owned Entity, (2) End User, and (1) Alternative Resources.

action, and may wish for now to direct the Working Group to reconvene to consider the request further and report back to the Participants Committee.

One of the following alternative forms of resolution can be used for Participants Committee action on the Markets Committee's recommendation to change the GIS:

> RESOLVED, that the Participants Committee refers to the NEPOOL Generation Information System (GIS) Operating Rules Working Group for further consideration of the request by Vistra Corp. to change the NEPOOL GIS to allow a NEPOOL GIS login to be linked and have access to multiple NEPOOL accounts and to report back to this Committee on the outcome of that consideration.

OR

> RESOLVED, that the Participants Committee approves the changes to the NEPOOL Generation Information System (GIS) to allow a GIS login to be linked and have access to multiple GIS accounts, as recommended by the Markets Committee at its October 15-16, 2025 meeting, together with [such changes as agreed to at this meeting and with] such non-material changes thereto as may be approved after the meeting by the Chair of the Participants Committee.

6A Proposed NEPOOL Policy Statement: GIS Waiver Requests

To receive background and an overview on a proposed NEPOOL Policy Statement regarding GIS Waiver Requests.

No action to be taken at this meeting.
Expected Dec 4, 2025 NPC Vote.

DRAFT (10/30/25)

NEPOOL Policy Statement re GIS Waiver Requests

1. Purpose and Guiding Principles

The NEPOOL Generation Information System ("GIS") issues and tracks certificates for all MWh of generation and load produced in the New England control area and for imported MWh from adjacent areas ("Certificates"). The GIS was established to provide the New England States with a reliable platform to support compliance with state renewable portfolio standard ("RPS") and related programs, e.g., GIS issues and tracks Renewable Energy Certificates or RECs.

This Policy Statement ensures that waiver requests of the GIS Operating Rules and GIS Administration Agreement are handled in a manner that preserves market predictability and fairness while deferring to the authority of state regulatory agencies, which remain the ultimate arbiters of compliance with their respective programs.

2. NEPOOL GIS Governing Framework

The NEPOOL GIS is operated under the GIS Operating Rules ("Rules") and the Amended and Restated Generation Information System Administration Agreement dated as of October 1, 2017, between APX, Inc. ("APX") and NEPOOL, as amended and extended (the "GIS Agreement"). Under the GIS Agreement, APX serves as the NEPOOL GIS Administrator.[1]

- GIS Operating Rule 1.4 and Section 4.2 of the GIS Agreement require APX to administer and operate the GIS in accordance with the GIS Operating Rules. Under these provisions, APX, as the GIS Administrator, has "the sole responsibility for the compilation, indexing, reasonable interpretation and implementation of the GIS Operating Rules."

- Rule 2.8(a) provides that any request for an adjustment of the number of Certificates of different types or classes needs to be submitted at least five days prior to the Creation Date for those Certificates. The submission deadline is firm.

The information on Certificates can be corrected without a waiver only if they were issued erroneously because of a software error in the GIS or in the ISO-NE settlement system or because of a data entry error by APX or ISO-NE (Rule 3.8).

[1] NEPOOL's GIS Operating Rules Working Group is responsible for discussing, exploring and recommending proposed changes to the GIS Operating Rules. In addition, NEPOOL has a GIS Usability Group that provides a forum to discuss and vet future potential improvements to the useability of the GIS.

DRAFT (10/30/25)

3. Seeking Waiver of the GIS Operating Rules & GIS Agreement

Neither the GIS Rules nor the GIS Agreement between APX and NEPOOL provides APX the contractual authority to change or alter Certificates after they have been issued. As such, absent a software-related error or data entry error as described above, APX does not have the authority to correct the monthly generation data on the Certificates without both APX and NEPOOL waiving Section 4.2 of the GIS Agreement and Rule 1.4, which again requires APX to administer and operate the GIS in accordance with the Rules.

For purposes of this Policy Statement, a "GIS Waiver Request" means the request by any GIS Account Holder to waive one or more provisions of the GIS Operating Rules to permit a change to be made to any of the information on Certificates that would not otherwise be permitted under the GIS Operating Rules.

To provide relief for a GIS Waiver Request, NEPOOL would specifically need to waive applicable provisions of both the GIS Operating Rules and the GIS Agreement. As Section 13.5 of the GIS Agreement requires that any modifications of that Agreement be in writing signed by both NEPOOL and the GIS Administrator, APX would also need to agree to any waiver.

To date, no provisions of the GIS Rules or the GIS Agreement have been waived.

4. State Jurisdictional Authority

Because the NEPOOL GIS was originally created as a service to the New England states to help demonstrate compliance with their RPS requirements, it is up to each state to make determinations on whether to accept Certificates to establish compliance with their state programs.

Historically, the New England States, through their relevant regulatory authority of jurisdiction have been willing to address certain errors or omissions in Certificates, with state regulators periodically resolving GIS Certificate related issues on a case-by-case basis. In doing so, NEPOOL rarely, if ever, has been presented with a request for waiver of the GIS Rules. This process has worked in the past, and NEPOOL encourages New England state regulators to continue to resolve these issues, as appropriate, outside of the NEPOOL process.

More recently though, with one New England state regulatory body no longer willing, in the normal course, to address such issues pursuant to its jurisdictional authority, there has been a steady increase in affected GIS Account Holders seeking NEPOOL's (and APX's) approval of requested waivers to the GIS Rules and GIS Agreement.[2]

[2] NEPOOL does not take a position on how state regulatory authorities respond to GIS Account Holder requests or waivers. NEPOOL recognizes the burdens such requests may place on regulators. However, NEPOOL is supportive of relevant state regulatory authorities addressing Certificate-related issues/requests, as appropriate, on a case-by-case basis.

DRAFT (10/30/25)

5. NEPOOL Policy Protocol(s)

As a matter of general policy, and all without prejudice as to the merits, NEPOOL will not consider a GIS Waiver Request until the requesting party first seeks relief and receives a determination from the relevant regulatory body with appropriate jurisdiction over its state compliance program(s) for which the GIS Waiver Request is made. Furthermore, when such determination is made by the state regulator(s), NEPOOL will not formally consider nor take action on a GIS Waiver Request unless and until the regulator has expressly indicated support for NEPOOL's review and consideration. Put simply, NEPOOL will not consider a request for waiver of the GIS Rules and/or GIS Agreement without explicit state support from a relevant state regulatory authority with jurisdiction over the applicable compliance program for its state.

This policy protocol does not preclude the requesting party and a relevant state regulatory authority to address a Certificate-related issue outside of the NEPOOL process.

Effective Date: This Policy Statement is effective immediately upon adoption by the NEPOOL Participants Committee and may be updated or amended as needed.

7 Litigation Report

Nov 6, 2025
Meeting

NEPOOL
NEW ENGLAND POWER POOL
Participants Committee

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of November 5, 2025

The following activity, as more fully described in the attached Litigation Report, has occurred since the report dated October 7, 2025 ("last Report") was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

FERC Administrative Developments

		New FERC Commissioners	Oct 27	***Laura V. Swett*** sworn in as new Chair, with a term expiring Jun 30, 2030; ***David A. LaCerte*** sworn in for a term expiring Jun 30, 2026

Executive Orders

No Activity to Report

I. Complaints/Section 206 Proceedings

*	4	BP Phantom Load Complaint (EL26-5)	Oct 14	BP files a complaint seeking relief from invoices issued by ISO-NE (for Jul, Aug and Sept 2024); comment deadline ***Nov 13, 2025***
			Nov 4	Eversource requests extension of time, to Dec 12, 2025, to answer Complaint

II. Rate, ICR, FCA, Cost Recovery Filings

*	11	PBOP Collections Report (RI Energy) (ER26-387)	Oct 31	RI Energy files to refund an over-recovery of ***$938,616*** in transmission-related PBOP expenses; comment deadline ***Nov 21, 2025***
*	12	PBOP Collections Report (National Grid) (ER26-172)	Oct 17	National Grid files to refund an over-recovery of ***$2,954,638*** in transmission-related PBOP expenses; comment deadline ***Nov 7, 2025***
*	12	2026 NESCOE Budget (ER26-145)	Oct 15	ISO-NE files materials for funding NESCOE's 2026 operations
			Oct 16-Nov 3	NESCOE, National Grid, MA DPU intervene
			Nov 3	NEPOOL files comments supporting 2026 NESCOE Budget
*	12	2026 ISO-NE Administrative Costs and Capital Budgets (ER26-144)	Oct 15	ISO-NE files its 2026 administrative costs and capital budgets
			Oct 17-Nov 3	National Grid, MA DPU intervene
			Oct 20	NEPOOL files comments supporting ISO-NE 2026 Budgets
*	13	Kleen Energy CIP-IROL (Schedule 17) Rate Schedule Filing (ER26-132)	Oct 14	Kleen files Rate Schedule
			Nov 3	National Grid intervenes
	13	Bucksport CIP-IROL (Schedule 17) Cost Recovery Filing (ER25-3233)	Oct 16	FERC accepts revisions to Bucksport's CIP-IROL Rate Schedule that will allow Bucksport to recover ***$292,870*** of incremental medium impact CIP-IROL Costs incurred between Apr 1, 2023 and Mar 31, 2025; *eff. Oct 19, 2025*
	14	MOPA Formal Challenge to TO's Annual (2023-24) Transmission Rate Update/Info Filing (ER20-2054)	Oct 17	VELCO/VTransco files response to Question 4

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

*	14	Waiver Request: Refund of Improperly Received CSO Payments (Brookfield) (ER26-143)	Oct 15	Brookfield requests limited waiver of the Tariff to allow it to refund to ISO-NE, with interest, improperly received CSO payments for its Lièvre Power portfolio and for ISO-NE to in turn refund those amounts to Participants that held FCM Load Obligations in the corresponding months
			Nov 3	National Grid intervenes
*	15	*Order 2222* Conforming Changes (ER26-105)	Oct 10	ISO-NE and NEPOOL jointly file *Order 2222* conforming changes (DRDERAs; Regulation min size; other clarifications)
	15	Waiver Granted (ISO-NE): Capacity Performance Payment Calculation & Use of Late Payment Account (ER25-3253)	Oct 31	FERC, in a 2-1 Decision, grants limited waivers requested
	15	Waiver Request Denied: Interconn. Request Reqs. (Evergreen Wind Power II) (ER25-3031)	Oct 16	FERC denies waiver request

IV. OATT Amendments / TOAs / Coordination Agreements

*	16	RI Energy Revision to Fixed PBOP Expense Amount (ER26-390)	Oct 31	RI Energy files to revise its PBOP expense amount under Appendix A to Attachment F of the OATT to limit potential over-recoveries of PBOP expenses; comment deadline ***Nov 21, 2025***

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

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

*	16	Schedule 21-RIE: Block Island Wind Farm Facilities Reclassification (ER26-397)	Oct 31	RI Energy submits adjustments to the BITS Surcharge in 2 BIPCO service agreements to reflect a change in the classification of Block Island Wind Farm's electric facilities from distribution to transmission; comment deadline ***Nov 21, 2025***
*	17	Schedule 21-GMP: BTM Gen & SSCDC Cost Revisions (ER26-386)	Oct 31	Green Mountain Power files revisions to Schedule 21-GMP; comment deadline ***Nov 21, 2025***
*	17	Schedule 21-ES: Eversource Filing to Remove Duplicative True Up of S&D Costs (ER26-321)	Oct 30	Eversource files changes to Schedule 21-ES
			Nov 3	Eversource amends filing; comment deadline ***Nov 20, 2025***
*	18	Schedule 21-GMP: Annual True Up Calculation Informational Filing (ER12-2304)	Oct 30	GMP submits annual info filing containing true-up calculation of its actual costs for the 2024 Service Period

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

*	18	Capital Projects Report – 2025 Q3 (ER26-152)	Oct 15	ISO-NE files 2025 Q3 Report
			Oct 20	NEPOOL files comments supporting the Q3 Report
			Nov 3	National Grid intervenes
	18	Capital Projects Report - 2025 Q2 (ER25-3137)	Oct 9	FERC accepts ISO-NE 2025 Q2 Capital Projects Report, *eff. Jul 1, 2025*

*	19	LFTR Implementation: 68th Quarterly Status Report (ER07-476)	Oct 15	ISO-NE files its 68th quarterly report

IX. Membership Filings

*	19	Nov 2025 Membership Filing (ER26-363)	Oct 31	***New member***: MRRA; comment deadline ***Nov 21, 2025***
	19	Sep 2025 Membership Filing (ER25-3342)	Oct 23	FERC accepts the following (i) ***new members***: Alpha Generation, Ryegate Associates, and TDI DevCo; and (ii) ***name changes***: ReGenerate Stratton LLC and Clearlight Energy Services LLC
*	19	Suspension Notice – Actual Energy (not docketed)	Oct 20	ISO-NE files notice of *Oct 20, 2025* suspension of Actual Energy from the New England Markets
*	19	Suspension Notice – AES Renewable Holdings, LLC (not docketed)	Oct 14	ISO-NE files notice of *Oct 9, 2025* suspension of AES Renewable Holdings, LLC from the New England Markets

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

	20	NERC FFT/CE Programs Annual Report (RC11-6-021)	Oct 10	FERC and NERC Staff identify certain FFTs and CEs for inclusion in the annual evaluation of the FFT and CE programs; documentation/ responses related to those FFT and CE data requests must be submitted by ***Nov 21, 2025***.
	20	Revised Reliability Standard: EOP-012-3 (RD25-7)	Oct 17, 20	NERC and Joint Trade Associations each request clarification of the *EOP-012-3 Order*
	22	2026 NERC/NPCC Business Plans and Budgets (RR25-5)	Oct 30	FERC approves NERC (including NPCC) Business Plans and Budgets

XI. Misc. - of Regional Interest

	24	PURPA Enforcement Petition – Allco Finance Ltd (EL25-117)	Oct 24	CT PURA and CL&P each urge the FERC to issue a notice of intent not to act with respect to the Petition
	25	D&E Agreement: PSNH/Kearsarge Grissom (ER25-3407)	Oct 20	FERC accepts D&E Agreement, eff. *Sep 11, 2025*
	25	Interconnection Study Agreement Cancellation: PSNH/Wok LLC (ER25-3359)	Oct 29	FERC accepts notice of cancellation, eff. Sep 4, 2025
	25	D&E Agreement: NSTAR/BXP (ER25-3309)	Oct 21	FERC accepts D&E Agreement, eff. *Aug 28, 2025*
	25	Saddleback Amended IAs (ER25-3187)	Oct 10	FERC accepts amended Saddleback IAs, eff. *Jul 3, 2025*
	25	NSTAR (MMWEC)-HQUS Use Rights Transfer Agreement (ER25-3170)	Oct 23	FERC accepts HQUS Transfer Agreement, eff. *Oct 31, 2025*
	26	NSTAR (CMEEC)-Vitol Use Rights Transfer Agreement (ER25-3011)	Oct 23	FERC accepts Vitol Transfer Agreement, eff. *Oct 31, 2025*
	26	Wholesale Distribution Tariff – Versant Power (ER25-2500)	Oct 17	FERC ***rejects*** Versant WDT
	26	*Order 904* Compliance Filing: Versant MPD OATT (ER25-1393)	Oct 31	Versant amends filing, requesting May 26, 2025 effective date

XII. Misc. - Administrative & Rulemaking Proceedings

	27	Tech Conf: Wildfire Risk Mitigation (AD25-16)	Oct 21	FERC holds tech conf
			Oct 23	FERC invites post-tech conf comments; comment deadline ***Nov 24, 2025***
	27	Annual Reliability Tech Conf (AD25-8)	Oct 21	FERC holds tech conf
			Oct 23	FERC invites post-tech conf comments; comment deadline ***Nov 24, 2025***
			Nov 4	Digital Power Network submits post-tech conf comments
	28	Joint Federal-State Current Issues Collaborative (AD24-7)	Nov 5	FERC postpones meeting of the Collaborative (previously set for Nov 12, 2025 in Seattle) to ***Feb 26, 2026*** in Washington, DC
*	28	ANOPR: Interconnection of Large Loads to the Interstate Transmission System (RM26-4)	Oct 27	FERC issues ANOPR on interconnection of large loads (>20 MW); comments deadline ***Nov 14, 2025***; reply comments deadline ***Nov 28, 2025***
			Nov 4	Org. of MISO states (OMS) requests a 2-week extension of time, until Nov 28, to submit initial comments
			Nov 5	OPSI supports OMS Request
	29	*Order 914*: Implementation of EO 14270 (RM25-14)	Oct 22	FERC issues Errata Notice to correct an error in the regulatory text section

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

30	American Efficient Show Cause Order (IN24-2)	Nov 3	American Efficient requests that the FERC conclude its Order to Show Cause proceeding by declining OERA's request for an Order Assessing Penalties and close out its investigation

XIV. Natural Gas Proceedings

32	Algonquin Cape Cod Canal Pipeline Relocation Project (CP25-552; PF25-4)	Oct 30	Algonquin supplements its Application
		Nov 4	Certain Cape Chambers of Commerce submit comments

XV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XVI. Federal Courts

34	*Order 904*: Compensation for Reactive Power Within the Standard Power Factor Range (5th Circuit – 25-60055 et al.) (consolidated)	Oct 15	The FERC requests a 30-day extension of time to file the administrative record
		Oct 17	Court grants the FERC request; administrative record now due ***Nov 17, 2025***
36	*Avangrid v. NextEra (NECEC Civil Suit) (D.MA 24-30141)*	Oct 30	A hearing on NextEra's motion to dismiss the State Law Claims set for ***Dec 18, 2025***
36	Allco PURPA Enforcement Petition (D.CT 3:25CV01321)	Oct 15-28	Court issues orders granting extensions of time, to ***Nov 24, 2025***, to answer Complaint

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Pat Gerity and Joan Bosma, NEPOOL Counsel

DATE: November 5, 2025

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 5, 2025. In addition, in the opening Section immediately below, we continue to summarize recent Executive Orders issued by the President of the United States and Executive Agency directives related to the energy industry. If you have questions on any of these summaries, please contact us.

