NEPOOL
NEW ENGLAND POWER POOL
Sebastian Lombardi
Secretary

August 27, 2025

VIA E-MAIL

TO: **PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES**

RE: Supplemental Notice of September 4, 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 September 2025 meeting of the Participants Committee will be held **in person on Thursday, September 4, 2025, at 10:00 a.m. at the Renaissance Boston Seaport District Hotel, located at 606 Congress Street, Boston, MA 02210** 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 using the app, join the meeting by clicking the following link for the meeting: **https://iso-newengland.webex.com/iso-newengland/j.php?MTID=mfc0447ffb17030dec5f3e8c1972b61d8** . 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**).

Looking ahead, please mark your calendars for the October and November Participants Committee meetings. October's meeting is on Thursday, October 9, and will be at the Delamar in West Hartford, Connecticut. The November 6 meeting will be held at the Hilton Boston Logan Airport Hotel and will commence following the second of this year's separately scheduled modified Sector meetings with the ISO Board and state officials. Details regarding group arrangements to stay at these venues the night before the meetings will be circulated under separate cover.

We hope all of you are able to enjoy your Labor Day weekend. See you in Boston on September 4.

Respectfully yours,

/s/

Sebastian Lombardi, Secretary

FINAL AGENDA

1. To approve the draft minutes of the June 24-25, 2025 and August 7, 2025 Participants Committee meetings, copies of which are included and posted with this supplemental notice. Please provide us with any comments on these draft minutes no later than **Tuesday, September 2, 2025.**

2. To adopt and approve the action recommended by the Markets Committee set forth on the Consent Agenda included with this supplemental notice and posted with the meeting materials [action on the Reliability Committee-recommended revisions to OP-2 and OP-2 Appendix A has been deferred to a subsequent Participants Committee meeting].

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

4. To receive an ISO Chief Operating Officer report.

   a. Operations Report Highlights (August data); and

   b. Update on Asset Condition Reviewer Project.

   The September Operations Report will be circulated and posted in advance of the meeting. Presentation materials related to the Asset Condition Reviewer Project are included and posted with this supplemental notice.

5. To receive a report on the following proposed budgets:

   a. 2026 ISO-NE Operating and Capital Budgets; and

   b. 2026 NESCOE Budget.

   Background materials are included and posted with this supplemental notice.

6. To receive an ISO Internal Market Monitor (IMM) Report by David Naughton, Executive Director, Market Monitoring. The IMM's 2024 Annual Markets Report is available on-line at https://www.iso-ne.com/static-assets/documents/100023/2024-annual-markets-report.pdf. A presentation with highlights of the IMM's 2024 Report will be circulated and posted in advance of the meeting.

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.

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.

FINAL AGENDA (cont.)

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.

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June 24-27, 2025 Minutes
August 7, 2025 Minutes

VOTE

66.67%

RESOLVED, that the Participants Committee approves the preliminary minutes of the June 24-27, 2025 Summer Meeting and the August 7, 2025 meeting, as circulated in advance of this meeting, with additional non-material clarifications, as the final minutes of the June 24-27, 2025 Summer Meeting and August 7, 2025 meeting.

PRELIMINARY

The 2025 Summer Meeting of the NEPOOL Participants Committee was held at the Wequassett in Harwich, Massachusetts, on Tuesday, June 24, and Wednesday, June 25, pursuant to notice duly given, followed on Thursday, June 26, by separate meetings between modified Sector groups and ISO Board Members, state officials, and FERC staff, respectively. A quorum determined in accordance with the Second Restated NEPOOL Agreement was present and acting throughout the meeting. All motions acted on at the meeting were voted on Tuesday, June 24. Attachment 1 identifies the members, alternates and temporary alternates attending the meeting.

Ms. Sarah Bresolin, Chair, presided and Mr. Sebastian Lombardi, Secretary, recorded for the meeting.

JUNE 24, 2025 SESSION

The June 24, 2025 session began at 10:00 a.m., with Ms. Bresolin welcoming the members, alternates, federal and state officials, ISO colleagues, including members of the ISO Board, and guests who were present. After reviewing some brief housekeeping items, including the deferral, again at Plainfield Renewable Energy's request, of consideration of its GIS-related waiver request, Ms. Bresolin invited, and those around the table each proceeded to, introduce themselves and identify on whose behalf they were participating in the meeting.

APPROVAL OF MAY 1, 2025 MEETING MINUTES

At the conclusion of those introductions, Ms. Bresolin referred the Committee to the preliminary minutes of the May 1, 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, 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, which included three items unanimously recommended for Participants Committee support by the Markets (MC) or Transmission Committees (TC).

Before proceeding to action, Mr. Lombardi provided additional information related to Consent Agenda Item No. 3 (Revisions to Tariff Section I.2.2 and Schedules 11, 22, 23, and 25 (*Order 2023/2023-A* Further Compliance Revisions). He said that, due to FERC-imposed compliance timing requirements, the Revisions recommended for Participants Committee support by the TC had already been filed by the ISO. He explained that comments reporting on NEPOOL's consideration and position would be submitted before the end of the public comment period, which was due to expire later that day.

Following motion duly made and seconded, the Consent Agenda was unanimously approved as circulated, with an abstention by Mr. Lamson noted.

ISO CEO REPORT

Before turning to his monthly report, Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), addressed the announcement from the day before that he would retire as ISO-NE CEO at the end of 2025. He reflected on his 25 years as ISO's CEO, noting with particular pride many of the ISO's accomplishments over that period of time, not the least of which was the group of talented and dedicated professionals with whom he had served during his tenure. He thanked them for their dedication, responsiveness, agility, and innovative spirit in making the region's markets, and the ISO itself, sophisticated and world-class. He also expressed his thanks and appreciation to the NEPOOL Participants with whom he had very much enjoyed collaborating to solve complex and challenging issues facing the region. He was pleased that, looking ahead into the early years of the next decade, the region appeared to have adequate resources to ensure reliability. He reflected on the solid foundation that had been laid through the development of competitive wholesale markets, transmission investment, and the establishment of operations and planning tools to guide the region into the future. He predicted that the energy transition would continue, with the need for additional investments in transmission and other resources, and an ever greater need for coordination and collaboration to secure the future of the power system for the people of New England. To that end, he noted the importance of the Capacity Market re-design underway, and the critical role that all around the table would play in creating and ensuring the cornerstones and structure for New England's future grid.

Mr. van Welie was pleased that the ISO Board of Directors had chosen Dr. Vamsi Chadalavada, with whom he had worked closely for more than 30 years, as his successor. He noted his admiration and respect for Dr. Chadalavada as both a person and as a leader. He expressed, without hesitation and with full confidence, that the Board had chosen the right person for the job.

Mr. van Welie also thanked Participants for their collaborative commitment to improving the region's arrangements and addressing the issues facing the region. While everyone did not agree on everything, Mr. van Welie commended Participants for the overall balance shown approaching the issues requiring attention, including healthy doses of intellectual jousting tempered by practical feedback and innovative solutions. His added that his tenure, and the region generally, were so much the better as a result.

On behalf of the Committee, Ms. Bresolin expressed a collective sense of gratitude, underscoring how, for more than 25 years with Mr. van Welie's steady hand at the helm, the region had achieved success on many fronts. She added that, notwithstanding the announcement, it was yet too soon to say goodbye, and looked forward to continued collaboration with Mr. van Welie over the remainder of the year. The Committee then expressed its appreciation and congratulations with a warm and extended round of applause.

Before concluding, Mr. van Welie invited any questions or comments on the June CEO Report, which had been circulated and posted with the materials for the meeting. There were no questions or comments on the CEO Report.

ISO COO REPORT

Ms. Bresolin congratulated Dr. Vamsi Chadalavada, the ISO's Chief Operating Officer, on his upcoming role as ISO CEO. On behalf of the Committee, she expressed appreciation for his hard work and engagement with NEPOOL over the past two decades and looked forward to working with him in this new capacity. Dr. Chadalavada thanked both Ms. Bresolin and Mr. van Welie. He similarly was looking forward to working with the Committee in the days ahead. Turning to his report, he focused on three discrete areas.

June 24 Operations

After highlighting a few operations-related items from the month of May, Dr. Chadalavada turned to expected operations for that day, June 24, which was expected to be challenging in light of forecasted temperatures and load. He summarized system conditions, noting that the ISO expected a peak load of 25,800 MW for hour ending 7:00 p.m., which also reflected what was expected to be record production from the region's behind-the-meter photovoltaic (BTM PV) facilities. System assets were online and there were no planned or expected outages. He felt the ISO was prepared for the day but was counting on the system to perform as designed.

Dr. Chadalavada said that system conditions would be very tight that day, with its lowest system margin since 2018. The system margin coming into the day was 105 MW, which was roughly equivalent to 0.25% of the expected dew point, and which would not exist if the dew point forecast was off by any more than that amount. Neighboring regions were also very tight, including PJM and New York, which was relying heavily on imports from Ontario.

Dr. Chadalavada reported that the dew point the day before was 80°, which was very high for New England. The ISO exceeded its load forecast the previous day by 550 MW (a peak of 23,800 MW was expected but reached 24,320 MW). In response to a question, Dr. Chadalavada explained that dew points and temperatures were what the weather forecast agencies focused on and what most impacted forecasted demand for load. Once dew point temperatures exceed 72° or 73°, every dew point percent increase represents a load increase of at least a couple hundred MW. Once dew point temperatures exceed 75° or 76°, every dew point increase would lead to an additional 300-400 MW of load. Accordingly, load forecasts on very hot days were very sensitive to dew point forecast, and the accuracy and predictive capability of weather forecasters on the dew point on very hot days, therefore, is extremely important. He noted that the dew point forecast for June 23 was 75° so there was a 5° difference between what was forecast vs. what was actually experienced. The dew point forecast was not uniform across the region, with a more granular temperature and dew point forecast available for 50-60 different locations in New England. However, an aggregate, regional composite is built, with multiple model variations, to support load forecasting, tying the ISO to the work of the forecast agencies. The ISO had also come to realize that critical to the accuracy of the load forecast is forecasted cloud cover, which itself was still an imprecise science. Dr. Chadalavada noted that a better understanding of cloud cover on a varied locational granular basis (given BTM PV distribution through the region) would have a big impact on the accuracy of the load forecast.

In response to another question, Dr. Chadalavada confirmed that the volume of imports from Hydro Québec for March, April, and May was lower than normal, and from published reports, was attributable to the ongoing drought conditions being experienced. Notwithstanding those conditions, the ISO continued to rely on Hydro Québec from a reliability perspective. If and how the volume of imports might change once those drought conditions were relieved remained to be seen.

Day Ahead Ancillary Services (DAAS) Market

Dr. Chadalavada reported on DAAS market performance between March and May 2025. He identified two broad system changes from the earliest DAAS impact analysis in 2019 that had impacted DAAS market performance. Most prominent was the penetration and duration of BTM PV. He explained that more BTM PV created more opportunities for incremental offers (INCs) to participate in the market. More INCs clearing Day-Ahead resulted in a need for more physical megawatt hours (MWh) to replace the INCs that clear. The Forecast Energy Requirement (FER) and Energy Imbalance Reserve (EIR) products were designed to ensure sufficient physical energy clears the Day-Ahead Market. He explained that Hourly Cleared EIR (176 MW in March, 97 MW in April, and 155 MW in May) was twice what the ISO had forecast in 2019. Dr. Chadalavada noted, however, that there was adequate competition, a sufficient number of assets bidding into the FER and EIR products, and the average FER price had declined from $3.26 to $2.00/MWh.

The second broad system change that had impacted DAAS Market performance was increased volatility. Real-Time price volatility was much higher than when the ISO created its first impact analysis models. Also more volatile were gas prices, weather, and the supply offer stack (in terms of expectations of imports from neighboring control areas). Increased price volatility and overall Real-Time risk was reflected in DAAS Market offer prices. Dr. Chadalavada added that the ISO expected DAAS co-optimization to lower Day-Ahead LMPs. Once evaluated, the ISO would report back on any such impact.

A member suggested that ISO also review DAAS Market strike prices, given doubts that the model was working as designed, especially on high priced days. Citing an counterintuitive example where the strike price was $130 when the Day-Ahead prices cleared at $460, the member urged the ISO to be proactive. Mr. Matt White, ISO-NE Chief Economist, indicated that the IMM and ISO staff had been monitoring many aspects of strike prices over the last few months, but suggested it was still premature to formally revisit strike prices. He committed to circle back at a later date specifically on the topic of strike prices, as well as on other issues that the ISO had identified since the DAAS Market was implemented.

Another member, suggesting that there had been an increase to seller risk since the 2019 impact analyses, asked for any insight into how much risk premium the ISO would entertain in seller offers to address that higher level of risk. Mr. David Naughton, Executive Director, ISO Internal Market Monitor (IMM), explained that the thresholds in place were sufficient in most intervals and on most days. However, if and when insufficient, a consultation process was available whereby the IMM could work with Participants on higher benchmark levels that were consistent with the value of the option and prevailing market conditions. Mr. Naughton said that the IMM would continue to assess the appropriateness of its thresholds with the benefit of additional experience with the DAAS market.

Dr. Chadalavada noted a higher level lesson learned with respect to impact analyses that would be important to the region's CAR efforts. He said that impact analyses, when conducted, were intended to be informational and not predictive, particularly given how situations and assumptions can change. He suggested that impact analyses could and should be relied on to provide a range of outcomes, not one specific outcome. To this end, and as would be discussed a bit later in the meeting, the ISO planned in connection with the CAR project, to improve the information and tools available to Participants.

Asset Condition Reviewer Project

Dr. Chadalavada ended his operations report with an update on the ISO's Asset Condition Reviewer project. After providing some background and context, Dr. Chadalavada reported that the ISO had agreed to explore taking on the role of Asset Condition Reviewer, subject to certain critical understandings, including an understanding that the ISO would not perform cost prudency reviews and its role would be that of a reviewer and not that of a regulator. He expected that the project would take roughly 18 months to fully implement, and described plans for both the interim process and full implementation.

Many around the table, but particularly consumer advocates and state representatives expressed their thanks and appreciation to the ISO for its efforts and progress. Citing impacts to customer bills, they emphasized the criticality and urgency of the Asset Condition Reviewer process. A State Commissioner further stressed the importance of getting review of Asset Condition projects right.

ISO MULTI-YEAR (2027-2030) ROADMAP

Dr. Chadalavada then referred the Committee to the presentation included with the materials for the meeting of the ISO's key areas of future focus, beyond that which was to be included in the upcoming annual work plan (the Multi-Year Roadmap). He summarized the reasons for reviewing now these areas of focus that were expected to become anchor projects and priority efforts in future years. He cautioned that the Multi-Year Roadmap did not reflect the full volume of future projected work, nor did it reflect work that may later emerge as a result of stakeholder, policy maker or federal regulator priorities or directives. The Multi-Year Roadmap did reflect the ISO's current and best projection of key areas of focus, and served as a productive platform for discussion and agreement on those areas. The ISO hoped that review of the Multi-Year Roadmap with stakeholders would be a natural extension of the robust annual work plan efforts and enhance and complement the roadmap review process which to that point had been limited to the ISO Board's November open meeting.

Dr. Chadalavada reviewed the following key areas of future focus: reliably managing increased operational uncertainty (developing high-performing tools and systems to manage operational uncertainty so as to enhance reliable and efficient operations of a dynamic power system, e.g. probabilistic forecasting methodologies and tools); Real-Time pricing improvements (developing new Real-Time "multi-interval" optimization and pricing algorithms incorporating probabilistic forecasts); establishing a comprehensive planning framework for grid efficiency (developing a suitable platform to address system uncertainties, e.g. innovating inverter-based resource (IBR) modeling and interconnection efficiency); actively engaging on emerging resource adequacy needs/policies; and continued investment in critical information technology (IT) areas (cloud computing, AI and cyber security).

Following up on Dr. Chadalavada's reference to the lessons learned from the Iberian Peninsula, voltage-related outage earlier in the year, a member highlighted the ISO's success in navigating its all-time low (5,450 MW) load day a few months earlier. That day demonstrated for him the importance of improving Inverter-Based Resource (IBR) modeling and otherwise developing platforms and processes to address system uncertainties, achieving results that only years earlier would not have been thought possible. Amplifying, Dr. Chadalavada predicted future uncertainties that could be created and looked forward to working with stakeholders to prepare for those kinds of outcomes specifically, and more generally on the key areas in the Multi-Year Roadmap.

2026/2027 ISO PRELIMINARY BUDGETS

Ms. Kelly Reyngold, the ISO's Controller and Director, Accounting, referred the Committee to the "top down" presentation of the ISO's 2026 and 2027 preliminary Operating and Capital Budgets (Budgets) included with the materials posted in advance of the meeting. She stated that the ISO's preliminary budget presentation provided an opportunity for stakeholder review and feedback prior to presentation of the proposed detailed Budgets reflecting that feedback at a future meeting. She expanded on how the development of the Budgets reflected the ISO's continued commitment to the region as it experiences an evolving resource mix and changing customer patterns, with many ongoing objectives and initiatives reflected in the Budgets. The preliminary Budget continues to support retaining the ISO's highly skilled workforce with competitive salaries and benefits, investing in advanced technologies and analytics to help support system operations and planning capacities, as well as the operational costs associated with the nGem program and the implementation/administration of DASI. The Budgets also include a placeholder for funding the Asset Condition Reviewer role/effort.

Ms. Reyngold then discussed how the Budgets are tied closely to the strategic plans and mission of the ISO. The ISO also looks and take into account current and emerging trends that may impact the ISO's workforce and workload, and they evaluate the risks and opportunities those trends present.

FAP CHANGES TO LETTER OF CREDIT (LC) ISSUER ELIGIBILITY, FORMS OF LC, SECURITY AND BLACKROCK CONTROL AGREEMENTS

Mr. Tom Kaslow, Budget & Finance (B&F) Subcommittee Chair, introduced proposed changes to the ISO Financial Assurance Policy, including to the form of Standby Letter of Credit (LOC). These changes were intended to mitigate risks of Market Participant defaults and LOC issuer credit downgrades, as more fully explained in the materials included and posted with the meeting materials. Mr. Kaslow reported that the proposed changes were reviewed by the B&F Subcommittee at its March, April and May meetings. At the May meeting, certain Participant-sponsored changes to the ISO's proposal were considered and eventually adopted by the ISO (as reflected in the materials circulated for the meeting). Following that overview, the following motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports the revisions to the ISO New England Financial Assurance Policy as reflected in the materials circulated to this Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair of the Budget & Finance Subcommittee.

Members expressed their thanks and appreciation for the ISO's engagement and willingness to incorporate Participant feedback during this effort, which they insisted exemplified the benefits and value of a fulsome and engaged stakeholder process. The Engie representative similarly expressed appreciation for the ISO's, particularly the credit group's, efforts and responsiveness, reported that Engie was satisfied with the changes made, and noted their support for the proposed revisions. Without further discussion, the Committee considered and approved unanimously the main motion, with an abstention by Mr. Lamson noted.

LITIGATION REPORT

Mr. Lombardi referred the Committee to the June 23 Litigation Report that had been circulated and posted in advance of the meeting. He highlighted (i) four Executive Orders issued by the current Administration since the last Report pertaining to nuclear-related issues; (ii) Executive Order 14262's requirement that the U.S. Department of Energy (DOE) develop and publish by July 7, 2025 a methodology to identify current and anticipated reserve margins for all RTO regions; (iii) the July 7, 2025 deadline for submitting comments following the FERC's June 4-5, 2025 technical conference on ISO/RTO Resource Adequacy challenges; and (iv) the nomination of Laura Swett to replace FERC Chairman Mark Christie at the end of his term. Mr. Lombardi encouraged anyone with questions on any matter in the Litigation Report to feel free to reach out to NEPOOL counsel.

COMMITTEE REPORTS

Markets Committee. Mr. Ben Griffiths, the MC Vice-Chair, reported that the next MC meeting was scheduled for July 8-9, 2025, at the DoubleTree in Westborough, MA, with the potential for a third meeting day, on July 10, still under consideration. Discussion at the July MC meeting would focus on CAR-related topics. Mr. Griffiths noted that, going forward, discussion on CAR-related topics and Tariff redlines would be consolidated at the MC, rather than taken up in parts separately by each of the Technical Committees.

Reliability Committee (RC). Mr. Robert Stein, the RC Vice-Chair, reported that the joint RC/TC Summer Meeting would be held July 15-16, 2025 at Wentworth by the Sea, in Newcastle, NH. In addition to a vote on *Order 2222* Conforming Changes, the RC would consider, through proposed Operating Procedure revisions, the ISO's initial Regional Energy Shortfall Threshold (REST) proposal and processes to leverage REST and the use of the Probabilistic Energy Adequacy Tool (PEAT).

Transmission Committee. Mr. David Burnham, the TC Vice-Chair, reported that the CAR deactivation-related redlines would not be on the RC/TC Summer Meeting agenda or at the TC meeting in August. Those Tariff redlines will be on the MC's July and August meeting agendas but will be back to the TC in the Fall. The RC/TC Summer Meeting agenda will include RNS Rate updates as well as items addressing the impact of the RENEW Complaint and additional information on the load impact on RNS Rates.

Budget & Finance (B&F) Subcommittee. Mr. Thomas Kaslow, B&F Chair, reported that the next B&F meeting would be July 18, 2025. There will be discussion on the potential impacts on the Financial Assurance Policy resulting from the CAR Project.

Membership Subcommittee. Mr. Brad Swalwell, Membership Subcommittee Chair, reported that the next Membership Subcommittee meeting would be held by Zoom on July 14, and encouraged all those interested to participate and reach out to him or NEPOOL Counsel for the Zoom information.

FERC STAFF INTRODUCTIONS & COMMENTS

Ms. Bresolin welcomed, introduced, and thanked the following FERC representatives for their attendance and participation in the Summer Meeting: Ms. Scotia Bennett, Ms. Pearl Donohoo-Vallett, Mr. Eric Jacobi, and Mr. Aaron Siskind.

Ms. Bennett, Technical Advisor for Commissioner Lindsay See, said she had been with FERC for eleven years and was originally in the Office of Energy Market Regulation (OEMR)-East. She works on an Eastern portfolio for the Commissioner focused mostly on the Eastern ISOs and assists on Markets issues in other regions as well.

Ms. Donohoo-Vallett, Technical Advisor for Commissioner Judy Chang, said she has a broad portfolio in Commissioner Chang's office so is open to many conversations. She is point for ISO-NE, NYISO, MISO, and Markets West. She also has a background and prior experience in rate making, on the retail space for Exelon running a regulatory team, and was in economic and litigation consulting.

Mr. Jacobi, the regional representative for New England, spoke briefly on his role and experience as decisional staff, particularly for larger New England matters coming before the FERC. He stated that he is a dedicated resource for New England and could help arrange pre-filing meetings with Staff, or answer more general process questions. He encouraged members to reach out to him if and as needed.

Mr. Siskind, from the FERC's Division of Economic and Technical Analysis in the Office of Energy Policy and Innovation (OEPI), had been with the FERC for 20 years. Although he is mostly New England and eastern RTO market focused, for the last six months he has been mostly focused on PJM. He said that he was looking forward to upcoming efforts on DASI, Resource Capacity Accreditation (RCA), and Capacity Market reforms.

Thanking the FERC staff representatives for their introductions, Ms. Bresolin also mentioned that Mr. Zachary Harris from the Office of Energy Market Regulation (OEMR)-East would be arriving later that evening and encouraged members to introduce themselves.

EMM 2024 ANNUAL MARKET REPORT

Overview

Dr. David Patton, President of Potomac Economics and the ISO's External Market Monitor (EMM), presented highlights from the EMM's 2024 Markets Report (EMM Annual Report), which had been circulated and posted in advance of the meeting. Dr. Patton's introductory remarks explained the key market areas to be addressed by the EMM Annual Report and complemented the Internal Market Monitor's report recently published that covered the same period.

Cross-Market Comparison

Dr. Patton began by discussing the "all-in" prices on a dollar-per-megawatt-hour basis across the various FERC-regulated markets and the Electric Reliability Council of Texas (ERCOT). His presentation showed that energy prices in New England were consistently higher than those in other markets, which he explained could be attributed primarily to region's higher natural gas prices. His presentation also showed that 2024 capacity prices were highest in New England, due to over forecasting of load leading up to 2024 (which in a forward capacity market, would take time to rectify). Dr. Patton explained that, for the 2024/2025 planning year, load was over forecasted by approximately 1 GW. He also noted an increase in NYISO's capacity prices due to recent retirements.

Next, Dr. Patton discussed transmission congestion costs. Even when adjusted for its geographic size, he explained that New England experiences only a fraction (about one-tenth) of the congestion that other RTOs experience, due to the region's heavy investment in transmission. In his view, the low congestion costs positively affected the market, lowering stress on the transmission network and reserve requirements. But, the positive impacts came at a high cost. At $23.9/MWh of load, New England had the highest transmission costs of any other region. Dr. Patton added that other RTOs had more recently increased their transmission investment for various reasons, including to support the clean energy transition, also with increasing costs. Responding to comments, he acknowledged concerns regarding unpriced congestion due to manual curtailments of some renewable resources in northern New England and committed to further study that issue.

Although virtual trading was generally profitable, Dr. Patton noted that ISO-NE's virtual trading activity was significantly lower than that of other RTOs. He attributed this in part to the overallocation of Net Commitment Period Compensation (NCPC) charges, which discourage virtual trading. As a result, he stated, the Day-Ahead Energy Market (DAM) was illiquid. In response to questions, he again recommended allocating NCPC costs to load, which would lead to more efficient DAM outcomes. He expected that the Day-Ahead Ancillary Services Initiative (DASI) to help reduce Day-Ahead and Real-Time NCPC over time.

Dr. Patton then compared NCPC costs in New England with those in MISO and NYISO. He explained that New England's NCPC (or "uplift") costs were higher on both a market-wide and size-adjusted basis. Dr. Patton noted that markets with higher fuel costs tend to have higher uplift costs, as New England demonstrated. Local reliability uplift costs, however, were significantly lower in New England than in other RTOs, particularly NYISO.

Next, Dr. Patton discussed maker power mitigation measures under DASI. He noted that, in 2024, there was no evidence of significant market power. However, an analysis of mitigation instances over two months (March 16 to May 15, 2025) following DASI's implementation raised concerns about the disproportionate mitigation of smaller suppliers. Referring to his presentation, the top 10 suppliers of DASI products, who represented 70 percent of the capability, were mitigated 9 percent of the time. By contrast, the smallest suppliers, who likely cannot exercise market power and represent 6 percent of the capability, were mitigated 35 percent of the time. Dr. Patton attributed this outcome to conduct and impact thresholds being set too low. He recommended revising those thresholds to allow suppliers to reflect legitimate risk preferences, which, he stated in response to a question, would not likely increase prices significantly. He noted that he would work with the ISO and the IMM on this recommendation.

Navigating the Clean Energy Transition

Dr. Patton continued his presentation by discussing the clean energy transition, beginning with a review of the interconnection queue. Of the more than 400 projects in the queue (representing about 40 GW of installed capacity), over half were solar (including hybrid solar-plus-storage resources), offshore wind, and battery storage. Offshore wind projects without contracts and battery storage accounted for about 75% of the queued GW. Dr. Patton also noted that renewable resources development in New England has lagged behind other RTOs/ISOs.

He highlighted several future challenges associated with increasing penetration of intermittent renewable resources. Referring to his presentation, Dr. Patton explained that solar resources may drive increased ramping needs, particularly because their output peaks between New England's two daily winter peaks, requiring the conventional fleet to ramp more aggressively. In response to questions, he noted that battery storage would be best positioned to address ramping challenges and that a diverse portfolio would be most beneficial.

Dr. Patton also noted that growing reliance on inverter-based resources may challenge the system's ability to maintain voltage. He further observed that, as in MISO, large intermittent generators often fail to follow curtailment instructions or respond as promptly to dispatch as conventional generators, which could create transmission security concerns.

Nonetheless, Dr. Patton stated that the ISO was well positioned to navigate the clean energy transition due to shortage pricing (i.e., the Pay-For-Performance (PFP) construct) and forthcoming marginal accreditation reforms under the Capacity Auction Reforms (CAR) initiative. He recommended developing a look-ahead dispatch model to manage ramp needs better. He added that capacity markets can provide sufficient incentives to build merchant resources and that New England's transition from a forward to a prompt/seasonal capacity market—coupled with accreditation reforms—should improve market signals.

Resource Commitment and Pricing Issues

Dr. Patton then turned to an operational issue. By way of background, he explained that the ISO uses the Real-Time Unit Commitment (RTUC) model, which runs every 15 minutes, to evaluate near-term conditions and commit fast-start resources. RTUC results are passed to the Unit Dispatch System (UDS) for execution. Referring to his presentation, the EMM observed that ISO operators adjust load upwards in RTUC by as much as 100 MW, resulting in price divergence between RTUC and UDS and increased Real-Time NCPC. He recommended that the ISO re-evaluate its operator procedures to improve price convergence.

Reserve Pricing in the Fast-Start Pricing Logic

Dr. Patton then touched on an issue he has previously discussed: a flaw in the fast-start pricing logic for Operating Reserves that, in his view, results in inefficient reserve pricing under certain conditions. As further discussed in the EMM Annual Report, he explained that when a fast-start resource is set at its Economic Minimum (EcoMin), it cannot set the marginal price. As a result, the megawatts available below the resource's EcoMin are undervalued, causing the system to appear short and artificially inflating energy and reserve prices.

Capacity Availability and Performance Issues

Referring to his presentation, Dr. Patton discussed a concern with what he described as overvalued Qualified Capacity (QC). He explained, as further detailed in the EMM Annual Report, that a thermal generator's QC is based on its Seasonal Claimed Capability (SCC) audit, which is not conducted under peak conditions. In the summer of 2024, such peak conditions included higher humidity and lower barometric pressure. Moreover, peak load hours had shifted to later in the afternoon due to increased retail-level solar penetration. As a result, under peak conditions, approximately 300 MW of thermal resources were unavailable due to high humidity and low pressure, with an additional 400 MW or so unavailable due to unreported forced derates. To ensure that the region is paying for QC that is available during peak conditions, Dr. Patton recommended that the ISO enhance its testing procedures to account for humidity and pressure and strengthen enforcement of derate reporting.

Assessment of the June 17 and August 1, 2024 Capacity Scarcity Condition (CSC) Events

Dr. Patton observed that the capacity shortage for the two CSC events ranged from 30 to 90 minutes and averaged nearly 250 MW. Based on his analysis, he did not view either event was a significant reliability risk or having posed a meaningful probability of loss load. His presentation showed that although the reliability impacts was low, the financial consequences for steam and combined cycle resources were significant, totaling nearly $50 million in PFP charges. In contrast, import resources without Capacity Supply Obligations (CSO) earned nearly $14 million, while export resources without CSOs would have faced PFP charges of approximately $8 million but for the current PFP rules.

Dr. Patton concluded that not pricing the expected shortage in the DAM is a flaw because it fails to commit resources, such as combined cycle and steam units, that are needed for reliability (especially in the winter). This, he warned, could contribute to premature retirements. He also noted that the PFP rate, slated to increase to nearly $9,400/MWh in June 2025, is unjustifiably high, particularly for short duration events with low probability of losing load. Accordingly, Dr. Patton continues to recommend that the ISO revise its PFP rules to charge exporters at the PFP rate during CSCs, modify the PFP rate to align with a reasonable estimate of the value of lost load, and scale the rate with the magnitude of the resource shortage. In response to a comment, he also suggested that the ISO could address the Balancing Ratio, which can exceed 1.

Winter Reliability in the Forward Capacity Market (FCM)

Dr. Patton offered brief comments on how the FCM addresses winter reliability needs. He commended the ISO's efforts to reform accreditation methodologies and transition from a forward to a prompt/seasonal capacity market. He further recommended that the ISO reconsider how Energy Efficiency (EE) is treated in the capacity market. Rather than including EE in the supply side, he recommended moving EE to the demand side, noting that PJM has already made this shift and that MISO appears to be moving in that direction.

Managing Price Volatility in a Prompt Capacity Market

In response to stakeholder concerns that transitioning from a forward market to a prompt market could introduce unmanageable price volatility, the final topic Dr. Patton discussed was how NYISO market participants manage volatility. Referring to his presentation, he highlighted capacity supply management practices in New York City, which faces the highest and most volatile spot prices in the NYISO market. His charts illustrated that price volatility was mitigated by hedging practices of utilities and access to competitive retail suppliers offering contracted rates. In response to a question about ISO-NE's current proposal to require two-year irrevocable retirement notifications, Dr. Patton opined that a one-year notice would be preferable, especially if the notice is irrevocable.

JUNE 25 SESSION

The Summer Meeting reconvened at 9:30 a.m. on June 25, 2025.

HOST STATE KEYNOTE REMARKS (MA EEA SECRETARY REBECCA TEPPER)

Ms. Bresolin welcomed members and guests back to the meeting and introduced Ms. Rebecca Tepper, the Secretary of the Commonwealth of Massachusetts' Executive Office of Energy and Environmental Affairs (MA EEA). Secretary Tepper thanked Ms. Bresolin for the invitation to speak at the Summer Meeting, recalling fondly her time at two different places where she had worked with Ms. Bresolin. She also recognized by name a number of other Participant and State representatives around the room with whom she had had the pleasure of working directly, as well as her team that had built on her vision of having for the first time a federal and regional affairs division within the MA EEA. She shared her appreciation for NEPOOL's role in the collaboration amongst the States, the ISO and the industry to reach consensus on the many and often difficult issues facing New England over the years. Secretary Tepper congratulated Dr. Chadalavada on his forthcoming new role at the ISO and thanked Mr. van Welie for his many years of balanced and poised leadership, guiding New England to be one of the most reliable in the country, growing the region's competitive wholesale markets from the ground up, and his commitment to collaborating with New England's diverse and determined group of stakeholders.

Secretary Tepper addressed Massachusetts Governor Healey's vision to deliver on affordability, reliability, and clean energy priorities. She began by summarizing key elements of the Energy Affordability, Independence and Innovation Act (the Act) on which she would be testifying later that day. The first of those elements included lowering overall costs to consumers, by approximately $10-$13 billion over the next 10 years (on the top of the savings estimated in the energy affordability agenda announced in March), by removing, phasing out, and financing in other ways certain charges on consumers' utility bills. The Act would also address costs by authorizing the Massachusetts Energy Facilities Siting Board to review one of the fastest growing components on Massachusetts electric bills – cost recovery for Asset Condition Projects. She expressed her appreciation and optimism for the success of discussions under way amongst the ISO, TOs and her state colleagues to identify and advance solutions for addressing the Asset Condition Project issues.