Executive Orders

Questions concerning any of the Executive Orders ("EO") or Agency Directives summarized below can be directed to Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Joan Bosma (617-345-4651; jbosma@daypitney.com).

- **Revolution Wind Stop-Work Order**

On August 22, 2025, the Department of the Interior's Bureau of Ocean Energy Management ("BOEM") issued a Director's Order ("Stop-Work Order") to Revolution Wind, LLC to halt all ongoing activities related to the Revolution Wind Project to allow time for BOEM to "address concerns that have arisen during the review that the Department is undertaking pursuant to the President's Memorandum of January 20, 2025".[2] The Stop-Work Order effectively halts the Revolution Wind offshore wind farm project, which was 80% complete. Revolution Wind may not resume activities until BOEM informs it that BOEM has completed its review.

- **Executive Order: Accelerating Federal Permitting of Data Center Infrastructure (EO 14318)**

On July 23, 2025, President Trump issued an EO to facilitate "the rapid and efficient buildout" of Artificial Intelligence ("AI") data centers and associated infrastructure. The EO directs the Secretary of Commerce to launch an initiative to provide financial support for "Qualifying Projects," which are defined as data centers and related infrastructure that require over 100 MW of incremental electric load, a commitment of $500 million or more in capital expenditures, or are otherwise designated as such. All relevant agencies were directed to identify existing National Environmental Policy Act ("NEPA") categorical exclusions that could facilitate the construction of Qualifying Projects to the Council on Environmental Quality within 10 days; the EO also establishes a presumption that federal financial assistance that is less than half of the total project cost does not constitute a "major Federal action" under NEPA. The Environmental Protection Agency ("EPA") is tasked with reviewing and revising permitting regulations under the Clean Air Act, Clean Water Act ("CWA"), and other laws to streamline approval processes, and must issue guidance to support the reuse of Superfund and Brownfield sites for data centers by ***January 19, 2026***. And, the Army must assess whether a new nationwide permit is necessary under the CWA or Rivers and Harbors Appropriation Act to facilitate the efficient permitting of Qualifying Projects. Additionally, the

[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] 90 Fed. Reg. 8,363 (Jan. 29, 2025).

EO instructs the Departments of the Interior, Energy, and Defense to identify and authorize federal and military lands for qualifying development, including streamlined consultations under the Endangered Species Act for construction of Qualifying Projects over the next 10 years and competitively leasing sites for data centers. The EO also mandates FAST-41 transparency project designation and permitting dashboard integration by August 22, 2025.

- **Executive Order: Ending Market Distorting Subsidies for Unreliable, Foreign Controlled Energy Sources (EO 14315)**

On July 7, 2025, following the recent signing of the One Big Beautiful Bill Act ("OBBB"), President Trump issued an EO directing the Secretary of the Treasury to implement provisions of the OBBB aimed at eliminating federal support for wind and solar energy and directing the Department of the Interior to review and revise any policies that provide preferential treatment to wind and solar energy sources, by August 21, 2025. Specifically, the EO requires the Treasury to issue guidance to enforce the OBBB's termination of Sections 45Y and 48E tax credits, including restricting safe harbor provisions and "beginning of construction" standards. The Treasury is also directed to implement the OBBB's enhanced Foreign Entity of Concern ("FEOC") restrictions.

- **Executive Order: Empowering Commonsense Wildfire Prevention and Response (EO 14308)**

On June 12, 2025, President Trump issued an EO to consolidate wildfire programs, develop a technology roadmap, and revise rules to enable more effective wildfire prevention and response through the use of prescribed burns, improved power system practices, and modernized response metrics and satellite data. As it relates to the FERC, the EO directed the FERC to consider by September 15, 2025 rulemakings to establish best practices to reduce wildfire ignition risk from the bulk-power system ("BPS") without increasing end-user costs. As summarized in Section XII below (AD25-16), the FERC issued on September 10, 2025 a notice of an October 21, 2025 Staff-led technical conference on wildfire mitigation, including cost-effective best practices to reduce the risk of wildfire ignition from the BPS.

- **Executive Order: Reinvigorating the Nuclear Industrial Base (EO 14302)**

On May 23, 2025, President Trump issued an EO directing the U.S. Department of Energy ("DOE") to accelerate the growth of the U.S. nuclear sector. EO 14302 specifically directs the DOE to facilitate 5 GW of power uprates to existing reactors and the start of construction on ten new large reactors ***by 2030***. The DOE Loan Programs Office is directed to prioritize projects including restarts, uprates, new construction, and fuel supply chain improvements. The DOE and the Department of Defense ("DoD") are to assess the use of closed nuclear sites for military energy hubs. EO 14302 also requests a report and sets timelines for action on nuclear fuel recycling, enrichment, and cooperative procurement, including near-term use of Defense Production Act authorities.

- **Executive Order: Reforming Nuclear Reactor Testing at the Department of Energy (EO 14301)**

Also on May 23, 2025, President Trump issued EO 14301 mandating the DOE revise NEPA regulations by June 30, 2025 to streamline environmental reviews for reactor testing through new or existing categorical exclusions. EO 14301 also directs the DOE to issue guidance on "qualified test reactors" and establish a pilot program for at least three test reactors outside the National Laboratories by ***July 4, 2026***.

- **Executive Order: Ordering the Reform of the Nuclear Regulatory Commission (EO 14300)**

Also on May 23, 2025, President Trump issued EO 14300 directing the Nuclear Regulatory Commission ("NRC") to overhaul its licensing and fee structures to expedite approvals. EO 14300 specifically mandates final decisions on applications for new reactors within 18 months, and for continued operation of existing reactors within one year, with caps on hourly fee recovery. EO 14300 also directs the NRC to streamline approval of reactor designs already tested and demonstrated by the DOE or DoD, so to focus reviews only on new application-specific risks.

- **Executive Order: Deploying Advanced Nuclear Reactor Technologies for National Security (EO 14299)**

President Trump issued yet another Executive Order on May 23, 2025 directing the DOE, DOD, and the Secretary of State to accelerate the deployment and export of advanced nuclear reactor technologies to meet national security objectives and support rapid growth of advanced nuclear technologies. EO 14299 requires the DOE to designate AI data centers at DOE sites as critical defense infrastructure and to select sites within 90 days for deployment of advanced nuclear reactors to support AI and other national security missions, with the first reactor to be operational within 30 months. The DoD must also commence operation of a nuclear reactor at a domestic military installation by no later than ***September 30, 2028***. EO 14299 also directs the Secretary of State to pursue at least 20 new section 123 of the Atomic Energy Act of 1954 Agreements for Peaceful Nuclear Cooperation by the close of the 120th Congress and requires the DOE to review and act on export authorization requests within 30 days of completion.

- **Executive Order: Zero-Based Regulatory Budgeting to Unleash American Energy (EO 14270)**

On April 9, 2025, President Trump issued an EO directing the FERC, along with DOE, EPA, and the NRC, to incorporate conditional sunset provisions into specified "Covered Regulations" that requires these regulations expire after one year unless extended at the agency's discretion for a period of up to five years. The agencies must provide the public with an opportunity to comment on the costs and benefits of each such regulation prior to its expiration. For the FERC, the EO applies to regulations promulgated under the Federal Power Act ("FPA"), Natural Gas Act ("NGA"), and the Powerplant and Industrial Fuel Use Act. On October 1, 2025, the FERC issued a direct final rule (*Order 914*) and a related NOPR, in response to EO 14270, to sunset 53 regulations identified as outdated or unnecessary. *Order 914* establishes a one-year sunset from its effective date (45 days after *Order 914*'s publication in the Federal Register), after which the regulations will be removed from the U.S. Code of Federal Regulations and the FERC will no longer treat them as effective. (*see* Section XII below).

- **Executive Order: Strengthening the Reliability and Security of the United States Electric Grid (EO 14262)**

On April 8, 2025, President Trump issued an EO directing the Secretary of the DOE to strengthen use of emergency authority under Section 202(c) of the FPA and to implement a new national methodology for assessing electric reliability. The EO requires the DOE to streamline and expedite the issuance of 202(c) emergency orders during forecasted supply interruptions and to develop, within 30 days, a uniform framework for evaluating reserve margins across all FERC-jurisdictional regions. This framework will be used to identify regions with insufficient capacity and determine which generation resources are critical to reliability. The DOE is further directed to use the methodology to prevent the retirement or fuel conversion of any resource over 50 MW that would cause a net reduction in accredited capacity. While FERC is not directly tasked under EO 14262, implementation of its provisions may influence FERC-jurisdictional processes.

DOE Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid ("DOE RA Report"). On July 7, 2025, the DOE released a Report in response to Section 3(b) of EO 14262 (which directed the DOE to develop a uniform methodology for analyzing current and anticipated reserve margins in FERC-regulated regions of the bulk power system). The DOE RA Report provides an assessment of the U.S. grid's ability to meet projected load growth through 2030 using a deterministic approach that simulates system stress in all hours of the year and incorporates grid conditions and scenarios based on historical data.[3] Overall highlights of from the DOE RA Report include conclusions that: (i) the status quo is unsustainable; (ii) grid growth must match the pace of AI innovation; (iii) with projected load growth, retirements increase the risk of power outages by 100 times in 2030; (iv) planned supply falls short, reliability at risk; and (v) old tools won't solve new problems.

[3] The DOE RA Report employs three different 2030 cases: a Plant Closures Case (which assumes all announced retirements occur), a No Plant Closures Case (which assumes no announced retirements proceed and mature additions), and a Required Build Case (which compares impacts of retirements on perfect capacity additions necessary to return 2030 to current level of reliability). In the Plant Closures Case, only New England and NYISO met the reliability thresholds, while all other regions failed. ISO-NE's peak demand is projected to grow from 28 GW in 2024 to 31 GW by 2030, with capacity rising from 40 GW to 45.5 GW in the No Plant Closures case and to 42.8 GW in the Plant Closures case.

Not New England. The DOE RA Report identifies several regions facing acute reliability issues in the near future, though not New England. The DOE RA Report cites sharp load growth from electrification, AI, and data centers as the key drivers of resource adequacy concerns. Noting the absence of additional AI/data center load growth in New England, the DOE RA Report concludes that no additional capacity in New England would be necessary to meet the study's reliability standards.

Request for Rehearing – DOE RA Report. On August 6, Clean Energy Organizations,[4] concluding that the DOE RA Report is a rule subject to rehearing, despite being styled as a report, requested rehearing of the DOA RA Report, asserting that the Report "fails to account for [] important aspects of the resource adequacy puzzle."[5] Clean Energy Organizations request that DOE "withdraw the Resource Adequacy Protocol or otherwise address the errors contained in it."

- **Executive Order: Reinvigorating America's Beautiful Clean Coal Industry and Amending EO 14241 (EO 14261)**

Also on April 8, 2025, President Trump issued an EO that (i) reclassifies Coal as a Strategic National Asset (granting coal eligibility for federal support programs, including those under the Defense Production Act and DOE's loan authorities, and directing a review of policies that may discourage coal production, with agencies tasked to revise or rescind such policies within 60 days); (ii) accelerates coal access on federal lands (directing federal agencies to identify coal-rich areas on federal lands, address barriers to mining on federal lands and propose actions to maximize coal mining on federal lands, and prioritize coal leasing and encourage the use of emergency authorities to expedite permitting and environmental reviews, including a push for broader use of categorical exclusions under NEPA. The assessment requires an analysis of the impact the use of coal resources could have on electricity costs and grid reliability); and (iii) aligns coal with emerging industrial needs (positioning coal as a critical resource for emerging industries, directing agencies to assess its potential for powering AI data centers and supporting steelmaking, and calling for accelerated development of coal technologies and commercial applications in advanced manufacturing).

- **Executive Order: Protecting American Energy From State Overreach (EO 14260)**

On April 8, 2025, President Trump issued an EO directing the U.S. Attorney General to identify and challenge state and local laws, regulations, and policies that may act as "illegitimate impediments" to the development, siting, production, investment in, or use of domestic energy resources, and further instructs the Attorney General to stop the enforcement of these state climate-related policies. While the EO does not directly implicate FERC, it may affect regional efforts such as the Regional Greenhouse Gas Initiative ("RGGI") and other state-led programs. A report detailing the Attorney General's actions and recommended executive or legislative responses was due to the President within 60 days.

I. Complaints/Section 206 Proceedings

- **BP Phantom Load Complaint (EL26-5)**

On October 14, 2025, as supplemented October 17, BP Energy Retail Company ("BP") filed a complaint seeking relief from invoices issued by ISO-NE for July, August, and September of 2024 based on phantom load shifted from the NEMA to the SEMA zone, which BP asserts was incorrectly assigned to BP by Eversource (NSTAR) due to an IT system error. Responses and comments on the Complaint are currently due on or before ***November 13, 2025***. On November 4, 2025, Eversource filed a motion for a 29-day extension of time, to December 12, 2025,

[4] "Clean Energy Organizations" are, for the purposes of this matter, the American Clean Power Association ("ACPA"), Advanced Energy United ("AEU"), and American Council on Renewable Energy ("ACORE").

[5] Clean Energy Organizations assert that DOE's analysis "fails to take account of (or simply mischaracterizes) major developments that will affect resource adequacy in the next half-decade and beyond, primarily the pace of new resource development, the retirement of existing resources, and the well-established regulatory and market mechanisms that connect these threads. The [Report] also excludes mention of President Trump's own policies aimed at making the headline outcomes of the [Report] highly unlikely.

to file an answer, which is pending before the Commission. Thus far, Calpine, National Grid, The Retail Energy Supply Association ("RESA"), and Public Citizen have intervened doc-lessly. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **NEPGA Balancing Ratio and Stop Loss Allocation Methodology Complaint (EL25-106)**

On July 25, 2025, NEPGA filed a complaint in response to the impacts of the events of June 24, 2025, seeking (i) a Balancing Ratio cap at 1.0; and (ii) a revised allocation of the "bonus pool" that gets collected to pay over-performers. In the Complaint, NEPGA proposed, pointing to precedent established in PJM, that the FERC (a) cap the Balancing Ratio at 1.0 and (b) adopt the PJM charge and bonus allocation (instead of charging resources with a Capacity Supply Obligation to make up any bonus revenue shortfall, simply split the bonus pool that gets collected to pay over-performers). NEPGA asked that the FERC set an immediate refund effective date and requested fast track processing of the Complaint.

Following an unopposed request by ISO-NE for an additional one week to substantively answer the Complaint, answers and comments to the Complaint were due on or before August 21, 2025.[6] ISO-NE filed its answer, requesting (i) with respect to the PFP stop-loss mechanism cost allocation, the FERC deny the Complaint on the merits; (ii) with respect to the Balancing Ratio, the FERC "take account of ISO-NE's arguments and narrow concession", and (iii) provide at least 180 days to file any replacement rate deemed necessary as a result of the Complaint. NEPOOL filed limited comments to provide additional context but taking no substantive position on the Complaint. Comments supporting the Complaint were filed by MMWEC, FirstLight Power, RENEW, LS Power Development, Electric Power Supply Association ("EPSA"), and jointly by Braintree and Taunton. Comments on the Complaint were also filed by NESCOE and the New England Consumer Advocates ("CANE").[7] Vitol filed a protest requesting the FERC deny the Complaint. Interventions only were filed by the IMM, AEU, Avangrid (out-of-time), Brookfield, Calpine, CPV Towantic, Dominion, Energy New England ("ENE"), Enel, Eversource, LS Power, ME OPA, National Grid, NextEra, RI Energy, Shell, Vistra, MA DPU, the National Hydropower Association ("NHA"), and Public Citizen.

Since the last Report, the following parties filed answers: ***ISO-NE*** ((i) answering NEPGA's second answer, reiterating that, while it would not oppose a FERC order capping the Balancing Ratio at 1.0, it continued to oppose NEPGA's position that the current stop-loss cost allocation approach is unjust and unreasonable and opposes adopting PJM's general stop loss approach; and (ii) and asserting that FirstLight's alternative requests for relief are outside the scope of this proceeding); ***NEPGA*** (emphasizing broad support for the Complaint, reiterating its argument that holding capacity resources to obligations beyond their committed capability is unjust and unreasonable, and urging the FERC to adopt PJM's allocation methodology as the replacement rate); ***the IMM*** (expressing sympathy with NEPGA's complaint, supporting a 1.0 cap on the Balancing Ratio, and requesting clarification as to how related payments would be allocated); ***RENEW*** (supporting NEPGA's proposed reforms to ISO-NE's PFP cost allocation rules); and ***Vitol*** (opposing NEPGA's second answer and requesting that the FERC deny the Complaint, stating that the reforms should be addressed through the stakeholder process).

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

[6] ISO-NE's preliminary answer also opposed NEPGA's request for fast track processing. The FERC did not address that opposition in its notice extending the comment period to Aug. 21, 2025.

[7] The New England Consumer Advocates or "CANE" consist of the: Massachusetts Attorney General's Office ("MA AG"), Connecticut Office of Consumer Counsel ("CT OCC"), Maine Office of the Public Advocate ("ME OPA"), New Hampshire Office of the Consumer Advocate ("NH OCA"), and Rhode Island Division of Public Utilities and Carriers ("RI Division").

- **Local Transmission Planning Complaint (EL25-44)**

As previously reported, a group of "Consumer Complainants"[8] filed a complaint on December 19, 2024 against all FERC-jurisdictional public utility transmission providers with local planning tariffs (including ISO-NE and the remaining ISO/RTOs) asserting that their tariffs, which authorize individual transmission owners to plan FERC-jurisdictional transmission facilities at 100 kV and above ("Local Planning") without regard to whether such Local Planning approach is the more efficient or cost-effective transmission project for the interconnected transmission grid and cost-effective for electric consumers, coupled with the absence of an independent transmission system planner, "are unjust and unreasonable, having produced inefficient planning and projects that are not cost-effective, resulting in unjust and unreasonable rates for both individual projects and cumulative regional transmission plans and portfolios." Specifically, the Consumer Complainants asserted that the FERC must mandate (i) revision of local and regional planning tariffs to (a) prohibit individual transmission owner planning of FERC-jurisdictional transmission facilities 100 kV and above; and (b) require exclusive regional planning of all transmission facilities 100 kV and above, utilizing existing *Order 1000* regions; and (ii) that all regional planning must be conducted through an Independent Transmission Planner as described in their Complaint.

Answers, interventions, comments, and protests to the Consumers RTP Complaint were due on or before March 20, 2025[9] and were filed by, among others, ISO-NE, New England Transmission Owners ("NETOs"),[10] AEU, CT OCC, NECPUC, NESCOE, MA AG, NH OCA (supporting the Complaint), MPUC (urging the FERC to reject the remedies proposed by the Complainants and open its own investigations pursuant to Section 206 of the FPA), EEI, NARUC, Public Interest Organizations,[11] and WIRES. Interventions only were filed by more than 100 parties, including NEPOOL. On April 4, 2025, ISO-NE answered certain comments and reiterated its request that it be dismissed as a respondent to the proceeding. Answer and reply comments were also filed by Complainants (requesting FERC grant the Complaint and deny the motions to dismiss), NESCOE (addressing the standard of review that may apply to certain reforms), MOPA (asking FERC to reject motions to dismiss and open an investigation), MPUC (requesting FERC accept its motion for to leave to answer and consider its answer), and AMP (asking FERC to deny motions to dismiss). On May 20, 2025, ISO-NE responded to Complainant's Answer and the responses of NESCOE, MPUC, and MOPA, again requesting it be dismissed as a respondent to the proceeding as a matter of law and because the Complainants failed to meet their burden under FPA Section 206. On June 30, 2025, Complainants answered the May 22 answer by "Southeast Respondents"[12] and on July 25, 2025 ATC

[8] "Consumer Complainants" are Industrial Energy Consumers of America, American Forest & Paper Assoc., R Street Institute, Glass Packaging Institute, Public Citizen, PJM Industrial Customer Coalition, Coalition of MISO Transmission Customers, Assoc. of Businesses Advocating for Tariff Equity, Carolina Utility Customers Assoc., PA Energy Consumer Alliance, Resale Power Group of Iowa, Wisconsin Industrial Energy Group, Multiple Intervenors (NY), Arkansas Elec. Energy Consumers, Inc., Public Power Assoc. of NJ, OK Industrial Energy Consumers, Large Energy Group of Iowa, Industrial Energy Consumers of PA, MD Office of People's Counsel, Pennsylvania Office of Consumer Advocate, Consumer Advocate Div. of the Public Service Commission of WV, and Missouri Industrial Energy Consumers.

[9] On Jan. 7, 2025, the FERC granted a motion by EEI/WIRES for an extension of time, extending the comment deadline to Mar. 20, 2025. See Notice of Extension of Time, *Industrial Energy Consumers of America et al. v. Avista Corporation et al.*, Docket No. EL25-44-000, (Jan. 7, 2025).

[10] For purposes of this proceeding, "NETOs" are: Eversource Energy Service Company on behalf of The Connecticut Light and Power Co. ("CL&P"), Public Service Co. of New Hampshire ("PSNH"), and NSTAR Elec. Co. ("NSTAR", and together with CL&P and PSNH, "Eversource"); Central Maine Power Co. ("CMP"), Maine Elec. Power Co., Inc. ("MEPCO"), and The United Illuminating Co. ("UI"); New England Power Co. d/b/a National Grid; The Narragansett Elec. Co. d/b/a Rhode Island Energy ("RI Energy"); Vermont Electric Power Co., Inc. ("VELCO") and Vermont Transco LLC ("VTransco"), and Versant Power ("Versant").

[11] "Public Interest Organizations" or "PIOs" are Earthjustice, Natural Resources Defense Council ("NRDC"), Sustainable FERC Project, and the Southern Environmental Law Center.

[12] Complainants defined "Southeast Respondents" as: Dominion Energy South Carolina, Inc. ("DESC"), Duke Energy Progress, LLC, Duke Energy Carolinas, LLC, and Duke Energy Florida, LLC (together, "Duke Energy"), Louisville Gas and Electric Company and Kentucky Utilities Company (together, "LG&E/KU"), Tampa Electric Company ("TEC"), Florida Power and Light ("FPL"), and Alabama Power Company, Georgia Power Company, and Mississippi Power Company.

answered Complainants April 24, 2025 answer. 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).

- **Allco PP5 Complaint (EL25-43)**

Still pending is the December 19, 2024 complaint by Allco Finance Limited ("Allco") asking the FERC to (i) direct ISO-NE to abolish its Planning Procedure No. 5 ("PP5") procedures by (ii) finding that PP5's procedures are unjust and unreasonable and unduly discriminatory and/or preferential in violation of section 206 of the FPA; and (iii) find that ISO-NE has violated the FPA by forcing on State jurisdictional interconnections, such as Allco's, the requirement to pay for transmission level interconnection studies, to pay for Power Systems Computer Aided Design ("PSCAD") models in connection with such studies, and by causing delays to the execution by distribution utilities of State jurisdictional generator interconnection agreements (particularly for Allco's 2 MW Winsted solar energy project). ISO-NE answered the Allco PP5 Complaint on January 15, 2025 (as corrected on January 30, 2025). On January 23, 2025, Allco answered ISO-NE's January 15 Answer. On February 7, 2025, ISO-NE answered Allco's January 23 Answer and on February 25, 2025 Allco answered ISO-NE's February 7 Answer. Doc-less interventions only were filed by NEPOOL, Calpine, National Grid, the MA DPU, and Public Citizen. There was no activity in this proceeding since the last Report. 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).

- **206 Proceeding: TO Initial Funding Show Cause Order (EL24-83)**

As previously reported, on June 13, 2024, the FERC instituted a Section 206 proceeding finding that the ISO-NE Tariff appears to be unjust, unreasonable, and unduly discriminatory or preferential because it includes provisions for transmission owners to unilaterally elect transmission owner ("TO") Initial Funding (the funding of network upgrade capital costs that the TO incurs to provide interconnection service to an interconnection customer, with the network upgrade capital costs subsequently recovered from the interconnection customer through charges that provide a return on and of those network upgrade capital costs).[13] TO Initial Funding, the FERC found, may increase the costs of interconnection service without corresponding improvements to that service, may unjustifiably increase costs such that it results in barriers to interconnection, and may result in undue discrimination among interconnection customers.[14] The FERC also found that there may be no risks associated with owning, operating, and maintaining network upgrades for which transmission owners are not already otherwise compensated.[15] Accordingly, ISO-NE was directed, on or before September 11, 2024, 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.[16] The refund effective date for this proceeding is June 24, 2024.[17] A more detailed summary of the *TO Initial Funding Show Cause Order* was circulated to, and was reviewed with, the Transmission Committee.

Interventions were due on or before July 5, 2024 and were filed by the following New England-related parties:[18] NEPOOL, Advanced Energy United ("AEU"), Avangrid, Calpine, CMEEC (out-of-time), EDP Renewables, Eversource, Invenergy, MA AG, National Grid, NESCOE, NextEra, NRDC, PPL, Maine Public Utilities Commission ("MPUC"), Massachusetts Department of Public Utilities ("MA DPU"), American Clean Power Association ("ACPA"), American Council on Renewable Energy ("ACRE"), Edison Electric Institute ("EEI"), Electric Power Supply

[13] *ISO New England Inc. et al.,* 187 FERC ¶ 61,170 (June 13, 2024) ("*TO Initial Funding Show Cause Order*").

[14] *Id.* at P 1.

[15] *Id.*

[16] *Id.* at P 2.

[17] Notice of this 206 proceeding was published in the *Fed. Reg.* on June 24, 2024 (Vol. 89, No. 121) pp. 52,454-52,455.

[18] The notice instituting this 206 proceeding was issued in the following four unconsolidated dockets (which resulted in some parties intervening in all four proceedings): EL24-80 (MISO); EL24-81 (PJM); EL24-82 (SPP); and EL24-83 (ISO-NE).

Association ("EPSA"), RENEW Northeast ("RENEW"), Solar Energy Industries Association ("SEIA"), WIRES, Cordelio Services, and Public Citizen.

NE Response to Show Cause Order (Attaching Substantive Response by NETOs). On September 11, 2024, ISO-NE submitted a response ("NE Response") explaining that, because the rules identified in the *TO Initial Funding Show Cause Order*[19] fall within the exclusive purview of, and are implemented by, the Participating Transmission Owners ("PTOs") under the Transmission Operating Agreement ("TOA") between ISO-NE and the PTOs, it had requested that the PTOs respond to the *TO Initial Funding Show Cause Order* and attached the response of Indicated New England Transmission Owners ("NETOS")[20] to the NE Response. NETOs' response identified several reasons why the FERC's proposal is in their view beyond the FERC's authority and power.

Responses to the September NE Response were due on or before October 25, 2024. Responses from ISO-NE-related parties to this joint proceeding were filed by, among others: NE TOs, Invenergy, Public Interest Organizations, Public Systems, Clean Energy Associations, EEI, WIRES, and the Harvard Law Initiative. Since the last Report, the ISO-NE IMM filed comments in the MISO version of this proceeding to urge the FERC to reject MISO's request for a broad, and what the IMM asserts is an inappropriately limited, declaration on the authority of an IMM to monitor long-term transmission planning for impacts on the wholesale markets and assumed efficiency improvements to those markets. Each of the regional matters, including the New England-specific docket, remain pending before the FERC.

Federal Court Appeals. On August 30, 2024, certain parties[21] filed a petition for review of the FERC's orders in this proceeding in the 8th Circuit, since challenged by the FERC. Developments on the federal court appeals will be reported in Section XVI below. In the meantime, if you have questions on this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

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

There are four proceedings, long pending before the FERC, in which the TOs' return on equity ("Base ROE") for regional transmission service has been challenged.

- ***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,[22] 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*

[19] The rules identified in the *Order to Show Cause* were those that establish the methodology to recover costs associated with interconnection-related upgrades, and the related financial obligations of the PTO or the interconnecting party – in New England, set forth in Article 11.3 of the LGIA, Article 5.2 of the SGIA, and Article 11.3 of the ETU IA, as well as Schedule 11 of the OATT.

[20] The NETOs, for purposes of this proceeding, are: Eversource; Central Maine Power Company ("CMP"); The United Illuminating Company ("UI"); New England Power Company ("National Grid"); The Narragansett Electric Company ("RI Energy"); Fitchburg Gas and Electric Light Co. ("Unitil"); and Versant Power ("Versant").

[21] The parties to the 8th Circuit Appeal are: Ameren Services Co., Ameren Illinois Co., Union Elec. Co. d/b/a Ameren Missouri, Ameren Trans. Co. of IL, American Trans. Co. LLC, Duke Energy Corp., Duke Energy Business Services, LLC, Duke Energy Ohio, Inc., Duke Energy KY, Inc., Duke Energy IN, LLC, Exelon Corp., Atlantic City Elec. Co., Baltimore Gas and Elec. Co., Commonwealth Edison Co., Delmarva Power & Light Co., PECO Energy Co., Potomac Elec. Power Co., Northern Indiana Pub. Srvc. Co. LLC, Xcel Energy Services Inc., Northern States Power Co., a MN Corp., Northern States Power Co., a WI Corp., and Southwestern Pub. Srvc. Co. ("8th Circuit Parties").

[22] 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*")).

531-A).[23] However, the FERC's orders were challenged, and in *Emera Maine,*[24] 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)[25] and third (EL14-86)[26] 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.[27] 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[28] also went to hearing before an Administrative Law Judge ("ALJ"), Judge Glazer, who issued his initial decision on March 27, 2017.[29] 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.[30] 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*.

---

[23] *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*").

[24] *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).

[25] 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%.

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

[27] *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*").

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

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

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

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.[31] 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*[32] (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.[33]

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

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

The FERC provided preliminary analysis of how it would apply the proposed methodology in the Base ROE I Complaint, suggesting that it would affirm its holding that an 11.14% Base ROE is unjust and unreasonable. The FERC suggested that it would adopt a 10.41% Base ROE and cap any preexisting incentive-based total ROE at 13.08%.[34] 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

---

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

[32] *Ass'n of Bus. 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*.

[33] *Id.* at P 19.

[34] *Id.* at P 59.

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[35] 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*[36] 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 Complainant-Aligned Parties ("CAPs") opposed the TOs' request and brief. No action was ever taken in response to this activity.

Nov 2023 Supplemental Brief. As reported at the December 5, 2024 Annual Meeting, the TOs filed, on November 13, 2024, a "Motion to File Supplemental Brief Addressing the Inability of the [FERC]'s MISO Methodology to Satisfy the Mandate of the *Emera Maine* Court in these Cases, the Requirements of Section 206, and the Need to Promote Transmission Investment in New England". On December 13, 2024, WIRES/EEI supported the TOs Motion,[37] and CAPs[38] replied in opposition to the Motion. On December 20, 2024, the TOs filed an answer to the CAPs' statements concerning the FERC's authority to order refunds for the period from when the FERC issues its order on remand back to October 16, 2014.

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

- **PBOP Collections Report (RI Energy) (ER26-387)**

On October 31, 2025, RI Energy filed a report identifying planned collection activity related to the over recovery of post-retirement benefits other than pensions ("PBOP") under Appendix A to Attachment F to the ISO-NE OATT. The report was required to be filed with the FERC because the absolute value of the over-recovery exceeds the threshold identified in OATT Attachment F.[39] No changes to the filed rate were sought. The report shows an over-recovery, after interest, of ***$938,616***. If accepted, the PBOP figures will be used in RIE's 2026

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

[36] *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).

[37] Agreeing with the TOs, the WIRES/EEI comments asserted: (i) that the FERC lacks the statutory authority to order refunds outside the 15-month refund period; (ii) the FERC's claim of remedial authority to correct legal error does not justify retroactive ROE refunds; and (iii) the FERC should accept and give consideration to the NETOs' supplemental brief and supporting affidavits.

[38] "CAPs" are: the Conn. Pub. Utils. Regulatory Authority ("CT PURA"); the Conn. Office of Consumer Counsel ("CT OCC"); Mass. Mun. Wholesale Elec. Co. ("MMWEC"); NH Elec. Coop. ("NHEC"); the RI Div. of Pub. Utils. and Carriers ("RI Div"); and Eastern Mass. Consumer-Owned Systems ("EMCOS"), who consist of the Belmont Mun. Light Dept. ("Belmont"); Braintree Elec. Light Dept. ("Braintree"); Concord Mun. Light Plant ("Concord"); Georgetown Mun. Light Dept. ("Georgetown"); Groveland Elec. Light Dept. ("Groveland"); Hingham Mun. Lighting Plant ("Hingham"); Littleton Elec. Light & Water Dept. ("Littleton"); Merrimac Mun. Light Dept. ("Merrimac"); Middleton Elec. Light Dept. ("Middleton"); Reading Mun. Light Dept. ("Reading"); Rowley Mun. Lighting Plant ("Rowley"); Taunton Mun. Lighting Plant ("Taunton"); and Wellesley Mun. Light Plant ("Wellesley").