Another component of the Act would change how Massachusetts procures clean energy, authorizing the Department of Energy Resources (DOER) to directly procure resources, in times, amounts and kinds that would maximize rate payer savings, eliminating fees charged by the utilities for serving as the contracting agent. She said that this authority would build on the authority to procure offshore wind, energy storage, and the upgraded solar incentives that had been announced the week before. There were also proposed reforms that would reduce barriers for small modular nuclear reactors and proposed innovative interconnection solutions for distribution-connected resources.

Addressing affordability, which she described as a shared responsibility within the energy sector, Secretary Tepper stressed the importance of seeking efficiencies when and where possible, maximizing the benefits of the grid, and cultivating and advancing transmission and other technologies. She stated that, as Massachusetts plans and completes major energy investments, consumers would be kept front of mind, and implored all those present to likewise keep consumers front of mind.

Secretary Tepper affirmed Massachusetts' commitment to the regional wholesale electricity markets as the primary vehicle for attracting new investments and ensuring resource adequacy in New England. Massachusetts viewed its siting and permitting authority as complementary to that goal. Further, Massachusetts sought additional ways in which it could minimize customer price volatility, and the proposed reforms to standard offer contracting in the Act had been proposed to address in part that goal.

Looking ahead, facing the potential for system conditions to tighten through the end of the decade, Secretary Tepper said that the region would be called on to tackle challenges head on and together. She believed and explained how Massachusetts was working to do its part. She expected that Massachusetts, as it had since restructuring began, would continue to rely on competitive wholesale markets to drive down costs, shift risk away from consumers, and to attract and retain resources. Massachusetts would continue to monitor the changes to the markets and resource adequacy and would be prepared, if and to the extent necessary, to use state authority to protect its consumers and lower prices.

Sectary Tepper addressed the importance and benefits of offshore wind, for which she was a strong advocate. She thanked Mr. van Welie for his recent congressional testimony addressing offshore wind, and committed Massachusetts, even amidst growing uncertainty due to federal policy and actions, to continue to invest in infrastructure and do what Massachusetts was able to support the development of the offshore wind industry off the coast of Massachusetts.

Secretary Tepper also addressed Massachusetts' relationship with its neighbors. She expressed pride in the relationship among the Northeast States, which she believed had never been stronger. She noted active discussions concerning new resources, both inside and outside of New England, including the recent transmission solicitation to procure transmission infrastructure, and efforts underway to explore opportunities to increase transfer capacity between ISO-NE, NYISO, and PJM, and the recent request for information seeking interregional transmission project concepts that would improve grid reliability, support economic growth, and reduce costs for consumers issued by the Northeast States Collaborative on Interregional Transmission (States Collaborative). Beyond the Northeast, she noted Massachusetts' long-standing relationship with Canada, and efforts to explore opportunities for cross-border collaboration on energy priorities, highlighting a recent meeting hosted by Massachusetts with the Canadian Premiers.

Secretary Tepper concluded her prepared remarks by reiterating that it had been an honor to serve in her role since she took office in 2023. Acknowledging increasing challenges, she remained committed to accomplishing what could be done to help Massachusetts and New England ratepayers, and continuing to work with those in the region, and beyond, to meet those challenges head on.

In response to questions, Secretary Tepper commented further on the discussions with the Canadian Premiers, offshore wind developments, state procurements alongside wholesale markets, and the developing collaboration amongst Northeast state representatives.

Secretary Tepper emphasized ongoing U.S.–Canada cooperation on energy projects despite grassroots Canadian advocacy for an East-West Energy Corridor, noting that both sides remain focused on project design, costs, and allocations. She highlighted the Vineyard Wind Project as a priority, expressing confidence it would be operational by year-end to demonstrate the benefits of offshore wind for New England. On the procurement side, Secretary Tepper outlined Massachusetts' shift toward emphasizing clean energy attributes while continuing to rely on wholesale markets for energy and capacity. She also noted expected savings for customers with the DOER taking on contracting responsibilities (rather than the distribution utilities) under a stakeholder-driven, MA DPU-approved framework modeled on NYSERDA. Finally, Secretary Tepper underscored the role of the nine-state States Collaborative, working with the DOE to pursue transmission expansion projects that improve reliability, manage costs, and deliver regional benefits.

PANEL DISCUSSION – FINANCING THE POWER GRID: INVESTMENT CHALLENGES & OPPORTUNITIES

The panel discussion was moderated by ISO Board member Ms. Catherine Flax, and featured as panelists: Ms. Susan D. Nickey, Executive Vice President and Chief Client Officer at Hannon Armstrong Sustainable Infrastructure Capital, Inc. (HASI); Mr. Edwin Stone, Executive Director, U.S. Project Finance & Infrastructure, CIBC Capital Markets; and Mr. Nick Violandi, Senior Director, Power & Infrastructure, Project Finance, John Hancock. Ms. Flax set the stage for the discussion, noting the critical importance of creating a market environment that enables and encourages investment, and that the morning's discussion would explore with the panelists the investment challenges and opportunities associated with financing the power grid in New England and beyond.

For the benefit of the broad-based group of meeting attendees, Ms. Flax began by asking Mr. Stone to provide a high-level introduction to project finance and to identify the attributes that would make a particular project interesting to an investor. Mr. Stone explained by way of analogy that the point of project finance is to allocate every element of risk to the party best able to appropriately handle that risk. At highest level, he explained, project finance is a series of financing tools to support to the development of large, long-lived, capital assets. It is secured financing, predicated on stable, predictable cash flows from those capital assets. Those cash flows are almost always, at least to some degree, embedded in some form of contractual relationship for revenue, for capital formation, and in the case of power assets, for a predictable amount of energy generation. Project finance is typically non-recourse to the developer or to the corporate entity that is supporting the development of the power asset or a transmission line (limiting lender recovery to the specific asset/collateral pledged as security for the loan). Project finance typically takes the form of a partnership between regulated entities, a utility developer in many cases, and private investors to support equity capital coordination for the build out of a large asset that has a multi-billion dollar financing associated with it.

Adding additional perspective, Mr. Violandi said that insurance companies as project finance funders are diligently-focused on projecting cash flows, with analysis almost exclusively focused on downside risk. They determine a “break-even” analysis and evaluate that against their overall investment strategy. Ms. Nickey stated that companies like HASI are focused more on long-term equity, but also look for long-term stable cash flows. Referring back to Secretary Tepper’s earlier comments, Ms. Nickey said that issues like affordability led to HASI’s start in project finance. As long-term investors, they sought to drive down the cost of energy to rate payers by bringing abundant, low-cost capital to finance the capital-intensive energy industry. She noted challenges, including those for low-cost fuel resources like wind and solar, to get capital expenditures right.

Ms. Flax asked the panelists to speak about the current trends and attributes in a region like New England that would be relevant to building power plants or transmission. Mr. Violandi identified intra-state volatility and changing contract structures, particularly a move away from longer-term revenue contracts towards contracts in the 7 to 10-year range, which required flexibility and creativity in financing. He also identified the impact from a financing perspective of growing demand for power, specifically growing data center demand. Load growth suggested the need not only for additional renewable resources, but for base load, quick-start type products with which intermittent resources could be matched. Ms. Nickey noted the importance of the availability and transferability of near and medium term tax credits, particularly for technologies like offshore wind, distributed generation, storage, and carbon capture. Mr. Stone spoke to the confluence of two trends – one the shift to renewables and the other how the region will support supply for data centers and large loads expected to come online in the near term. He said that the confluence required a regional outlook and would influence whether, from a capital markets perspective, a project would be seen as either bankable or investible.

Panelists then provided their thoughts and experience with the impacts of public policy on project finance as well as their views on what appeared to be an ever growing public-private partnership that added to traditional long-term contract assessment consideration of tax credits, interest by public sector offtakers, etc. They addressed the increased complexity of the market, how that changed how projects could or would be financed and brought front and center the importance of public policies at all levels to ensure that energy demand could be met and capital investment available to support meeting that demand. They noted that the prevalence of distributed resources on the grid had shifted focus towards reliability and transmission planning. Coordination with and involvement of the public policy apparatus was particularly critical to transmission projects, both from the perspective of the long-lived nature of the asset, but also from the perspective of the stability and predictability of the cash flow revenue mechanism.

Panelists then addressed the impact of technology risks on investment decisions. Each acknowledged that technology risk tolerance impacted investment decisions. Using batteries and small modular nuclear reactors (SMRs) as examples, one explained how technology risks, when well understood were not an impediment to investment. Technology risks often presented as a function of cost, with the more costly technologies often requiring some level of public policy incentives to support investment/development. They further discussed the correlation between technology risk tolerance, higher rates of return on investment, and the importance of understanding the hierarchical structure and cost overrun risk of a project's financing.

The panelists affirmed that the power project finance market (particularly the financing of renewables) was robust and increasing year-over-year, notwithstanding geopolitical risks and rising interest rates. Competition for capital and capital deployment was fierce, with a notable increase in attractive investing solutions being offered by private credit funds in addition to the traditional offerings by banks and institutional investors. Some sensed that investors were moving away from risky assets and into safer ones, including into energy markets which had historically proven to be profitable and successful -- good projects, good sponsors, and a stable regulatory environment tends to always attract capital. Both RTO market mechanisms and private projects, if appropriately structured, could support investment.

In response to questions from Ms. Flax, panelists stressed the critical importance of market structure stability in evaluating investment decisions. They emphasized the adverse impacts of changing rules or policies retroactively, particularly after capital has been committed to a project in reliance on the rules or policies to be changed. panelists also went on to describe the focus of and processes undertaken by their respective investment committees with respect to projects under assessment/consideration.

Referring to the New England Clean Energy Connect and the ISO's request for proposals on a transmission line from Maine, Ms. Flax then asked the panelists what they would have the ISO know about financing major infrastructure projects such as a transmission line. Panelists emphasized that private investment depends on establishing an authorized ROE, supported by appropriate project scale and contractual certainty, and that accelerating permitting, reducing delays, allocating upfront risks, and ensuring financial flexibility can strengthen project economics and lower capital costs.

Meeting attendees then asked questions of the panelists. Regarding the potential impact of tariffs, panelists agreed that while tariffs raise supply chain costs, their impact would generally be manageable within project economics. Some sponsors would be willing to provide additional equity, guarantees, or funding to offset risks, and opportunities exist to adapt through higher inventory levels and more standardized technical requirements.

In response to a question on financing of projects in the absence of price-locks and long-term contracts, panelists indicated that institutional investors would likely continue to insist on a contract revenue stream as a condition for funding, with limited exceptions, such as the financing of storage projects in California and Texas. They additionally noted that rising development costs further limit the ability to build new assets without secure revenue streams.

Responding to another member's question, panelists remarked that certain contract provisions can significantly affect financeability. Risk-shifting terms, such as shape risk clauses or provisions reducing payments if tax credit rules change, can weaken cash flow predictability and/or deter lenders. By contrast, mechanisms like guaranteed floor prices or curtailment compensation can strengthen project financing prospects.

With respect to their views on whether proposed market reforms in New England would support or enhance financeability, panelists observed that rewarding reliability could encourage investment. They suggested that broader financeability would depend on stable market structures, predictable pricing, strong counterparties, and financing designs that reduce exposure to long-term volatility.

The panel discussion concluded with panelists addressing questions related to demand growth, federal transmission incentives, the impact of proposed cuts to monetary incentives supporting policy goals, development and use of pricing curves, and experience with project defaults.

There being no other business the meeting adjourned at 11:45 a.m.

Respectfully submitted,

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Sebastian Lombardi, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
JUNE 24-26, 2025 SUMMER MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Advanced Energy United	Associate Non-Voting	Alex Lawton		
AR RG Large Group Member	AR-RG		Aidan Foley	
Ashburnham Municipal Light Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
AVANGRID: CMP/UI Avangrid Renewables	Transmission	Alan Trotta Kevin Kilgallen (Web)	Jason Rauch	
Bath Iron Works Corporation	End User			Bill Short
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
BlueWave Public Benefit Corp.	AR-DG	Mike Berlinski		
Boylston Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
BP Energy Company (BP)	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
Brookfield Renewable Trading and Marketing	Supplier	Aleks Mitreski		
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
Clear River Electric	Publicly Owned Entity		Dave Cavanaugh	
Clearway Power Marketing LLC	Supplier			Pete Fuller
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop. (CMEEC)	Publicly Owned Entity	Brian Forshaw (Web)	Richard Gaudet	
Connecticut Office of Consumer Counsel (CT OCC)	End User		Jamie Talbert-Slagle	
Conservation Law Foundation (CLF)	End User	Phelps Turner (Web)		
Constellation Energy Generation	Supplier	Gretchen Fuhr	Bill Fowler	
CPV Towantic, LLC	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Dominion Energy Generation Marketing	Generation	Wes Walker	Susan Adams	
DTE Energy Trading, Inc. (DTE)	Supplier			José Rotger
Durgin and Crowell Lumber Co., Inc.	End User			Bill Short
Dynegy Marketing and Trade, LLC	Supplier	Ryan McCarthy	Andy Weinstein	Bill Fowler
ECP Companies Calpine Energy Services, LP (Calpine) New Leaf Energy	Generation	Andy Gillespie		Bill Fowler
EDF Trading North America, LLC	Supplier	Eric Osborn		
Elektrisola, Inc.	End User		Gus Fromuth	Bill Short
Emera Energy Companies	Supplier			Bill Fowler
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Eversource Energy	Transmission	Vandan Divatia	Dave Burnham	
First Point Power, LLC	Supplier	Peter Schieffelin (Web)		
FirstLight Power Management, LLC	Generation	Tom Kaslow	Peter Rider	
Galt Power, Inc. (Galt)	Supplier	José Rotger	Jeff Iafrati (Web)	
Garland Manufacturing Company	End User			Bill Short
Generation Bridge Companies	Generation		Bill Fowler	
Generation Group Member	Generation	Dennis Duffy	Abby Krich (Web)	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Granite Shore Companies	Generation			Bob Stein
Grid United LLC	Provisional		Lawrence Mott (Web)	

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Groton Electric Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQ US)	AR-RG	Louis Guibault (Web)	Bob Stein	
Hammond Lumber Company	End User			Bill Short
Harvard Dedicated Energy Limited	End User			Ariella Fuzaylov
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Holyoke Gas & Electric Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Hudson Light and Power Department	Publicly Owned Entity			Dave Cavanaugh
Hull Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
Icetec Energy Services, Inc. (Icetec)	AR-LR	Doug Hurley		
Industrial Wind Action Corp.	End User	Lisa Linowes		
Ipswich Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Jericho Power LLC (Jericho)	AR-RG	Ben Griffiths		
Jupiter Power	AR-RG		Frank Swigonski	
KCE Companies	AR-DG		Paul Williamson	
Lamson, Jon	End User	John Lamson		
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	
Long Island Power Authority (LIPA)	Supplier	Bill Kilgoar		
Maine Power LLC	Supplier	Jeff Jones (Web)		
Maine Public Advocate's Office (Maine OPA)	End User	Drew Landry		Ariella Fuzaylov
Mansfield Municipal Electric Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Marble River, LLC	Supplier	John Brodbeck (Web)		
Marblehead Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Mass. Attorney General's Office (MA AG)	End User	Jacquelyn Bihrle	Jamie Donovan	
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Climate Action Network (MCAN)	End User			Abby Krich
Mass. Department of Capital Asset Management	End User		Paul Lopes (Web)	
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Matt Ide	Dan Murphy	
MDC – The Metropolitan District	Publicly Owned Entity		Dave Cavanaugh	
Mercuria Energy America, LLC	Supplier			José Rotger
Merrimac Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Moore Company	End User			Bill Short
Natural Resources Defense Council	End User	Claire Lang-Ree		
Nautilus Power, LLC	Generation		Bill Fowler	
New Hampshire Electric Cooperative	Publicly Owned Entity			Brian Forshaw (Web)
New Hampshire Office of Consumer Advocate (NHOCA)	End User	Matthew Fossum		
New England Power (d/b/a National Grid)	Transmission	Tim Brennan	Tim Martin	
New England Power Generators Assoc. (NEPGA)	Associate Non-Voting	Bruce Anderson	Dan Dolan	Molly Connors
NextEra Energy Resources, LLC	Generation	Michelle Gardner	Nick Hutchings	
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
NRG Business Marketing, LLC	Supplier		Pete Fuller	
Nylon Corporation of America	End User			Bill Short
Onward Energy	AR-RG		Emily Chapin	

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JUNE 24-26, 2025 SUMMER MEETING

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Pawtucket Power Holding Company LLC	Generation	Dan Allegretti		
Paxton Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Peabody Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
PowerOptions	End User			Ariella Fuzaylov
Princeton Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
RENEW Northeast, Inc.	Associate Non-Voting	Francis Pullaro	Nathan Raike	
RI Division (DPUC)	End User	Linda George		
RI Energy (Narragansett Electric Co.)	Transmission	Brian Thomson	Robin Lafayette	Janell Fabiano
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity		Matt Ide	Dan Murphy
Saint Anselm	End User			Bill Short
Shell Energy North America (US)	Supplier	Jeff Dannels		
Shipyard Brewing LLC	End User			Bill Short
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Matt Ide	Dan Murphy
Sierra Club	End User			Claire Lang-Ree
Sliski, Alan	End User	Alan Sliski (Web)		
South Hadley Electric Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Sterling Municipal Electric Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Tangent Energy Inc.	AR-LR	Brad Swalwell	Meghan Dutton	
Taunton Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
Union of Concerned Scientists	End User	Susan Muller (Web)		
Vermont Electric Cooperative	Publicly Owned Entity		Dan Potter	
Vermont Electric Power Company (VELCO)	Transmission	Frank Ettori		
Vermont Energy Investment Corporation	AR-LR			Ariella Fuzaylov
Vermont Public Power Supply Authority	Publicly Owned Entity		Brian Forshaw (Web)	
Versant Power	Transmission	Dave Norman	Stephen Johnston	
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity	Dave Cavanaugh		
Vineyard Offshore	Generation	Carrie Hitt		
Vitol Inc.	Supplier	Seth Cochran		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler	
ZTECH, LLC	End User			Bill Short

PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held by Webex beginning at 10:00 a.m. on Thursday, August 7, 2025. 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 by Webex or by telephone.

Ms. Sarah Bresolin, Chair, presided, and Mr. Sebastian Lombardi, Secretary, recorded.

APPROVAL OF JUNE 2025 SUMMER MEETING MINUTES

Ms. Bresolin noted that approval of the June Summer Meeting minutes would be deferred to the September 7, 2025 Participants Committee Meeting.

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 recorded for Mr. Jon Lamson.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), referred the Committee to the summary (dated August 7, 2025) of ISO New England Board Committee meetings that had occurred in June and July, which had been circulated and posted in advance of this meeting. There were no questions or commentary on that summary.

ISO COO REPORT

Operations Report

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), began by referring the Committee to his August operations report, which had been circulated and posted in advance of the meeting. Dr. Chadalavada noted that the data in the report was through July 30, 2025, unless otherwise noted. The August report highlighted: (i) that the Peak Hour for July, with 25,295 MW of Revenue Quality Metered (RQM) Data (including settlement-only generation), occurred on July 29, 2025 during the hour ending 7:00 p.m.; (ii) July averages for Day-Ahead Hub LMP ($70.56/MWh), Real-Time Hub LMP ($60.22/MWh), and natural gas prices ($4.27/MMBtu), resulting in a nearly $10 premium in the Day-Ahead market; (iii) Energy Market value for July 2025 was $1 billion, up from $672 million in July 2024 and up from the updated June Energy Market value of $523 million (an expensive month due in large part to high loads during the month, including a peak load of 24,863 MW on July 29, and peak loads reaching from 23,000 MW to close to 25,000 MW at several points in the month); (iv) Ancillary Services Markets value ($40.5 million) was up from July 2024 ($19.9 million); (v) average Day-Ahead cleared physical energy during the peak hours as a percentage of forecasted load was 100.5% during July (up from 99.2% reported for June 2025); (vi) Daily Net Commitment Period Compensation (NCPC) payments for July totaled $2 million (representing just 0.5% of July's monthly Energy Market value), comprised of (a) $4.4 million in First Contingency payments (including $701,000 in Dispatch Lost Opportunity Costs, $581,000 in Rapid Response Pricing Opportunity Costs, and $84,000 paid to resources at external locations), (b) no Second Contingency or voltage payments, and (c) $300,000 in Distribution payments; and (vii) a Forward Capacity Market (FCM) value of $88.6 million.

Dr. Chadalavada noted the temperature and load fluctuations experienced by the region in July, with temperature variations of 8-10° F above and below normal and related load volatility. He explained that the temperature fluctuations had adversely impacted ISO load forecast models, which had missed every forecast metric for both the peak hour and average across the month of July. He also highlighted how recent load fluctuations demonstrated changes to the System, contrasting the 5,318 MW mid-day minimum load experienced on April 20, 2025 to the peak load of 26,551 MW experienced on June 24.

After reviewing Day-Ahead Ancillary Services (DAAS) results, Dr. Chadalavada explained the importance, notwithstanding the challenges in quantifying the financial benefits, of incenting and compensating suppliers through the Day-Ahead market for the critical reliability services being provided. In response to a question, Dr. Chadalavada confirmed that battery storage systems could certainly provide ancillary services and participate in the DAAS market. He also confirmed that there had been a notable increase in virtual transactions, particularly incremental offers (INCs), following the March 1, 2025 implementation of the DAAS Market. He explained that, because INCs, purely financial instruments, can cause the amount of cleared physical energy in the Day-Ahead market to be less than the expected Real-Time load (an "energy gap"), a Forecast Energy Requirement (FER) and Energy Imbalance Reserve (EIR) product would be relied on to ensure sufficient physical energy clears the Day-Ahead Market. Dr. Chadalavada said that the INC effect was addressed by the IMM in its most recent quarterly markets report and was part of the DAAS Market evaluation under way. The results of that DAAS Market evaluation and any related recommendations would be presented to stakeholders in early 2026.

Dr. Chadalavada then previewed plans for a presentation at the upcoming September Participants Committee meeting on the status of the Asset Condition Reviewer efforts. He reported that the ISO had made good progress on the project plan, including on both the interim and permanent processes, and looked forward to discussion and feedback on that process.

In response to additional questions, Dr. Chadalavada confirmed that the relatively high average Day-Ahead LMPs in July were driven primarily by high loads and the volatility discussed. He said that LMPs were also impacted by system operations at the top of the supply stack, with reserve product offers notably higher than usual, and likely larger risk premiums built into offers given the possibility for Capacity Scarcity Conditions. He added that many of the elements impacting LMPs, including strike-price adders, were under review and consideration by the ISO.

Addressing questions regarding energy gaps and EIR offers and credits in light of Forecast Energy Requirements, Dr. Chadalavada explained that, in July, the ISO did not need to clear many EIR offers because energy imbalance gaps were very small. He explained that almost all of the physical energy (with load bidding in at almost 100.5% of the ISO's projected Day-Ahead peak forecast) was able to be cleared through physical supply offers, leaving a small amount to be covered by EIR. He noted that the hourly cleared EIR obligation for July averaged roughly 55 MW and agreed to explore whether more granular data would be useful to provide going forward. In addition, he confirmed that approximately 155 assets offered DAAS MW in July, but the number and type of assets with cleared DAAS MW was not identified in the COO Report.

June 24, 2025 OP-4 Event and Capacity Scarcity Condition

Referring to the materials on the June 24, 2025 OP-4 Event and Capacity Scarcity Condition (CSC), Dr. Chadalavada briefly summarized the information provided in the COO Report, touching on the conditions and forecasts leading up to and on June 24, outages, sources of energy supply, CSC intervals, and the system peak experienced, and the various ISO actions taken in response. He addressed system and resource performance, including a summary of pay-for-performance (PFP) settlements (performance payments, charges, credits and a summary of stop-loss allocation).

In response to questions, Dr. Chadalavada confirmed that the June 24 reserve shortage was not attributable to a specific or large generator unit trip, or to transmission or fuel-related issues. Rather, the shortages were a combination of mechanical and environmental factors, including reductions due to ambient air temperatures, and ramp times for units coming back online to get to their full output. He also confirmed that, despite calls for Emergency Energy Transactions (EETs), no EETs were submitted during the scarcity event. Dr. Chadalavada agreed to look into whether the more granular information on EET e-mail notifications as described earlier by a member could again be reported.

In response to additional questions, Dr. Chadalavada clarified the information presented on net interchange flows and hourly imports by interface. He agreed to look into whether and how additional information on gross and net exports could be provided and, if and when possible, to provide that information to Participants. In the meantime, he cautioned that PFP scores could not be deduced from the information reported on the “Hourly Imports by Interface” slide.

LITIGATION REPORT

Mr. Lombardi referred the Committee to the August 6, 2025 Litigation Report that had been circulated and posted before the meeting. He noted that, since the Summer Meeting, Mr. David LaCerte had been nominated to serve out the remainder of former FERC Commissioner Willie Phillips' term (set to expire on June 30, 2026). Mr. LaCerte joined Ms. Laura Swett, who had been nominated in early June to fill the seat held by Chairman Mark Christie that would officially become vacant the day after the meeting. Both nominees still needed to be confirmed by the U.S. Senate. Progress updates on these nominations would be provided at future meetings.

From the Litigation Report, Mr. Lombardi then highlighted (i) NEPGA's Balancing Ratio and Stop Loss Allocation Methodology Complaint (EL25-106), where answers and comments were due on or before August 21, 2025; (ii) the activity in the FERC's Resource Adequacy technical conference proceeding, where post-technical conference comments had been filed by more than 60 parties; and (iii) the release of the U.S. Department of Energy's (DOE) resource adequacy report and associated analysis in response to a Presidential Executive Order on "*Strengthening the Reliability and Security of the United States Electric Grid*." He noted the request for rehearing of the DOE's report submitted the day before by a group of industry trade associations.

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 the MC Summer Meeting on August 12-14, 2025, at the Lodge at Spruce Peak, in Stowe, VT. Discussion at the MC Summer Meeting would include Capacity Auction Reforms (CAR)-related project topics (including draft Tariff language, ISO presentations, and at least one stakeholder amendment).

Reliability Committee (RC). Mr. Bob Stein, RC Vice-Chair, reported that the next RC meeting would be held on August 19, 2025 at the DoubleTree Hotel in Westborough, MA. Principal topics for discussion would include operating procedures and planning procedures related to community benefit agreements, *Order 2023*-related changes to Planning Procedure 5-6, and the REST project, with proposed thresholds and the revisions to OP-21 to incorporate those thresholds.

Transmission Committee (TC). Mr. Dave Burnham, TC Vice-Chair, reported that the August 26, 2025 TC meeting had been canceled. The next TC meeting would be on September 25, 2025.

Budget & Finance Subcommittee (B&F). Mr. Tom Kaslow, B&F Chair, reported that the next B&F meeting would be held virtually on August 8, 2025. In addition to its regular reports, the B&F would review the 2026 ISO and NESCOE budgets. A second August B&F meeting, on August 27, 2025, would focus on proposed Financial Assurance and Billing Policy changes associated with the CAR project.

Membership Subcommittee. Mr. Brad Swalwell, Membership Subcommittee Chair, reported that the next Membership Subcommittee meeting would be held by Zoom on August

11, 2025. He encouraged all those interested to participate and to reach out to him or NEPOOL Counsel for the Zoom information.

ADMINISTRATIVE MATTERS

Mr. George Twigg, NECPUC Executive Director, reported that, as part of NARUC's 2025 Summer Policy Summit held in Boston on July 27, the Joint Federal-State Current Issues Collaborative had convened a meeting at the beginning of the Summit, with Maine PUC Chair Philip Bartlett and New Hampshire PUC Commissioner Pradip Chattopadhyay addressing the states' role in RTO governance. He said that their comments touched on a number of issues, including transparency, resource adequacy, and asset condition project oversight, offering praise for the relationship in New England between the states, the ISO and Participants, but also offering thoughts on opportunities for improvement. Mr. Twigg encouraged all interested to watch the video of those comments, which was available for viewing for a period of time from the FERC's website.

Mr. Lombardi reported that the September Participants Committee meeting would be held in person at the Renaissance Boston Seaport Hotel. He directed those needing an overnight room for the September meeting to contact Pat Gerity or Jaki Sloan as soon as possible. Looking ahead further, the October meeting would be at the Delamar Hotel in West Hartford, Connecticut and the November meeting at the Hilton Boston Logan Airport hotel. Further details on meeting and room block information would be circulated in advance of those meetings.

There being no other business, the meeting adjourned at 11:15 a.m.

Respectfully submitted,

Sebastian Lombardi, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN THE AUGUST 7, 2025 WEBEX MEETING

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Acadia Center	End User	Joe LaRusso		
Advanced Energy United	Assoc. Non-Voting		Alex Lawton	
Ashburnham Municipal Light Plant	Publicly Owned Entity		Dan Murphy	
AVANGRID (CMP/UI)	Transmission	Alan Trotta		
Bath Iron Works	End User			Bill Short
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
Boylston Municipal Light Department	Publicly Owned Entity		Dan Murphy	
BP Energy Company (BP)	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
Brookfield Energy Trading and Marketing LLC	Supplier	Aleks Mitreski		
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Dan Murphy	
Clear River Electric	Publicly Owned Entity		Dave Cavanaugh	
CLEAResult Consulting, Inc.	AR-DG	Tamera Oldfield		
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw		
Connecticut Office of Consumer Counsel	End User		Jamie Talbert-Slagle	Wooddynne Dejeanlouis
Conservation Law Foundation	End User	Phelps Turner		
Constellation Energy Generation (Constellation)	Supplier		Bill Fowler	
CPV Towantic, LLC (CPV)	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Dominion Energy Generation Marketing, Inc.	Generation	Wes Walker		
DTE Energy Trading, Inc. (DTE)	Supplier			José Rotger
ECP Companies Calpine Energy Services, LP New Leaf Energy	Generation	Andy Gillespie		Bill Fowler
Elektrisola, Inc.	End User			Bill Short
Emera Energy Services	Supplier			Bill Fowler
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Eversource Energy	Transmission		Dave Burnham	
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Gabel Associates, Inc.	Supplier	Sarah Yasutake		
Galt Power, Inc.	Supplier	José Rotger	Jeff Iafrati	
Garland Manufacturing Company	End User			Bill Short
Generation Bridge Companies	Generation			Bill Fowler
Generation Group Member	Generation		Abby Krich	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Groton Electric Light Department	Publicly Owned Entity		Dan Murphy	
Granite Shore Companies	Generation			Bob Stein
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQUS)	AR-RG		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		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Holyoke Gas & Electric Department	Publicly Owned Entity		Dan Murphy	
Hudson Light & Power Department	Publicly Owned Entity			Dave Cavanaugh
Hull Municipal Lighting Plant	Publicly Owned Entity		Dan Murphy	
Icetec Energy Services, Inc.	AR-LR	Doug Hurley		
Ipswich Municipal Light Department	Publicly Owned Entity		Dan Murphy	

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN THE AUGUST 7, 2025 WEBEX MEETING

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Jericho Power LLC (Jericho)	AR-RG	Ben Griffiths		
Lamson, Jon	End User	Jon Lamson		
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	
Littleton (NH) Water & Light Department	Publicly Owned Entity		Craig Kieny	
Long Island Power Authority (LIPA)	Supplier	Bill Kilgoar		
Maine Power LLC	Supplier	Jeff Jones		
Maine Public Advocate's Office	End User	Drew Landry		Wooddynne Dejeanlouis
Mansfield Municipal Electric Department	Publicly Owned Entity		Dan Murphy	
Marble River	Supplier		John Brodbeck	
Marblehead Municipal Light Department	Publicly Owned Entity		Dan Murphy	
Mass. Attorney General's Office (MA AG)	End User	Jackie Bihrle	Jamie Donovan	Chris Modlish
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Climate Action Network (MCAN)	End User			Abby Krich
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity		Dan Murphy	
MDC – The (CT) Metropolitan District	Publicly Owned Entity		Dave Cavanaugh	
Mercuria Energy America, LLC	Supplier			José Rotger
Merrimac Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Moore Company	End User			Bill Short
Nautilus Power, LLC	Generation		Bill Fowler	
New England Power (d/b/a National Grid)	Transmission	Tim Brennan	Tim Martin	
New England Power Gens. Assoc. (NEPGA)	Assoc. Non-Voting	Bruce Anderson		
New Hampshire Electric Cooperative	Publicly Owned Entity			Brian Forshaw
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		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
NRG Business Marketing	Supplier		Pete Fuller	
Nylon Corporation of America	End User			Bill Short
Pawtucket Power Holding Company	Generation	Dan Allegretti		
Paxton Municipal Light Department	Publicly Owned Entity		Dan Murphy	
Peabody Municipal Light Department	Publicly Owned Entity		Dan Murphy	
Princeton Municipal Light Department	Publicly Owned Entity		Dan Murphy	
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
RENEW Northeast, Inc.	Assoc. Non-Voting	Francis Pullaro		
Rhode Island Division (DPUC)	End User	Linda George		
Rhode Island Energy (Narragansett Electric Co.)	Transmission	Brian Thomson	Robin Lafayette	
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity		Dan Murphy	
Saint Anselm College	End User			Bill Short
Shipyard Brewing LLC	End User			Bill Short
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Dan Murphy	
South Hadley Electric Light Department	Publicly Owned Entity		Dan Murphy	
Sterling Municipal Electric Light Department	Publicly Owned Entity		Dan Murphy	
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Tangent Energy	AR-LR	Brad Swalwell		
Taunton Municipal Lighting Plant	Publicly Owned Entity	Nick Parrotta	Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity		Dan Murphy	
Vermont Electric Company	Transmission	Frank Ettori		

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN THE AUGUST 7, 2025 WEBEX MEETING

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Vermont Electric Cooperative	Publicly Owned Entity	Craig Kieny		
Vermont Energy Investment Corporation	AR-LR			Wooddynne Dejeanlouis
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw
Versant Power	Transmission	Dave Norman	Stephen Johnston	
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity	Dave Cavanaugh		
Vistra (Dynegy Marketing and Trade, Inc.)	Supplier	Ryan McCarthy		
Vitol Inc.	Supplier	Seth Cochran		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Dan Murphy	
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned Entity		Dan Murphy	
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler	
ZTECH, LLC	End User			Bill Short

2 Consent Agenda

66.67%

1. Conforming Changes to Manuals M-28 and M-06 (NECEC Implementation)

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

CONSENT AGENDA

Markets Committee (MC)

*From the previously-circulated notice of actions of the MC's **August 12-14, 2025 Summer Meeting**, dated August 15, 2025*:[1]

1. **Conforming Changes to Manuals M-28 and M-06 (NECEC Implementation)**

Support the conforming changes to Manuals M-28 (Market Rule 1 Accounting) and M-06 (Financial Transmission Rights), to reflect the addition of the New England Clean Energy Connect (NECEC) HVDC tie line between Hydro-Québec and New England, as recommended by the MC at its August 12-14, 2025 Summer Meeting, with such further non-substantive changes as the MC Chair and Vice-Chair may approve.