[39] A Report is required when "the absolute value of [(Cumulative Under/(Over) Recovery, including Current Year interest)] is greater than $100,000 and the absolute value of [(Cumulative Under/(Over) recovery, including Current Year interest, as a percent of transmission-related PBOP expense)] is greater than 20%. See ISO-NE OATT, Attachment F, Appendix A, Worksheet 9, Note (j).

Annual Update. Comments on this filing are due on or before ***November 21, 2025***. If you have any questions concerning this proceeding, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **PBOP Collections Report (National Grid) (ER26-172)**

On October 17, 2025, National Grid (New England Power) filed a report identifying planned collection activity related to the over recovery of post-retirement benefits other than pensions ("PBOP") under Appendix A to Attachment F to the ISO-NE OATT. The report was required to be filed with the FERC because the absolute value of the over-recovery exceeds the threshold identified in OATT Attachment F. No changes to the filed rate were sought. The report shows an over-recovery, after interest, of ***$2,954,638***. If accepted, the PBOP figures will be used in National Grid's 2025 Annual Update. Comments on this filing are due on or before ***November 7, 2025***. If you have any questions concerning this proceeding, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **2026 NESCOE Budget (ER26-145)**

On October 15, 2025, ISO-NE, joined by NESCOE, filed Tariff changes for the funding of NESCOE's 2026 operations. The 2026 Operating Expense Budget for NESCOE is $2,731,108. The amount to be recovered reflects true-ups from 2024 (over-collections of $933,127). Accordingly, if accepted, the NESCOE budget will result in a charge of $0.00806 per kilowatt ("kW") of Monthly Network Load (a $0.00090/kW increase from 2025). The 2026 NESCOE budget was supported by the Participants Committee at its October 9, 2025 meeting (Agenda Item #5b). Comments and any interventions are on or before November 5, 2025. On November 3, 2025, NEPOOL submitted comments supporting NESCOE's 2026 Budget. National Grid and the MA DPU intervened doc-lessly. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **2026 ISO-NE Administrative Costs and Capital Budgets (ER26-144)**

On October 15, 2025, ISO-NE filed for recovery of its 2026 administrative costs (the "2026 Revenue Requirement") and submitted its capital budget for calendar year 2026 ("2026 Capital Budget", and together with the 2026 Revenue Requirement, the "2026 ISO Budgets"). The 2026 ISO Budgets were filed together pursuant to the Settlement Agreement entered into to resolve challenges to the 2013 ISO-NE Budgets. In the October 15, 2025 filing, ISO-NE reported that the 2026 Revenue Requirement is $330.0 million (a $23.6 million or 7.7% increase over 2025), which decreases to $314.4 million after the overcollection for 2024 is subtracted. Of that total, ISO-NE's administrative costs (i.e., the 2026 Core Operating Budget) comprise $281.8 million; depreciation and amortization of regulatory assets total $48.2 million; and a $15.6 million true-up decrease for 2022 over-collections. An effective date of January 1, 2026 was requested.

ISO-NE further reported that the 2026 Capital Budget is $42.5 million, consistent with 2025, and is comprised of the following (with 2026 projected costs and target completion dates, if available, in parentheses):

nGEM Real-Time Market Clearing Engine Implementation (May 2026)	($3.2 million)	Oracle Platform Replacement (Nov 2026)	($2.2 million)
Single Interval MCE Improvements (2028)	($5 million)	Managing Transmission Line Ratings; *Order 881* (Dec 2026)	($1 million)
Order 2222 Integration (Nov 2026)	($2.6 million)	Adoption of NERC CIP Compliance of Synchrophasor Systems (Aug 2026)	($1 million)
EMS Short-Term Load Forecast (Jan 2026)	($1.2 million)		

Comments were due on or before November 5, 2025. On October 20, 2025, NEPOOL filed comments in support of the 2026 ISO Budgets, noting that the Participants Committee unanimously supported the Operating and Capital Budgets at its October 9, 2025 meeting (with abstentions). National Grid and MA DPU filed doc-less interventions only. This matter is pending before FERC. If there are any questions on this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **Kleen Energy CIP-IROL (Schedule 17) Rate Schedule Filing (ER26-132)**

On October 14, 2025, Kleen Energy Systems, LLC ("Kleen Energy") requested FERC acceptance of a proposed rate schedule to allow Kleen Energy to begin the recovery period for certain Interconnection Reliability Operating Limits critical infrastructure protection ("CIP") costs ("CIP-IROL Costs") under Schedule 17 of the ISO-NE Tariff. Kleen Energy stated that the rate schedule will provide interested parties notice of Kleen Energy's intent to recover CIP-IROL Costs for its 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. An October 14, 2025 effective date was requested. Comments were due on or before November 4, 2025; none were filed. National Grid intervened doc-lessly. 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).

- **Kleen Energy CIP-IROL (Schedule 17) Rate Schedule Filing (ER26-132)**

On October 14, 2025, Kleen Energy Systems, LLC ("Kleen Energy") requested FERC acceptance of a proposed rate schedule to allow Kleen Energy to begin the recovery period for certain CIP-IROL Costs under Schedule 17 of the ISO-NE Tariff. Kleen Energy stated that the rate schedule will provide interested parties notice of Kleen Energy's intent to recover CIP-IROL Costs for its 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. An October 14, 2025 effective date was requested. Comments were due on or before November 4, 2025; none were filed. National Grid intervened doc-lessly. 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).

- **PBOP Collections Report (Eversource) (ER26-58)**

On October 7, 2025, Eversource filed a report identifying planned collection activity related to the over recovery of post-retirement benefits other than pensions ("PBOP") under Appendix A to Attachment F to the ISO-NE OATT. The report was required to be filed with the FERC because the absolute value of the over-recovery exceeds the threshold identified in OATT Attachment F. No changes to the filed rate were sought. The report shows an over-recovery, after interest, of ***$368,462*** for CL&P, ***$759,568*** for NSTAR East, and ***$179,779*** for PSNH. If accepted, the PBOP figures will be used in Eversource's 2025 Annual Updates. Comments on this filing were due on or before October 28, 2025; none were filed. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Bucksport CIP-IROL (Schedule 17) Cost Recovery Filing (ER25-3233)**

On October 16, 2025, the FERC accepted the revised rate schedule of Bucksport Generation LLC ("Bucksport") to allow Bucksport's recovery of ***$292,870*** in eligible CIP-IROL Costs under Schedule 17 of the ISO-NE Tariff.[40] Bucksport's revised rate schedule was accepted effective *October 19, 2025*. Unless the October 16, 2025 is order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

[40] *Bucksport Generation LLC*, Docket No. ER25-3233-000 (Oct. 16, 2025) (unpublished letter order).

- **Transmission Rate Annual (2023-24) Update/Info Filing (MOPA Formal Challenge (ER20-2054-000)**

As summarized in the last Report, on September 18, 2025, the FERC accepted in part and denied in part[41] the Maine Office of the Public Advocate's ("MOPA") formal challenge ("MOPA Formal Challenge")[42] to the TO's 2023-24 Annual Update.[43] Specifically, the FERC directed Eversource, National Grid, and MEPCO to respond to Maine OPA's Information Request Questions 1(b)(1) and 1(c)(2), and directed all of the Identified NETOs (Eversource; National Grid; MEPCO; Narragansett ; and VELCO/VTransco) to respond to Question 4,[44] on or before October 19, 2025. In addition, the FERC granted MOPA's request to permit it to supplement the MOPA Formal Challenge, as requested, with regard to the prudence of Identified NETOs' asset condition project costs reflected in the 2023 Annual Update, with such supplement to be filed on or before ***December 18, 2025***. Of note, Commissioner Chang's concurrence emphasized stakeholders' fundamental right to transmission planning and investment information through existing formula rate protocols and encouraged transmission owners/planners to proactively share information on transmission projects and planning.

Of the 4 Identified TOs, only one (VELCO/VTransco on October 17, 2025) filed its response to Question 4 publicly. Subject to any further information exchange and any MOPA supplement to its Formal Challenge due ***December 18, 2025*** as described above, the MOPA Formal Challenge remains pending before 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

- **Waiver Request: Return of CSO Payments (Brookfield) (ER26-143)**

On October 15, 2025, Brookfield Renewable Trading and Marketing LP ("Brookfield") requested a limited waiver of the Tariff to allow it to refund to ISO-NE, with interest, improperly received CSO payments for its Lièvre Power portfolio. The payments were received for the months of Oct, Nov, and Dec 2024 and Jan 2025 (because Brookfield failed to shed a portion of its full-year CSO through the respective monthly reconfiguration auctions) and would be returned to Participants with Capacity Load Obligations during the corresponding months. While Brookfield would like to refund these payments ("BRTM Refund"), with interest, to ISO-NE, the Tariff does not have a provision that allows ISO-NE to accept the BRTM Refund or specifies how refunds should in turn be made. to the FCM's Capacity Load Obligation. Brookfield asked the FERC for an order allowing ISO-NE to accept the BRTM Refund and directing ISO-NE to return the BRTM Refund to the FCM's Capacity Load Obligation for the months of October, November, and December 2024 and January 2025 ("FCM Refund"). Brookfield reported that ISO-NE authorized it to state that ISO-NE does not oppose the Waiver Request and can, if the Waiver Request is

[41] *ISO New England Inc.*, 192 FERC ¶ 61,234 (Sep. 18, 2025) ("*MOPA 2023-24 Annual Rate Update Challenge Order*").

[42] In the MOPA Formal Challenge, MOPA asserted that, (i) with respect to the cost of asset condition projects placed into service in 2022, "Identified TOs" (Eversource (CL&P, NSTAR East, NSTAR West, and PSNH); National Grid; MEPCO; Narragansett; and VELCO/VTransco) have refused to answer questions regarding investment policies and practices related to prudence of these investments and (ii) that the Identified TOs' decision not to respond to these questions violates their obligation under the OATT's Protocols.

[43] On July 31, 2023, the PTO-AC submitted its annual filing identifying adjustments to Regional Transmission Service charges, Local Service charges, and Schedule 12C Costs under Section II of the Tariff for 2024 (the "2023-24 Annual Update"). The filing reflected the charges to be assessed under annual transmission and settlement formula rates, reflecting actual 2022 cost data, plus forecasted revenue requirements associated with projected PTF, Local Service and Schedule 12C capital additions for 2023 and 2024, as well as the Annual True-up including associated interest. The PTO-AC stated that the annual updates result in a Pool "postage stamp" RNS Rate of $154.35/kW-year effective Jan. 1, 2024, an increase of $12.71 /kW-year from the charges that went into effect on Jan. 1, 2023. In addition, the filing included 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 $1.95 kW-year (effective June 1, 2023 through May 31, 2024), a $0.20/kW-year increase from the Schedule 1 charge that last went into effect on June 1, 2023.

[44] Question 1(b)(1) requested copies of any written policies that describe the procedures and processes employed to evaluate the need for a particular asset condition project; Question 1(c)(2) requested copies of any documents (or a narrative description if no documents exist) identifying the reasons why those participating in the decision-making process recommended against proceeding with a particular asset condition project; Question 4 related to the existence and employment of safeguards against the placement of asset condition projects into service before they are needed.

granted, implement the FCM Refund as described. Comments on this Waiver Request were due on or before November 5, 2025; none were filed. National Grid filed a doc-less intervention. 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).

- ***Order 2222* Conforming Changes (ER26-105)**

On October 10, 2025, ISO-NE and NEPOOL filed conforming changes to the ISO-NE Tariff to (i) clarify participation rules for Demand Response Distributed Energy Resource Aggregations ("DR DERAs") in the Energy and Ancillary Services Markets, (ii) reduce the minimum size for Generator Assets participating in the Regulation Market consistent with *Order 2222*-compliant resources, and (iii) make other clarifying and conforming Tariff edits to facilitate participation by DERAs. An effective date of November 1, 2026 was requested. Comments were due on or before October 31, 2025; none were submitted. Calpine, MA DPU, NRG Business Marketing and National Grid intervened doc-lessly. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **ISO-NE Waiver Granted: Capacity Performance Payment Calculation and Use of Late Payment Account (ER25-3253)**

On October 31, 2025, in a 2-1 decision (Commissioner See dissenting), the FERC granted ISO-NE the limited waivers of Market Rule 1 section 13.7.2.6 (Calculation of Capacity Performance Payments), and the Billing Policy, section 3.3(e) (Late Payment Account) that it requested so that it can reimburse/make whole Brookfield White Pine Hydro's Harris Hydro Unit 2 ("Harris 2").[45] ISO-NE explained that Harris 2 was incorrectly assessed a $68,000 Performance Payment Charge for the June 24, 2025 Capacity Scarcity Condition ("CSC") when ISO-NE manually prevented Harris 2 from running at its EcoMax during the CSC because a non-commercial resource that was not conducting an otherwise permitted commissioning activity was incorrectly permitted to run. The limited waivers ensure that ISO-NE is able to exclude the charge from Harris 2's final invoice for that operating day and return the amount to Harris 2 through a withdrawal from the Late Payment Account. Commissioner See reluctantly dissented, finding the FERC didn't have the power to grant the relief (retroactive in her view) under the filed rate doctrine. She said that "sticking to [that] conclusion []would uphold the filed rate doctrine's cornerstone principle that ratepayers are entitled to sufficient notice before the rules change. At the same time, no one wants to see a costly error go uncorrected. I encourage ISO-NE to explore revising its Tariff to prevent similar predicaments in the future. (A Tariff without sufficient error-correction protections might even raise questions about its justness and reasonableness.)" Unless the *Harris 2 Waiver Order* is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com) or Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Waiver Request Denied: Interconnection Request Requirements (Evergreen Wind Power II) (ER25-3031)**

On October 16, 2025, the FERC denied the wavier requested by Evergreen Wind Power II ("Evergreen")[46] of certain LGIP and Tariff provisions that require a prospective New Capacity Resource to have submitted a valid Interconnection Request seeking Capacity Network Resource ("CNR") Interconnection Service, and to have been assigned a valid Queue Position associated with that request, as of June 13, 2024, as a condition of participating in the Interim Reconfiguration Auction Qualification process ("Evergreen Waiver Request").[47] In denying the Evergreen request, the FERC found that the request was retroactive in nature and prohibited by the filed rate

---

[45] *ISO New England Inc.*, 193 FERC ¶ 61,084 (Oct. 31, 2025) ("*Harris 2 Waiver Order*").

[46] Evergreen stated that the Waiver Request would allow it to seek qualification of its capacity for participation in the FCM, through participation in the Transitional CNR Group Study. Evergreen explained the circumstances that preceded and resulted in the Waiver Request. Evergreen stated that a waiver would allow ISO-NE to accept Evergreen's updated request for CNR Interconnection Service, and place Evergreen at the back of the Interconnection Queue, lower in priority to all other projects being evaluated in the Transitional CNR Group Study.

[47] *Evergreen Wind Power II, LLC*, 193 FERC ¶ 61,028 (Oct. 16, 2025) ("*Order Denying Evergreen Waiver*").

doctrine.[48] Unless the *Order Denying Evergreen Waiver* is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

IV. OATT Amendments / TOAs / Coordination Agreements

- **RI Energy Revision to Fixed PBOP Expense Amount (ER26-390)**

On October 31, 2025, RI Energy filed to revise its PBOP expense amount under Appendix A to Attachment F of the OATT to limit potential over-recoveries of PBOP expenses. An effective date of January 1, 2026 was requested. Comments on this filing are due on or before ***November 21, 2025***. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- ***Order 676-K* Compliance Filings (ER25-2654; ER25-2657)**

On June 27, 2025, in accordance with *Order 676-K*,[49] the following *Order 676-K* compliance filings to incorporate, or seek waiver of, the WEQ Version 004 Standards were submitted:

  - *Order 676-K* Compliance Filing (ISO-NE, NEPOOL, CSC: Tariff Schedule 24 and Schedule 18-Attachment Z) (ER25-2654); and
  - *Order 676-K* Compliance Filing (ISO-NE, PTO AC, Schedule 20-A Service Providers: Schedules 20A-Common and 21-Common) (ER23-2657).

Comments on the compliance filings were due on or before July 17, 2025; none were filed. Calpine intervened in each proceeding. The *Order 676-K* compliance filings remain pending before the FERC. If there are questions on any of these compliance filings, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Order 904* Compliance Filing – Reactive Power Compensation Revisions (ER25-1703)**

On September 16, 2025, the FERC accepted the revisions to Schedule 2 of the ISO-NE OATT filed in compliance with *Order 904* ("Reactive Power Compensation Changes").[50] As previously reported, the Reactive Power Compensation Changes eliminate compensation for reactive power capability within the standard power factor range of 0.95 leading to 0.95 lagging, while continuing to allow compensation for capability outside that range. The proposed revisions to Schedule 2 of the OATT will become effective 6-12 months from the date of the September 16 order, with an actual date to be submitted one month in advance. Unless the September 16 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes & Agreements[51]

- **Schedule 21-RIE: Block Island Wind Farm Facilities Reclassification (ER26-397)**

On October 31, 2025, RI Energy submitted adjustments to the Block Island Transmission System ("BITS") Surcharge set forth in 2 service agreements with Block Island Power Company ("BIPCO") to reflect a

[48] *Id.* at P 21.

[49] *Standards for Business Practices and Communication Protocols for Public Utilities*, Order No. 676-K, 190 FERC ¶ 61,116 (Feb. 19, 2025) ("*Order 676-K*").

[50] *ISO New England Inc.*, Docket No. ER25-1703-000 (Oct. 16, 2025).

[51] Reporting on the following Time Value Refunds Reports, which have each been pending before the FERC for more than a year and a half, has been suspended and will be continued if and when there is new activity to report: Schedule 21-VP: Versant/Jonesboro LSA

change in the classification of the electric facilities associated with the Block Island Wind Farm from distribution to transmission. The proposed adjustments are expected to increase the BITS Surcharge, but the overall impact on customers is expected to be minimal. A January 1, 2026 effective date was requested. Comments on this filing are due on or before ***November 21, 2025***. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-GMP: BTM Gen & SSCDC Cost Revisions (ER26-386)**

On October 31, 2025, Green Mountain Power ("GMP") filed revisions to Schedule 21-GMP intended to provide more commercially and operationally reasonable terms for generators to take local non-firm point-to-point service on GMP's system. The revisions clarify that behind-the-meter ("BTM") generation is excluded from Local Network Load, which is consistent with how Regional Network Load is calculated under the ISO-NE OATT; and revise the billing methodology for Scheduling, System Control and Dispatch Costs ("SSCDC") to replace the rolling 12-month average billing methodology in Schedule 1. A December 31, 2025 effective date was requested. Comments on this filing are due on or before ***November 21, 2025***. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-ES: Eversource Removal of Duplicative True Up of S&D Costs (ER26-321)**

On October 30, 2025, Eversource, on behalf of CL&P, NSTAR (East/West), and PSNH, filed changes, to Schedule 21-ES to eliminate a duplicative true up of scheduling and dispatch costs ("S&D"), which added to the ISO-NE OATT ("Formula Rate Template") and eliminates the need for the Schedule 21-ES S&D calculation. On November 4, 2025, Eversource amended the filing to request a January 1, 2026 effective date. Comments on the amended filing are due on or before ***November 20, 2025***. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-GMP: Green Mountain Power/Hardwick NITSA Notice of Cancellation (ER25-298)**

On October 30, 2024, GMP submitted a notice of cancellation of the Network Integration Transmission Service Agreement and Local Operating Agreement ("NITSA") with the Village of Hardwick Electric Department ("Hardwick") filed under Schedule 21-GMP. GMP reported that, as of June 30, 2024, Hardwick is no longer taking service pursuant to the NITSA. GMP requested that the FERC grant waiver of its notice requirement[52] to the extent necessary to permit a requested June 30, 2024 effective date. Comments on this filing were due on or before November 20, 2024; none were filed. As of the date of this Report, the FERC has still not acted on this filing. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-VP: 2022 Annual Update Settlement Agreement (ER20-2054-003)**

Still pending is Versant's August 29, 2023 Joint Offer of Settlement ("Versant 2022 Annual Update Settlement Agreement") between itself and the MPUC.[53] Versant stated that, if approved, the 2022 Annual Update Settlement Agreement would resolve all issues raised by the MPUC with respect to the 2022 Annual Update. Although no adverse comments on the Versant 2022 Annual Update Settlement Agreement 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).

(ER24-24); Schedule 21-GMP: National Grid/Green Mountain Power LSA (ER23-2804); and Schedule 21-VP: Versant/Black Bear LSAs (ER23-2035).

[52] 18 CFR § 35.11 (which permits, upon application and for good cause shown, the FERC to allow a rate schedule, tariff, service agreement, or a part thereof, to become effective as of a date prior to the date of filing or the date such change would otherwise become effective in accordance with the FERC's rules (e.g. 60 days after filing)). FERC policy is to deny waiver of the prior notice requirement when an agreement for new service is filed on or after the date that services commence, absent a showing of extraordinary circumstances.

[53] Joint Offer of Settlement Regarding Versant Power, Bangor Hydro District Charges.

- **Schedule 21-GMP: Annual True Up Calculation Informational Filing (ER12-2304)**

On October 30, 2025, pursuant to Section 4 of Schedule 21-GMP, Green Mountain Power ("GMP") submitted its annual informational filing containing the true-up calculation of its actual (rather than estimated) costs for the January 1, 2024 through December 31, 2024 ("2043 Service Period"). The FERC will not notice this filing for public comment, and absent further activity, no further FERC action is expected. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports[54]

- **Capital Projects Report – 2025 Q3 (ER26-152)**

On October 15, 2025, ISO-NE filed its Capital Projects Report and Unamortized Cost Schedule for the third quarter ("Q3") of calendar year 2025 (the "Report"). ISO-NE is required to file the Report under section 205 of the FPA pursuant to Section IV.B.6.2 of the Tariff. Report highlights include the following new projects: (i) Oracle Platform Replacement ($2,795,600); (ii) CIP Electronic Security Perimeter Redesign Phase III ($1,180,000); (iii) IMM Datamart Infrastructure Deployment ($750,000); (iv) Capital Projects Issue Resolution Phase II ($713,700); and (v) VAR Capability Testing Application ($420,000). Projects placed in service this quarter include: CAMS Application Software Technology Upgrade; FCM Delivery Financial Assurance; and Replace Employee Expense Management System. And projects reported to have significant changes in funds include: Enterprise Core Network Refresh (reduced by $350,000); Identity Access Management Automation Improvements (reduced by $152,800); ARD Circuit Continuity Improvements (reduced by $150,000); SMS Application Technology Upgrade (reduced by $144,200); and the NECEC Transmission Line (increased by $100,100). Comments on this filing were due on or before November 5, 2025. On October 20, 2025, NEPOOL filed comments in support of the Report. National Grid intervened doc-lessly. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **Capital Projects Report – 2025 Q2 (ER25-3137)**

On October 9, 2025, the FERC accepted ISO-NE's Capital Projects Report and Unamortized Cost Schedule covering the second quarter ("Q2") of calendar year 2025 (the "Report"), effective July 1, 2025, as requested. As previously reported, Report highlights included the following new projects: (i) Distributed Energy Resources *Order 2222* Integration ($5,351,600); (ii) Synchrophasor Systems NERC CIP Compliance ($2,074,100); (iii) Microsoft 365 Phase II ($815,800); (iv) Circuit Inventory Management Platform ($190,700); (v) CAMS High Priority Application Modification Request ("AMR") Project ($397,700); (vi) Solver Performance Study ($346,500); (vii) Centralized Application Security ($204,600); and (viii) Enterprise Document Library MS 365 Conversion ($186,700). The CIP Electronic Security Perimeter Redesign Phase II ($4,760,600) was completed this quarter. Projects with significant budget changes included: CAMS Application Software Technology Upgrade (increase of $283,800 to $1,639,600); Identity Access Management Automation Improvements (decrease of $282,400 to $476,400); 2025 Issue Resolution (decrease of $180,000 to $523,000); and Replace Employee Expense Management System (decrease of $137,900 to $289,500). Significant budget changes for projects in planning include a decrease of $2 million for the nGEM Software Development Part IV project, which is no longer needed due to the program being completed with Part III. ISO-NE's non-project capital spending budget increased by $300,000, for a total of $5.3 million, due to an accelerated repair of the Sullivan North building roof. Unless the October 9 Order is challenged, this matter will be concluded. If you

[54] Reporting on the *Opinion 531* Refund Reports (EL11-66) has been suspended and will be continued if and when there is new activity to report.

have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **LFTR Implementation: 68th Quarterly Status Report (ER07-476)**

ISO-NE filed the 68th of its quarterly status reports regarding LFTR implementation on October 15, 2025. ISO-NE reported that it implemented monthly reconfiguration auctions (accepted in ER12-2122) beginning with the month of October 2019. ISO-NE further reported that, while it will continue to evaluate its as-filed LFTR design and financial assurance issues, including an ongoing evaluation of the FTR market and risk associated with FTRs and LFTRs, it is currently focused on higher priority market-design initiatives. ISO-NE concluded its report by describing the 18-month implementation that would be required once the LFTR financial assurance issues are resolved. These status reports are not noticed for public comment.

IX. Membership Filings

Questions concerning any of the Membership Filings can be directed to Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Nov 2025 Membership Filing (ER26-363)**

On October 31, 2025, NEPOOL requested that the FERC accept the membership in NEPOOL of the Mid-Coast Region Redevelopment Authority ("MRRA") (Publicly Owned Entity Sector). Comments on this filing, if any, are due on or before ***November 21, 2025***.

- **Oct 2025 Membership Filing (ER25-3571)**

On September 30, 2025, NEPOOL requested that the FERC accept: (i) the following Applicants' membership in NEPOOL: AE-ESS Holyoke, LLC [Related Person to Agilitas Companies (AR Sector, DG Sub-Sector)]; American Power & Gas of RI, LLC [Related Person to American Power & Gas of MA, LLC (Supplier Sector)]; and Burgess BioPower [Related Person to Berlin Station (Generation Sector Group Member)]; and (ii) the termination of the Participant status of Hudson Energy Services. Comments on this filing, if any, were due on or before October 21, 2025; none were filed. This matter is pending before the FERC.

- **Sep 2025 Membership Filing (ER25-3342)**

On October 23, 2025, the FERC accepted: (i) the following Applicants' membership in NEPOOL: energyRe Giga-Projects, LLC (Provisional Member, QTPS); and Janus Power LLC (Supplier Sector); (ii) the termination of the Participant status of Windham Energy Center; and (iii) the corporate name changes of Icetec Energy Services, LLC (f/k/a Icetec Energy Services, Inc.); and Research Power Corporation (f/k/a Centre Lane Trading Ltd.). Unless the October 23 order is challenged, this proceeding will be concluded.

- **Suspension Notice (not docketed)**

Since the last Report, ISO-NE filed, pursuant to Section 2.3 of the Information Policy, a notice with the FERC noting that the following Market Participant was suspended from the New England Markets on the date indicated (at 8:30 a.m.):

Date of Suspension/ FERC Notice	***Participant Name***	***Default Type***
Oct 14/9, 2025	AES Renewables Holdings, LLC	Financial Assurance
Oct 16/20, 2025	Actual Energy Inc.	Financial Assurance

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

X. Misc. - ERO Rules, Filings; Reliability Standards[55]

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

- **NERC FFT/CE Programs Annual Report (RC11-6-021)**

On September 23, 2025, NERC filed its annual report on the Find, Fix, and Track ("FFT") and Compliance Exception ("CE") programs, in accordance with prior orders.[56] Building upon NERC and FERC Staff's annual coordinated review of FFTs and CEs summarized in the last Report, NERC reported that the FFT and CE Programs continue to meet expectations. NERC added that the results of the annual joint review show continued overall improvement in program implementation and significant alignment across the ERO Enterprise, particularly in the processing and understanding of the risk associated with individual noncompliance. Comments on the Annual Report were due on or before October 8, 2025; none were filed. Since the last Report, FERC and NERC Staff in a letter dated October 10, 2025 identified certain FFTs and CEs for inclusion in its annual evaluation of the FFT and CE programs. Documentation/ responses related to those FFT and CE data requests must be submitted by ***November 21, 2025.***

- **Wildfire Prevention, Detection, and Mitigation Best Practices (RD25-9)**

On September 10, 2025, the FERC directed NERC to submit in an informational filing a report on best practices to reduce the risk of wildfire ignition from the BPS on or before ***May 1, 2026***.[57] The report must assess methods such as "vegetation management, the removal of forest-hazardous fuels along transmission lines, improved engineering approaches, and safer operational practices.[58] The report must also include an assessment of known and emerging technologies that can be deployed to detect and mitigate wildfire in the context of protecting the BPS and its use to provide reliable service to customers. The FERC noted its concurrently issued notice of technical conference on wildfire mitigation (*see* AD25-16 in Section XII below) and said NERC should consider the testimony from that conference as an input for its informational filing, including in its consideration of the need for new or revised Reliability Standards or alternative further action. Since the last Report, one set of comments, identifying the role that ACCC Conductors play in mitigating wildfire risk was filed by CTC Global.

- **Revised Reliability Standard: EOP-012-3 (RD25-7)**

On September 18, 2025, the FERC approved Reliability Standard EOP-012-3 (Extreme Cold Weather Preparedness and Operations)[59] and directed NERC, for a period of time,[60] to collect and submit certain information to the FERC.[61] As previously reported, EOP-012-3 is intended to improve the efficiency and

---

[55] Reporting on the following ERO Reliability Standards or related rule-making proceedings has been suspended and will be continued if and when there is new activity to report: NERC Report on Evaluation of Physical Reliability Standard (CIP-014) (RD23-2); *Order 901*: IBR Reliability Standards (RM22-12); and 2024 Reliability Standards Development Plan (RM05-17 *et al.*).

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

[57] *N. Am. Elec. Rel. Corp.*, 192 FERC ¶ 61,212 (Sep. 10, 2025).

[58] *See* Exec. Order No. 14308 (Empowering Commonsense Wildfire Prevention and Response), 90 Fed. Reg. 26175 (June 12, 2025), https://www.whitehouse.gov/presidential-actions/2025/06/empowering-commonsense-wildfire-prevention-and-response/ (Executive Order 14308).

[59] *N. Am. Elec. Rel. Corp.*, 192 FERC ¶ 61,229 (Sep. 18, 2025) ("*EOP-012-3 Order*").

[60] Starting no later than ***Oct. 2026*** and ending in ***Oct. 2034*** (*EOP-012-3 Order* at P 37).

[61] The FERC directed NERC to submit: (i) for each Regional Entity, anonymized ***data on***: (a) the number of submitted Generator Cold Weather Constraint declarations, (b) the number of approved declarations, (c) the aggregate MVA of approved declarations, and (d) a summary of the rationale(s) provided for approved declarations. (*EOP-012-3 Order* at P 34); (ii) a ***narrative analysis addressing*** the following issues: (a) whether reliability coordinators, transmission operators, and balancing authorities (or other relevant entities) are timely notified of Generator Cold Weather Constraint declarations and corrective action plan extensions; (b) the reliability impact, if any, of allowing generators 36 months, rather than a shorter time period, such as 24 months, to correct known freeze related issues; and (c)

effectiveness of the BPS in future cold weather seasons by providing clarity regarding the criteria for declaring Generator Cold Weather Constraints, shortening timelines for implementing corrective action plans following cold weather reliability events, and requiring more frequent review of validated constraints to reflect evolving technologies and operating conditions. Revised EOP-012-3 also includes new requirements for BES generating units entering commercial operation on or after October 1, 2027 to have cold weather capability upon entry, unless a validated constraint applies. EOP-012-3 will go into effect on *October 1, 2025*. Requests for clarification of the *EOP-012-3 Order* were filed by each of NERC and Joint Trade Associations.[62] Those requests are pending, with FERC action required on or before ***November 17, 2025***, or the requests will be deemed denied by operation of law.

- **NOPR: Revised Reliability Standards: CIP-002-7 through CIP-013-3 (Virtualization[63]) (RM24-8)**

On September 18, 2025, the FERC issued a notice of proposed rulemaking ("NOPR")[64] proposing to approve 11 modified CIP Reliability Standards,[65] and 4 new and 18 modified definitions in the NERC Glossary of Terms,[66] to facilitate the full implementation of virtualization and to address the risks associated with virtualized environments.[67] As previously reported, the proposed CIP Reliability Standards would permit Responsible Entities with more "traditional" architecture to continue with their current configurations. In the NOPR, the FERC seek comments specifically on the proposed replacement of the phrase "where technically feasible" with the phrase "per system capability", including alternative approaches, which the FERC said would assist it in formulating a possible directive in a final rule.[68] Comments on the *Visualization NOPR* are due on or before ***November 24, 2025***.[69]

---

whether the Generator Cold Weather Constraint declarations approval process is consistently interpreted and applied by the CEAs in a timely manner to address the reliability risks presented by extreme cold weather; whether the Generator Cold Weather Constraint declaration criteria in Attachment 1 is adequately defined and clear so that applicable entities understand what is required of them; and the reliability impact on the BPS due to Generator Cold Weather Constraint declarations from each criterion in Attachment 1, in addition to the reliability impact from approved corrective action plan extensions.

[62] "Joint Trade Associations" are the American Public Power Association ("APPA"), Electric Power Supply Association ("EPSA"), Large Public Power Council ("LPPC"), National Rural Electric Cooperative Association ("NRECA"), and Transmission Access Policy Study Group ("TAPS").

[63] Virtualization is "the process of creating virtual, as opposed to physical, versions of computer hardware to minimize the amount of physical hardware resources required to perform various functions."

[64] *Virtualization Reliability Standards*, 192 FERC ¶ 61,228 (Sep. 18, 2025) ("*Virtualization NOPR*").