The motion to recommend Participants Committee support was approved unanimously, with one abstention in the End User Sector.

[DEFERRED]

Reliability Committee (RC)

*From the previously-circulated notice of actions of the RC's **August 19, 2025** meeting, dated August 19, 2025.*[2]

Revisions to OP-2 and OP-2 Appendix A (Biennial Review and NERC Compliance)

Support the proposed revisions to ISO-NE Operating Procedure (OP) No. 2 (Maintenance of Communications, Computers, Metering and Computer Support Equipment) (OP-2)[3] and Appendix A to OP-2 (Itemized Equipment) (OP2-A),[4] as recommended by the RC at its August 19, 2025 meeting, together with such 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 5 abstentions (3 in the Transmission Sector, 2 in the End User Sector).

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[1] MC Notices of Actions are posted on the ISO-NE website at: https://www.iso-ne.com/committees/markets/markets-committee/?document-type=Committee%20Actions.

[2] 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.

[3] The OP-2 revisions, to be effective Sep. 30, 2025, are to achieve compliance with NERC standards and include: (i) the removal of steps for the Resource Analyst to approve or disapprove OP-2 Appendix C requests to align with current practice; (ii) the addition of steps to verify all OP-2 Appendix C submission information is included, and to resolve any conflicts; and (iii) other minor revisions.

[4] The OP-2A revisions, to be effective by January 2026, include: (i) the addition of Phasor Data Concentrators (PDCs), Dynamic Data Recorders (DDRs), and Phasor Measurement Units (PMUs) to the list of itemized equipment and their associated maintenance priority (Table 1); and (ii) a note to clarify PMU/DDR/PDC effective dates based on OP-22 publication.

3 CEO Report

Sep 4, 2025
Meeting

NEPOOL
NEW ENGLAND POWER POOL
Participants Committee

Summary of ISO New England Board and Committee Meetings

September 4, 2025 Participants Committee Meeting

Since the last update, the Board of Directors met virtually in executive session on August 1 and August 4. The Audit and Finance Committee and the Information Technology & Cyber Security Committee each met virtually on August 21.

The Board of Directors met in executive session on August 1 and 4 to discuss details related to Chief Executive Officer succession.

The Audit and Finance Committee received an update regarding the development of the 2026 operating and capital budgets, including a review of the capital structure, and a report on budget discussions with stakeholders. Next, the Committee conducted its annual review of the Company's liability insurance coverage for officers and directors, noting the consistency of terms and conditions and the increase in total premium costs. The Committee also received a report on the 2025 budget and approved the second quarter unaudited financial statements after management confirmed that all relevant disclosures from managers were included in the financial statements. The Committee received an update on internal audit activities, as well as highlights of recent external audits. Next, the Company's external auditors, KPMG, presented a three-year engagement proposal for both financial statement audits and system and organization controls engagements. After the KPMG representatives left the meeting, the Committee reviewed the proposal, and approved the reappointment. The Committee then discussed a number of changes to various Company documents to address increased regulatory and litigation risks related to diversity, equity and inclusion programming. After considering the changes, the Committee concurred with management's proposals. Next, the Committee held an executive session with the Company's Director of Internal Audit. Following that, the Committee held an executive session with management to discuss Board contingency funds and their use to alleviate some of the anticipated pressures on the budget. The Committee then met without management to review the results of its self-evaluation. Following a short break, the Committee was joined by the Information Technology & Cyber Security Committee for a joint update on the Company's Enterprise Resource Planning Project.

The Information Technology & Cyber Security Committee. After the joint session with the Audit and Finance Committee, the Committee continued with its regular meeting and was provided with an update on the Company's cyber security work plan. The Committee discussed activities related to the cloud services transition and cyber security operations updates. The Committee then reviewed the annual vendor report, which illustrated the year over year change in vendor spending and highlighted key vendors and risks associated.

4.a COO Report – Operations Report Highlights

Sep 4, 2025
Meeting

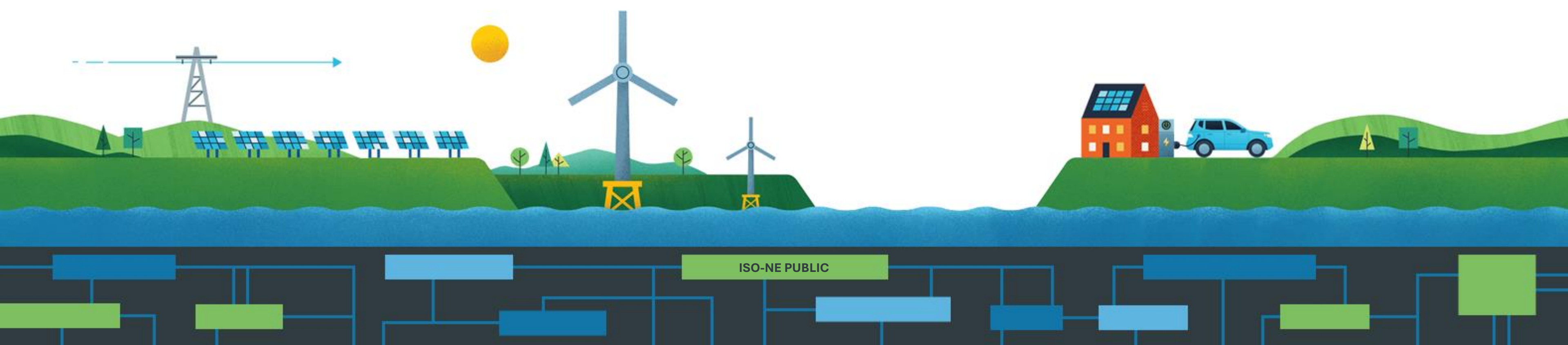
ISO new england

NEPOOL Participants Committee Report

September 2025

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER



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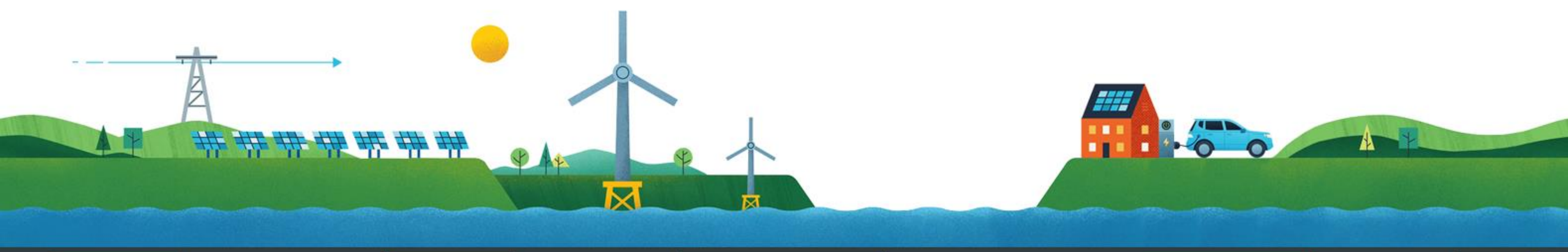
Regular Operations Report - Highlights



Highlights: August 2025

Data through August 26th, unless otherwise noted

- **Peak Hour** on August 11
  - 23,069 MW system peak (Revenue Quality Metered/RQM); hour ending 6:00 P.M.
- **Minimum Telemetered Load**
  - 8,416 MW; hour ending 12:00 P.M. on Saturday, August 2
- **Average Pricing**
  - Day-Ahead (DA) Hub Locational Marginal Price (LMP): $49.39/MWh
  - Real-Time (RT) Hub LMP: $43.96/MWh
  - Natural Gas: $2.74/Mmbtu (MA Natural Gas Avg)
- **Energy Market** value $560M up from $454M in August 2024
  - Ancillary Markets* value $18.6M up from $16.3M in August 2024
  - Average DA cleared physical energy** during the peak hours as percent of forecasted load was 100.7% during August, up from 100.4% during July
  - Updated July Energy Market value: $1.1B
- **Net Commitment Period Compensation (NCPC)** total $2.4M
  - Represents 0.4% of monthly Energy Market value
  - First Contingency $2.2M
    - Dispatch Lost Opportunity Cost (DLOC) - $350K; Rapid Response Pricing (RRP) Opportunity Cost - $225K; Posturing - $0; Generator Performance Auditing (GPA) - $0
    - $74K paid to resources at external locations, down $23K from July
      - $33K charged to Day-Ahead Load Obligation (DALO) at external locations; $14K to Day-Ahead Generation Obligation (DAGO) at external locations; $27K to RT Deviations
  - Second Contingency $29K; Distribution $210K; Voltage zero
- **Forward Capacity Market (FCM)** market value $88.6M
  - FCM peak for 2025 is currently 26,184 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: **26,551 MW** (initial)
  - hour ending 6:00 P.M. on Tuesday, June 24
- FCM Peak Load: **26,184 MW** (preliminary & subject to change)
  - 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, 10,055 MW in Rest-of-Pool, and 10,746 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: **$22.5M**
- DAAS Settlements:
  - Average daily Gross (pre-closeout) DAAS Credits: **$860K**
    - Includes EIR, TMOR, TMNSR, and TMOR
  - Net (post-closeout) DAAS Credits per MWh Cleared: **$10.98/MWh**
  - Net (post-closeout) DAAS Credits as % of total DA E&AS Value: **2.8%**
- FER Credits* as % of total DA E&AS Market Value: **6.6%**
- Energy Gap:
  - Average hourly cleared EIR MWh: **83 MWh**
  - Average hourly cleared FER Price: **$3.30/MWh**

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

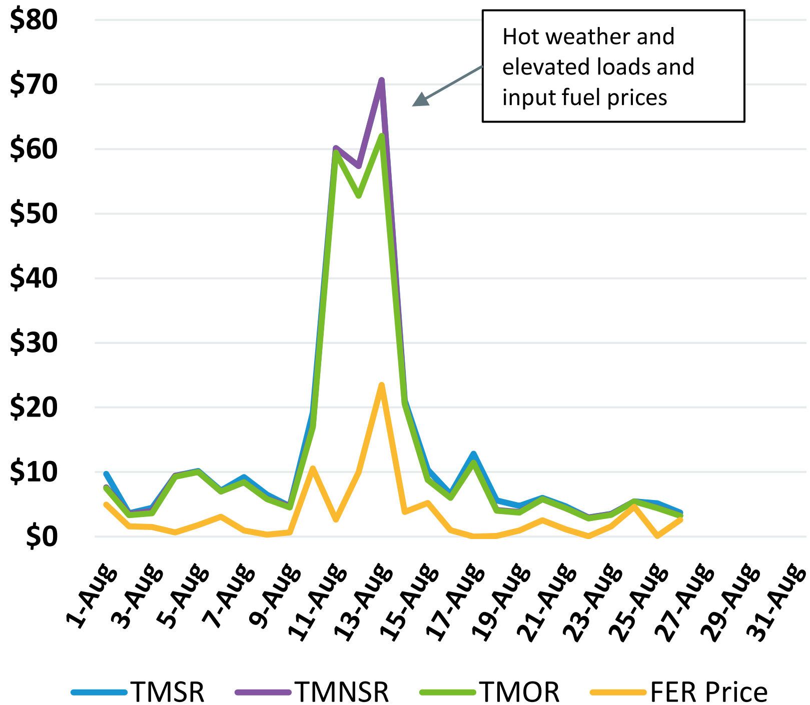
DA Ancillary Services (DAAS) Results

Month	Avg. Daily 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 DA E&AS Credit	FER Credit as % of DA E&AS Credit	Avg. Hourly Cleared EIR Obligation MWh	Avg. FER Price per MWh Cleared
3/2025	$17.3M	$466K	$202K	$3.35	1.2%	6.2%	176	$3.26
4/2025	$13.9M	$332K	$175K	$3.23	1.3%	5.8%	97	$2.66
5/2025	$11.0M	$190K	$52K	$0.94	0.5%	5.2%	155	$2.06
6/2025	$20.2M	$885K	$173K	$2.97	0.9%	6.6%	125	$3.15
7/2025	$35.8M	$1,704K	$1,139K	$19.53	3.2%	3.7%	55	$3.06
8/2025	$22.5M	$860K	$621K	$10.98	2.8%	6.6%	83	$3.30

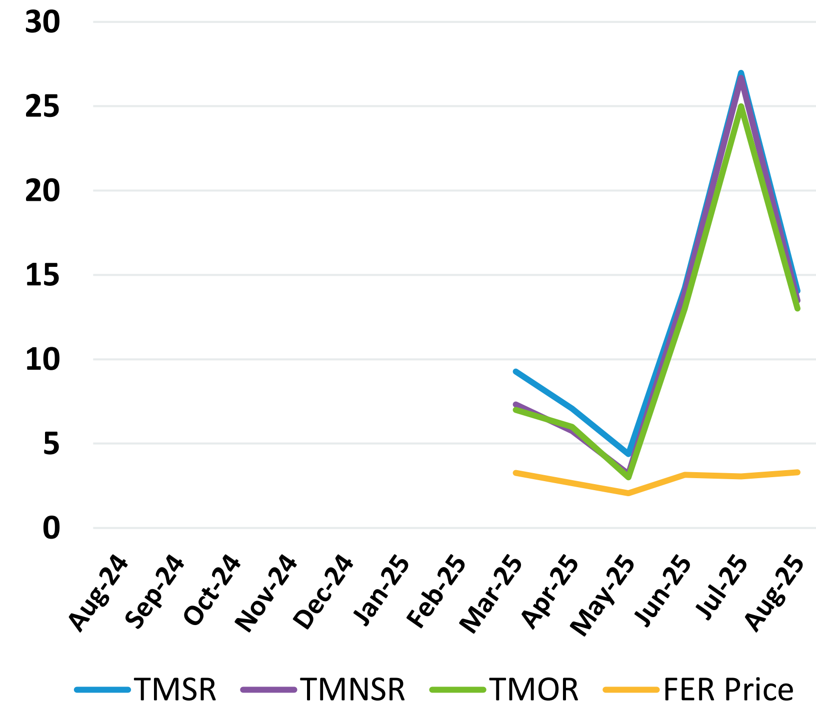
Note: DA E&AS refers to DA Energy and Ancillary Services
*Forecast Energy Requirements (FER) credits are paid to all DA cleared energy supply from physical resources (Gen, Imports, DRR).
FER credits are allocated to DA Exports and RTLO excluding RTLO associated with RT Exports and Dispatchable Asset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

Average Hourly DA Ancillary Services (DAAS) Prices

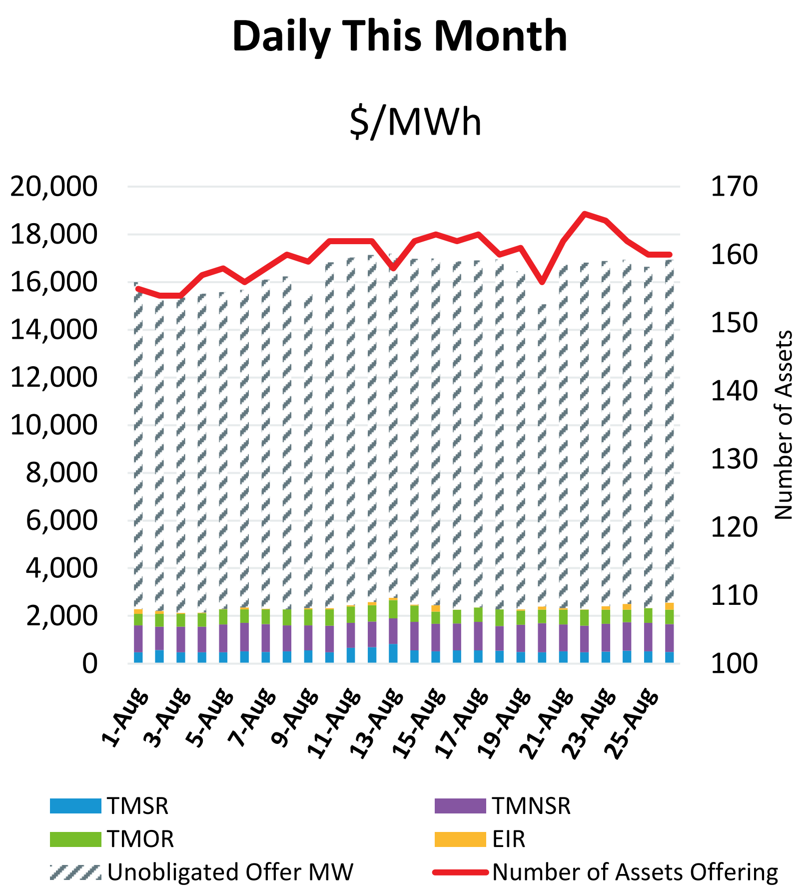
Daily This Month

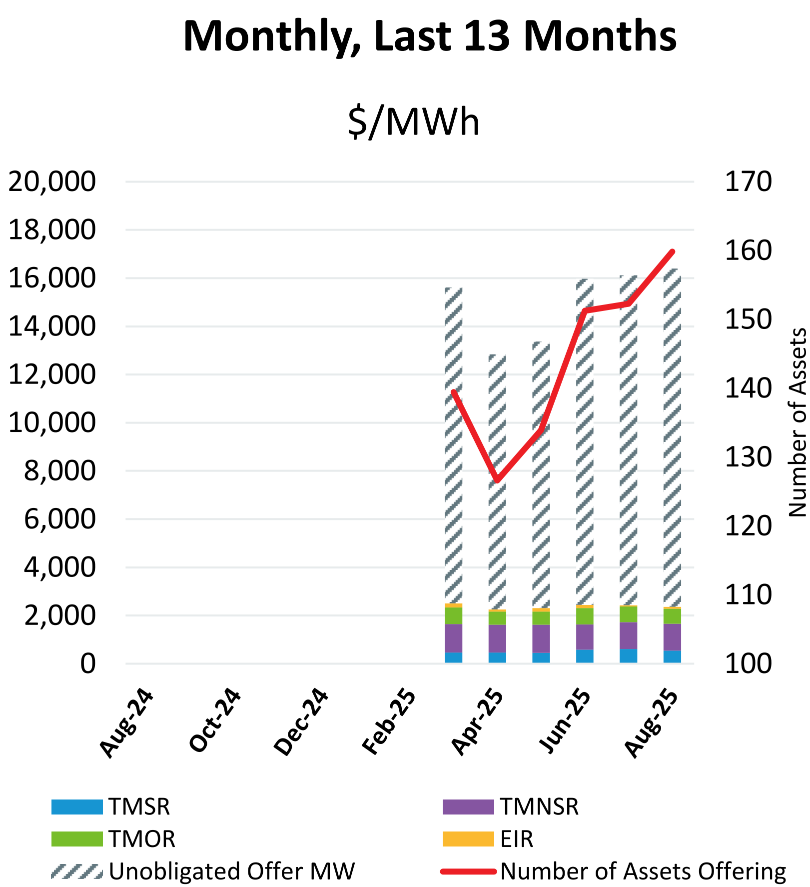


Monthly, Last 13 Months



Average Hourly DAAS Obligated (Awarded) and Unobligated Offer MWh*





*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.

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 will be posted by September 3
- CCP 18 (2027-2028)
  - The first annual reconfiguration auction (ARA1) was held June 2-4 and results were posted on July 2
  - At the August 28 PSPC meeting, the ISO presented assumptions for the ICR and related values studies for the ARAs to be conducted in 2026

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
      - 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

Load Forecast

- An introduction to the 2026 forecast cycle will be provided to the Reliability Committee on September 16
- Stakeholder discussions related to CELT 2026 will begin at the Load Forecast Committee on September 26

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Below Normal (-1.9°F) Max: 92°F, Min: 56°F Precipitation: 0.76" – Below Normal Normal: 2.84"	Hartford	Temperature: Below Normal (-2.2°F) Max: 92°F, Min: 50°F Precipitation: 2.45" - Below Normal Normal: 3.74"

Peak Load:	22,635 MW	August 11, 2025	19:00 (ending)
Mid-Day Minimum Load - Month:	8,416 MW	August 02, 2025	12:00 (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			

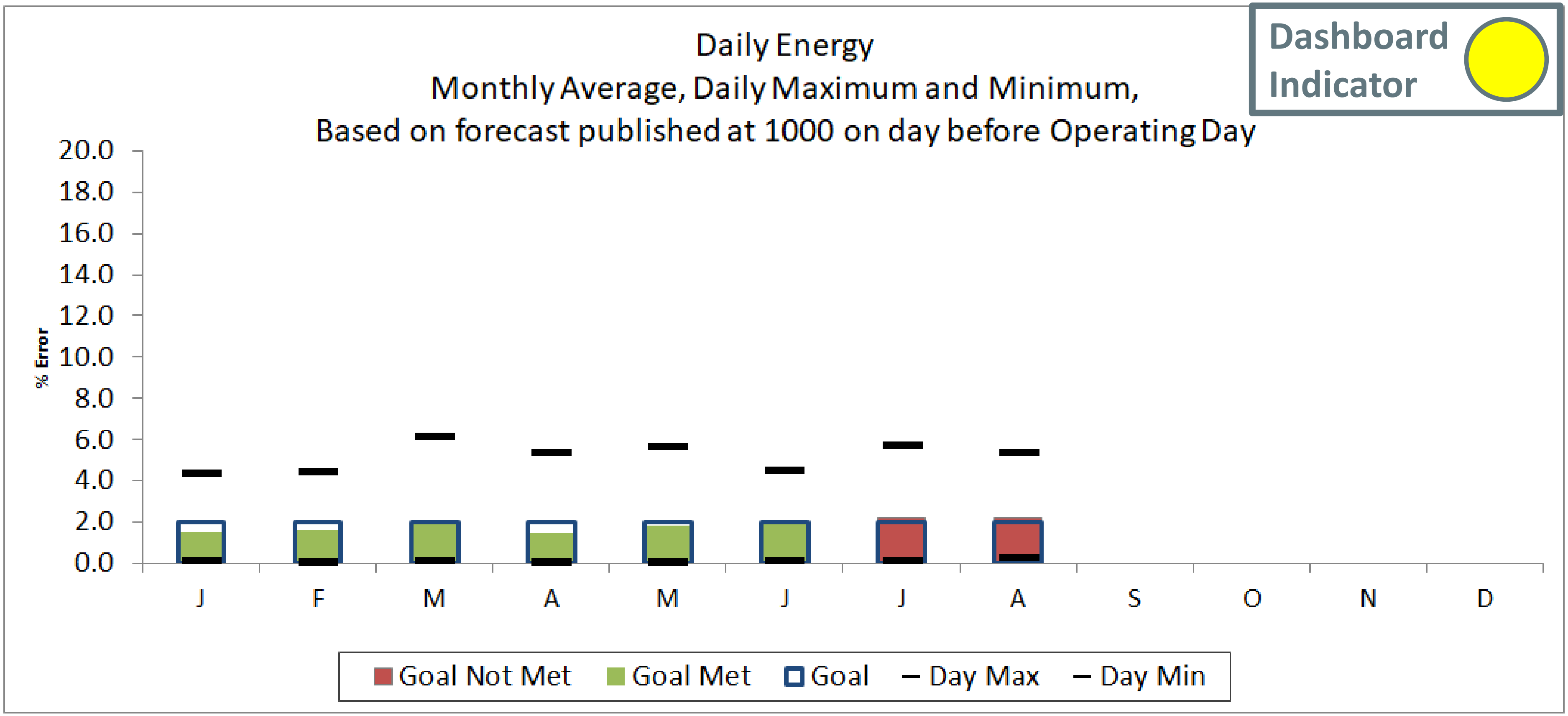
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
08/05/2025	NYISO	500

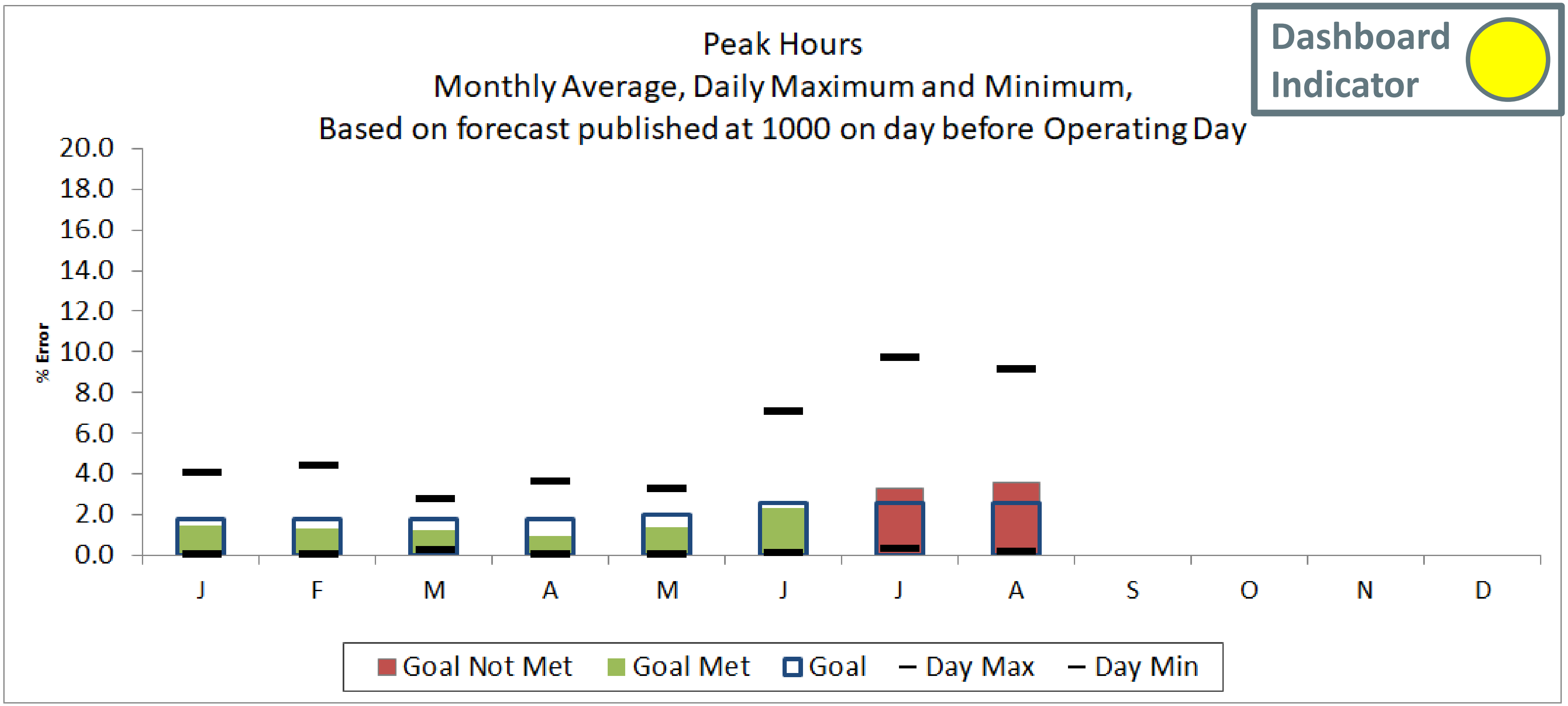
2025 System Operations - Load Forecast Accuracy cont.

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					6.10
Day Min	0.12	0.04	0.12	0.05	0.06	0.08	0.11	0.23					0.04
MAPE	1.54	1.62	1.89	1.45	1.80	1.98	2.24	2.25					1.85
Goal	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00					

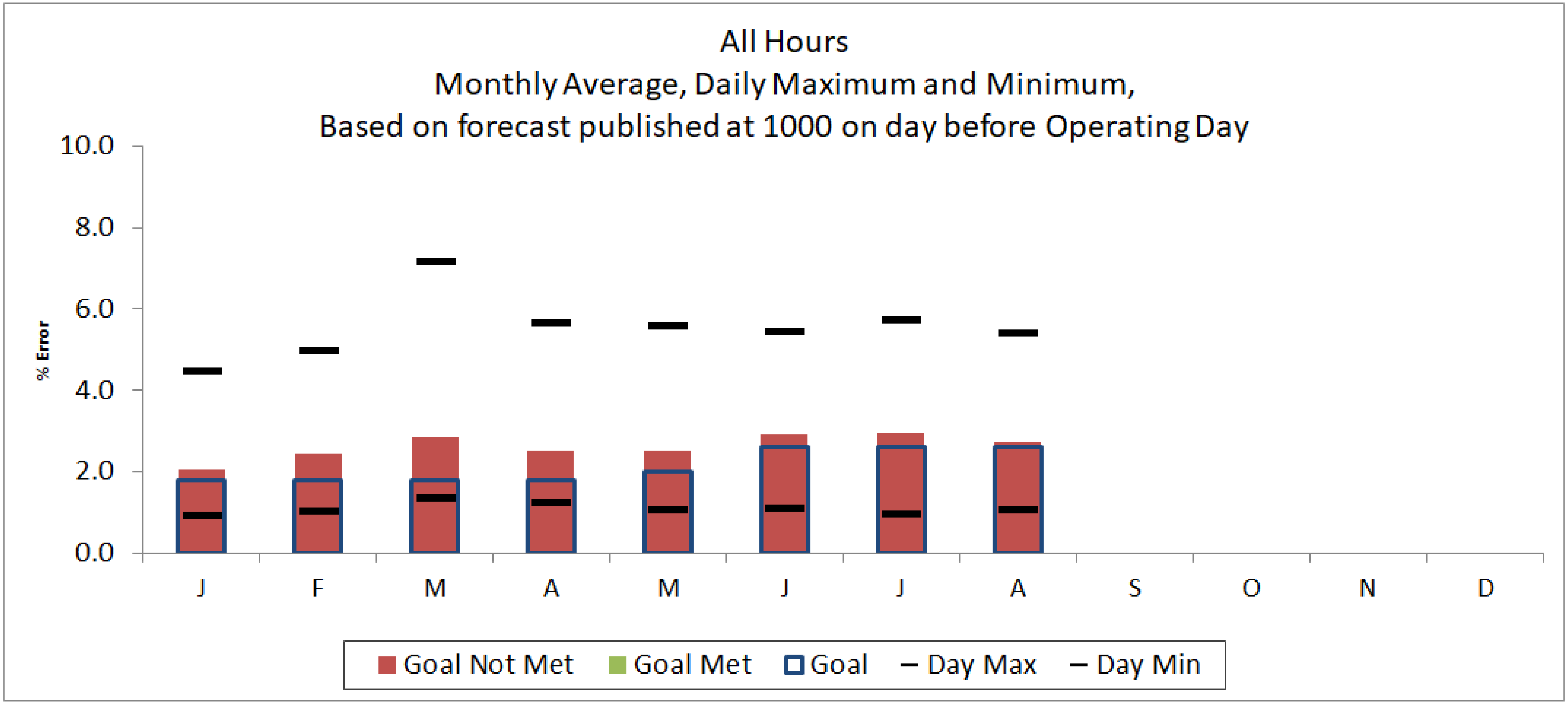
2025 System Operations - Load Forecast Accuracy cont.