[65] The revised Cyber Security Standards are: CIP-002-7 (BES Cyber System Categorization); CIP-003-10 (Security Management Controls); CIP-004-8 (Personnel & Training); CIP-005-8 (Electronic Security Perimeter(s)); CIP-006-7 (Physical Security of BES Cyber Systems); • CIP-007-7 (Systems Security Management); CIP-008-7 (Incident Reporting and Response Planning); CIP-009-7 (Recovery Plans for BES Cyber Systems); CIP-010-5 (Configuration Change Management and Vulnerability Assessments); CIP-011-4 (Information Protection); and CIP-013-3 (Supply Chain Risk Management).

[66] The new and/or revised Glossary Terms are: BES Cyber Asset ("BCA"), BES Cyber System ("BCS"), BES Cyber System Information ("BCSI"), CIP Senior Manager, Cyber Assets, Cyber Security Incident, Cyber System, Electronic Access Point ("EAP"); External Routable Connectivity ("ERC"), Electronic Security Perimeter ("ESP"), Interactive Remote Access ("IRA"), Intermediate System, Management Interface, Physical Access Control Systems ("PACS"), Physical Security Perimeter ("PSP"), Protected Cyber Asset ("PCA"), Removable Media, Reportable Cyber Security Incident, Shared Cyber Infrastructure ("SCI"), Transient Cyber Asset ("TCA"), and Virtual Cyber Asset ("VCA").

[67] The FERC also proposed to approve the associated violation risk factors, violation severity levels, implementation plans, and effective dates for the proposed Reliability Standards, as well as to approve the retirement of the currently effective version of each proposed Reliability Standard.

[68] *Virtualization NOPR* at P 3.

[69] The *Visualization NOPR* was published in the *Fed. Reg.* on Sep. 23, 2025 (Vol. 90, No. 182) pp. 45,679-45,685.

- ***Order 912*: Supply Chain Risk Management ("SCRM") Reliability Standards (RM24-4)**

On September 18, 2025, almost a year to the day the FERC issued its *SCRM Standards NOPR*, the FERC issued its final rule (*Order 912*)[70] largely adopting the NOPR's proposals, directing NERC to develop (i) new or modified Reliability Standards that address the sufficiency of responsible entities' SCRM plans related to the identification of and response to supply chain risks and (ii) modifications related to supply chain protections for protected cyber assets. Although the FERC declined to direct NERC to require responsible entities to validate data received from vendors, it nonetheless encouraged entities to voluntarily implement this security practice as appropriate.[71] *Order 912* will become effective November 24, 2025.[72] In response to comments, the FERC directed NERC to submit the new or revised Reliability Standards within 18 months of the effective date.

- **ITCS: Strengthening Reliability Through the Energy Transformation (AD25-4)**

On November 19, 2024, NERC submitted for FERC consideration the Interregional Transfer Capability Study ("ITCS") directed by the U.S. Congress in the Fiscal Responsibility Act of 2023 ("Fiscal Responsibility Act"). NERC stated that the ITCS is the first-of-its-kind assessment of transmission transfer capability under a common set of assumptions. The ITCS focuses on transfer capability in accordance with the congressional directive, while acknowledging that other processes and pending projects may help support a reliable future grid. The ITCS was not designed to be a transmission plan or blueprint. NERC stated that the ITCS demonstrates that sufficient transfer capability and resources exist at present to maintain energy adequacy under most scenarios, but when calculating current transfer capability and projected future conditions, the ITCS identifies potential energy inadequacy across several transmission planning regions in the event of extreme weather. The ITCS recommends an increase of 35 GW of transfer capability across different regions as technically prudent additions to demonstrably strengthen reliability. The ITCS also recommends region-specific enhancements to transfer capability, "because a one-size-fits all approach across the U.S. may be inefficient and ineffective."

Comments on NERC's ITCS were filed by, among others: AEU, ENGIE, Eversource, Grid United, Invenergy, National Grid, NRG, ACPA/SEIA, ACORE, APPA, EEI, EIPC, EPSA, Public Interest Organizations, Northeast States, NRECA, NASUCA, R Street, and WIRES. On March 25, 2025, NERC submitted a reply to clarify certain of the matters raised in those comments on the ITCS.

- **2026 NERC/NPCC Business Plans and Budgets (RR25-5)**

On October 30, 2025, the FERC accepted NERC's proposed Business Plan and Budget, as well as the Business Plans and Budgets for the six Regional Entities,[73] including NPCC, for 2026.[74] As previously reported, NERC reported that its 2026 funding requirement represents an increase of 4.3% from 2025 with a total budget of $128.3 million and a total funding requirement of $128.7 million. The NPCC U.S. allocation of NERC's net funding requirement is $15.69 million. NPCC will have $26.6 million in statutory funding (a U.S. assessment per kWh (2024 NEL) of $0.000024) and $1.2 million for non-statutory functions. NERC will allocate to NPCC $13.6 million of its 2026 assessment. Unless the *2026 NERC Budgets Order* is challenged, this proceeding will be concluded.

---

[70] *Supply Chain Risk Mgmt. Reliability Standards Revisions*, Order No. 912, 192 FERC ¶ 61,230 (Sep. 18, 2025) ("*Order 912*").

[71] *Id.* at P 2.

[72] *Order 912* was published in the *Fed. Reg.* on Sep. 23, 2025, 2025 (Vol. 90, No. 182) pp. 45,661-45,671.

[73] The Regional Entities are Midwest Reliability Organization ("MRO"), Northeast Power Coordinating Council, Inc. ("NPCC"), ReliabilityFirst Corporation ("ReliabilityFirst"), SERC Reliability Corporation ("SERC"), Texas Reliability Entity ("Texas RE"), and Western Electricity Coordinating Council ("WECC").

[74] *N. Am. Elec. Rel. Corp.*, 193 FERC ¶ 61,075 (Oct 30, 2025) ("*2026 NERC Budgets Order*").

XI. Misc. - of Regional Interest

- **203 Application: Cricket Valley Energy Center (EC25-116)**

On September 19, 2025, the FERC authorized a transaction pursuant to which certain parties[75] will indirectly acquire voting interest of 10% or more in Cricket Valley Energy Center ("CVEC") and the right to appoint one or more non-independent directors or managers to the board of one of CVEC or its upstream owners.[76] When consummated, CVEC will become a Related Person to Bridgewater Power and Burgess BioPower (each in the Generation Group Seat). Pursuant to the September 19 order, Applicants must file a notice 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: CPower/NRG (EC25-102)**

On June 12, 2025, as amended and supplemented, NRG East Generation Holdings LLC ("NRG East Holdings"), NRG Demand Response Holdings LLC ("NRG DR Holdings"), Lightning Power, LLC ("Lightning Power" and together with NRG East Holdings and NRG DR Holdings, "NRG") and Enerwise Global Technologies, LLC d/b/a CPower ("CPower") (collectively, Applicants") requested authorization for NRG to acquire indirect interests in CPower. Comments on this application were due on or before August 11, 2025.

On July 3, 2025, the PJM IMM submitted a report analyzing the proposed transaction and stating that the transaction, without specific behavioral conditions for emergency and pre-emergency demand resources, will "increase structural market power without any mitigating factors and therefore would not be in the public interest." Without such conditions related to emergency and pre-emergency demand resources, the PJM IMM recommended rejection of the demand side part of the Transaction. The Maryland Office of People's Counsel ("MPC") and the New Jersey Division of Rate Counsel ("Rate Counsel") (together, the "Joint Consumer Advocates") similarly protested the Application, stating that, because the transaction otherwise harms competition, the FERC should only approve the transaction with the PJM IMM's suggested modifications. Since the last Report, NRG answered the PJM IMM's and Joint Consumer Advocates' comments. On August 27, the PJM IMM answered NRG's August 7 answer. NRG answered the PJM IMM's August 27 answer on September 2, 2025.

Deficiency Letter Response. On September 2, 2025 (as further supplemented on September 12, 2025), Applicants filed a supplement in response to an August 13 deficiency letter issued by FERC Staff. Comments on that supplement were due on or before September 23, 2025; 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).

- **203 Application: Burgess BioPower/White Mountain Power (EC25-99)**

On August 13, 2025, the FERC authorized a transaction by which White Mountain Power (an affiliate of, among others, Bridgewater Power and David Energy Supply) will acquire from Burgess BioPower all of the indirect ownership interests of Berlin Station in connection with a plan of reorganization under Chapter 11 of the US Bankruptcy Code.[77] Pursuant to the August 13 order, White Mountain Power must file a notice 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).

---

[75] Kiwoom US, PE-US Jiminy OFLEX Blocker, LLC and PE-US Jiminy Aggregator, L.P., Cricket Valley Funding, and Cricket Valley Energy Holdings II LLC ("Applicants").

[76] *Cricket Valley Energy Center, LLC*, 192 FERC ¶ 62,181 (Sep. 19, 2025).

[77] *Burgess BioPower, LLC and White Mountain Power, LLC*, 192 FERC ¶ 62,085 (Aug. 13, 2025).

- **203 Application: Constellation/Calpine (EC25-43)**

On July 23, 2025, the FERC conditionally authorized[78] Constellation's acquisition of Calpine, subject to Applicants' commitments to divest certain generation facilities ("Mitigation Plan"), to extend certain pre-existing commitments that apply to the Constellation Applicants and their public utility subsidiaries in PJM market to all Applicants in the PJM market, to abide by the terms of an agreement reached between Constellation and the PJM IMM, and to implement interim mitigation ("Interim Behavioral Mitigation") until the Mitigation Plan is completed. Pursuant to the July 23 order, Applicants must file a notice within 10 days of consummation of the transaction, which as of the date of this Report has not yet occurred. When consummated, Constellation and Calpine will become Related Persons.

On August 22, 2025, two requests for rehearing of the *Merger Order* were filed, one by the Pennsylvania Office of Consumer Advocate; the other by the Public Citizen Petitioners.[79] The Constellation Applicants filed an answer on September 8, 2025, requesting the FERC deny the requests for rehearing. On September 22, 2025, the FERC issued an *Allegheny* Notice,[80] noting that the requests for rehearing may be deemed denied by operation of law, but noting that the requests will be addressed in a future order.[81] If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **PURPA Enforcement Petition – Allco Finance Ltd/CT DEEP (EL25-117)**

On September 24, 2025, Allco Finance Limited ("Allco") petitioned the FERC to initiate an enforcement action against the Connecticut Department of Energy and Environmental Protection ("CT DEEP") to remedy what it asserts is CT DEEP's improper implementation of section 210 of PURPA. Specifically, Allco asked the FERC to remedy violations that (i) permit Eversource to charge a QF for interconnection costs than are higher than the interconnection costs permitted under 18 C.F.R. §292.101(b)(7) and PURPA, and (ii) permit Eversource to allow generators that applied for interconnection after Allco to jump ahead of Allco's interconnections. Comments on this latest Allco complaint were due on or before October 24, 2025. Protesting, both CT PURA and CL&P urged the FERC to issue a notice of intent not to act with respect to the Petition. The Petition is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Facilities (Distrigas) Support Agreement Cancellation - NSTAR/National Grid (ER25-3550)**

On September, 29, 2025 NSTAR filed a notice of cancellation of a Facilities Support Agreement between itself and National Grid (Service Agreement No. DSA-NSTAR-002).[82] The Agreement provided NEP access to certain NSTAR distribution facilities as a back-up supply to serve National Grid's retail customer, Distrigas of Massachusetts. NSTAR reported that the Agreement is no longer required because all work under the Agreement has been completed and invoices have been paid. Comments on the notice of cancellation were due on or before October 20, 2025; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Joan Bosma (617-345-4651; jbosma@daypitney.com).

---

[78] *Constellation Energy Corp. et al.*, 192 FERC ¶ 61,074 (July 23, 2025) ("*Merger Order*").

[79] "Public Citizen Petitioners" are: Public Citizen, PennFuture, Clean Air Council, and Citizens Utility Board.

[80] The FERC issues an "Allegheny Notice" when it does not act within 30 days after receiving a challenge (a request for clarification and/or rehearing) to a FERC order. An Allegheny Notice confirms that the request is deemed denied by operation of law (see *Allegheny Def. Project v. FERC*, 964 F.3d 1, 2020 WL 3525547 (D.C. Cir. June 30, 2020) (*en banc*)) and the FERC order is final and ripe for appeal. The FERC has the right, up to the point when the record in a proceeding is filed with a Federal Court of appeals, to modify or set aside, in whole or in part, any finding or order made or issued by it. The FERC's intention to avail itself of its right and to issue a further order addressing the issues raised in the request (a "merits order") is signaled by the phrase "and providing for Further Consideration"; the absence of that phrase signals that the FERC does not intend to issue a merits order in response to the rehearing request.

[81] *Constellation Energy Corp. et al.*, 192 FERC ¶ 61,183 (Sep. 22, 2025) ("*Constellation Merger Order Allegheny Notice*").

[82] The FERC accepted the Facilities Support Agreement in Docket No. ER22-1124-000 (April 19, 2022).

- **D&E Agreement: PSNH/Kearsarge Grissom (ER25-3407)**

On October 20, 2025, the FERC accepted an Engineering, Design and Procurement ("D&E") Agreement between PSNH and Kearsarge Grissom LLC ("Kearsarge"), designated as Service Agreement No. IA-PSNH-17.[83] The D&E Agreement was accepted effective as of *September 11, 2025*, as requested. As previously reported Kearsarge will interconnect its 4.99 MW solar generating facility to the 46 kV sub-transmission line between Green Mountain Power's Maple Avenue B-42 and the 4402 breaker at the Green Mountain Power and National Grid demarcation considered at Bellows Falls (ISO-NE Queue Position 1226). The D&E Agreement allows PSNH to cover the costs to perform necessary engineering and design services related to that interconnection (including applicable overheads and loaders). Unless the October 20, 2025 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Interconnection Study Agreement Cancellation: PSNH/Wok LLC (ER25-3359)**

On October 29, 2025, the FERC accepted the notice of cancellation filed by PSNH of an Interconnection Study Agreement ("ISA") with Wok, LLC pursuant to which PSNH performed certain study services for Wok for a potential load interconnection in New Hampshire.[84] PSNH reported that the ISA is no longer required because all work pursuant to the ISA is complete and all invoices for that work paid. The notice was accepted for filing effective as of *September 4, 2025*, as requested. Unless the October 29 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement: NSTAR/BXP (ER25-3309)**

On October 21, 2025, the FERC accepted the D&E Agreement between NSTAR and BXP, Inc. ("BXP") under which NSTAR will assess and be reimbursed for its work to assess the feasibility and cost to underground two 115 kV transmission lines in Waltham, Massachusetts.[85] The D&E Agreement was accepted effective as of August 28, 2025, as requested. Unless the October 21 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **LGIA-ISO-NE/CMP/CPV Saddleback and CPV Canton (ER25-3187)**

On October 10, 2025, the FERC accepted ISO-NE and CMP's Second Revised LGIA with CPV Saddleback Ridge Wind, LLC and a First Revised LGIA with CPV Canton Mountain Wind, LLC, effective *July 3, 2025*, as requested.[86] The Second Revised LGIA reflects ownership changes and revised certain Appendix details. Unless the October 10 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).

- **NSTAR (MMWEC)-HQUS Use Rights Transfer Agreement (ER25-3170)**

On October 23, 2025, the FERC accepted the Agreement for the Transfer of Use Rights on the Phase I/II HVDC Transmission Facilities between NSTAR and H.Q. Energy Services (U.S.) Inc. ("HQUS") ("HQUS Transfer Agreement").[87] The Transfer Agreement reflects NSTAR's transfer of transmission capacity Use Rights previously held by the Massachusetts Municipal Wholesale Electric Company ("MMWEC") on the HQ Interconnection. The HQUS Transfer Agreement was accepted effective as of *October 31, 2025*, as requested. Unless the October 23 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).

[83] *Public Service Co. of New Hampshire*, Docket No. ER25-3407-000 (Oct. 20, 2025) (unpublished letter order).

[84] *Public Service Co. of New Hampshire*, Docket No. ER25-3359-000 (Oct. 29, 2025) (unpublished letter order).

[85] *NSTAR Elec. Co.*, Docket No. ER25-3309-000 (Oct. 21, 2025) (unpublished letter order).

[86] *Central Maine Power Co.*, Docket No. ER25-3187-000 (Oct. 10, 2025) (unpublished letter order).

[87] *NSTAR Elec. Co.*, Docket No. ER25-3170-000 (Oct. 23, 2025) (unpublished letter order).

- **NSTAR (CMEEC)-Vitol Use Rights Transfer Agreement (ER25-3011)**

Also on October 23, 2025, the FERC accepted the Agreement for the Transfer of Use Rights on the Phase I/II HVDC Transmission Facilities from CMMEC to Vitol ("Vitol Transfer Agreement").[88] While CMEEC has the contractual right under the Restated Use Agreement to enter into a transfer agreement to transfer its Use Rights to another party, CMEEC is relying on NSTAR to effectuate the transfer since CMEEC does not offer its capacity pursuant to an open access transmission tariff or OASIS page. The Vitol Transfer Agreement was accepted effective as of *October 31, 2025*, as requested. Unless the October 23 order is challenged, this proceeding will be concluded. 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).