Dashboard Indicator

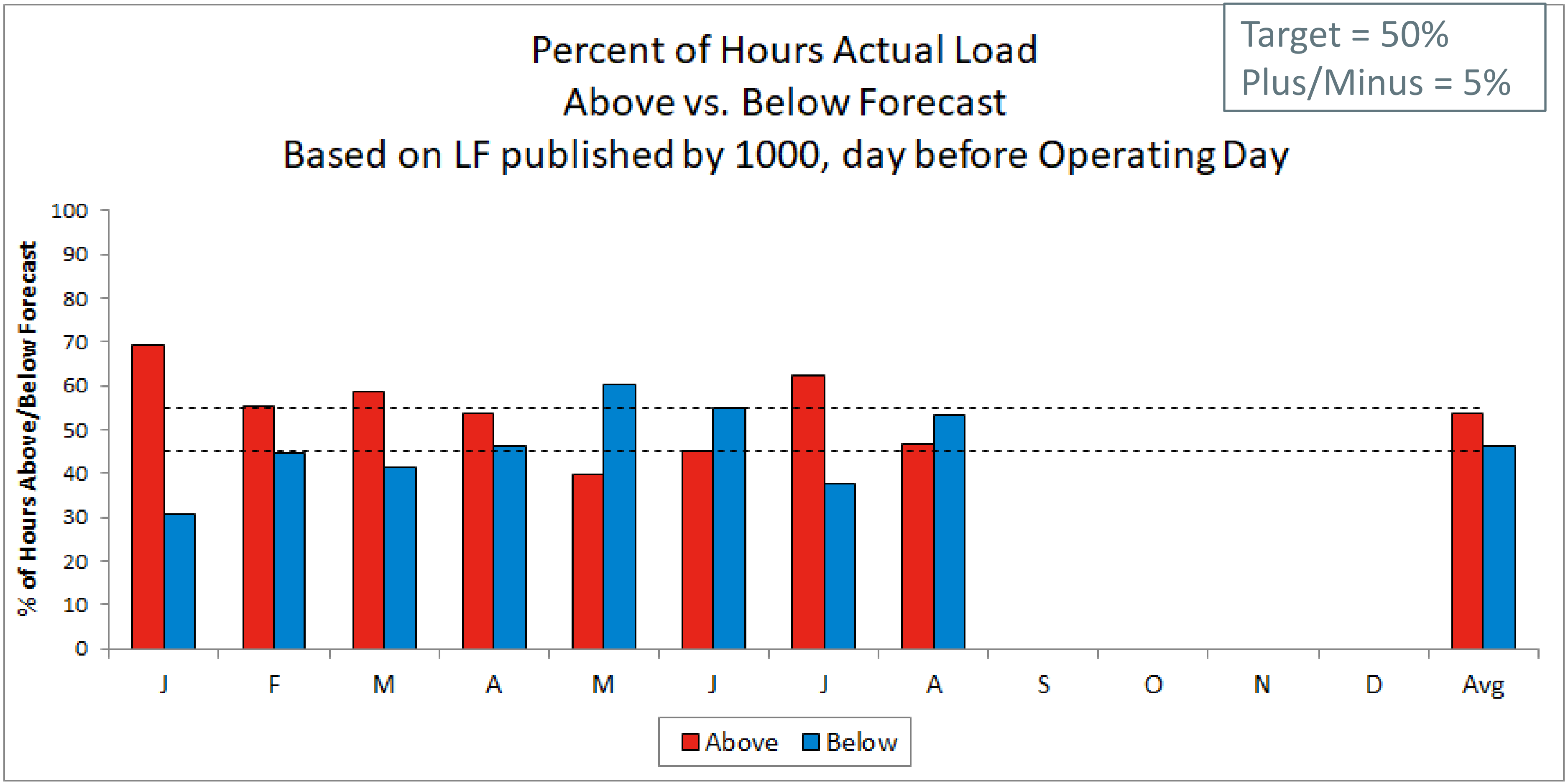
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.04	4.41	2.77	3.63	3.29	7.08	9.71	9.15					9.71
Day Min	0.03	0.06	0.24	0.03	0.06	0.11	0.34	0.15					0.03
MAPE	1.48	1.34	1.29	1.00	1.41	2.30	3.28	3.61					1.97
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60					

2025 System Operations - Load Forecast Accuracy cont.



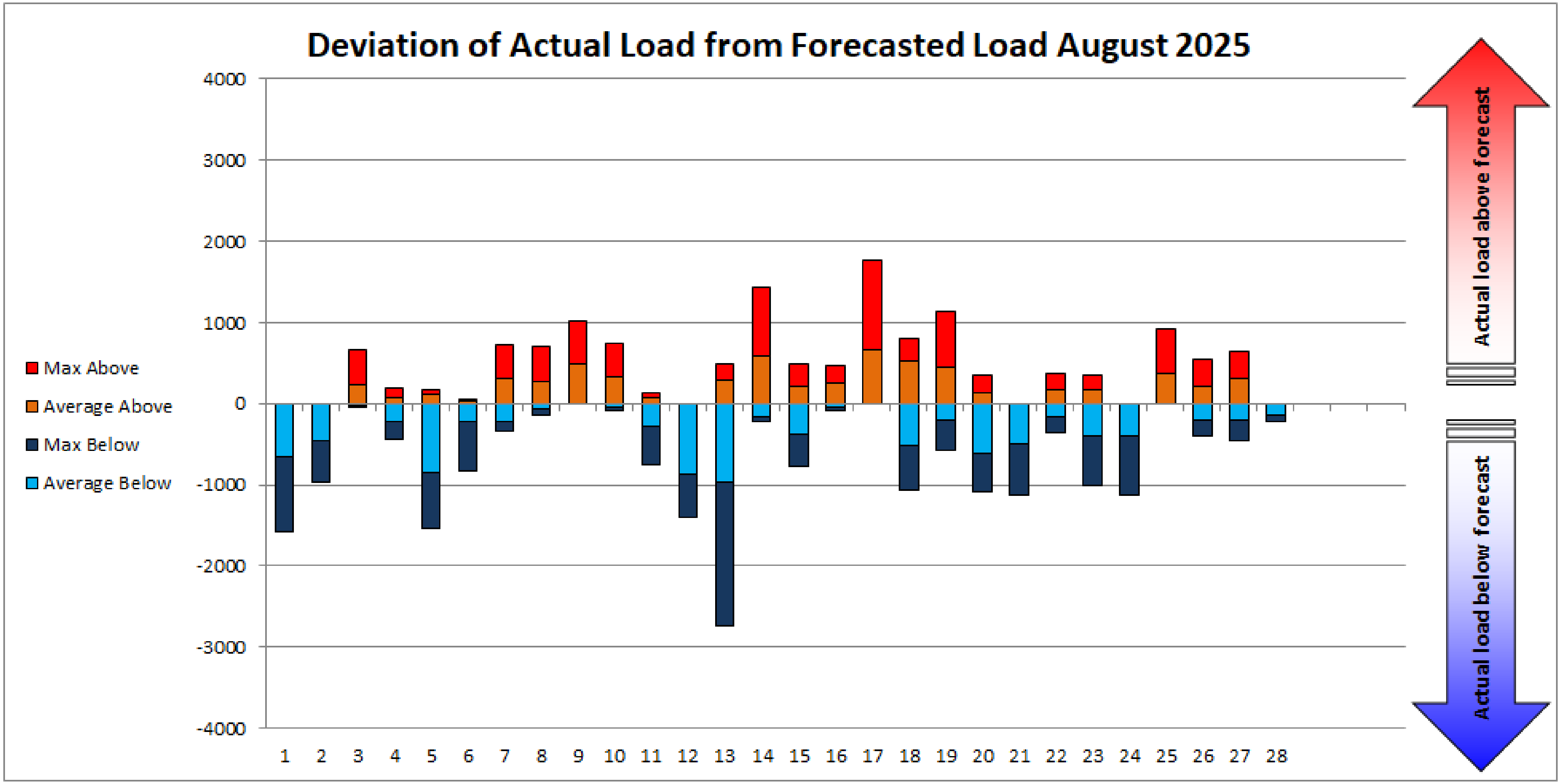
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.46	4.98	7.13	5.65	5.57	5.44	5.72	5.41					7.13
Day Min	0.90	1.02	1.33	1.23	1.07	1.11	0.95	1.07					0.90
MAPE	2.07	2.47	2.83	2.53	2.53	2.93	2.94	2.73					2.63
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60					

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	46.9					54
Below %	30.8	44.8	41.5	46.5	60.2	54.9	37.5	53.1					46
Avg Above	280.5	282.1	246.5	255.8	164.5	307.8	397.3	203.2					397
Avg Below	-178.6	-287.9	-273.2	-190.7	-254.1	-310.2	-270.0	-283.3					-310
Avg All	138	24	12	49	-82	-24	145	-79					23

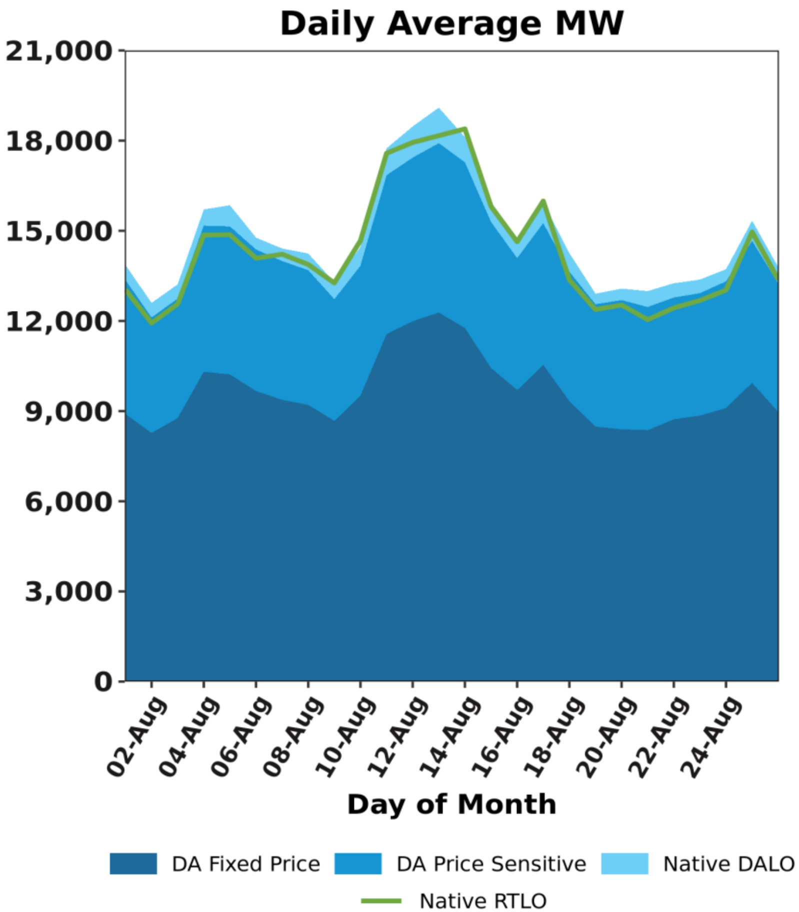
2025 System Operations - Load Forecast Accuracy

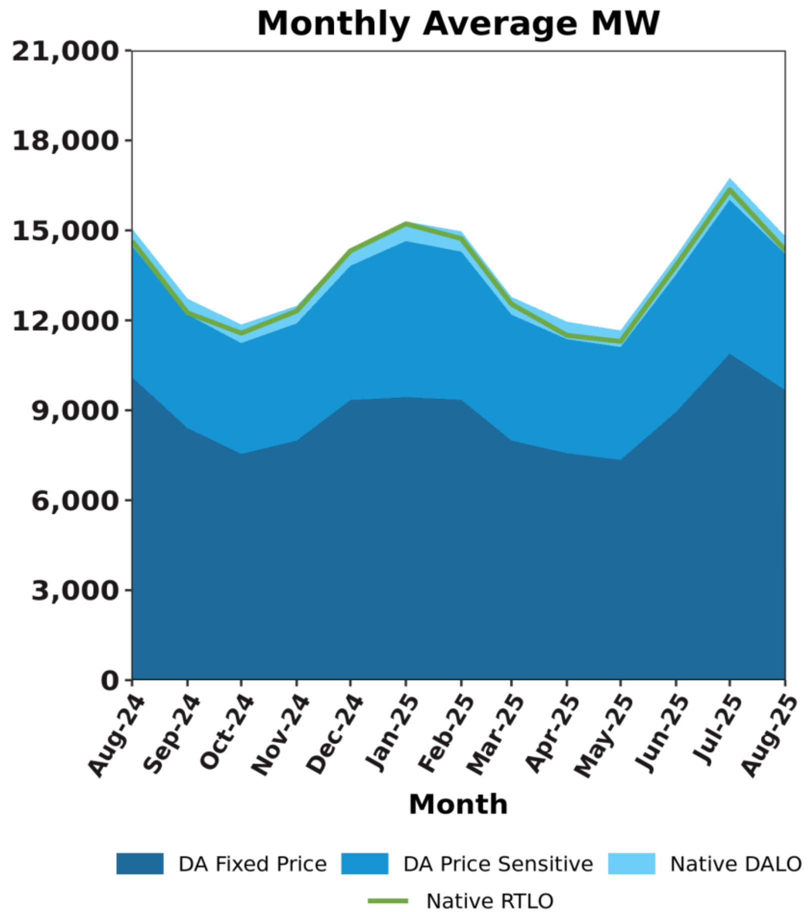


MARKET OPERATIONS

SUPPLY AND DEMAND VOLUMES

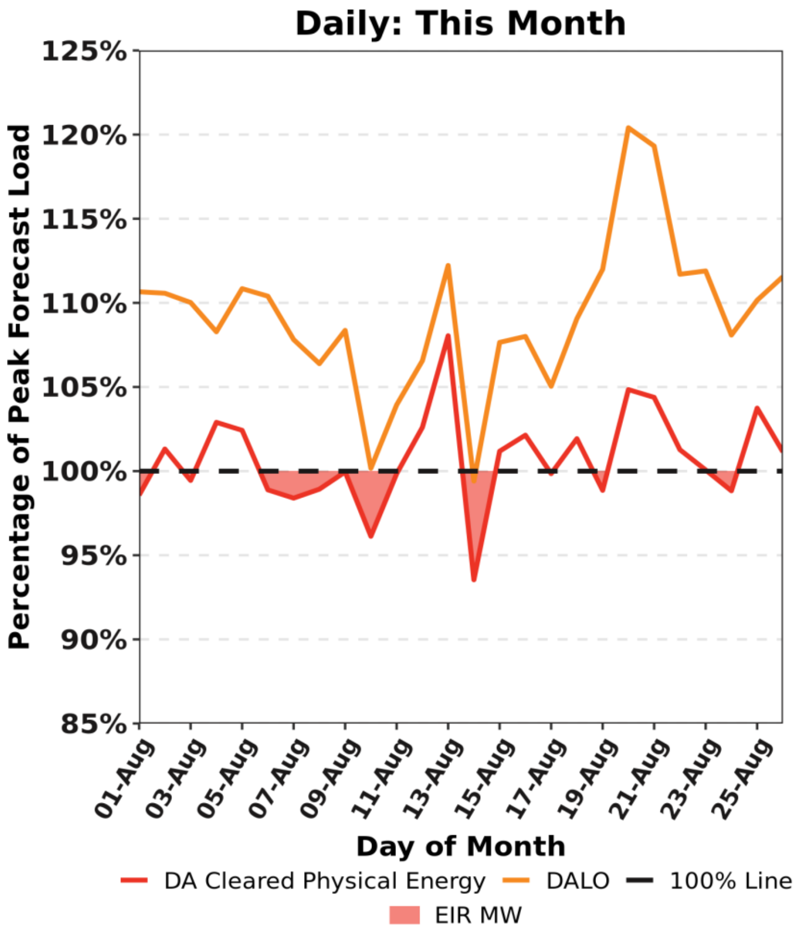
DA Cleared Native Load by Composition Compared to Native RT Load

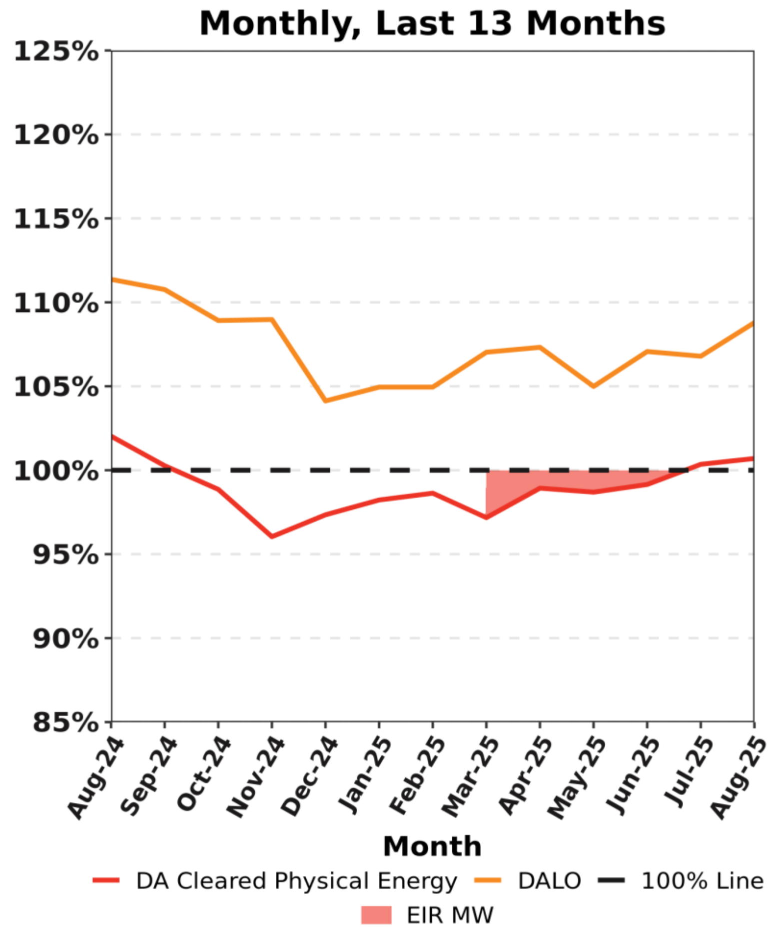




Native Day-Ahead Load Obligation (DALO) is the sum of all internal DA cleared load obligation, including internally cleared decrement bids (DECs). Native Real-Time Load Obligation (RTLO) is the sum of all internal real-time load obligation. Modeled transmission losses and exports are excluded in these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

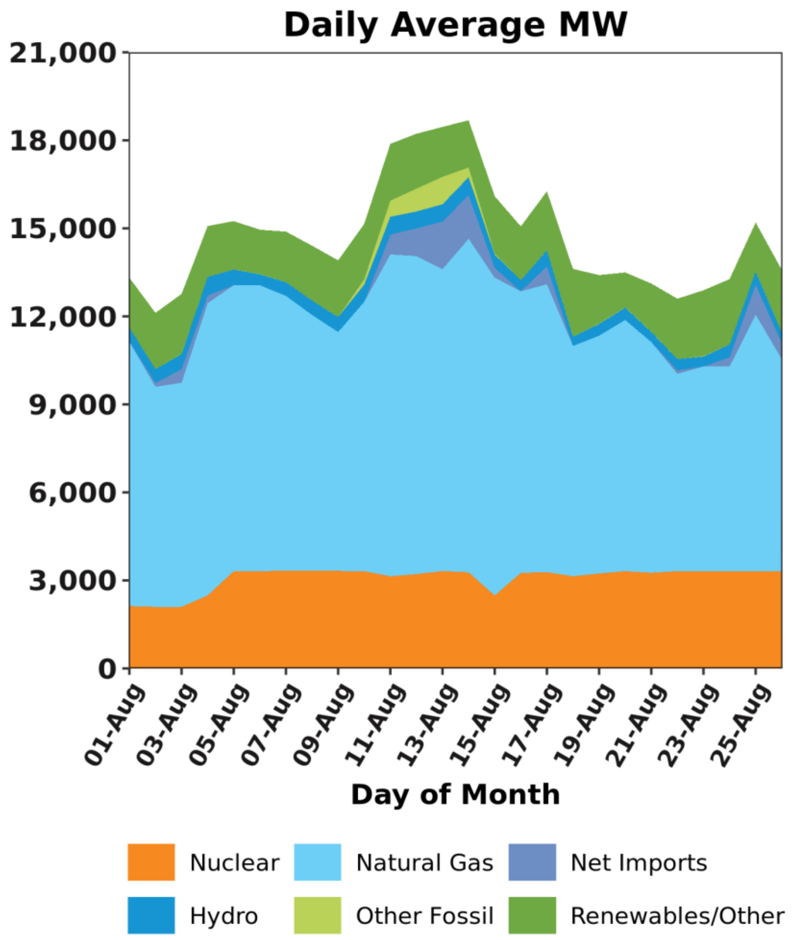
DA Volumes as % of Forecast in Peak Hour

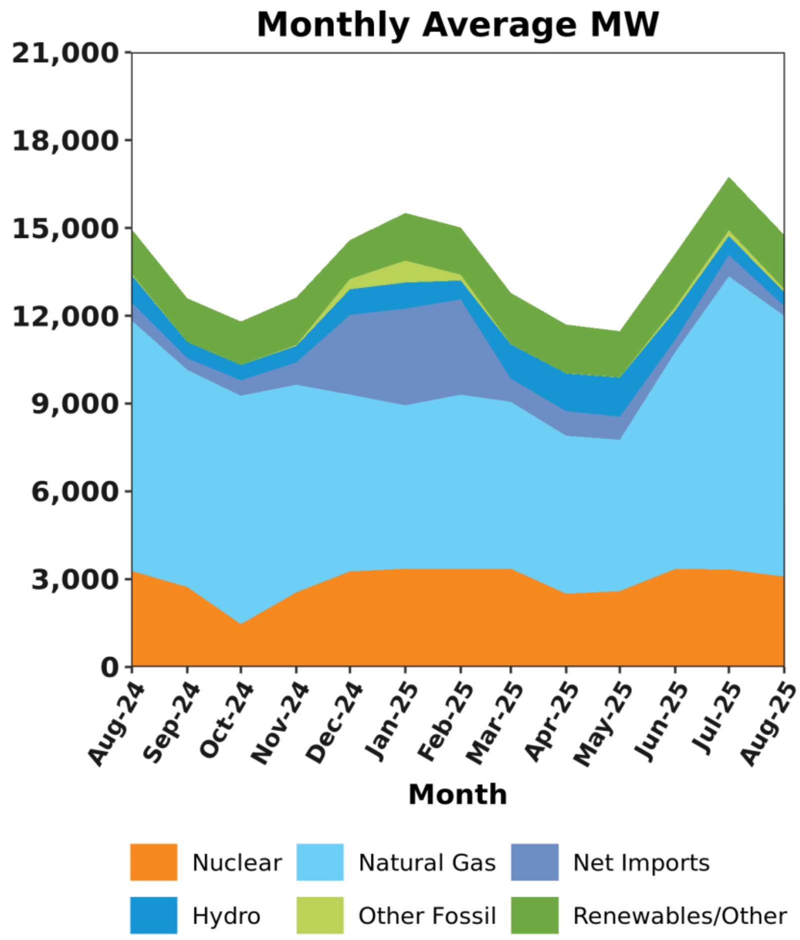




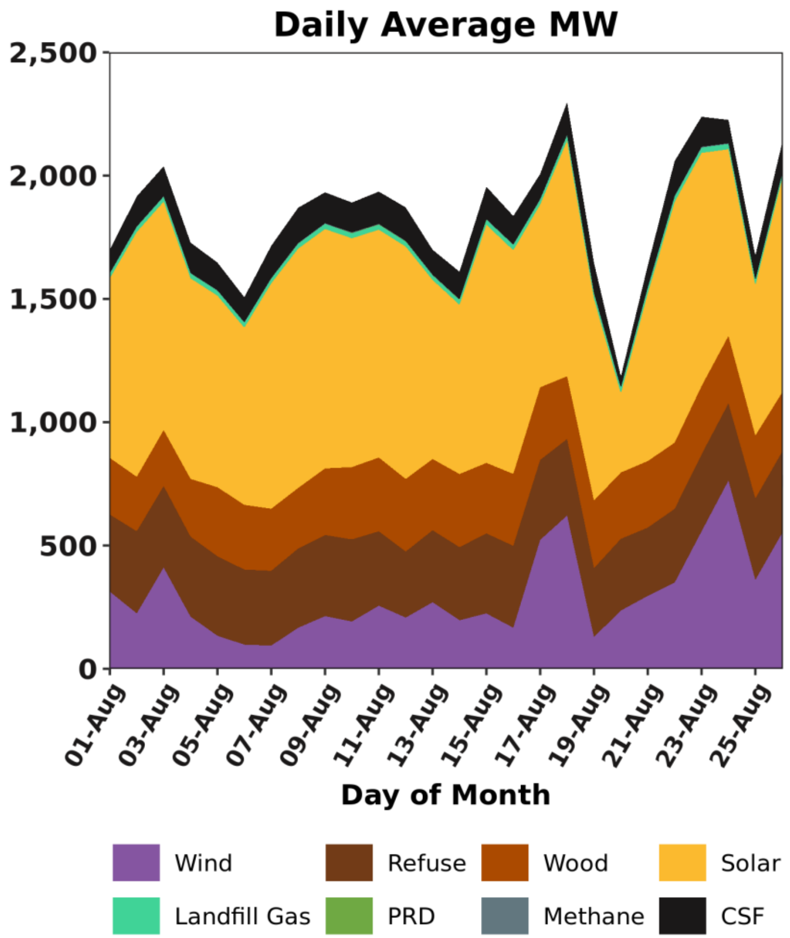
*DA cleared physical energy is the sum of generation, DRR and net imports cleared in the DA Energy Market and does not include EIR MW. Effective March 1, 2025, EIR MW obligations from physical generation and DRR are additionally procured up to (but not exceeding) 100% of the forecasted energy requirement.

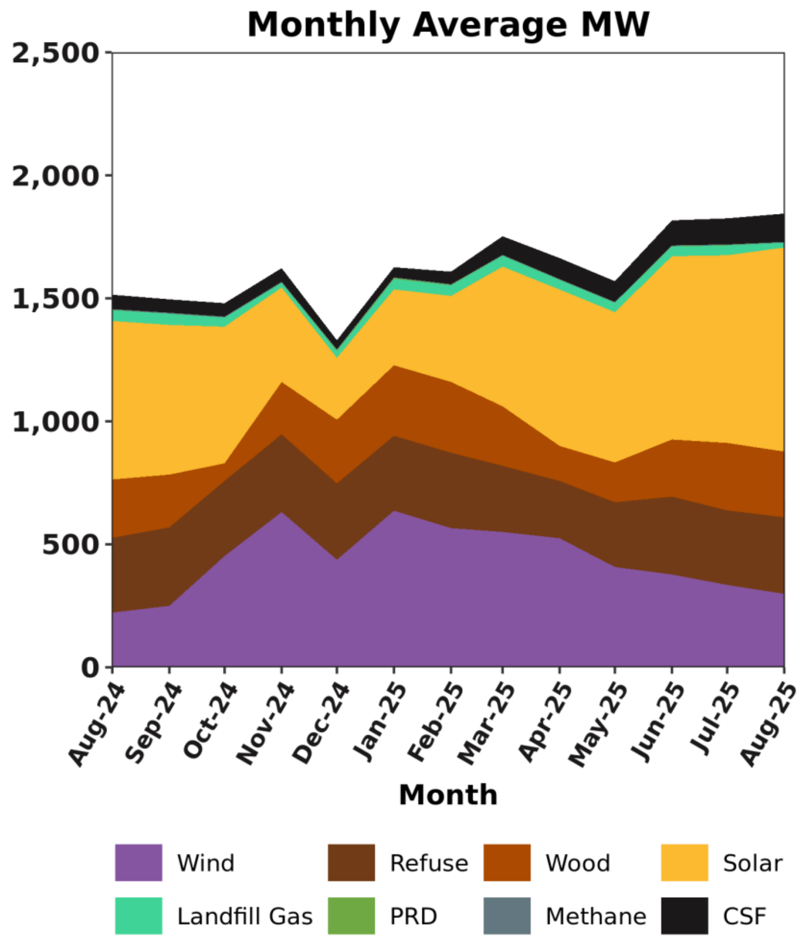
Resource Mix





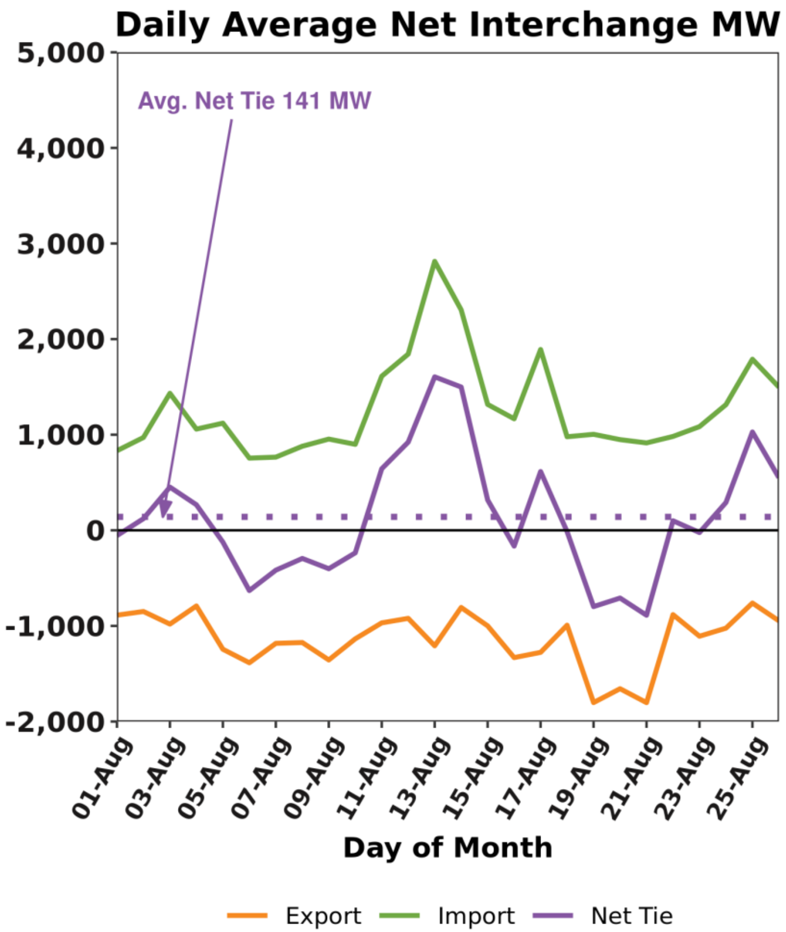
Renewable Generation by Fuel Type

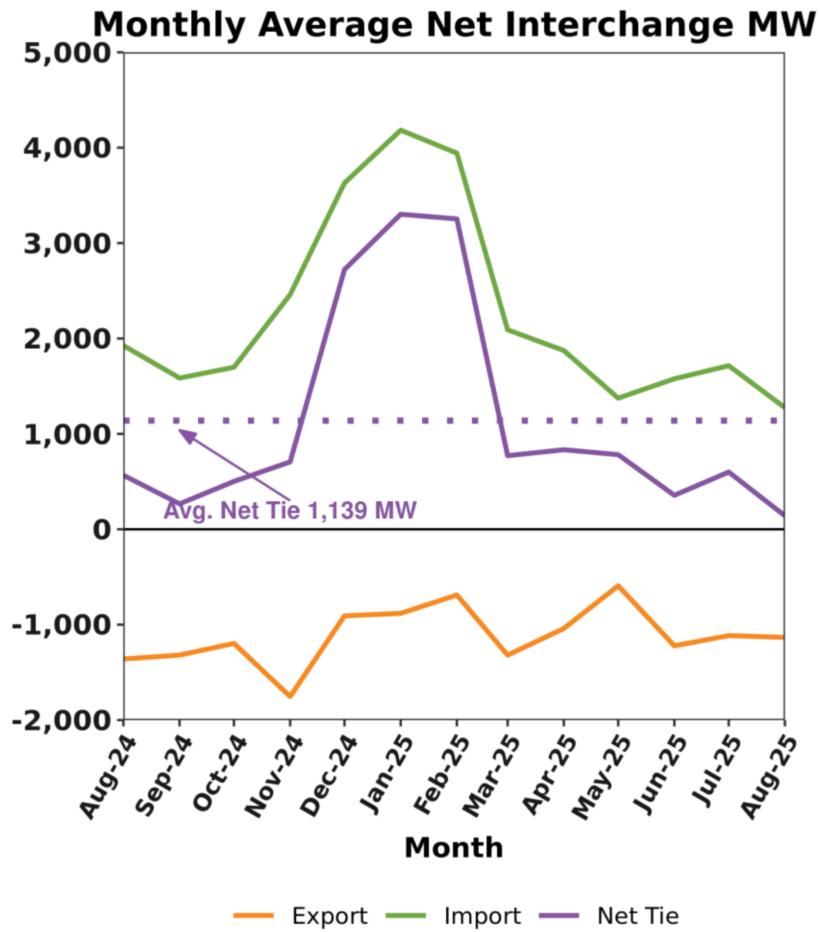




CSF = Continuous Storage Facilities (a.k.a. Batteries); PRD=Demand Response Resources (DRR)

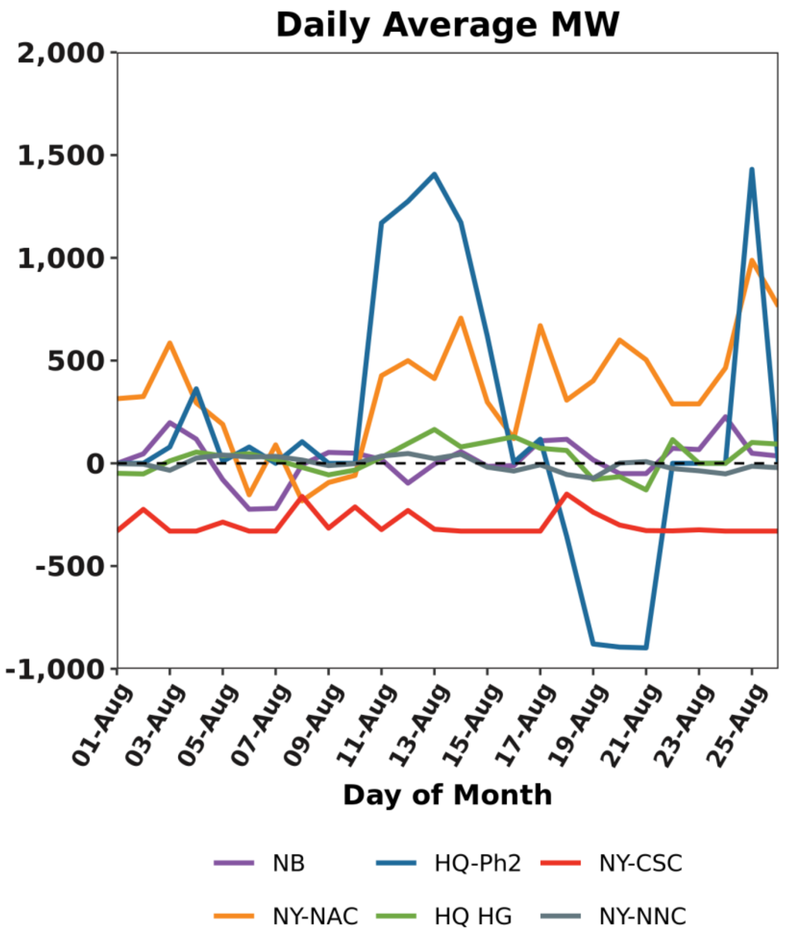
RT Net Interchange

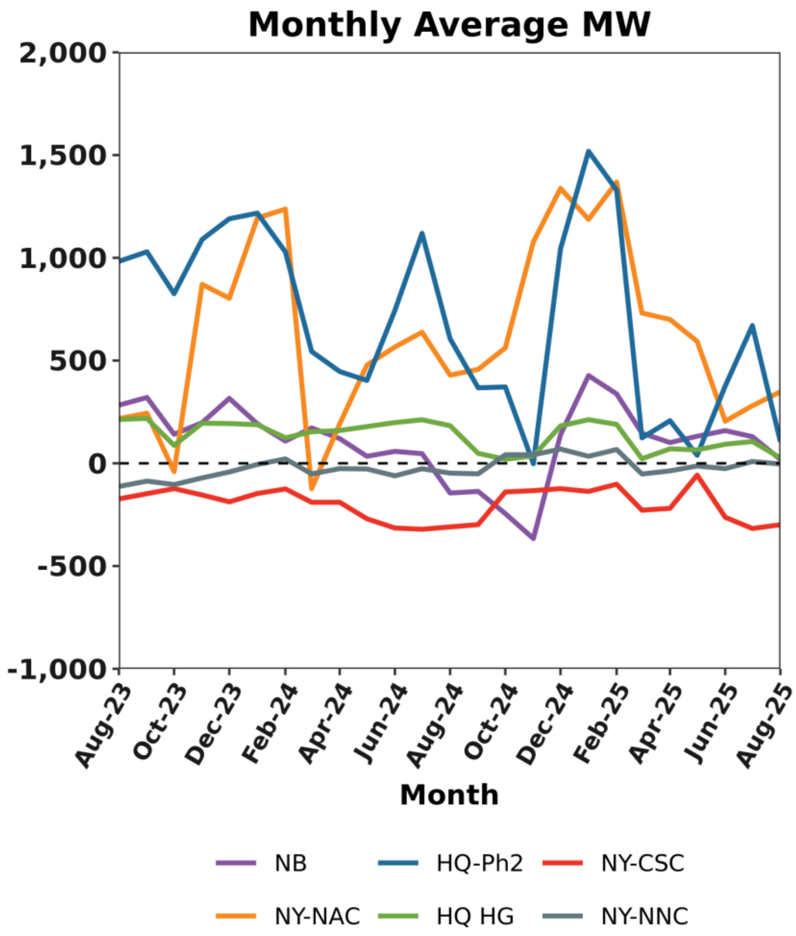




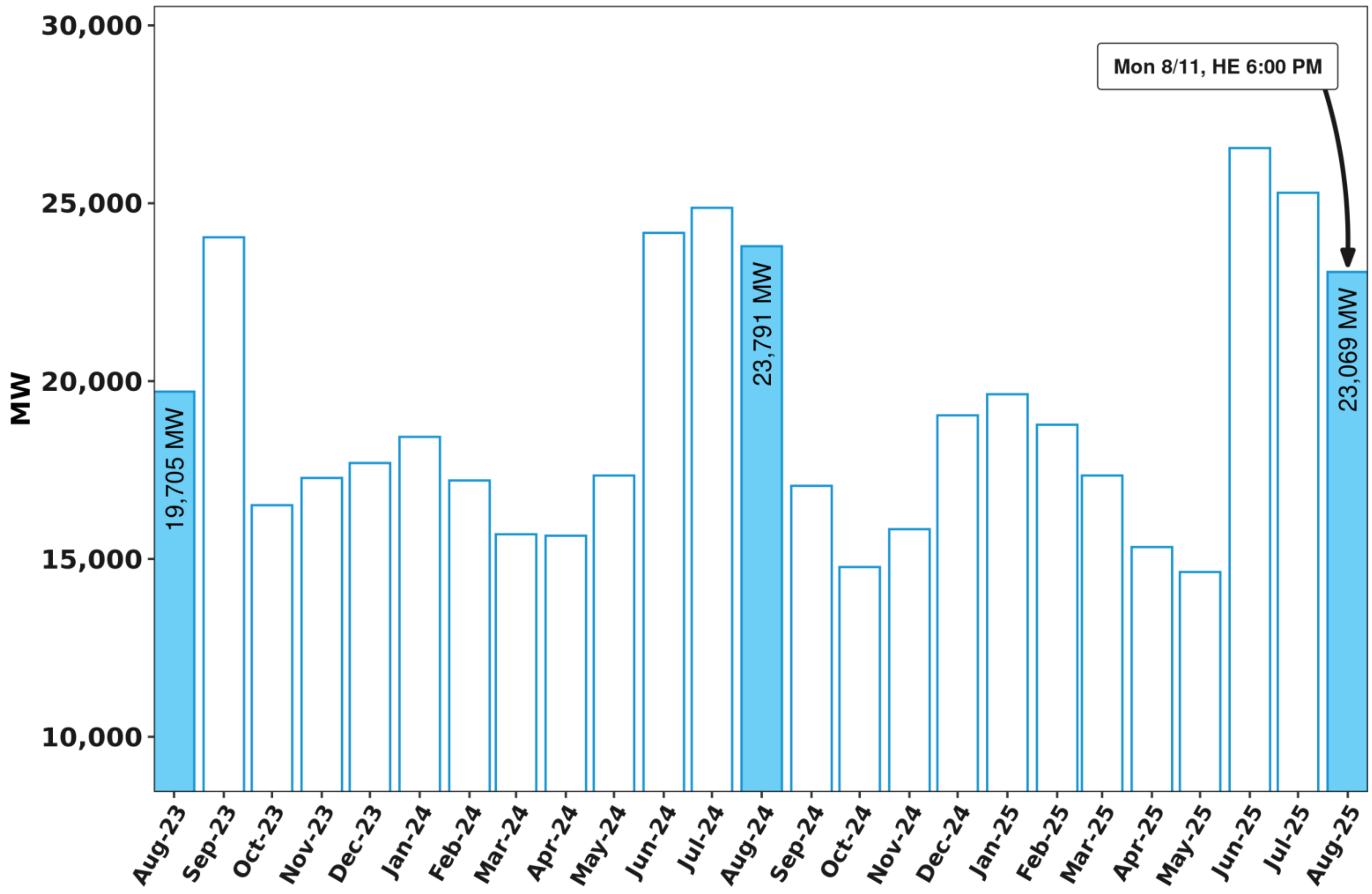
Net Interchange is the net of Participant scheduled imports (+) and exports (-). Inadvertent flows are not reflected.