- ***Order 676-K* Compliance Changes Versant Power (ER25-2566)**

On June 23, 2025, Versant filed revisions to Section 4 of the Versant Power Open Access Transmission Tariff for Maine Public District (the "MPD OATT"), which incorporate by reference certain of the revisions required by *Order No. 676-K*. Versant also requested waiver of certain of the standards that Maine Public District ("MPD") is unable to meet. Versant requested effective dates of February 27, 2026 and August 27, 2026. Comments on Versant's *Order 676-K* changes were due on or before July 14, 2025; none were filed. Versant's *Order 676-K* Compliance Changes remain pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Wholesale Distribution Tariff – Versant Power (ER25-2500)**

On October 17, 2025, the FERC ***rejected*** Versant Power's proposed new Wholesale Distribution Tariff ("WDT") that was to provide for Versant's recovery of costs associated with the provision of Wholesale Distribution Service ("WDS") to customers who own electric energy storage systems ("ESS") connected to Versant's distribution system.[89] In rejecting the Tariff, the FERC found the WDT's Subschedule 1 inconsistent with *Order 841* and ISO-NE's Tariff because it proposed to assess RNS and LNS charges to an energy storage facility ("ESF"), even when the ESF is charging to provide a service in response to an ISO-NE dispatch order. Unless the *Order Rejecting Versant WDT* is challenged, with any challenges due on or before November 17, 2025, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- ***Order 904* Compliance Filing: Versant MPD OATT (ER25-1393)**

On February 25, 2025, Versant submitted a compliance filing in response to *Order 904*,[90] proposing revisions to its MPD OATT, effective June 1, 2025. Versant's filing: (i) revises Schedule 2 to exclude charges for reactive power within the standard power range; (ii) removes related payment provisions from the *pro forma* LGIA and SGIA; and (iii) removes Note 1 from Exhibit 1a in Attachment J. Comments on Versant's compliance filing were due on or before March 18, 2025; none were filed. On October 31, 2025, Versant amended its filing to request that the proposed compliance changes be made effective May 26, 2025 (rather than June 1, 2025 as originally requested). Comments on the October 31 amendments are due on or before ***November 21, 2025***. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

[88] *NSTAR Elec. Co.*, Docket No. ER25-3011-000 (Oct. 23, 2025) (unpublished letter order).

[89] Versant Power, 193 FERC ¶ 61,044 (Oct. 17, 2025) ("*Order Rejecting Versant WDT*").

[90] *Compensation for Reactive Power Within the Standard Power Factor Range*, Order No. 904, 189 FERC ¶ 61,034 (2024) ("*Order 904*").

- **CMP ESF Rate (ER24-1177)**

On August 4, 2025, the FERC approved the settlement agreement that resolves all issues set for settlement in this proceeding,[91] effective August 4, 2025.[92] CMP was directed to make a compliance filing with revised tariff records in eTariff format on or before September 3, 2025, reflecting that effective date and the FERC's action in the Settlement Order. CMP submitted that compliance filing on September 3, 2025, with any comments due on or before September 24, 2025; none were filed. On September 15, 2025, CMP submitted a refund report confirming the $365,000 was refunded to Rumford ESS, LLC. Comments on the refund report were due on or before October 6; none were filed. The refund report is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

XII. Misc. - Administrative & Rulemaking Proceedings[93]

- **Technical Conf: Wildfire Risk Mitigation (AD25-16)**

On October 21, 2025, the FERC convened a Staff-led technical conference (right after the tech conf in AD25-8 discussed below) to discuss cost-effective best practices to reduce the risk of wildfire ignition from the Bulk Power System ("BPS") in response to Executive Order 14308. There were two panel discussions – (i) interagency coordination challenges and grid-focused best practices for wildfires (Panel 1); and (ii) leveraging technology to monitor, evaluate, and mitigate wildfire risks (Panel 2). Panelists pre-filed statements are posted in the FERC's eLibrary. A recording of the technical conference will be available for 90 days. On October 23, 2025, the FERC invited post-technical conference comments to address issues raised during the technical conference or identified in the October 15, 2025 Second Supplemental Notice. Those comments are due on or before ***November 24, 2025***.

- **Annual Reliability Technical Conference (AD25-8)**

The FERC also convened on October 21, 2025 its annual Commissioner-led Reliability Technical Conference to discuss policy issues related to the reliability and security of the BPS. The following two topics were discussed: (i) leadership perspectives on the state of the BPS and priorities (Panel 1); and ensuring reliability with large loads (Panel 2). Panelists pre-filed statements are posted in the FERC's eLibrary. A recording of the technical conference will be available for 90 days. Post-technical conference comments addressing issues raised during the technical conference or identified in the October 15, 2025 Third Supplemental Notice for this technical conference may be submitted on or before ***November 24, 2025***. Thus far, post-technical conference comments have been submitted by Digital Power Network.

- **Tech Conf: Meeting the Challenge of Resource Adequacy in ISO/RTOs (AD25-7)**

On June 4-5, 2025, the FERC convened a Commissioner-led technical conference to discuss generic issues related to resource adequacy constructs, including the roles of capacity markets in ISO/RTO regions that utilize them and alternative constructs in regions without capacity markets. The conference explored current and impending risks to resource adequacy, including increasing load forecasts and potential resource shortfalls; the effectiveness of capacity markets in ensuring resource adequacy at just and reasonable rates; comparisons between capacity markets and alternative constructs; and the roles and interests of states and other entities with legal authority over resource adequacy. A June 5 panel that addressed Resource Adequacy Challenges in the Northeast RTOs/ISOs included Emilie Nelson (NYISO, Executive Vice President and Chief Operating Officer), Stephen George (ISO-NE, Vice President of System Operations and Market Administration), Adam Evans (NY DPS,

---

[91] *See Central Maine Power Co.,* 187 FERC ¶ 61,002 (Apr. 1, 2024) ("*CMP ESF Rate Order*") (accepting, subject to refund and settlement judge procedures, CMP's rate schedule for distribution services for electric storage facilities ("ESFs") seeking to participate in the ISO-NE Market ("ESF Rate")).

[92] *Central Maine Power Co.,* 192 FERC ¶ 61,110 (Aug. 4, 2025) ("*CMP ESF Rate Settlement Order*").

[93] Reporting on the following administrative and rulemaking proceedings has been suspended and will be continued if and when there is new activity to report: Large Loads Co-Located at Generating Facilities (AD24-11); Annual Reliability Tech. Conf. (AD24-10); Innovations and Efficiencies in Generator Interconnection (AD24-9); and the EQR Filing Process and Data Collection NOPR (RM23-9).

Chief of Wholesale and Clean Energy Markets), MPUC Chairman Phil Bartlett, CT DEEP Commissioner Katie Dykes, Michelle Gardner (NextEra Energy Resources, Executive Director Northeast Region), Pallas Lee VanShaick (Potomac Economics), and Sarah Bresolin (NEPOOL Chair).

Panelists pre-filed statements are posted in the FERC's eLibrary. A recording of the technical conference will be available for 90 days. On June 5, 2025, the FERC invited post-technical conference comments to be filed on or before July 7, 2025. Post-technical conference comments were filed by over 60 parties, including the following: Acadia Center, Dominion, LS Power, National Grid, NEPGA, NESCOE, Shell, ACPA, AMP, APPA, Concentric, EEI, EPSA, FRS, LPPC, NRECA, TAPS, UCS, and Public Citizen.

- **Joint Federal-State Current Issues Collaborative[94] (AD24-7)**

Next Meeting Feb 2026. The next meeting of the Collaborative (previously scheduled for November 12 in Seattle, Washington) has been moved to ***February 2026*** during NARUC's Winter Policy Summit in Washington, DC.

Notice of 2025/26 State Commission Representatives. In accordance with the *Appointment Procedure Order*,[95] the FERC gave notice on September 22, 2025 of NARUC's appointment of the state commission representatives to the Collaborative for the August 28, 2025 through August 27, 2026 term. The NECPUC representatives will again be MPUC Chairman Phil Bartlett and NH PUC Commissioner Pradip Chattopadhyay.[96]

- **ANOPR: Interconnection of Large Loads to the Interstate Transmission System (RM26-4)**

On October 27, 2025, the FERC issued a Notice inviting comments on a Department of Energy ("DOE") proposed Advance Notice of Proposed Rulemaking ("ANOPR")[97] concerning standardized procedures for the timely and orderly interconnection of large loads to the interstate transmission system.[98] The ANOPR requests FERC take expeditious action and propose a framework under which "large loads" (defined as >20 MW) interconnecting directly to transmission (including AI data centers) would be studied and processed using LGIP/LGIA-style deposits, readiness requirements, and withdrawal penalties. Comments are for now due on or before ***November 14, 2025*** and reply comments are due on or before ***November 28, 2025***. On November 4, the Organization of MISO States ("OMS") requested a 2-week extension of time, to November 28, 2025, to file initial

---

[94] *Joint Federal-State Task Force on Elec. Transmission and Federal and State Current Issues Collaborative*, 186 FERC ¶ 61,189 (Mar. 21, 2024) ("*Order Establishing Collaborative*"). The Collaborative will provide a venue for federal and state regulators to share perspectives, increase understanding, and, where appropriate, identify potential challenges and coordination on matters that impact specific state and federal regulatory jurisdiction, including (but not limited to) the following: electric reliability and resource adequacy; natural gas-electric coordination; wholesale and retail markets; new technologies and innovations; and infrastructure. The Collaborative will be comprised of all FERC Commissioners as well as representatives from 10 state commissions, who will be nominated for and serve one-year terms from the date of appointment by the FERC. The FERC will issue notices announcing the time, place and agenda for each meeting of the Collaborative, after consulting with members of the Collaborative and considering suggestions from state commissions. Collaborative meetings will be on the record, and open to the public for listening and observing. The Collaborative will expire 3 years after its first public meeting, but may be extended for an additional period of time prior to its expiration by agreement of both FERC and NARUC.

[95] *Federal and State Current Issues Collaborative*, 192 FERC ¶ 61,056, at P 3 (July 17, 2025) ("*Appointment Procedure Order*") (explaining that NARUC will fill state commissioner vacancies on the Collaborative without formal FERC appointment and that the FERC will issue periodic notices listing new members).

[96] The remaining representatives are: from the Mid-Atlantic Conf. of Regulatory Utils. Comm'rs ("MACRUC") Comm'r Kelsey Bagot, VA State Corp. Comm'n and Comm'r Kathryn Zerfuss, PA PUC; from the Mid-America Regulatory Conf. Chair Sarah Martz, IA Utils. Comm'n and Comm'r Stacey Paradis, IL Commerce Comm'n; from the Southeastern Assoc. of Regulatory Util. Comm'rs Comm'r Karen Kemerait, NC Utils. Comm'n and Comm'r Gabriella Passidomo Smith, FL Pub. Srvc. Comm'n; and from the Western Conf. of Pub. Srvc. Comm'rs Vice Chair Nick Myers, AZ Corp. Comm'n and Chair Brian Rybarik, WA Utilities and Transportation Comm'n.

[97] *Ensuring the Timely and Orderly Interconnection of Large Loads*, Advance Notice of Proposed Rulemaking (Oct. 23, 2025). The FERC Notice and DOE letter accompanying the ANOPR noted that the ANOPR was issued pursuant to the Secretary of Energy's authority in section 403 of the Department of Energy Organization Act.

[98] The full text of the October 23, 2025 ANOPR is available here: https://www.energy.gov/sites/default/files/2025-10/403%20Large%20Loads%20Letter.pdf.

comments. The OMS request was supported by the Organization of PJM States ("OPSI") on November 5, 2025. The request for an additional 2-weeks' time is pending before the FERC.

- ***Order 914*: Implementation of EO 14270 (RM25-14)**

On October 1, 2025, the FERC issued a direct final rule (*Order 914*)[99] and a related NOPR, in response to Executive Order 14270 ("Zero-Based Regulatory Budgeting to Unleash American Energy") (*see* Executive Orders Section above),[100] to sunset 53 regulations identified as outdated or unnecessary. *Order 914* establishes a one-year sunset from its *December 5, 2025* effective date,[101] after which the regulations will be removed from the Code of Federal Regulations and the FERC will no longer treat them as effective, unless adverse comments are received by ***November 20, 2025***. If "significant adverse comments"[102] are filed, the FERC will publish a document that withdraws any such part of this action and will address the comments received in a subsequent final rule as a response to the companion NOPR (RM25-14) or take other action as it may deem appropriate.

- **ANOPR: Implementation of Dynamic Line Ratings (RM24-6)**

On June 27, 2024, the FERC issued an advanced notice of proposed rulemaking ("ANOPR")[103] seeking comments on both the need for a dynamic line ratings ("DLRs")[104] requirement and proposed framework of DLR reforms to improve the accuracy of transmission line ratings. Proposed reforms would require transmission providers to implement, on all transmission lines, DLRs that reflect solar heating, based on the sun's position and forecastable cloud cover, and on certain transmission lines, DLRs that reflect forecasts of wind speed and wind direction. The FERC seeks comments about whether to reflect hourly solar conditions and wind conditions in all transmission line ratings, how transmission congestion levels and environmental factors could identify locations of transmission lines that would most benefit from DLR, and what other technical details of transmission line ratings reflect wind conditions. A more detailed summary of the ANOPR was provided to and reviewed with the Transmission Committee. Comments in response to the ANOPR were due October 15, 2024[105] and were filed by nearly 70 parties, including by the following New England parties: ISO-NE, AEU, Avangrid, Dominion, Eversource, MA AG, National Grid, NESCOE, NextEra (on October 22), EEI, EPSA, NASUCA, NERC, PIOs, Public Power,[106] TAPS, and R Street Institute. Nine sets of reply comments were filed, including from: ISO-NE, DC Energy, and the US DOE.

[99] *Implementation of the Executive Order Entitled "Zero-Based Budgeting to Unleash American Energy"*, Order No. 914, 193 FERC ¶ 61,002 (Oct. 1, 2025) ("*Order 914*"); Errata Notice correcting regulatory text section, Oct. 21, 2025.

[100] EO 14270, Zero-Based Regulatory Budgeting to Unleash American Energy (Apr. 9, 2025).

[101] *Order 914* was published in the *Fed. Reg.* on Oct. 21, 2025 (Vol. 90, No. 201) pp. 48,397-48,408.

[102] *See Order 914* at P 3.

[103] *Implementation of Dynamic Line Ratings*, 187 FERC ¶ 61,201 (Jun. 27, 2024) ("*DLR ANOPR*"). The ANOPR reflects public comments in response to the FERC's February 17, 2022, Notice of Inquiry ("NOI") on DLRs. The NOI, in turn, found its roots in *Order 881*, which required transmission line ratings to reflect ambient air temperatures to improve efficiency in operating transmission lines.

[104] DLRs, are transmission line ratings that reflect up-to-date forecasts of weather conditions, such as ambient air temperature, wind, cloud cover, solar heating, and precipitation, in addition to transmission line conditions such as tension or sag.

[105] The *ANOPR* was published in the *Fed. Reg.* on July 15, 2024 (Vol. 89, No. 135) pp. 57,690-57,716.

[106] "Public Power" is: The National Rural Elec. Coop. Assoc. ("NRECA"), the American Public Power Assoc. ("APPA"), and the Large Public Power Council ("LPPC").

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

- **American Efficient Show Cause Order (IN24-2)**

As previously reported, the FERC issued on December 16, 2024 a show cause order[107] in which it directed American Efficient, LLC, its various subsidiary companies,[108] and its corporate parents[109] (collectively, "American Efficient") to show cause why they should not be found to have violated (i) Section 222 of the FPA and § 1c.2 of the FERC's regulations through a manipulative scheme and course of business in PJM and MISO that extracted millions of dollars in capacity payments for a purported energy efficiency project that did not actually cause reductions in energy use;[110] and (ii) provisions of MISO's and PJM's Tariffs for failure to satisfy the tariff requirements for participation as an Energy Efficiency Resource ("EER").[111] American Efficient was also directed to show cause why they should not (i) ***disgorge $2,116,057 and $250,937,821***, back to MISO and PJM, respectively (in each case plus interest); (ii) ***disgorge additional unjust profits*** received between April 2024 and the date of any future FERC order directing disgorgement back to PJM; and (iii) pay a ***$722 million*** civil penalty. American Efficient may seek a modification of these amounts consistent with FPA § 31(d)(4).[112]

On March 17, 2025, American Efficient answered the show cause order explaining that American Efficient did not violate a tariff or commit fraud, requesting the FERC dismiss the proceeding and close its investigation without further action. OE replied to American Efficient's answer on April 15, 2025 and American Efficient subsequently responded to OE's April 15 reply, supplemented its answer with financial information, and provided updates on some related federal court developments, each of which it asserted weigh against rushing if not issuing a penalty order. Since the last Report, On July 10, 2025, American Efficient filed another letter supporting its position that this "proceeding should be terminated without further action."

On November 3, 2025, American Efficient requested that the FERC conclude its Order to Show Cause proceeding by declining the Office of Enforcement and Regulatory Accounting's ("OERA") request for an Order Assessing Penalties and closing out this investigation.

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

---

107 *American Efficient, LLC et al.,* 189 FERC ¶ 61,196 (Dec. 16, 2024) ("*American Efficient Show Cause Order*").