RT Net Interchange by External Interface



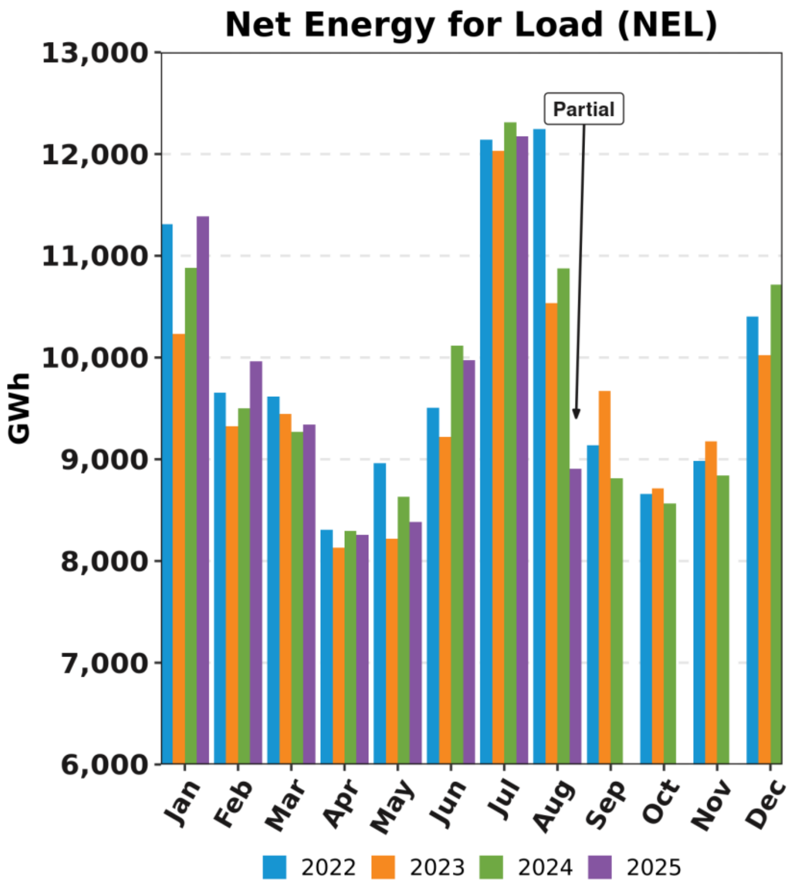


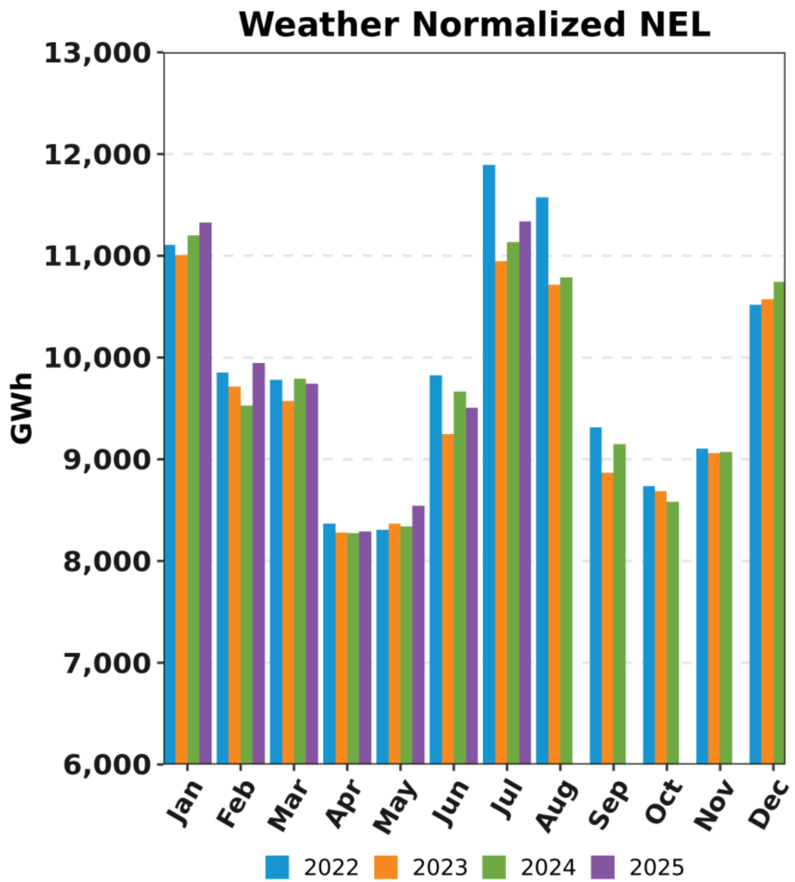
RQM System Peak Load MW by Month



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

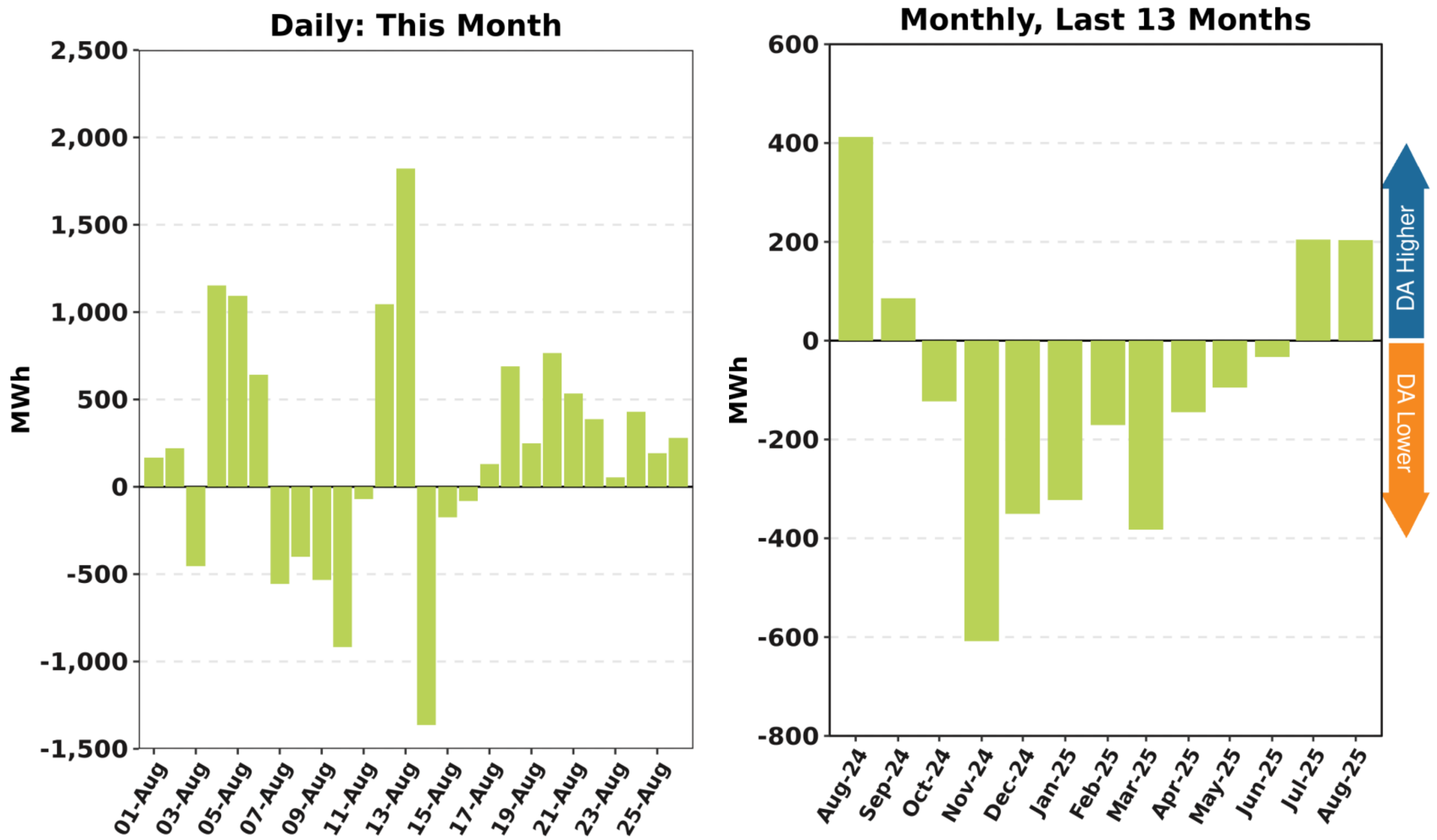
Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL





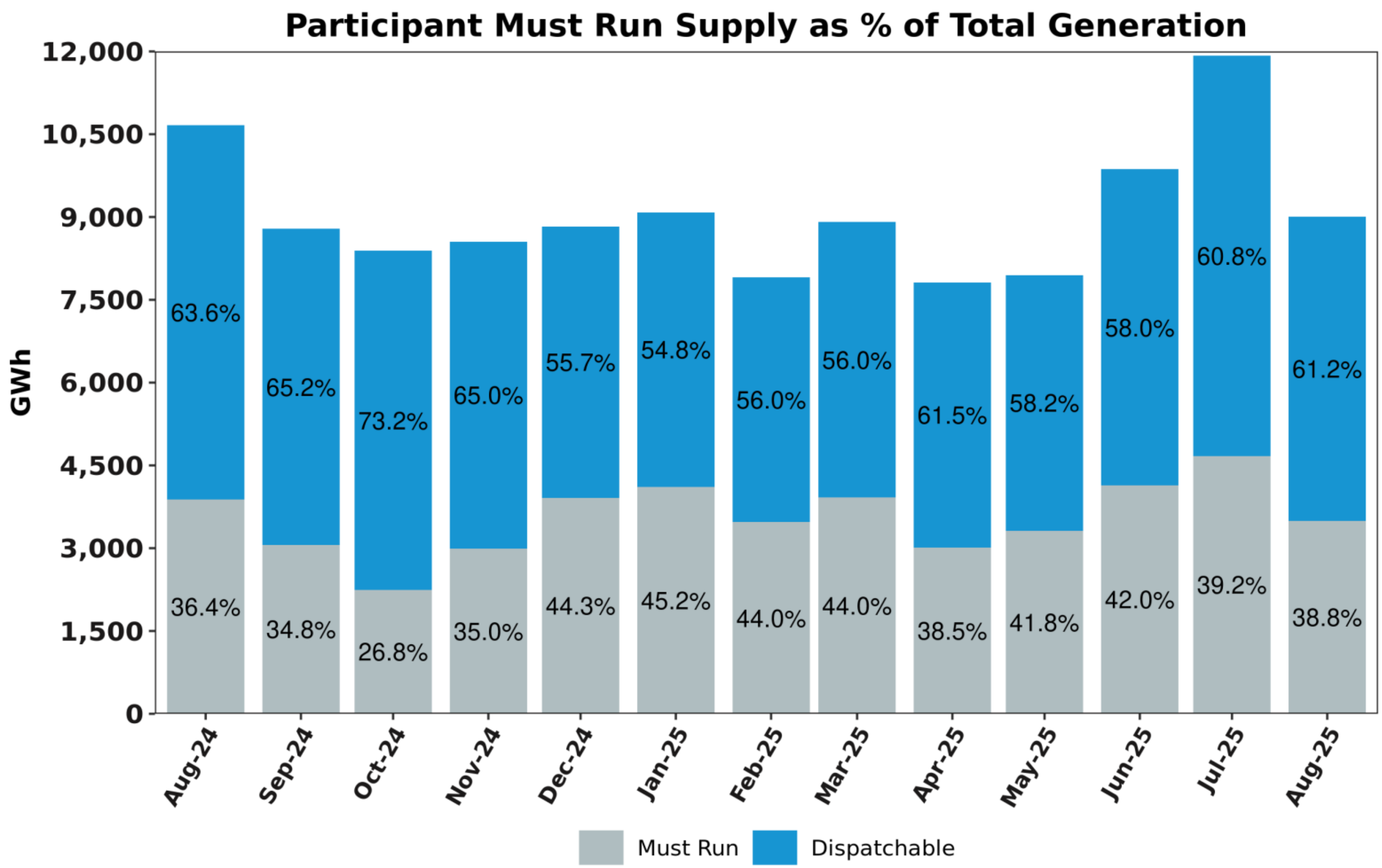
NEPOOL NEL is the total net revenue quality metered energy required to serve load and is analogous to ‘RT system load.’ NEL is calculated as: Generation + Demand Response Resource output - pumping load + net interchange where imports are positively signed. Current month’s data may be preliminary. Weather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

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



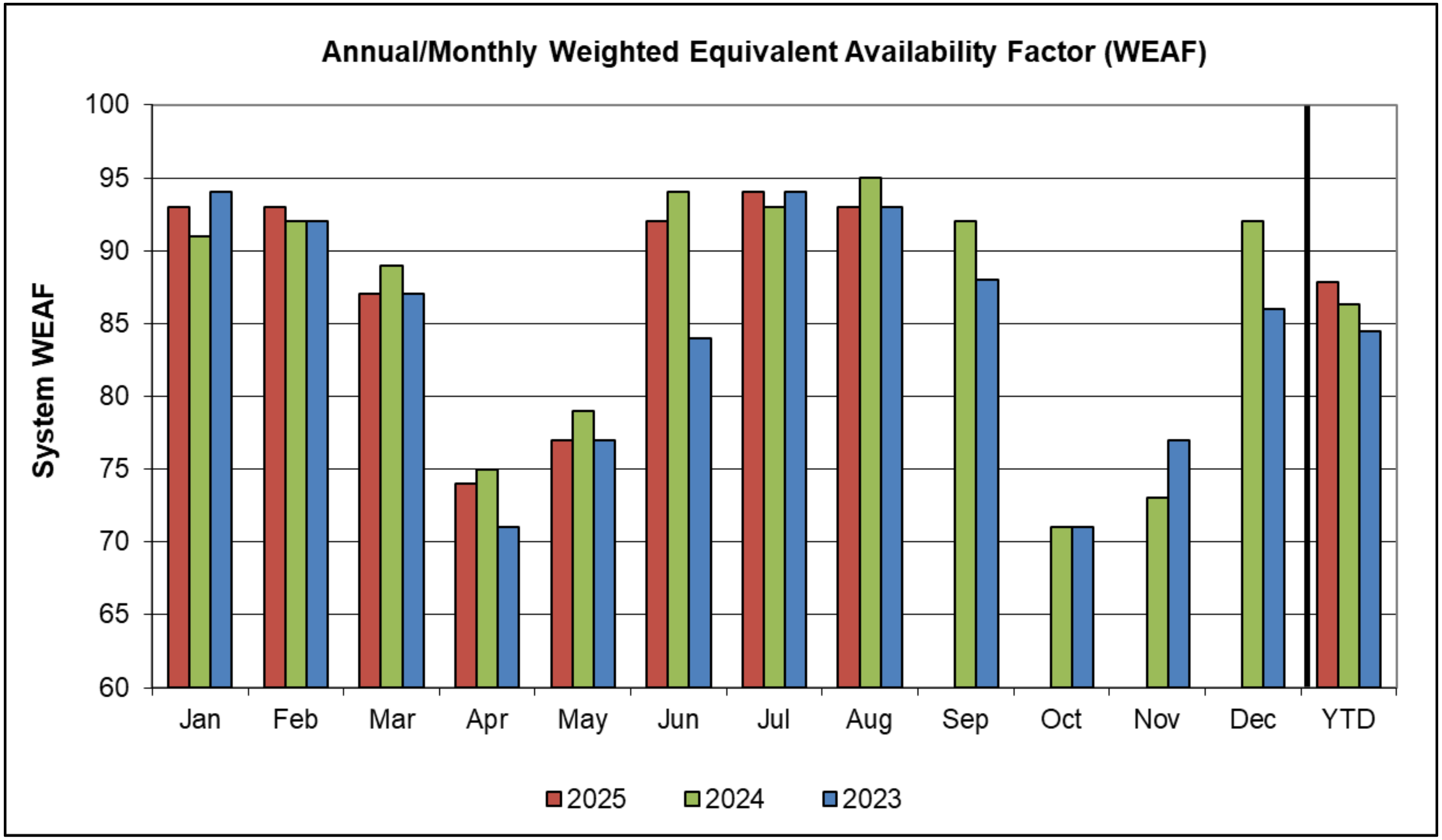
Negative values indicate DA Cleared Physical Energy value below its RT counterpart. EIR MW are not included in DA Physical Energy.

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	93					88
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 8/25/25

MARKET PRICING

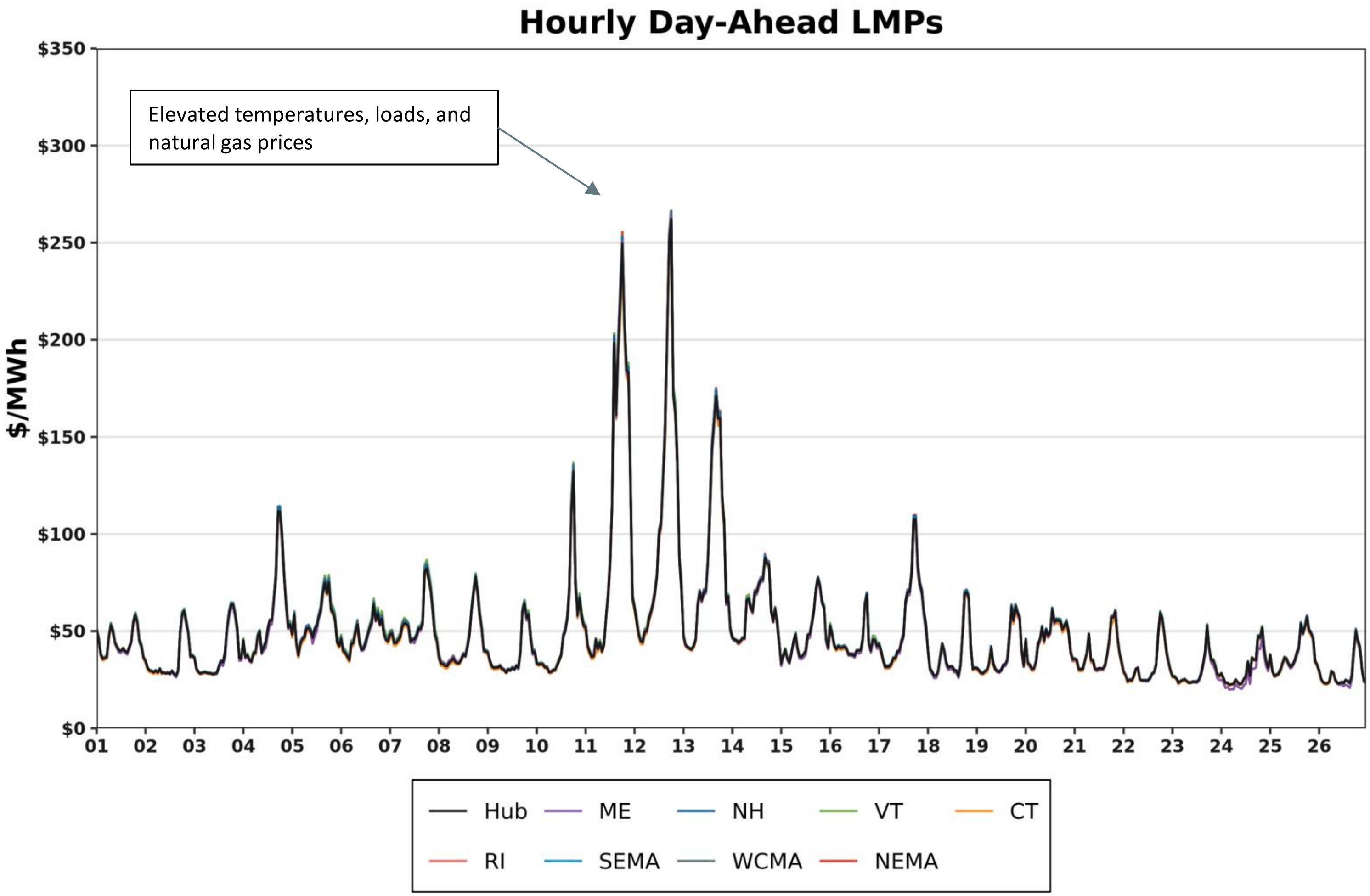
DA vs. RT LMPs ($/MWh)

Arithmetic Average

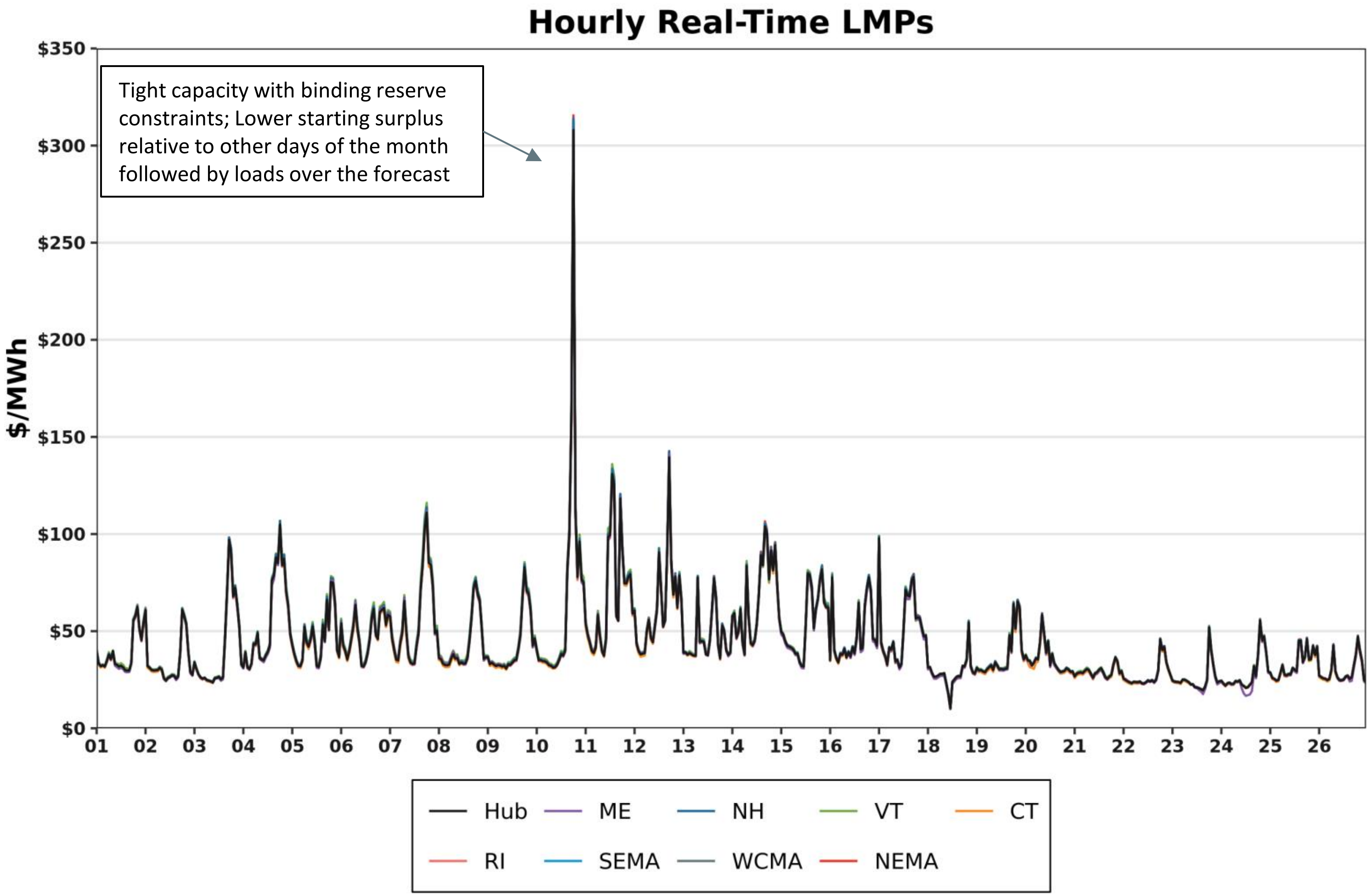
Year 2023	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$37.04	$36.59	$37.22	$36.78	$36.25	$36.89	$37.34	$37.07	$37.35
Real-Time	$35.91	$35.36	$36.05	$35.55	$35.26	$35.71	$36.17	$35.92	$36.21
RT Delta %	-3.05%	-3.36%	-3.14%	-3.34%	-2.73%	-3.20%	-3.13%	-3.10%	-3.05%
Year 2024	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	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%

August-24	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$35.66	$35.29	$35.86	$35.68	$34.85	$35.75	$36.12	$35.71	$36.14
Real-Time	$38.57	$38.04	$38.85	$38.73	$37.96	$38.30	$38.87	$38.64	$39.03
RT Delta %	8.16%	7.79%	8.34%	8.55%	8.92%	7.13%	7.61%	8.20%	8.00%
August-25	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$49.39	$48.73	$50.01	$50.24	$48.47	$48.91	$49.78	$49.55	$50.15
Real-Time	$43.96	$43.54	$44.54	$44.91	$43.27	$43.43	$44.15	$44.09	$44.56
RT Delta %	-10.99%	-10.65%	-10.94%	-10.61%	-10.73%	-11.20%	-11.31%	-11.02%	-11.15%
Annual Diff.	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Yr over Yr DA	38.50%	38.08%	39.46%	40.81%	39.08%	36.81%	37.82%	38.76%	38.77%
Yr over Yr RT	13.97%	14.46%	14.65%	15.96%	13.99%	13.39%	13.58%	14.10%	14.17%

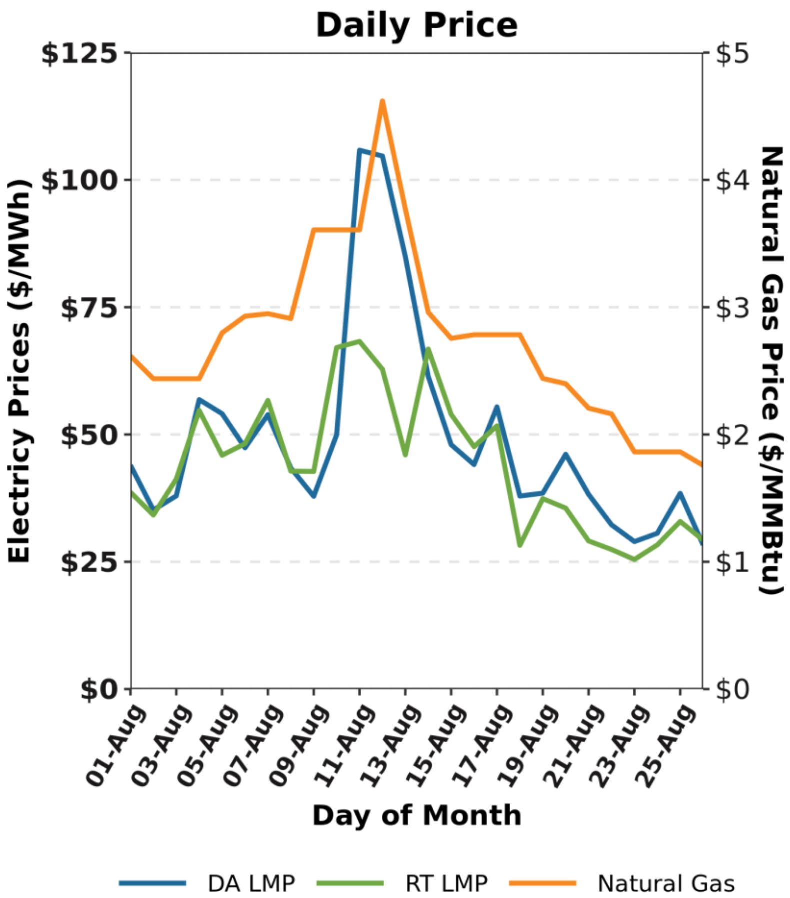
Hourly DA LMPs, August 1-26, 2025

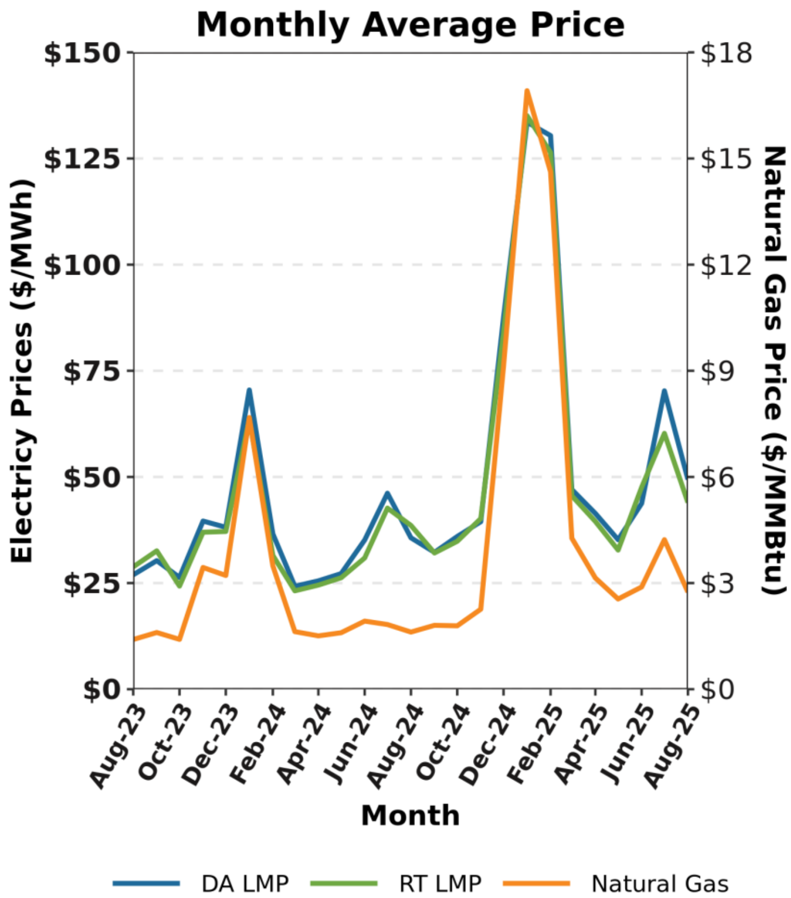


Hourly RT LMPs, August 1-26, 2025



Wholesale Electricity vs Natural Gas Price by Month

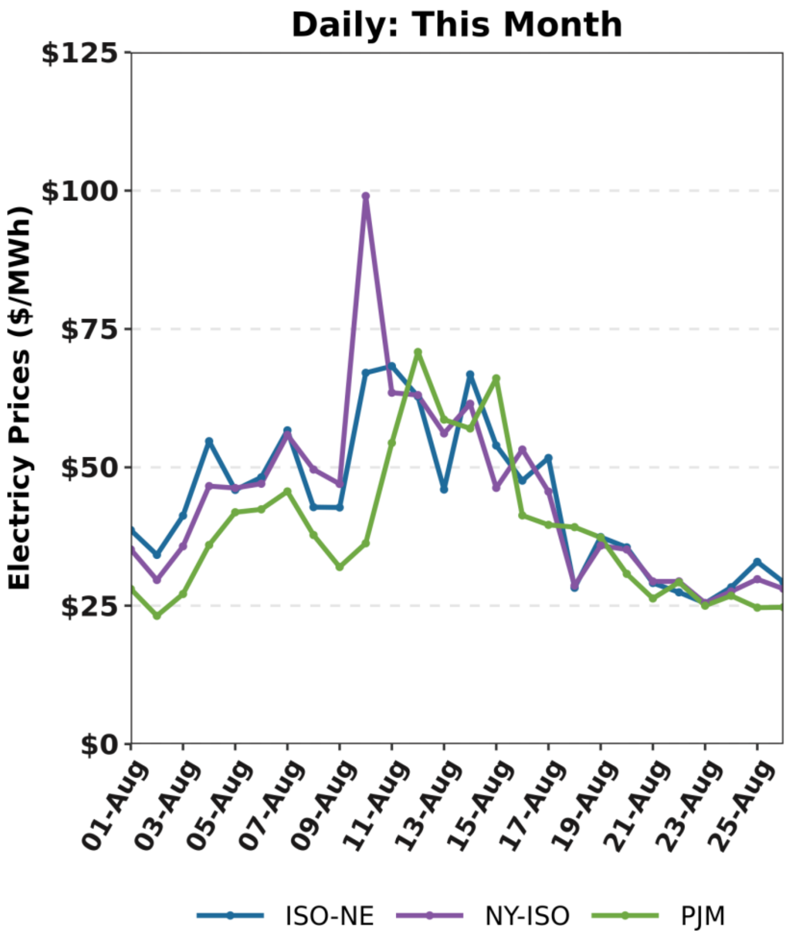


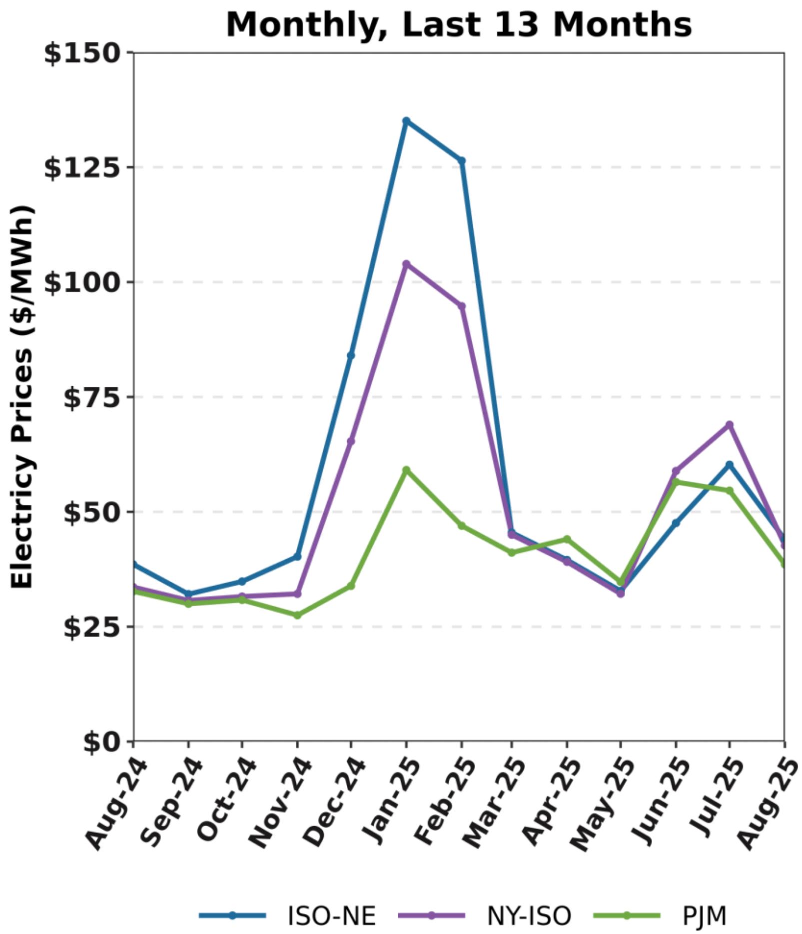


Underlying natural gas data furnished by:
ICE Global markets in clear view

Gas price is average of Massachusetts delivery points

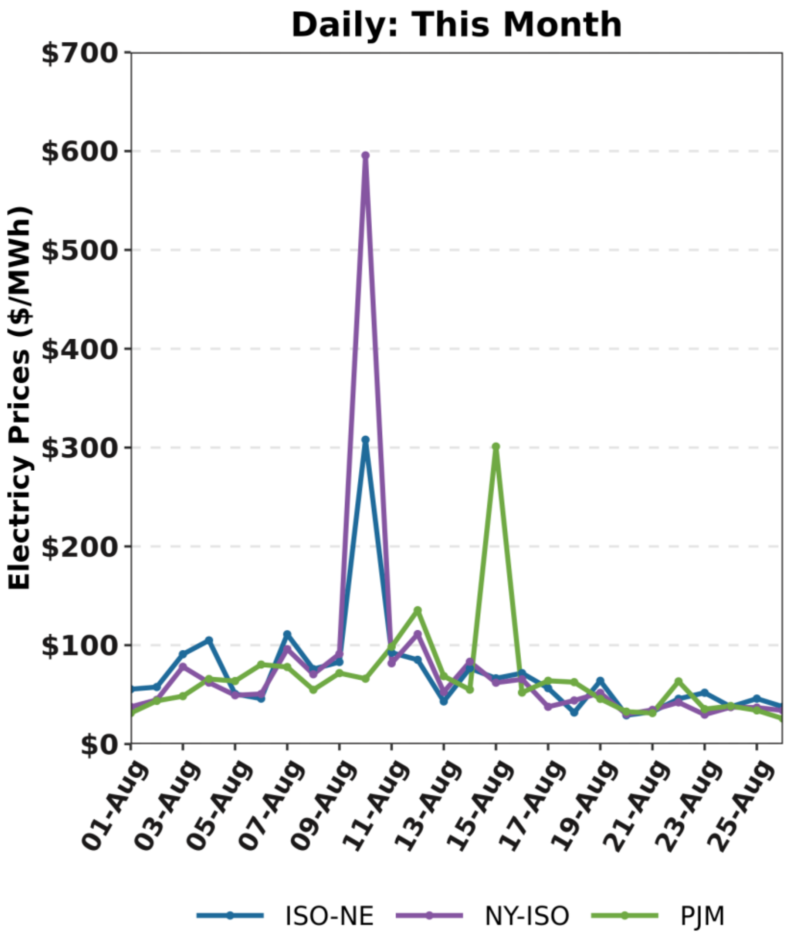
New England, NY, and PJM Hourly Average RT Prices by Month

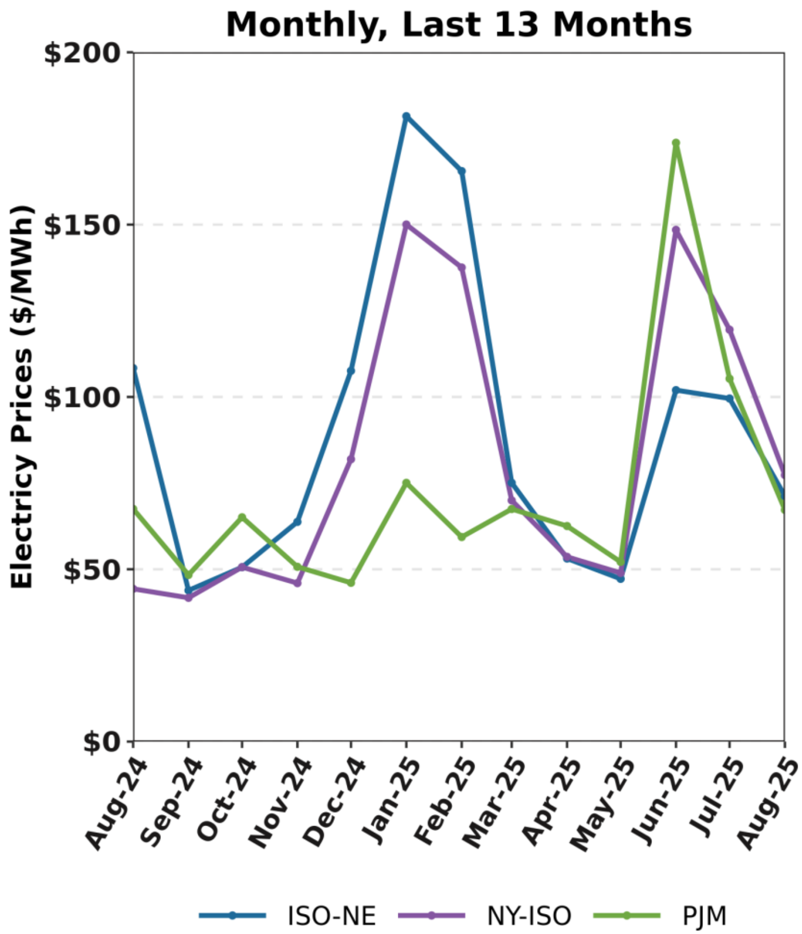




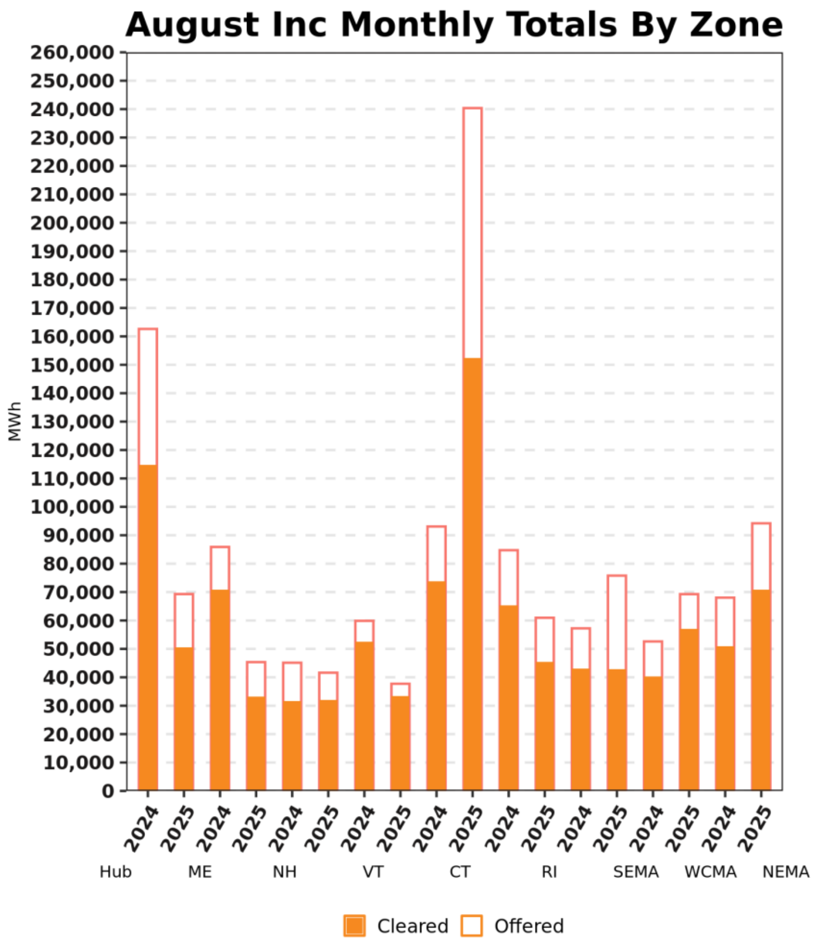
Hourly average prices are shown

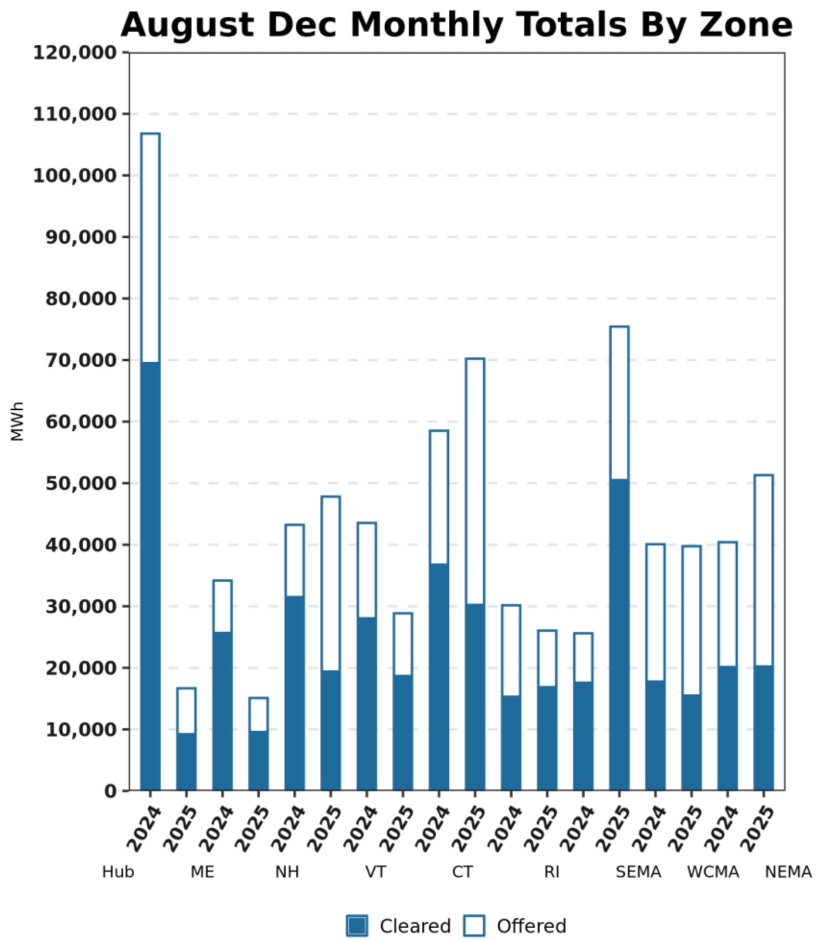
New England, NY, and PJM RT Pricing during New England's Forecasted Daily Peak Hours





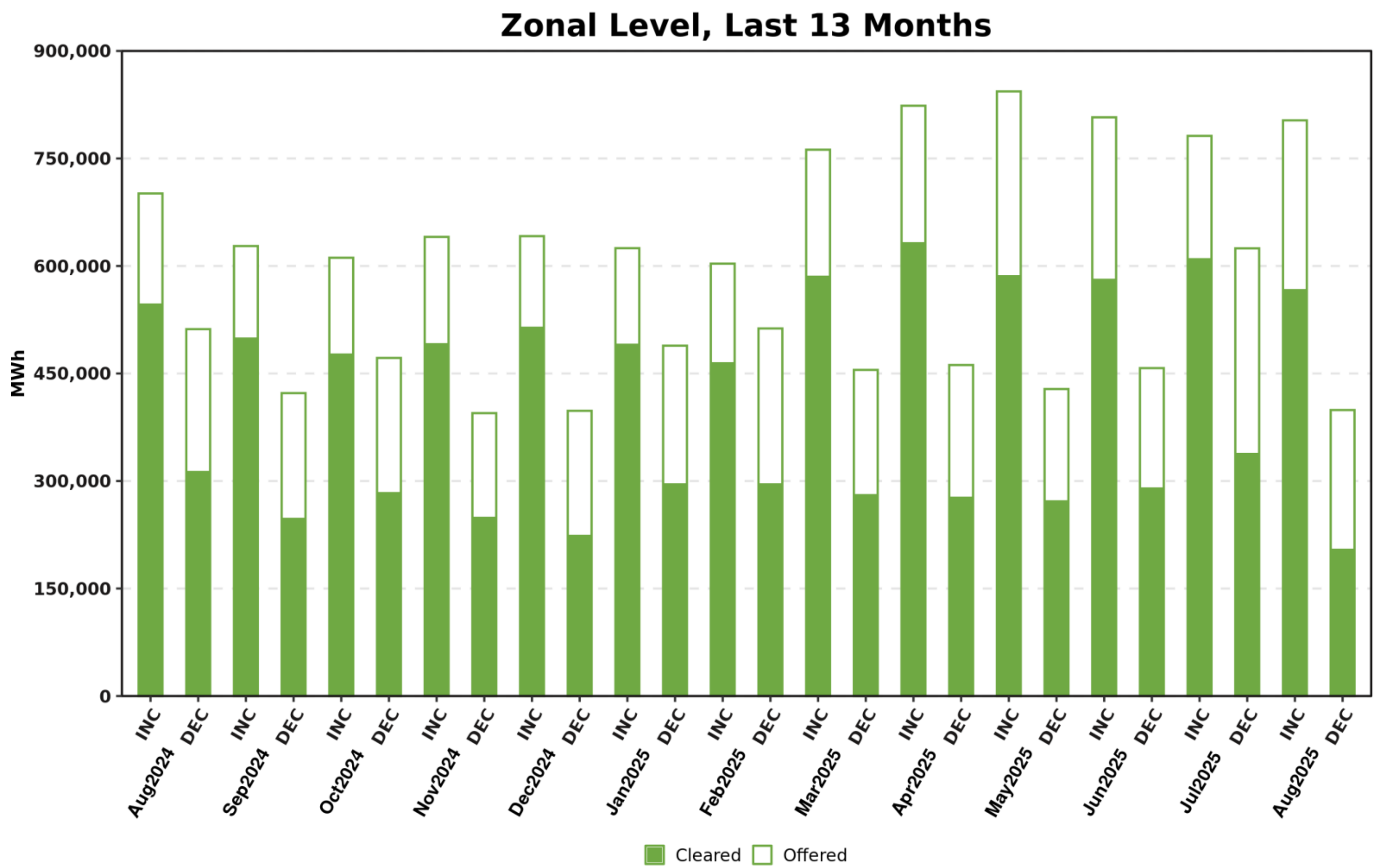
Zonal Increment Offers and Decrement Bid Amounts





Includes nodal activity within the zone; excludes external nodes

Total Increment Offers and Decrement Bids

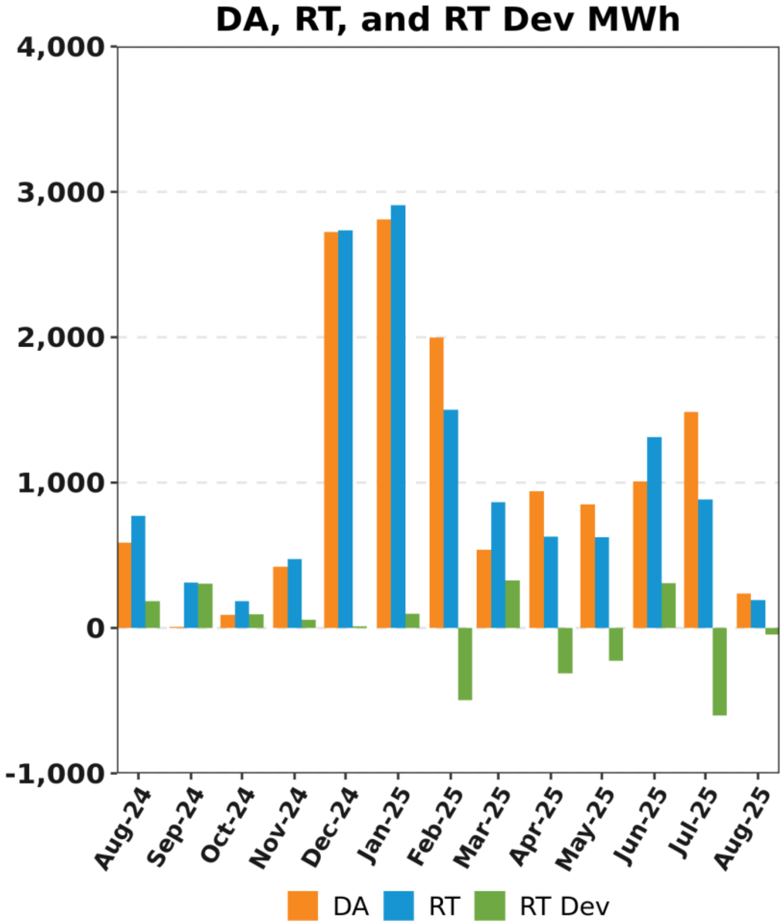


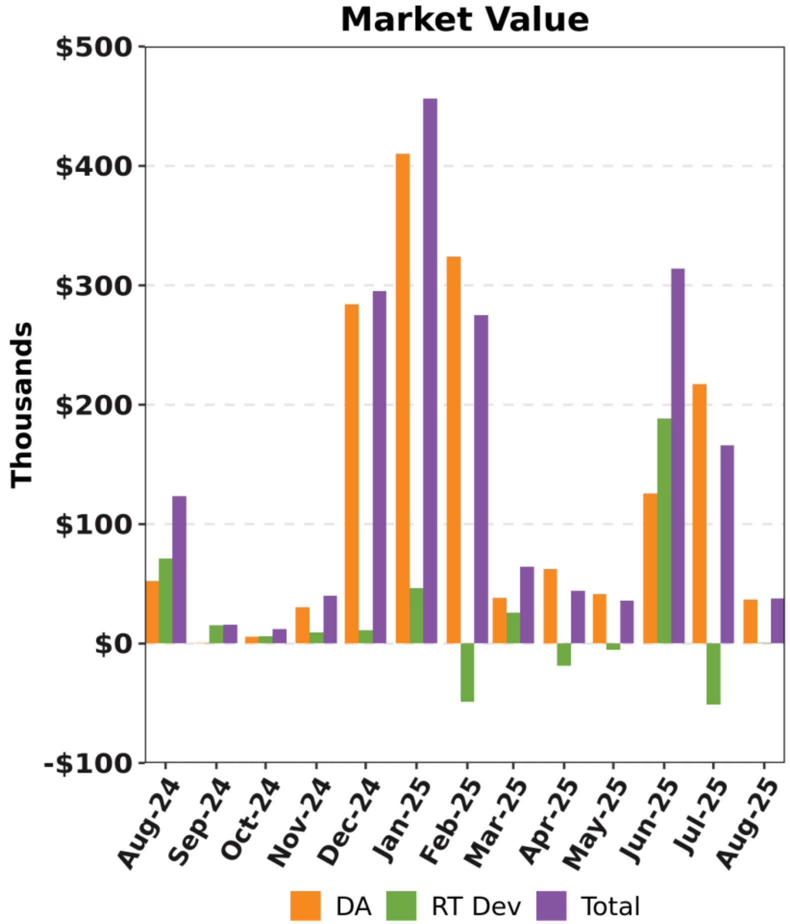
Includes nodal activity within the zone; excludes external nodes

BACK-UP DETAIL

DEMAND RESPONSE

Demand Response Resource's (DRR) Energy Market Activity by Month





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

NEW GENERATION

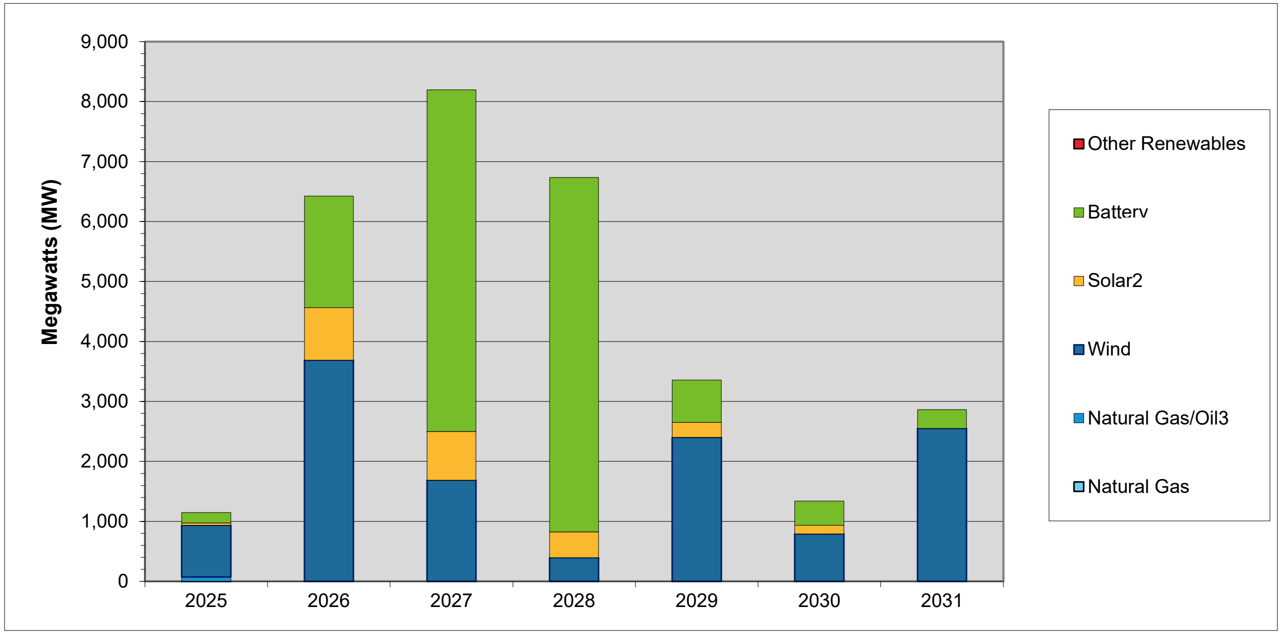
New Generation Update

Based on Queue as of 08/29/25

- No new projects were added to the interconnection queue since the last update
  - Any new ISO Interconnection Requests seeking to successfully enter the Order No. 2023 Transitional Cluster Study process were required to be submitted by June 13, 2024 at 23:59
    - Thereafter, the creation of new ISO Interconnection Requests is now suspended until the next Cluster Entry Window opens
    - ISO is no longer tracking non-FERC jurisdictional interconnection projects in the ISO queue
- In total, 134 generation projects are currently being tracked by the ISO, totaling approximately 33,668 MW

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	1,864	5,698	5,909	704	404	315	15,069	50.1
Solar[2]	40	874	811	433	252	146	0	2,556	8.5
Wind	859	3,689	1,687	394	2,400	791	2,550	12,370	41.1
Natural Gas/Oil[3]	73	0	0	0	0	0	0	73	0.2
Natural Gas	0	0	0	0	0	0	0	0	0.0
Totals	1,147	6,427	8,196	6,736	3,356	1,341	2,865	30,068	100.0

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

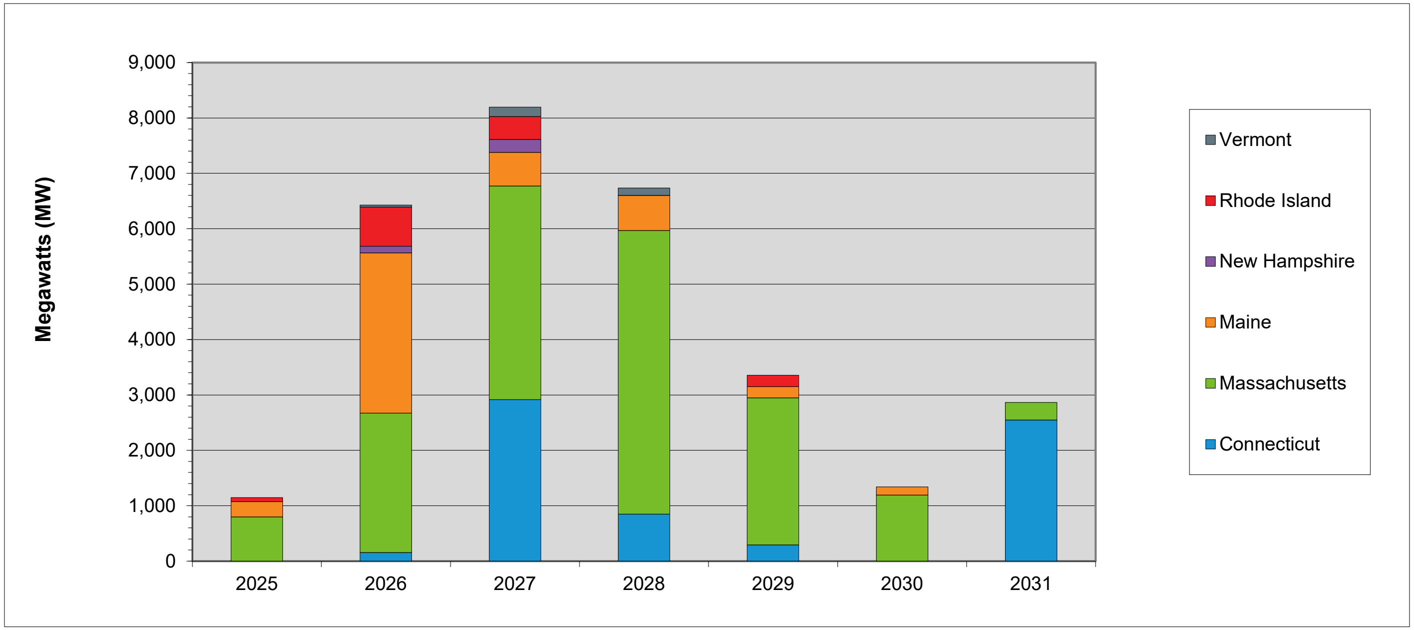
[2] This category includes both solar-only, and co-located solar and battery projects

[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	171	135	0	0	0	344	1.1
Rhode Island	73	704	415	0	205	0	0	1,397	4.6
New Hampshire	0	122	231	1	0	0	0	354	1.2
Maine	274	2,892	605	632	202	146	0	4,751	15.8
Massachusetts	800	2,517	3,860	5,118	2,654	1,195	315	16,459	54.7
Connecticut	0	154	2,914	850	295	0	2,550	6,763	22.5
Totals	**1,147**	**6,427**	**8,196**	**6,736**	**3,356**	**1,341**	**2,865**	**30,068**	**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	76	15,069	2	425	74	14,644
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	34	2,556	4	76	30	2,480
Wind	23	15,970	3	877	20	15,093
Total	134	33,668	9	1,378	125	32,290

- 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

Operating Type	Total		Green		Yellow	
	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	110	17,625	6	501	104	17,124
Wind Turbine	23	15,970	3	877	20	15,093
Total	134	33,668	9	1,378	125	32,290

- 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	76	15,069	0	0	0	0	76	15,069	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	34	2,556	0	0	0	0	34	2,556	0	0
Wind	23	15,970	0	0	0	0	0	0	23	15,970
Total	134	33,668	0	0	1	73	110	17,625	23	15,970

- 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
	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
	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				
Demand	*Passive Demand*	2,316.815	2,314.068	-2.747				
Demand Total		**2,939.669**	**2,898.981**	**-40.688**				
Generator	*Non-Intermittent*	26,507.420	26,715.489	208.069				
Generator	*Intermittent*	1,356.084	1,286.589	-69.495				
Generator Total		**27,863.504**	**28,002.078**	**138.574**				
Import Total		**566.998**	**564.079**	**-2.919**				
Grand Total*		**31,370.171**	**31,465.138**	**94.967**				
Net ICR (NICR)		**30,305**	**30,395**	**90.000**				

* 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.