108 Affirmed Energy LLC, Wylan Energy L.L.C., Midcontinent Energy LLC, and Maple Energy LLC.

109 Modern Energy Group LLC and MIH LLC.

110 OE concludes that "[w]hat American Efficient passes off as energy efficiency in its capacity supply offers really is just market research. It buys sales data of energy efficient products from large retailers like The Home Depot, Lowes, and Costco and then figures out how many MWs of electricity would be saved if end-use customers installed those products and used them in accordance with predictive models. It then bids those energy savings into the capacity markets as if it caused the savings. But American Efficient does not cause the energy savings."

111 OE's Report notes that American Efficient initially cleared 10.6 MWs (worth $518,000) in an ISO-NE Forward Capacity Auction. When American Efficient sought to expand its Program in ISO-NE from 10.6 MWs to 189 MWs, "ISO-NE and its IMM sent a series of emails and letters critiquing the Program and then disqualified the Company from expanded participation in the FCA. In one of those letters, ISO-NE explained that it never would have qualified any of American Efficient's capacity if it had understood the true nature of the Program from the beginning." Similar disqualification occurred in MISO. American Efficient expressly kept information about those disqualifications from PJM and expanded the Program in PJM. No disgorgement with respect to American Efficient's New England activity is contemplated.

112 Under Section 31(d)(4) of the FPA, 16 U.S.C. § 823b(d)(4), the Commission may "compromise, modify, or remit, with or without conditions, any civil penalty which may be imposed . . . at any time prior to a final decision by the court of appeals . . . or by the district court."

Natural Gas-Related Enforcement Actions

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

Procedural Schedule Suspended. As previously reported, on May 24, 2022, the Honorable Judge Karen Gren Scholer of the U.S. District Court for the Northern District of Texas ("Northern District") issued an order staying this proceeding. Consistent with that order and out of an abundance of caution, ALJ Joel DeJesus, who will be the presiding judge for hearings in this matter,[113] suspended the procedural schedule until such time as the Court's stay is lifted and the parties provide jointly a proposed amended procedural schedule.

On June 14, 2023, the FERC issued an Order on Presiding Officer Reassignment,[114] which (i) directed the Chief ALJ to reassign this proceeding to another ALJ not previously involved in the proceeding (i.e., designate a new presiding officer) once the *June 14 Order* takes effect; (ii) held that the *June 14 Order* will take effect once the Northern District clarifies or lifts its stay for the limited purpose of allowing the *June 14 Order* to take effect or the stay is lifted or dissolved such that hearing procedures may resume; and (iii) stated that this proceeding otherwise remains suspended until the Northern District's stay is lifted or dissolved such that hearing procedures may resume.

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

On December 16, 2021, the FERC issued a show cause order[115] 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,[116] 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;[117] (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 ***$40 million*** in civil penalties.

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, 2022, 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.[118] This matter is pending before the FERC.

---

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

[114] *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.,* 183 FERC ¶ 61,190 (June 14, 2023) ("*June 14 Order*").

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

[116] *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*").

[117] 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.

[118] *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.

XIV. Natural Gas Proceedings

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

- ***Order 915*: Removal of Regulations Limiting Authorizations to Proceed with Construction Activities Pending Rehearing (RM25-9)**

On October 7, 2025, the FERC issued its final rule removing from its regulations a rule that precludes the issuance of authorizations to proceed with construction activities with respect to natural gas facilities approved pursuant to section 3 or section 7 of the NGA for a limited time while certain requests for rehearing are pending before the FERC.[119] Unless *Order 915* is challenged, this proceeding will be concluded.

New England Pipeline Proceedings

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

- **Algonquin Cape Cod Canal Pipeline Relocation Project (CP25-552; PF25-4)**
  - Project to relocate and rebuild the Sagamore and Bourne meter and regulation ("M&R") stations to continue providing uninterrupted natural gas transportation service to National Grid to supply end users on both sides of the Cape Cod Canal. The proposed Project will not result in new or incremental capacity and is therefore not an expansion of the Algonquin system.
  - Abbreviated Application for a Certificate of Public Convenience and Necessity ("CPCN") and for Related Authorizations and Order Approving Abandonment ("Application") filed September 29, 2025. Application includes authorizations to (i) construct, install, own, operate, and maintain approximately 5.24 miles of pipeline; (ii) abandon by removal approximately 0.75 miles of existing pipeline; (iii) abandon by removal 2 existing M&R stations; and (iv) construct, install, own, operate, and maintain 4 new M&R stations.
  - Algonquin submits supplemental information to its Application on October 30, 2025.
  - Interventions filed by NSTAR Electric, NSTAR Gas, National Grid Gas Delivery Companies, and New York State Gas & Electric and Maine Natural Gas Co. Comments filed by a number of Chambers of Commerce on the Cape.

- **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 now requested for ***March 25, 2027***.
  - 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.[120] 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

[119] *Removal of Regulations Limiting Authorizations to Proceed with Construction Activities Pending Rehearing*, Order No. 915, 193 FERC ¶ 61,014 (Oct. 7, 2025) ("*Order 915*").

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

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.
- On October 28, 2024, Iroquois requested an extension of time, until ***March 25, 2027***, to construct and place into service its Enhancement by Compression Project (Project) located in Greene and Dutchess Counties, New York and Fairfield and New Haven Counties, Connecticut as authorized in the *Iroquois Certificate Order*. (The *Iroquois Certificate Order* required Iroquois to complete construction of the Project and make it available for service within three years of the date of the Order or by March 25, 2025.) Iroquois stated that construction of the Project has been delayed due to pending state permit approvals, specifically air permits from the New York State Department of Environmental Conservation and the Connecticut Department of Energy and Environmental Protection. Iroquois asserts that it has been working in good faith with these agencies and expects to receive approvals for the Project in the near future.
- Comments on Iroquois' request were due on or before November 15, 2024. Protests and comments were filed by the Sierra Club of Connecticut, Save the Sound, and nearly 20 individual citizens. A number of others requested an extension of time to comment, but those requests have not been (nor should be expected to be) acted on by the FERC.[121]
- On February 19, 2025, the FERC granted the requested two-year extension of time, to March 25, 2027, to construct the project and place it into service.[122] The FERC found that Iroquois has worked and continues to work toward obtaining the state permits necessary to enable construction to commence, no bad faith or delay on Iroquois's behalf, and therefore good cause to grant the two-year extension of time to complete construction of the project.[123]

XV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

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 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).

[121] The FERC will aim to issue an order acting on the request within 45 days. The FERC will address all arguments relating to whether the applicant has demonstrated there is good cause to grant the extension. The FERC will not consider arguments that re-litigate the issuance of the certificate order, including whether the Commission properly found the project to be in the public convenience and necessity and whether the Commission's environmental analysis for the certificate complied with NEPA.

[122] *Iroquois Gas Transmission System, L.P.*, 190 FERC ¶ 61,112 (Feb. 19, 2025).

[123] *Id*. at P 15.

- ***Order 904*: Compensation for Reactive Power Within the Standard Power Factor Range (5th Circuit – 25-60055 et al.) (consolidated)**
Case Title: Leeward *v. FERC*
Underlying FERC Proceeding: RM22-22[124]
Status: Docketing Statements and Appearance Filed; Briefing schedule not yet established

Appeals of *Order 904* have been transferred to and consolidated in the 5th Circuit Court of Appeals, with 25-60055 as the lead docket. A briefing schedule will issue upon the filing of the administrative record (which, following an unopposed motion to extend the time to file, is now due on ***November 17, 2025***) and will trigger the specific dates for the approved briefing schedule (Procedural Motions (Briefing Notice+14 days); Petitioners' Briefs (Briefing Notice+60 days); FERC's Brief (Petitioners' Briefs+90 days); Response Brief Intervenors in Support of FERC (FERC's Brief+14 days); Petitioners' Reply Briefs (Intervenors' Response Brief+30 days); Deferred Joint Appendix (FERC's reply brief+7 days); and Final Briefs (Joint Appendix+7 days)).

- ***Order 1920*: Transmission Planning Reforms (4th Circuit – 24-1650)**
Case Title: *Appalachian Voices v. FERC*
Underlying FERC Proceeding: RM21-17[125]
Status: Briefing Underway

As previously reported, on July 18, 2024, AEU/ACPA/SEIA and Invenergy petitioned the DC Circuit Court of Appeals for review of the FERC's *Order 1920*.[126] Petitions were also filed in the First, Second, Fourth, Fifth, Sixth, Seventh, Ninth, and Eleventh Circuits. The Judicial Panel on Multidistrict Litigation randomly selected the Fourth Circuit as the Circuit in which to consolidate the petitions for review. The DC Circuit ordered that its cases be transferred to the 4th Circuit. The 4th Circuit lead case no. is 24-1650. On August 26, 2024, the 4th Circuit granted the FERC's motion to hold the petitions for review in abeyance. Since the last Report, Appalachian Voice et al submitted their opening brief. FERC's Response Brief is due January 5, 2026. Looking further ahead, Intervenors in support of FERC may file response briefs by February 4, 2026; Petitioners reply briefs will be due February 25, 2026; the Joint Appendix must be filed by March 4, 2026; and final briefs by March 11, 2026.

- ***Orders 2023 and 2023-A* (23-1282 et al.) (consolidated)**
Case Title: *Advanced Energy United, et al. v. FERC*
Underlying FERC Proceeding: RM22-14[127]
Status: Oral Argument Held September 26, 2025; Decision Pending

Several Petitioners have challenged *Orders 2023 and 2023-A*. Those challenges were consolidated, with the AEU docket (23-1282) as the lead docket. Briefing is now complete. Oral argument was held ***September 26, 2025*** before a merits panel comprised of Judges Millett, Walker, and Childs. This matter is now pending before the Court.

[124] *Compensation for Reactive Power Within the Standard Power Factor Range*, Order No. 904, 189 FERC ¶ 61,034 (Oct. 17, 2024).

[125] *Constellation Mystic Power, LLC*, 185 FERC ¶ 61,170 (Dec. 5, 2023) ("*Second CapEx Info Filing Order*"); *Constellation Mystic Power, LLC*, 186 FERC ¶ 62,048 (Feb. 5, 2024) ("*Second CapEx Info Filing Order Allegheny Notice*").

[126] Petitioners for review of *Order 1920* have also been filed in the 1st, 4th, 5th, and 9th Circuits.

[127] *Improvements to Generator Interconnection Procedures and Agreements*, 184 FERC ¶ 61,054 (July 28, 2023) ("*Order 2023*"); 184 FERC ¶ 62,163 (Sep. 28, 2023) (Notice of Denial of Rehearing by Operation of Law).

- ***CASPR* (20-1333, 21-1031) (consolidated)****
  Case Title: *Sierra Club, et al. v. FERC*
  Underlying FERC Proceeding: ER18-619[128]
  Petitioners: Sierra Club, NRDC, RENEW Northeast, and CLF
  Status: Being Held in Abeyance; Motions to Govern Future Proceedings Due Mar 2, 2026

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 now four times. In the most recent request (filed March 1, 2024) (fourth abeyance request), Petitioners asked the Court to hold this matter in abeyance until March 1, 2026 "in light of the continued delay of the revisions to its capacity market that ISO New England previously asserted were a predicate to eliminating the market impediment that is the subject of the underlying claims before the Court". The Court granted the request on May 12, 2024, ordering the parties to file motions to govern future proceedings by ***March 2, 2026***.

- ***Opinion 531-A* Compliance Filing Undo (20-1329)**
  Case Title: *Central Maine Power Company, et al. v. FERC*
  Underlying FERC Proceeding: ER15-414[129]
  Petitioners: TOs (CMP et al.)
  Status: Being Held in Abeyance

On August 28, 2020, the TOs[130] 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*[131] decision. On September 22, 2020, the FERC submitted an unopposed motion to hold this proceeding in abeyance for four months to allow for the Commission to "a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the Commission." On October 2, 2020, the Court granted the FERC's motion, and directed the parties to file motions to govern future proceedings in this case by February 2, 2021. On January 25, 2021, the FERC requested that the Court continue to hold this petition for review in abeyance for an additional three months, with parties to file motions to govern future proceedings at the end of that period. The FERC requested continued abeyance because of its intention to issue a 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 reports at 120-day intervals. The parties were directed to file motions to govern

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

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

[130] 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.

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

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 FERC remain ongoing and that this appeal should continue to remain in abeyance, was filed on July 16, 2025.

- ***Avangrid/NextEra NECEC Civil Suit* (D.MA) (Civil Action No. 24-30141-MGM)**
  Case Title: *Avangrid, Inc. et al. v. NextEra Energy, Inc. et al.*
  Status: Federal Anti-Trust Claims Dismissed; State Law Claims Remain Pending

On November 12, 2024, Avangrid sued NextEra in US District Court for the District of Massachusetts ("D.MA") claiming NextEra's illegal use political and regulatory channels to delay or prevent Avangrid from obtaining the approvals needed to construct the NECEC project resulted in damages in excess of $350 million. Specifically, Avangrid alleged NextEra violations of US (Sherman Act) and MA Anti-Trust laws (alleging actual, attempted, and conspiracy to monopolize the markets) (the "Anti-Trust Claims"), as well as state law violations related to NextEra's: (i) conspiracy with others (to perpetuate an attack campaign based on false and misleading claims against NECEC using dark money in violation of campaign finance law, and to intervene without basis in NECEC's permitting process for unlawful purpose), (ii) intentional interference with CMP contracts, (iii) unjust enrichment; and (iv) unfair business practices (together the "State Law Claims").

On September 22, 2025, the presiding US District Judge, Mark Mastroianni, dismissed Avangrid's Antitrust Claims, noting that NextEra's motion to dismiss as to the State Law Claims remains under advisement. On October 6, 2025, Avangrid and NextEra submitted a joint request for a second oral argument to cover the remaining claims after the September 22 order, and Avangrid submitted an unopposed request for a status conference to discuss how to seek relief from the monopolizations claims in the September 22 order (either by seeking leave to amend or request for an appeal). A status conference was scheduled for and held on October 16, 2025. A hearing on NextEra's motion to dismiss the State Law Claims has been set for ***December 18, 2025***.

- **Allco PURPA Enforcement Petition (D.CT) (Case No. 3:25CV01321)**
  Case Title: *Allco Finance Limited Inc. v. Dykes et al.*
  Status: Responses to Complaint Due Nov 24, 2025

Following a FERC notice[132] that it had decided not to act on Allco's PURPA Complaint related to Connecticut's[133] implementation under section 210 of PURPA of its Shared Clean Energy Facility ("SCEF") Program,[134] Allco brought an enforcement action against Connecticut in federal district court in Connecticut.[135] *Allco Finance Limited Inc. v. Dykes et al.* (case no. 3:25CV01321). Responses to the Complaint are now due on or before ***November 24, 2025***.

---

[132] *Allco Finance Limited*, 192 FERC ¶ 61,116 (Aug. 4, 2025).

[133] For purposes of this proceeding, "Connecticut" is the Connecticut Department of Energy and Environmental Protection ("CT DEEP"), Connecticut Public Utilities Regulatory Authority ("CT PURA"), and the Connecticut Department of Agriculture ("CT DoA").

[134] Allco asserted that CT is improperly implementing PURPA by requiring the following criteria for participation in the Shared Clean Energy Facility ("SCEF") program: (i) that no more than 10% of the project site contains slopes greater than 15%; (ii) that separate QFs on the same parcel cannot receive a contract even when the total of the two QFs is less than 5MWs; (iii) documentation of "community outreach and engagement" regarding the bid for a contract; (iv) restrictions related to "Prime Farmland" location; (v) a QF cannot have been constructed or started construction; (vi) a workforce development program, and for certain projects a community benefits agreement; (vii) a contract that includes renewable energy credits; and (viii) a bidder must bear costs related to a utility's voluntarily seeking to re-sell the QF's energy in the ISO-NE market, if the utility chooses not to use the energy to supply its own customers. Allco argues that the criteria are neither objective nor reasonable and are unrelated to a QF's commercial viability or financial commitment. Allco further contends that some of CT's SCEF program requirements violate its constitutional rights. Allco also states that bids it submitted in 2024 and 2025 were rejected on the basis of these unlawful requirements.

[135] 16 U.S.C. § 824a-3(h)(2)(B).

INDEX
Status Report of Current Regulatory and Legal Proceedings as of November 5, 2025

Executive Orders

I. Complaints/Section 206 Proceedings

II. Rate, ICR, FCA, Cost Recovery Filings

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

IV. OATT Amendments/Coordination Agreements

V. Financial Assurance/Billing Policy Amendments

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

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

IX. Membership Filings

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

XI. Misc. Regional Interest

XII. Misc: Administrative & Rulemaking Proceedings

XIII. FERC Enforcement Proceedings

XIV. Natural Gas Proceedings

XV. State Proceedings & Federal Legislative Proceedings

No Activities to Report

XVI. Federal Courts

8 Committee Reports

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

9

Administrative Matters

Admin Matters

Nov 6, 2025 Meeting

NEPOOL NEW ENGLAND POWER POOL Participants Committee