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				
	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				
	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

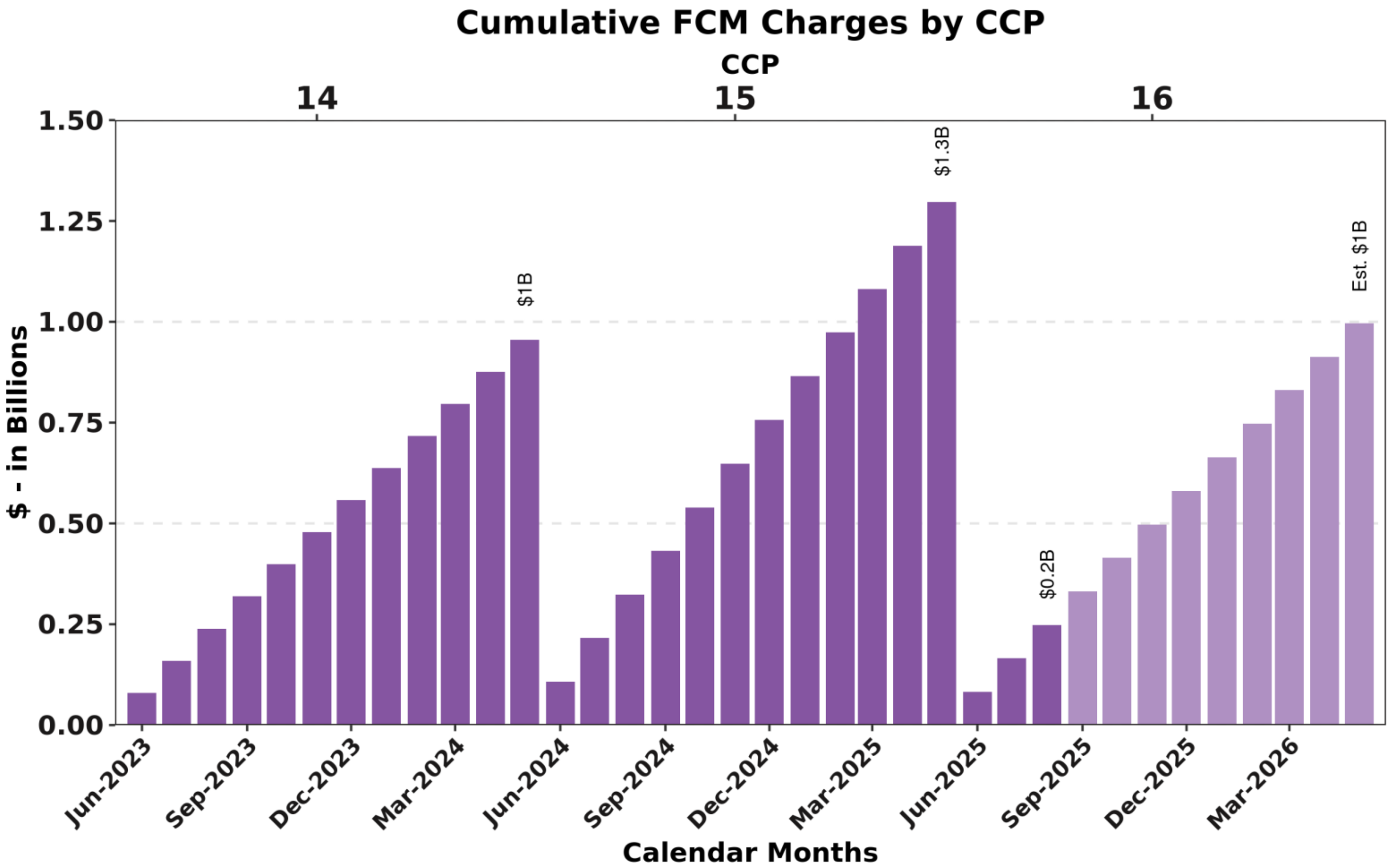
Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes 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**

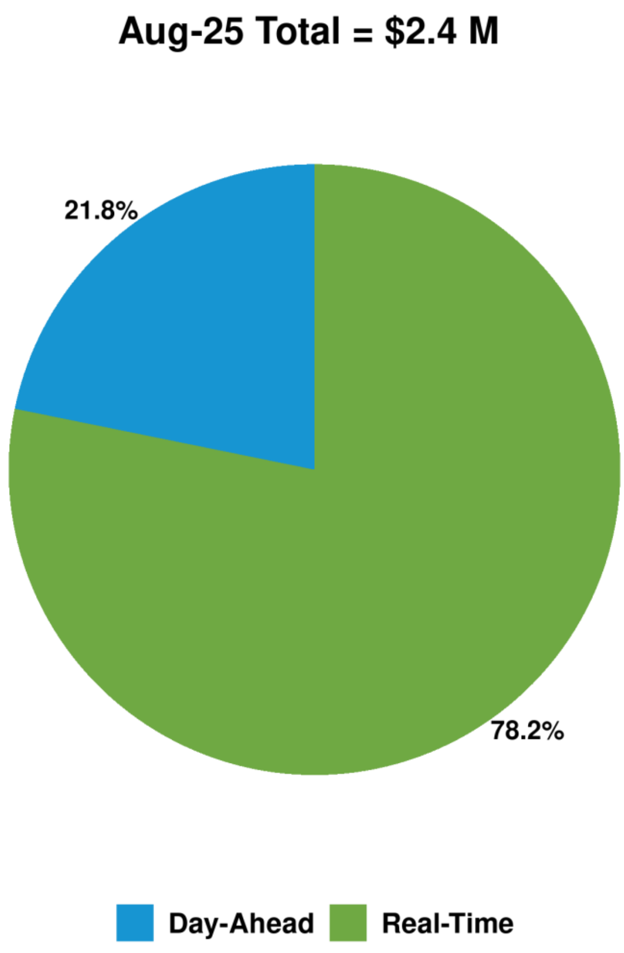
Forward Capacity Market Auctions

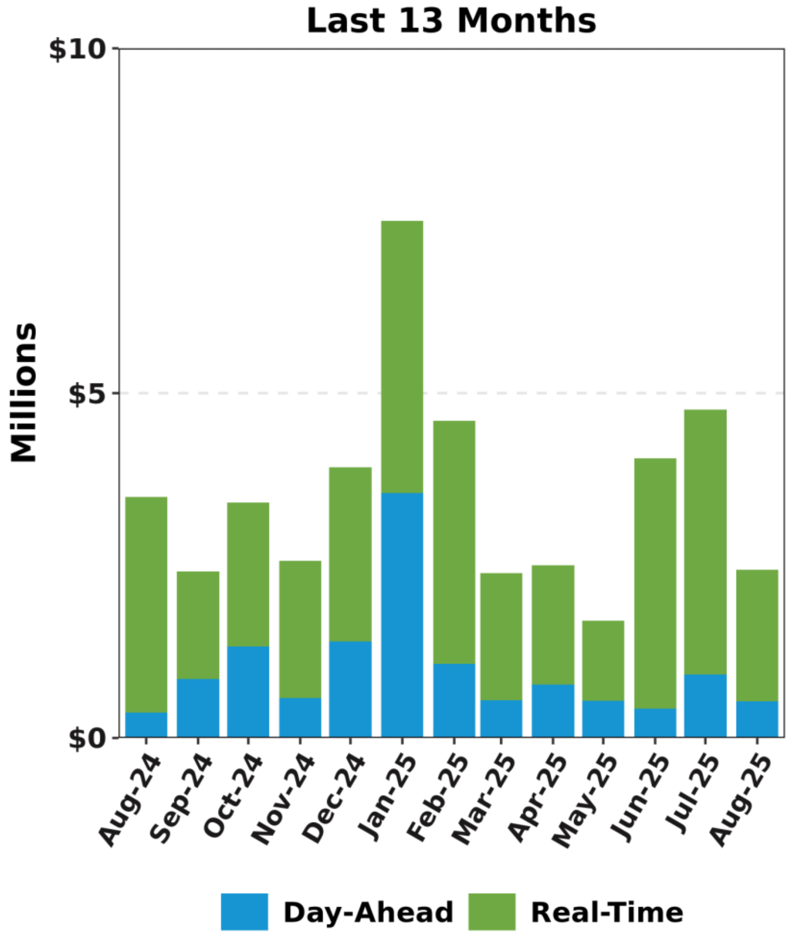


The items in the graph shaded in a lighter color represent the forecast for future months in the Capacity Commitment Period (CCP)

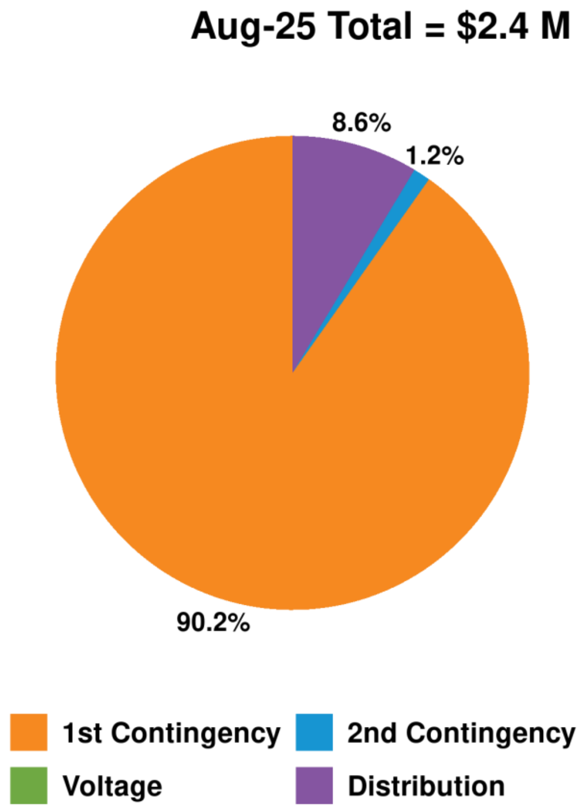
NET COMMITMENT PERIOD COMPENSATION

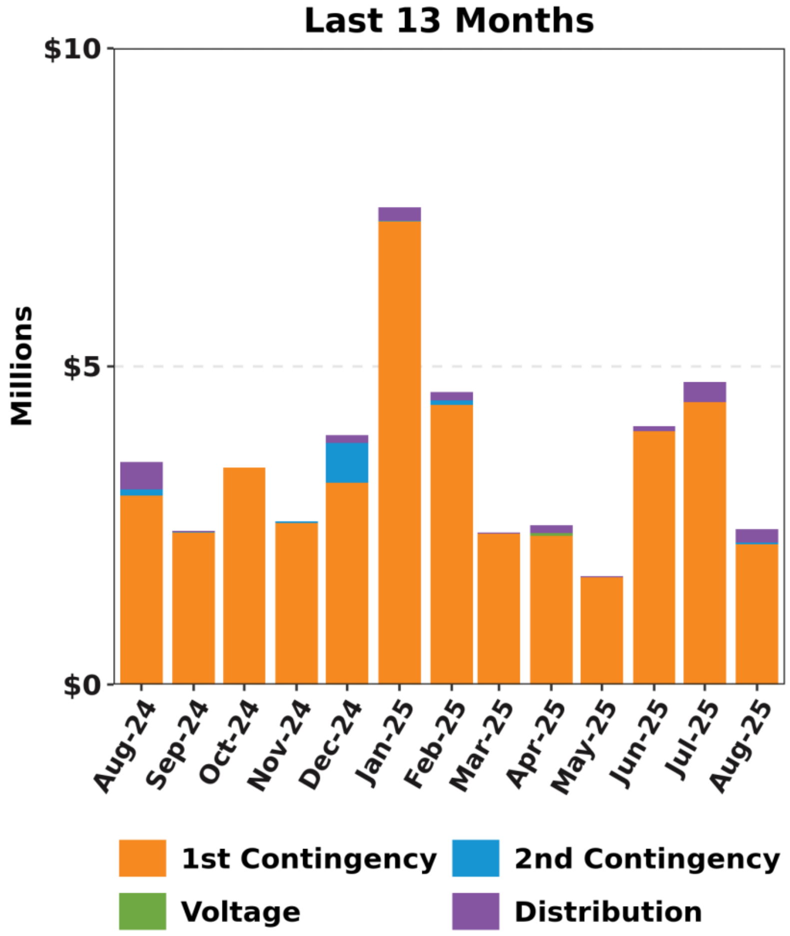
DA and RT NCPC Charges



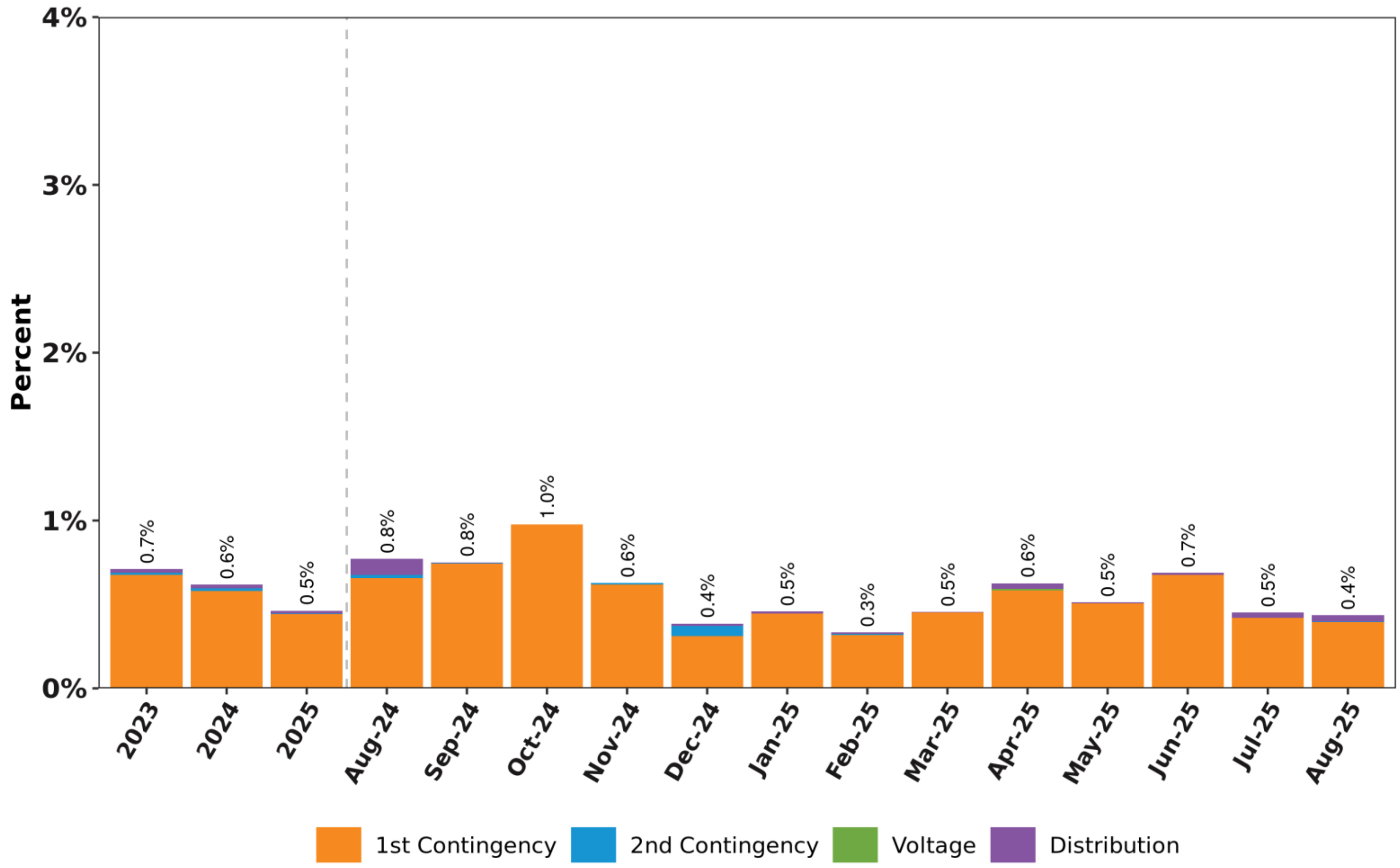


NCPC Charges by Type

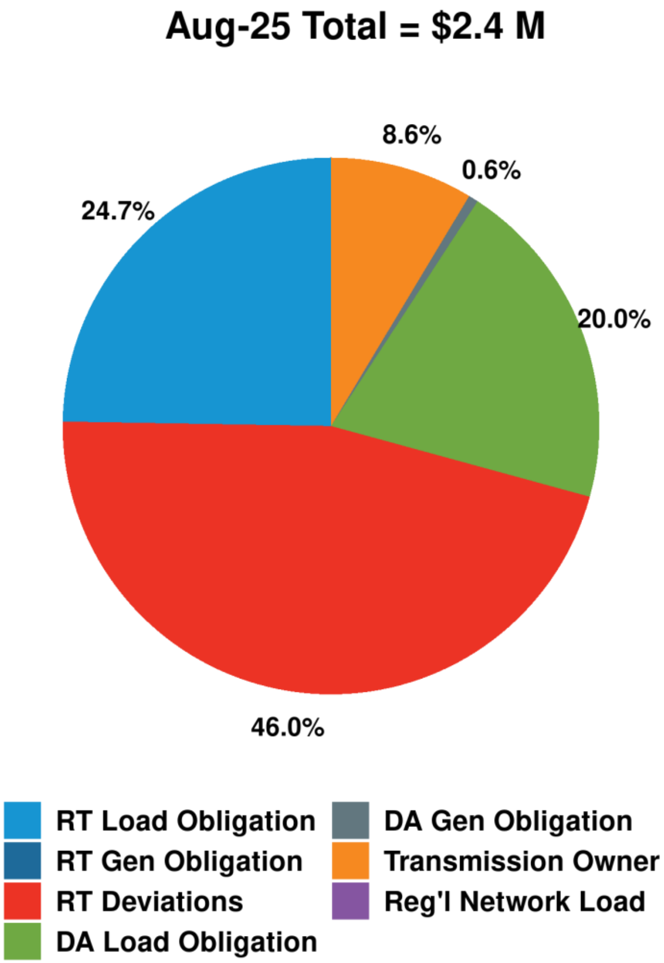


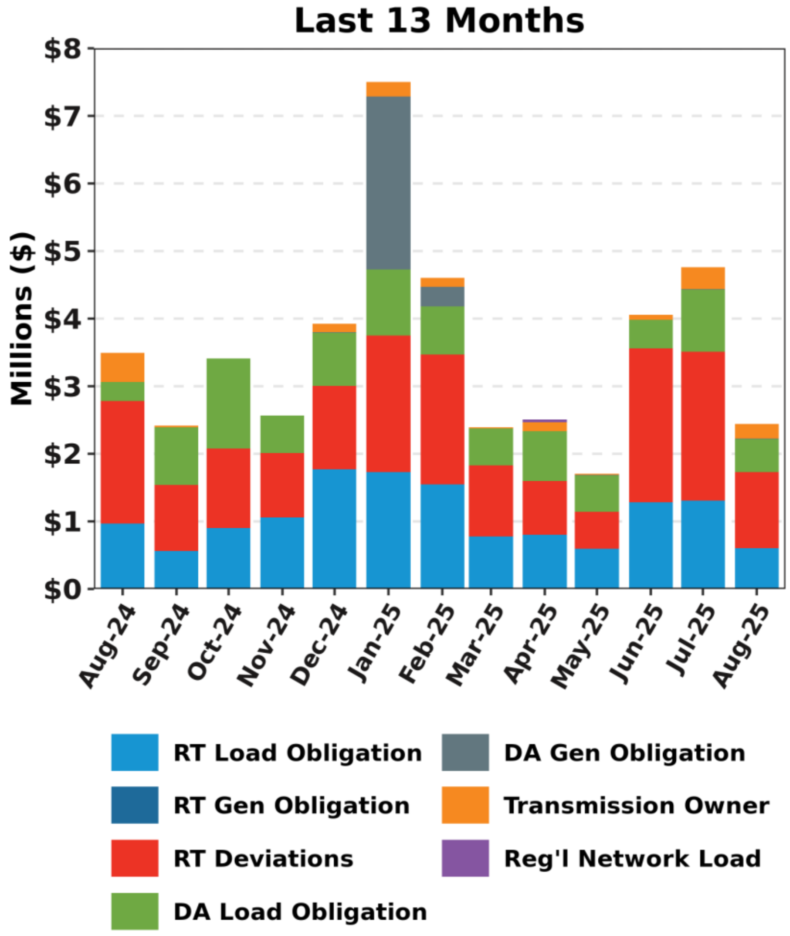


NCPC Charges by Type as Percent of Energy Market Value

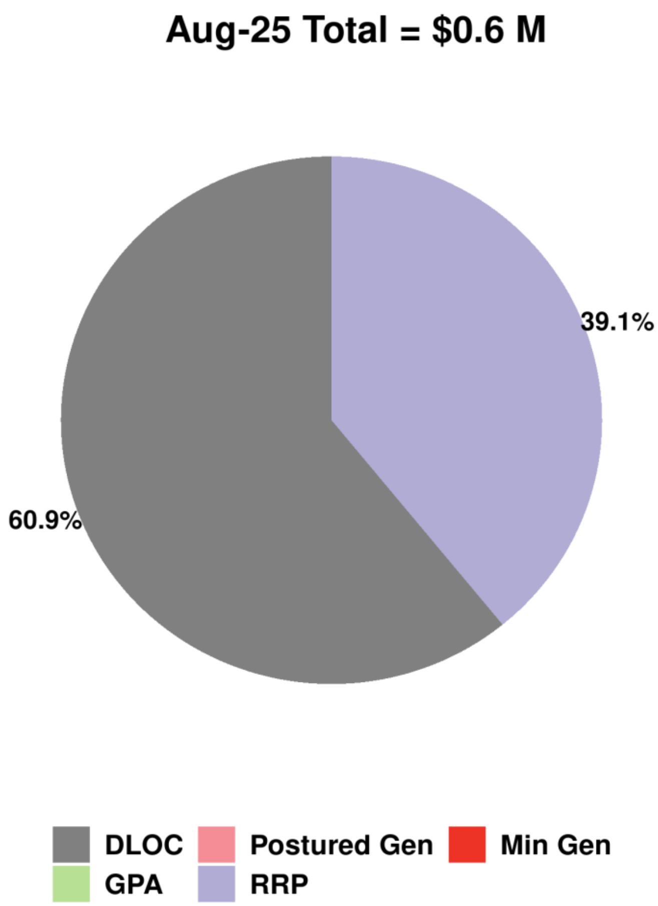


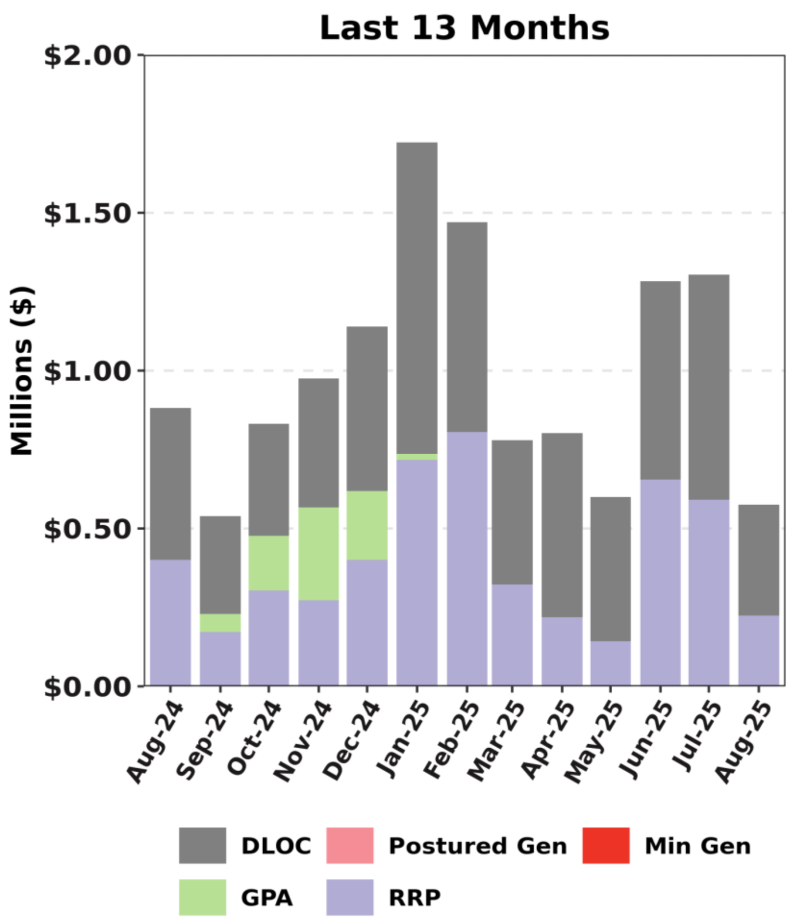
NCPC Charge Allocations





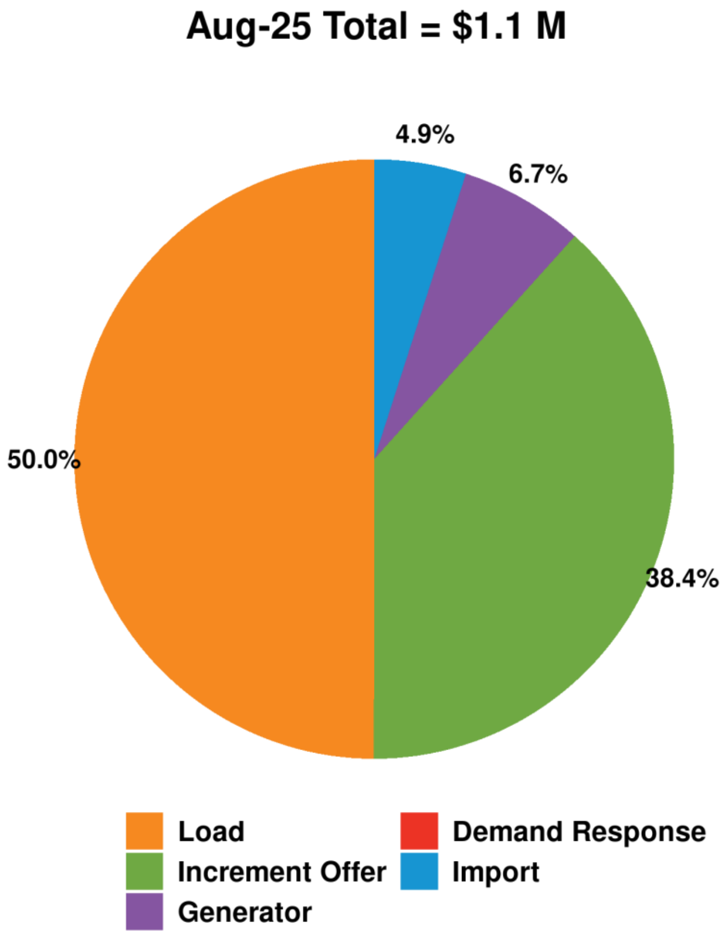
RT First Contingency NCPC Paid to Units and Allocated to RTLO and/or RTGO

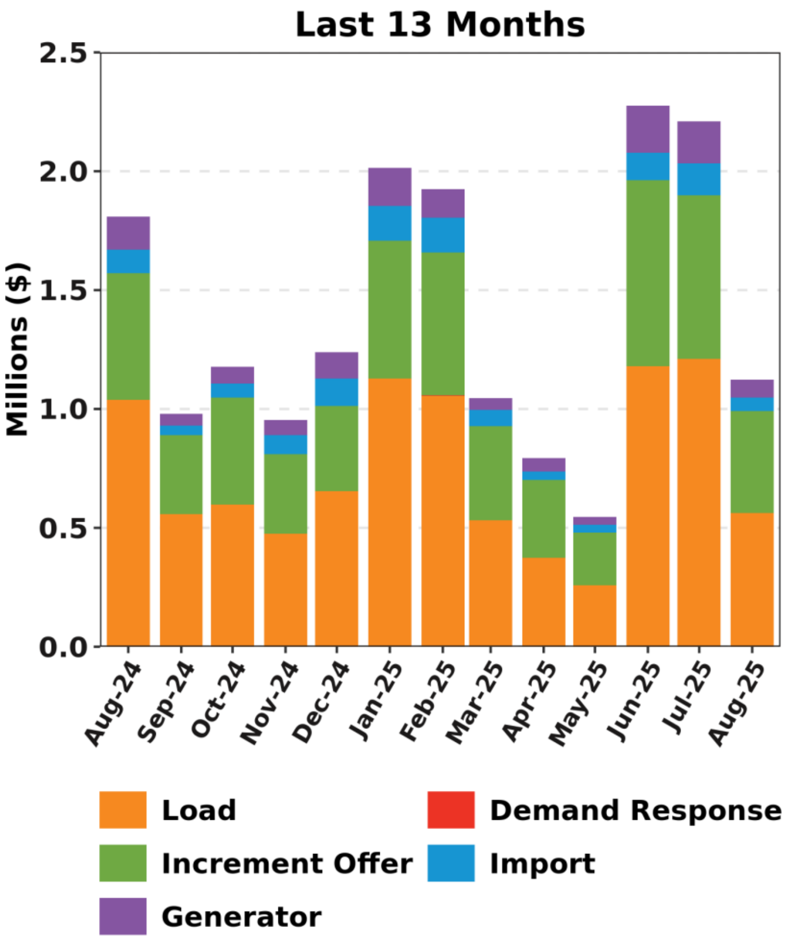




The categories shown above are a subset of those reflected in First Contingency NCPC throughout this report. The above categories are allocated to RTLO, except for Min Gen Emergency credits, which are allocated to RTGO.

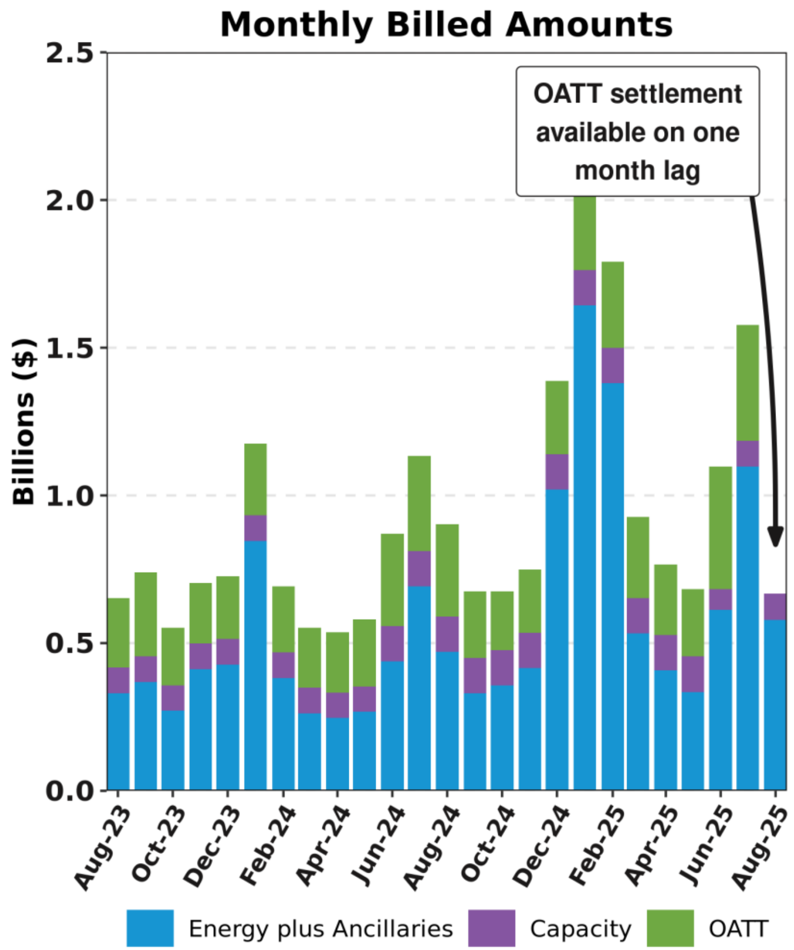
RT First Contingency Charges by Deviation Type

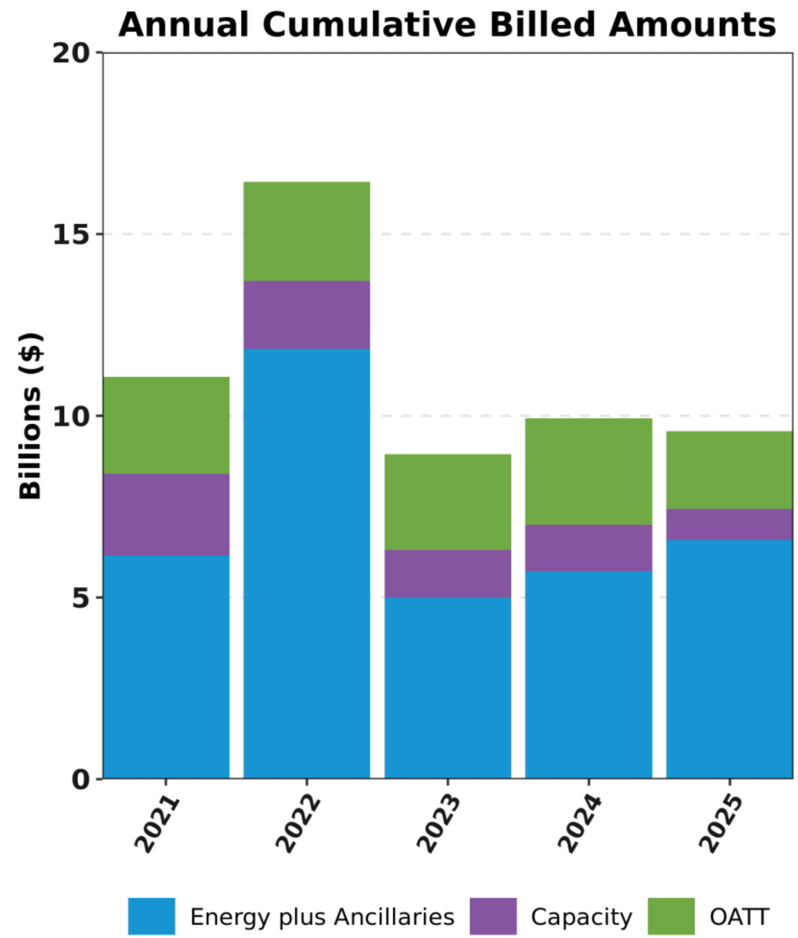




ISO BILLINGS

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)

- September 17 PAC Meeting Agenda Topics*
  - Asset Condition Projects
    - Bridgewater #16 Substation Asset Condition Upgrades – Update (NGRID)
    - I-135/I-135N/J-136N ACR (NGRID)
  - 2024 Economic Study – System Efficiency Needs Scenario Results

* 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 RFP

- NESCOE provided a letter on 10/16/24 discussing potential transmission needs for a Longer-term Transmission Planning (LTTP) RFP, which was discussed at the 10/23/24 PAC meeting
- On 12/13/24, NESCOE provided its LTTP 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**
- NESCOE's LTTP request was discussed at the 12/18/24 PAC meeting
- Further discussion on details of the RFP, led by the ISO, occurred at the 1/23/25 PAC meeting, and additional discussion occurred at the 2/26/25 PAC meeting
- QTPS training on the use of Responsive occurred on 2/20/25
- The ISO issued the LTTP RFP on 3/31/25, with proposals due by 9/30/25

* 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

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 will be issued in September
    - There will also be 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.

Greater Boston Projects

Status as of 8/25/2025

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1213, 1220, 1365	Install new 345 kV line from Scobie to Tewksbury	Dec-17	4
1527, 1528	Reconductor the Y-151 115 kV line from Dracut Junction to Power Street	Apr-17	4
1212, 1549	Reconductor the M-139 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
1549	Reconductor the N-140 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
1260	Reconductor the F-158N 115 kV line from Wakefield Junction to Maplewood and associated work at Maplewood	Dec-15	4
1550	Reconductor the F-158S 115 kV line from Maplewood to Everett	Jun-19	4
1551,1552	Install new 345 kV cable from Woburn to Wakefield Junction, install two new 160 MVAR variable shunt reactors and associated work at Wakefield Junction and Woburn	Mar-24	4
1329	Refurbish X-24 69 kV line from Millbury to Northboro Road	Dec-15	4
1327	Reconductor W-23W 69 kV line from Woodside to Northboro Road	Jun-19	4

Greater Boston Projects, cont.

Status as of 8/25/2025

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1330	Separate X-24 and E-157W DCT	Dec-18	4
1363	Separate Q-169 and F-158N DCT	Dec-15	4
1637, 1640	Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap	May-17	4
1516	Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook	Sep-20	4
965	Install third 115 kV line from West Walpole to Holbrook	Sep-20	4
1558	Install new 345 kV breaker in series with the 104 breaker at Stoughton	May-16	4
1199	Install new 230/115 kV autotransformer at Sudbury and loop the 282-602 230 kV line in and out of the new 230 kV switchyard at Sudbury	Dec-17	4
1335, 1672*	Install a new 115 kV line from Sudbury to Hudson	Dec-24, Jun-25*	4, 4

* The new 115 KV line from Sudbury to Hudson is currently in-service with some station work remaining at Hudson.

Greater Boston Projects, cont.

Status as of 8/25/2025

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1336	Replace 345/115 kV autotransformer, 345 kV breakers, and 115 kV switchgear at Woburn	Dec-19	4
1553	Install a 345 kV breaker in series with breaker 104 at Woburn	Jun-17	4
1337	Reconfigure Waltham by relocating PARs, 282-507 line, and a breaker	Dec-17	4
1339	Upgrade 533-508 115 kV line from Lexington to Hartwell and associated work at the stations	Aug-16	4
1521	Install a new 115 kV 54 MVAR capacitor bank at Newton	Dec-16	4
1522	Install a new 115 kV 36.7 MVAR capacitor bank at Sudbury	May-17	4
1352	Install a second Mystic 345/115 kV autotransformer and reconfigure the bus	May-19	4
1353	Install a 115 kV breaker on the East bus at K Street	Jun-16	4
1354, 1738	Install 115 kV cable from Mystic to Chelsea and upgrade Chelsea 115 kV station to BPS standards	Jul-21	4
1355	Split 110-522 and 240-510 DCT from Baker Street to Needham for a portion of the way and install a 115 kV cable for the rest of the way	Mar-21	4

Greater Boston Projects, cont.

Status as of 8/25/2025

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1356	Install a second 115 kV cable from Mystic to Woburn to create a bifurcated 211-514 line	Mar-24	4
1357	Open lines 329-510/511 and 250-516/517 at Mystic and Chatham, respectively. Operate K Street as a normally closed station.	May-19	4
1518	Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard	Mar-19	4
1519	Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-16	4

Greater Boston Projects, cont.

Status as of 8/25/2025

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

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

SEMA/RI Reliability Projects

Status as of 8/25/2025

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 8/25/2025

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	Mar-27	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 8/25/2025

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 8/25/2025

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 8/25/2025

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 8/25/2025

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 8/25/2025

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

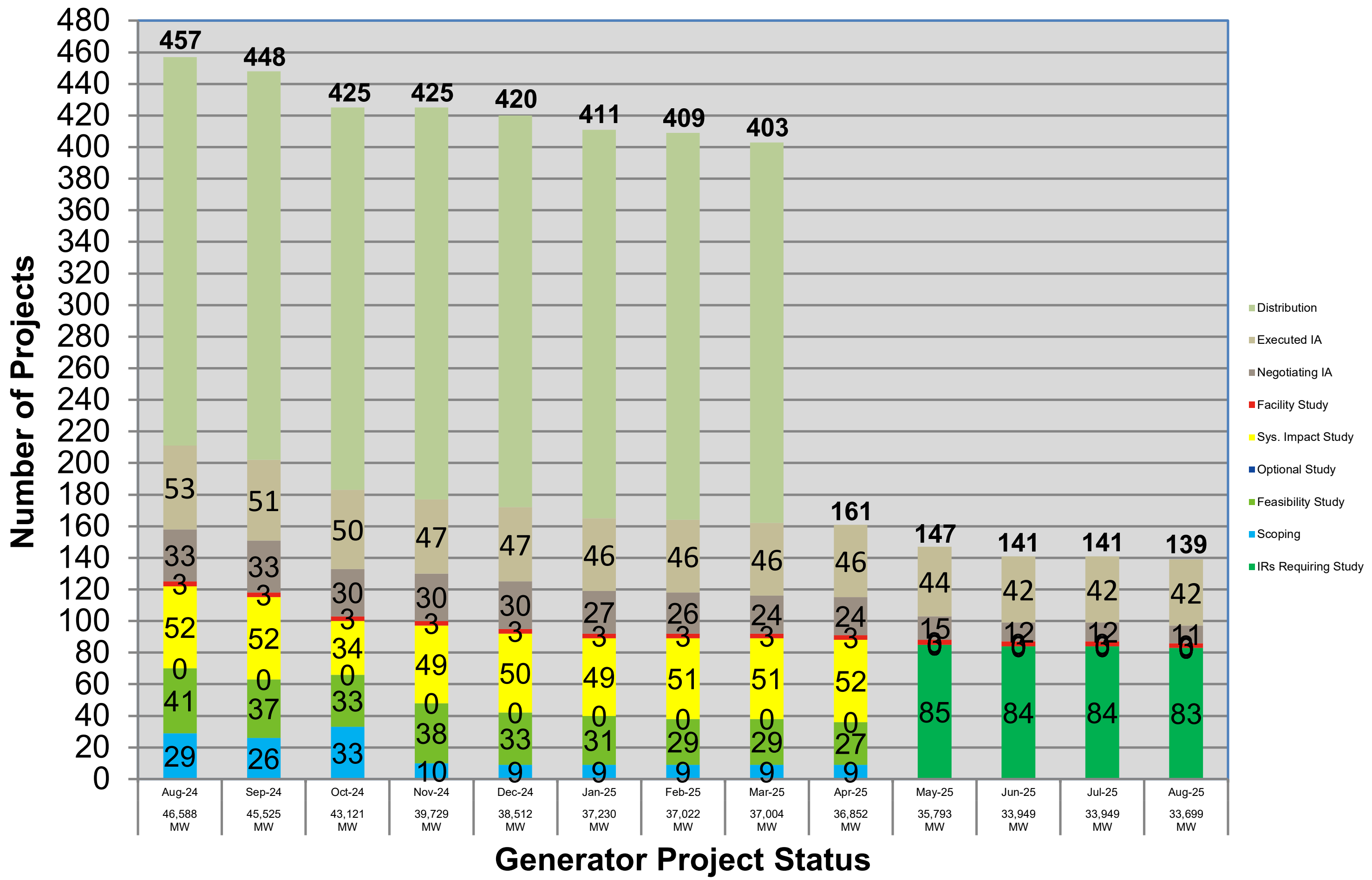
Boston 2033 Solutions Study

Status as of 8/25/2025

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)	Jun-26	1

Status of Tariff Studies as of August 25, 2025



ETUs: 4 with IRs Requiring Study, 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

Note: As of April 2025, the ISO is no longer tracking Distribution Projects in its interconnection queue. Also, 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.

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)	Sep - 2025[2] CSO (MW)	Sep - 2025[2] SCC (MW)
Operable Capacity MW [1]	25,967	27,640
Active Demand Capacity Resource (+) [5]	357	363
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	821	821
Non Commercial Capacity (+)	293	293
Non Gas-fired Planned Outage MW (-)	3,110	3,829
Gas Generator Outages MW (-)	930	950
Allowance for Unplanned Outages (-) [4]	2,100	2,100
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	21,298	22,238
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	21,167	21,167
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,292	23,292
Operable Capacity Margin	-1,994	-1,054

[1]Operable Capacity is based on data as of **August 29, 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 **August 29, 2025.**

[2] Load forecast that is based on the 2025 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **September 20, 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	Sep - 2025[2] CSO (MW)	Sep - 2025[2] SCC (MW)
Operable Capacity MW [1]	25,967	27,640
Active Demand Capacity Resource (+) [5]	357	363
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	821	821
Non Commercial Capacity (+)	293	293
Non Gas-fired Planned Outage MW (-)	3,110	3,829
Gas Generator Outages MW (-)	930	950
Allowance for Unplanned Outages (-) [4]	2,100	2,100
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	21,298	22,238
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	22,091	22,091
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	24,216	24,216
Operable Capacity Margin	-2,918	-1,978

[1]Operable Capacity is based on data as of **August 29, 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 **August 29, 2025.**

[2] Load forecast that is based on the 2025 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **September 20, 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

August 29, 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 September through November.

Report created: 8/29/2025

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 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
9/20/2025	25967	357	821	293	3110	930	2100	0	21298	21167	2125	23292	-1994	Y	Fall 2025
9/27/2025	25967	357	821	293	3409	1532	2100	0	20397	16018	2125	18143	2254	N	Fall 2025
10/4/2025	26737	354	893	147	3564	3693	2800	0	18074	16051	2125	18176	-102	N	Fall 2025
10/11/2025	26737	354	893	147	3173	3471	2800	0	18687	16898	2125	19023	-336	N	Fall 2025
10/18/2025	26737	354	893	147	2767	3474	2800	0	19090	17232	2125	19357	-267	N	Fall 2025
10/25/2025	26737	354	893	147	1596	3660	2800	0	20075	17422	2125	19547	528	N	Fall 2025
11/1/2025	26233	404	1235	568	1585	2205	3600	0	21050	17528	2125	19653	1397	N	Fall 2025
11/8/2025	26233	404	1235	568	1085	1997	3600	0	21758	17843	2125	19968	1790	N	Fall 2025
11/15/2025	26233	404	1235	568	623	1773	3600	0	22444	18520	2125	20645	1799	N	Fall 2025
11/22/2025	26233	404	1235	568	79	1535	3600	0	23226	19180	2125	21305	1921	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

August 29, 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 September through November.

Report created: 8/29/2025

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
9/20/2025	25967	357	821	293	3110	930	2100	0	21298	22091	2125	24216	-2918	Y	Fall 2025
9/27/2025	25967	357	821	293	3409	1532	2100	0	20397	16863	2125	18988	1409	N	Fall 2025
10/4/2025	26737	354	893	147	3564	3693	2800	0	18074	16897	2125	19022	-948	N	Fall 2025
10/11/2025	26737	354	893	147	3173	3471	2800	0	18687	17789	2125	19914	-1227	N	Fall 2025
10/18/2025	26737	354	893	147	2767	3474	2800	0	19090	18141	2125	20266	-1176	N	Fall 2025
10/25/2025	26737	354	893	147	1596	3660	2800	0	20075	18341	2125	20466	-391	N	Fall 2025
11/1/2025	26233	404	1235	568	1585	2205	3600	0	21050	18452	2125	20577	473	N	Fall 2025
11/8/2025	26233	404	1235	568	1085	1997	3600	0	21758	18784	2125	20909	849	N	Fall 2025
11/15/2025	26233	404	1235	568	623	1773	3600	0	22444	19496	2125	21621	823	N	Fall 2025
11/22/2025	26233	404	1235	568	79	1535	3600	1041	22185	20191	2125	22316	-131	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

Preliminary Winter 2025/26 Analysis

Preliminary Winter 2025/26 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Sept - 2025[2] CSO (MW)	Sept - 2025[2] SCC (MW)
Operable Capacity MW [1]	26,390	30,001
Active Demand Capacity Resource (+) [5]	403	309
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 (-)	40	766
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	3,583	3,969
Net Capacity (NET OPCAP SUPPLY MW)	22,173	24,578
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,371	20,371
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,496	22,496
Operable Capacity Margin	-323	2,082

[1] Operable Capacity is based on data as of **August 29, 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 **August 29, 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.

Preliminary Winter 2025/26 Operable Capacity Analysis

90/10 Load Forecast	Sept - 2025[2] CSO (MW)	Sept - 2025[2] SCC (MW)
Operable Capacity MW [1]	26,390	30,001
Active Demand Capacity Resource (+) [5]	403	309
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 (-)	40	766
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	4,331	4,828
Net Capacity (NET OPCAP SUPPLY MW)	21,425	23,719
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	21,446	21,446
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,571	23,571
Operable Capacity Margin	-2,146	148

[1] Operable Capacity is based on data as of **August 29, 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 **August 29, 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.

Preliminary Winter 2025/26 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

August 29, 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.

Report created: 8/29/2025

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 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	26390	403	1235	568	52	920	3200	695	23729	19363	2125	21488	2241	N	Winter 2025/2026
12/6/2025	26390	403	1235	568	65	275	3200	2093	22963	19628	2125	21753	1210	N	Winter 2025/2026
12/13/2025	26390	403	1235	568	47	0	3200	2745	22604	19638	2125	21763	841	N	Winter 2025/2026
12/20/2025	26390	403	1235	568	37	0	3200	3134	22225	19695	2125	21820	405	N	Winter 2025/2026
12/27/2025	26390	403	1235	568	37	0	3200	3733	21626	19695	2125	21820	-194	N	Winter 2025/2026
1/3/2026	26390	403	1235	568	35	0	2800	3728	22033	19946	2125	22071	-38	N	Winter 2025/2026
1/10/2026	26390	403	1235	568	40	0	2800	3583	22173	20371	2125	22496	-323	Y	Winter 2025/2026
1/17/2026	26390	403	1235	568	39	0	2800	3134	22623	20371	2125	22496	127	N	Winter 2025/2026
1/24/2026	26390	403	1235	568	28	0	2800	2835	22933	20371	2125	22496	437	N	Winter 2025/2026
1/31/2026	26390	403	1235	568	3	0	3100	2536	22957	20168	2125	22293	664	N	Winter 2025/2026
2/7/2026	26390	403	1235	568	3	0	3100	2237	23256	19923	2125	22048	1208	N	Winter 2025/2026
2/14/2026	26390	403	1235	568	3	0	3100	1788	23705	19897	2125	22022	1683	N	Winter 2025/2026
2/21/2026	26390	403	1235	568	35	0	3100	1489	23972	19656	2125	21781	2191	N	Winter 2025/2026
2/28/2026	26390	403	1235	568	134	334	2200	80	25848	18752	2125	20877	4971	N	Winter 2025/2026
3/7/2026	26390	403	1235	568	134	579	2200	0	25683	18432	2125	20557	5126	N	Winter 2025/2026
3/14/2026	26390	403	1235	568	74	1024	2200	0	25298	18253	2125	20378	4920	N	Winter 2025/2026
3/21/2026	26390	403	1235	568	105	760	2200	0	25531	17919	2125	20044	5487	N	Winter 2025/2026
3/28/2026	26233	404	1235	568	131	334	2700	0	25275	17401	2125	19526	5749	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.

Preliminary Winter 2025/26 Operable Capacity Analysis 90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

August 29, 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: 8/29/2025

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	26390	403	1235	568	52	920	3200	1872	22552	20384	2125	22509	43	N	Winter 2025/2026
12/6/2025	26390	403	1235	568	65	275	3200	3080	21976	20663	2125	22788	-812	N	Winter 2025/2026
12/13/2025	26390	403	1235	568	47	0	3200	3864	21485	20674	2125	22799	-1314	N	Winter 2025/2026
12/20/2025	26390	403	1235	568	37	0	3200	4280	21079	20734	2125	22859	-1780	N	Winter 2025/2026
12/27/2025	26390	403	1235	568	37	0	3200	4408	20951	20734	2125	22859	-1908	N	Winter 2025/2026
1/3/2026	26390	403	1235	568	35	0	2800	4539	21222	20998	2125	23123	-1901	N	Winter 2025/2026
1/10/2026	26390	403	1235	568	40	0	2800	4331	21425	21446	2125	23571	-2146	Y	Winter 2025/2026
1/17/2026	26390	403	1235	568	39	0	2800	4032	21725	21446	2125	23571	-1846	N	Winter 2025/2026
1/24/2026	26390	403	1235	568	28	0	2800	4032	21736	21446	2125	23571	-1835	N	Winter 2025/2026
1/31/2026	26390	403	1235	568	3	0	3100	3583	21910	21231	2125	23356	-1446	N	Winter 2025/2026
2/7/2026	26390	403	1235	568	3	0	3100	3284	22209	20974	2125	23099	-890	N	Winter 2025/2026
2/14/2026	26390	403	1235	568	3	0	3100	2686	22807	20946	2125	23071	-264	N	Winter 2025/2026
2/21/2026	26390	403	1235	568	35	0	3100	2237	23224	20693	2125	22818	406	N	Winter 2025/2026
2/28/2026	26390	403	1235	568	134	334	2200	977	24951	19741	2125	21866	3085	N	Winter 2025/2026
3/7/2026	26390	403	1235	568	133	334	2200	872	25057	19404	2125	21529	3528	N	Winter 2025/2026
3/14/2026	26390	403	1235	568	74	1024	2200	0	25298	19216	2125	21341	3957	N	Winter 2025/2026
3/21/2026	26390	403	1235	568	105	760	2200	0	25531	18864	2125	20989	4542	N	Winter 2025/2026
3/28/2026	26233	404	1235	568	131	334	2700	0	25275	18319	2125	20444	4831	N	Winter 2025/2026

Column Definitions

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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

4.b COO Report – Asset Condition Reviewer Project Update

Sep 4, 2025
Meeting

NEPOOL
NEW ENGLAND POWER POOL
Participants Committee

Asset Condition Reviewer Update

Interim Review Cycle & Development of Framework for Asset Condition Reviewer

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

ISO Is Developing a New Function to Provide Oversight of Asset Condition Projects

Includes Asset Condition Reviewer Role and Interim Review Cycle

- The purpose of this presentation is to provide updates on the Asset Condition Reviewer role, the interim review cycle, and opportunities for stakeholder engagement
- States and stakeholders have requested that the ISO take on this role
- The ISO has retained ECI (Electrical Consultants, Inc.) to help develop a framework for a new Asset Condition Reviewer role
  - The ISO may retain additional consultants, as needed
- ECI will also review selected asset condition projects in the interim review cycle, through the end of 2026
  - More information begins on slide 6 regarding the interim review cycle, which is distinct from the development of the more permanent framework

ISO Requirements for Consideration of an Asset Condition Reviewer Role – A Brief Recap

- As background, in May 2025, the ISO issued a memo* to provide a status update on its consideration of the ISO taking on a new role relative to review of transmission owners' (TOs) asset condition projects
- In the memo, ISO identified the following as threshold requirements to consider taking on this new Asset Condition Reviewer role:
  - The transmission owners will indemnify ISO-NE for any liability related to the ISO's reviewer role on asset condition projects, except for ISO-NE's gross negligence or willful misconduct;
  - The "Asset Condition Reviewer" role is advisory. It will not make decisions about whether to proceed with specific asset condition projects, nor will it be the petitioning party in any local, state or federal regulatory or siting proceeding concerning an asset condition project; and
  - The "Asset Condition Reviewer" will not make a legal finding on or issue an opinion on the question of whether the costs of any given asset condition project are prudent.
- The TOs and states indicated support for these threshold matters, and therefore, the ISO agreed to work on developing a framework for the ISO to take on the Asset Condition Reviewer role

**Update on Asset Condition Project Process* memo (May 15, 2025): https://www.iso-ne.com/static-assets/documents/100023/iso_memo_acr_5_15_2025.pdf

Asset Condition Reviewer Role: Overview

- Development of a framework to establish a new role for the ISO is a novel undertaking in the industry and will require time, resources, and stakeholder engagement
  - The ISO has prioritized this as a key project for the remainder of 2025 and 2026
- Under this new structure, New England TOs would continue to plan, develop, and own transmission facilities for asset conditions in their service territory
  - The ISO does not currently propose, fund, or select these projects, and this would not change under this proposal
- The new function is envisioned to provide an independent review and opinion of asset condition projects submitted for review by the TOs
  - The review is intended to help better inform states and stakeholders, including Planning Advisory Committee (PAC) attendees

Funding for Next Steps

- The 2026 budget request includes $1M of “placeholder” funding for Asset Condition Review work that will be used for efforts related to asset condition review
  - The 2026 budget is currently working through a stakeholder review process, after which it will need approval by the independent ISO Board of Directors and the Federal Energy Regulatory Commission (FERC)
  - The 2026 budget request of $1M is to largely fund the review of asset condition projects in the interim phase
  - ISO will confirm the costs associated with a permanent Asset Condition Reviewer role after the scope of the function is finalized, following discussions with stakeholders
- The ISO Consultant, ECI, will both review projects through an interim review cycle and help establish a more permanent process for the Asset Condition Reviewer role

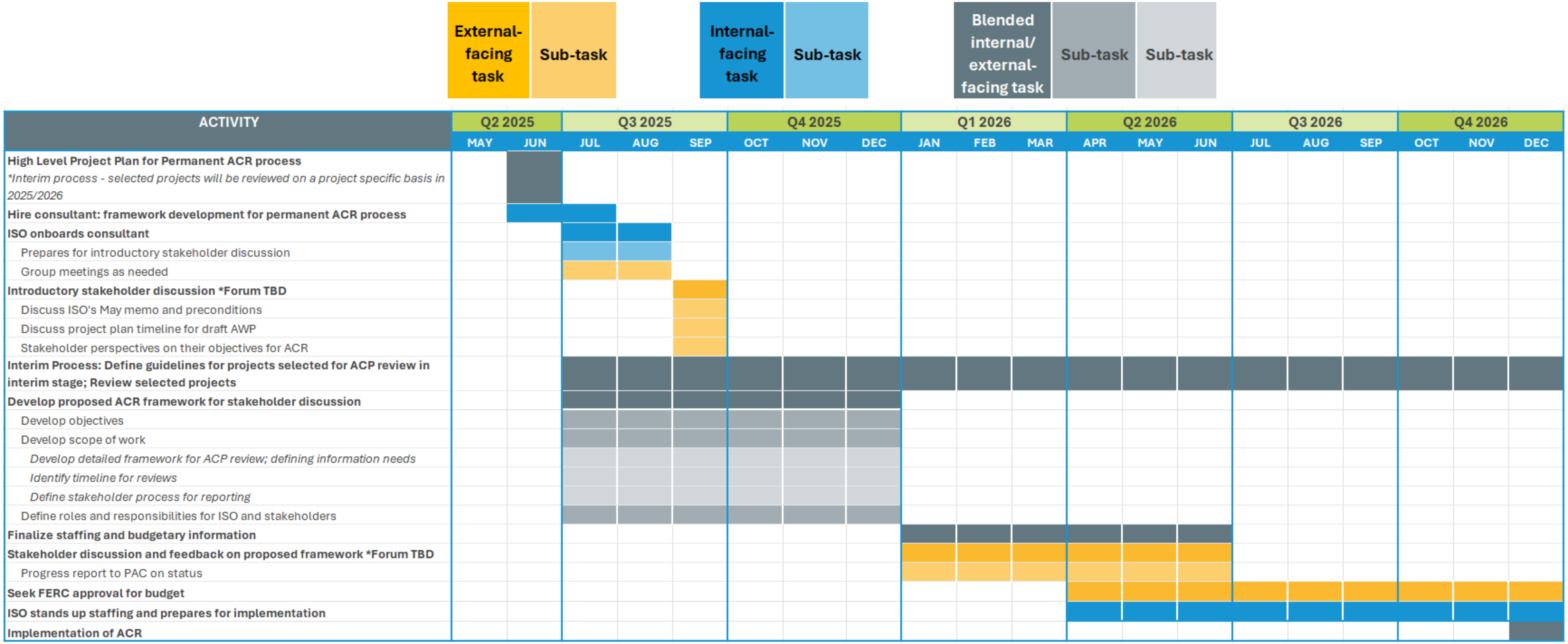
Interim Review Cycle: Outline

- The ISO and ECI will work together to develop and implement an interim review cycle
  - This will allow for project reviews to begin quickly in the near term, while work is completed to develop a more permanent framework for the Asset Condition Reviewer role at the ISO
  - The interim review cycle will help inform the development of the more permanent process
- Reviews will be conducted by ECI for a selected set of asset condition projects through 2026

Interim Review Cycle: Timeline

- At the October PAC meeting, the ISO will provide a list of recommended interim projects for review by ECI and discuss updates on how the interim reviews will proceed
- The interim review cycle will then begin as the TOs bring those selected projects forward to present and discuss at the PAC
- ISO, with the assistance of ECI, will discuss their project review findings at PAC

Asset Condition Reviewer High Level Project Plan



Development of Framework for Asset Condition Reviewer Role

- While the interim review cycle is underway, the ISO will work with ECI and stakeholders to develop a permanent framework for the Asset Condition Reviewer role at the ISO
- The ISO expects stakeholder discussions on the permanent framework to take place during Q1 and Q2 of 2026
- To begin, the ISO has put together a high-level summary of the key themes of stakeholder feedback received to date, provided on the following two slides
  - Feedback directed to the ISO is available on the Asset Condition Reviewer Key Project webpage on the ISO website

Review of Stakeholder Feedback

Stakeholder feedback has been organized into themes which are in blue below

- To ensure efficient and cost-effective investment in the region's transmission system, some stakeholders request the timeline to implement asset condition project reviews reflect the **urgency of the need**
  - While implementing changes in a timely manner, many stakeholders ask that the Asset Condition Reviewer framework be developed through an open stakeholder process with opportunities for feedback to **improve stakeholder involvement, understanding, and confidence**
- Regarding **role description**, many stakeholders assert that the Asset Condition Reviewer role should be independent and impartial, provide technical expertise, and serve in an advisory role, allowing for the TOs to retain ultimate decision-making authority
- In terms of **role governance**, certain stakeholders propose the Asset Condition Reviewer report directly to the ISO Board

Review of Stakeholder Feedback, continued

Stakeholder feedback has been organized into themes which are in blue below

- Several stakeholders call for **review process criteria** that is clear, objective, and transparent, and the establishment of clearly defined best practices to aid in project review
  - To ensure a clear process for review and feedback, multiple stakeholders note the need for project reviews to begin early in the project development timeline
  - A structured process could include notice sent to the states and stakeholders when a review process begins, clear timeline of TO submissions and presentations to PAC, and expectations for how TOs will address feedback
- Some stakeholders request **actionable, cost-focused review outputs** that may include examination of alternative options to ensure selected project proposals are reasonable and appropriate, and transparently assess project costs and cost changes
  - In addition to individual project reviews, there is also suggestion for regular analysis of aggregate asset condition project cost trends over time
- To maximize the benefit of transmission investment, many stakeholders request that asset condition project reviews should fit into more **holistic transmission planning**

Interim and Permanent Review Process: Feedback Opportunities

At the October PAC meeting, there will be opportunity to provide additional feedback on:

- The scope of the interim review cycle, and
- ISO's recommended list of projects for interim review

- This meeting also serves as a forum for feedback on the objectives of the permanent Asset Condition Reviewer role, interim review cycle, and feedback that falls within these categories:
  - Urgency and timeliness of reform
  - Role description (independent and impartial, technical expertise, advisory)
  - Governance
  - Review process criteria
  - Stakeholder engagement
  - Holistic systems planning
  - Other considerations

- Note that written feedback may be provided to pacmatters@iso-ne.com

Next Steps

- At the October PAC meeting, the ISO will provide a list of recommended asset condition projects for the interim review cycle and discuss updates on how the interim reviews, performed by ECI, will proceed
  - Feedback can be provided through PAC
- The interim review cycle will begin as the TOs bring the projects selected for the interim review cycle forward to present and discuss at PAC
- Based, in part, on lessons learned from the interim reviews and stakeholder feedback, the ISO will begin discussion of a framework for the Asset Condition Reviewer role with stakeholders in Q1 and Q2 of 2026

5.a 2026 ISO-NE Budget

Sep 4, 2025
Meeting

NEPOOL
NEW ENGLAND POWER POOL
Participants Committee

ISO new england

memo

To: NEPOOL Participants Committee Members and Alternates

From: Robert C. Ludlow, VP & CF/CO and Kelly Reyngold, Director, Accounting

Date: September 4, 2025

Subject: ISO New England Inc. 2026 Operating and Capital Budgets

Budget Process

This memo provides an update to the NEPOOL Participants Committee ("NPC") on the 2026 budget process. At its August 8, 2025 meeting, the NEPOOL Budget & Finance Subcommittee ("B&F") reviewed the ISO's proposed 2026 operating and capital budgets (collectively, the "Budgets"). Included with this memorandum is a presentation of the Budgets. The more detailed presentation provided to B&F can be found on the ISO's website at 6_isone_2026_proposed_op_cap_budget.pdf (iso-ne.com).

At the August B&F meeting, participants asked questions, and we responded as noted, on the following:

- Changes in the 2026 budget from what we had projected for 2026 during the 2025 budget process
  - We noted that for 2026 we included fewer FTE requests and technology cost increases were less than expected, compared to what we had projected for 2026 during the 2025 budget process
- How long-term study results drive near-term work
  - We noted that ISO-NE has conducted various length transmission studies, including 2040 (Future Grid Reliability Study) and more recently a 2050 Transmission Study and continues to ensure that the power system is operating reliably as conditions on the grid change
- Clarification on 2026 positions for Participant Relations & Services
  - We provided a follow-up response via email on this to B&F Subcommittee members that is noted in footnote [1]

[1] *The budget request for 2 FTEs in Participant Support covers a project manager with a primary focus on CAR (current and future phases) within the Project Services group. CAR is a multifunctional project that PRS is involved in along with market development, planning, IT, finance, etc. The budget also covers participant readiness needs via analyst and instructional designer positions within the Participant Training Services and NEPOOL Relations groups. These responsibilities focus on the development and implementation of participant sessions, forums, and meetings with ISO on FERC-mandated projects such as Order 2023 and Order 2222, as well as myriad new trainings and webinars needed for the upcoming implementation of CAR and other new projects stemming from the ISO's work plan. Overall, the PRS department is responsible for managing and preparing the workflows within each stage of the external lifecycle of ISO corporate initiatives, which impact nearly all departments of the organization, including market development, planning, and system and market operations.*

- Information regarding 2025 and 2026 funding for Asset Condition Reviewer work
  - We responded that there is interim 2025 funding of approximately $300,000 for this and a placeholder of $1 million in 2026 as we develop a new framework for conducting independent reviews of asset condition projects
- Impacts on executive compensation and the 2026 budget for changes in officer positions due to upcoming retirements
  - We responded that adjustments were not reflected in the 2026 budget since greater organizational staffing changes impacting 2026 are not fully known at this time

The ISO has also presented the Budgets to the New England state agencies; following that presentation we received questions from multiple state agencies. The ISO responded to state agencies' questions and those responses are posted under the budget section on the ISO's website at Budget (iso-ne.com).

The Participants Committee will be asked to vote on the proposed budgets at the October 9, 2025 meeting. During the week of September 22, 2025, we will distribute a memo with the projected 2026 Revenue Requirement by ISO-NE Administrative Cost Tariff Schedule, including the draft 2026 rate components.

Proposed 2026 Budgets

The 2026 Budgets represent the organization's commitment to supporting the region as it continues to experience an evolving resource mix and changing customer use patterns while ensuring that markets and grid operations are efficient and reliable. The budget request represents continued progress on the stakeholder-supported workplan as the ISO operationalizes initiatives undertaken over the past several years. To ensure a successful grid transition, the ISO must focus on the near-term and what it must do to strengthen reliability today while supporting New England over a longer-term grid transition.

The 2026 operating budget increase includes funding for many market and energy adequacy initiatives; implementation of FERC orders; cloud modernization initiatives; and forecasting/modeling improvements that become operational and require ongoing support. Budget drivers include salaries for FTE additions necessary for servicing the workplan; merit and promotion increases to remain competitive in what is still a tight labor market for the unique, in-demand skill sets needed at the ISO; and computer services, including support costs for capital projects that have gone into operation - much of these support costs are driven by third party vendor cost increases.

The 2026 operating budget year-over-year increase before depreciation and regulatory fees is $21.6 million or 8.3%; the increase, including depreciation is $23.6 million or 7.7%. The 2026 Revenue Requirement, taking into account the 2024 true-up, is an increase of $3.1 million or 1.0% over 2025.

The net overall change from the preliminary (top-down) operating budget is a decrease of approximately $0.9 million. Changes include decreases for changes in Salary and Overhead estimates with savings related to lower new hire salaries, lower incentive compensation, and other small $ estimate refinements with some offset as a result a lower budgeted vacancy rate for 2026; and lower Depreciation Expense due to changes in planned capital projects and/or $ amounts and estimated completion date. Partially offsetting increases were made for Professional and Legal Services including funding for research

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and implementation of enhanced workforce security best practices, Capacity Auction Reforms support, Transmission Planning work, and external regulatory counsel fees.

The 2026 capital budget is $42.5 million which is consistent with the 2025 capital budget and the preliminary 2026 capital budget presented in June. While the 2026 capital budget is consistent with the 2025 budget capital budget, the capital budget is expected to increase in future years. Additionally, the ISO is considering additional building space as discussed with this committee during the 2026 preliminary budget presentation in June.

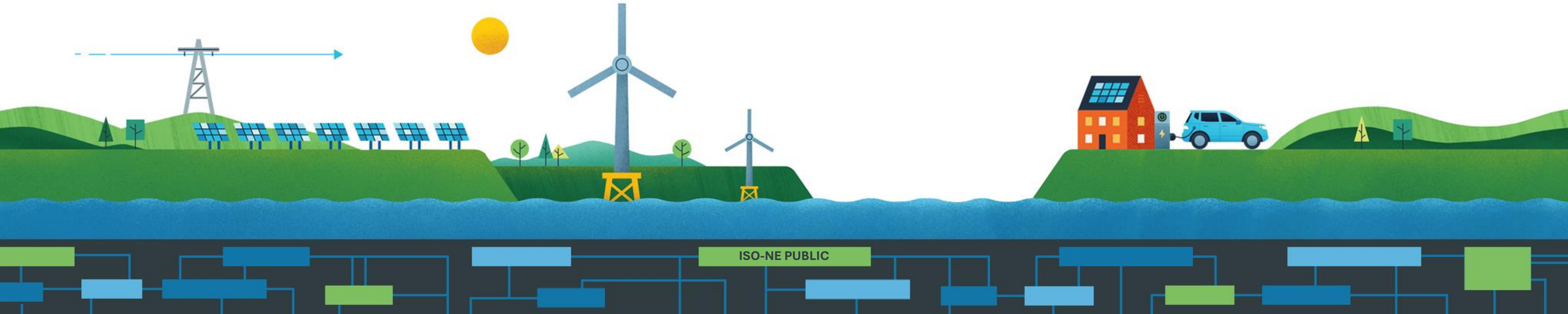
We will be available during the meeting for any questions regarding the 2026 Budgets. Please also feel free to reach out to us after today with any additional comments or questions regarding the 2026 Budgets.

ISO New England Proposed 2026 Operating and Capital Budgets

NEPOOL Participants Committee Meeting

Robert Ludlow
CHIEF FINANCIAL OFFICER

Kelly Reyngold
DIRECTOR, ACCOUNTING



Contents of Presentation

The Presentation Includes:

Contents of Presentation *(cont.)*

The following appendices are also included for reference:

- Appendix 1: Compensation
- Appendix 2: 2026 Operating Budget Risks
- Appendix 3: 2024 Deliverables and Select Metrics
- Appendix 4: Cyber Security and CIP Compliance History and Costs
- Appendix 5: ISO/RTO Financial Comparison

EXECUTIVE SUMMARY

Introduction

- The budget for 2026 represents the ISO's commitment to supporting the region as it continues to experience an evolving resource mix and changing customer use patterns; ensuring that markets and grid operations are efficient and reliable
- The budget request represents continued progress on the stakeholder-supported workplan as the ISO operationalizes initiatives undertaken over the past several years
- To ensure a successful grid transition, the ISO must focus on the near-term and what it must do to strengthen reliability today while supporting New England over a longer-term grid transition

2026 Budget Inputs and 2040 Scenario Outlook

- The 2026 ISO-NE budget implements the stakeholder-supported workplan, including items that were previously in development such as, market and energy adequacy initiatives; implementation of cloud modernization initiatives; forecasting/modeling improvements; and FERC directives that are moving from development to becoming operational
- Our review of the long-term/2040 Scenario also supports the near-term workplan and budget
  - Electrification will continue, as well as the decarbonization of the energy sector
  - States are progressing to achieve interim 2030 economy-wide emissions reductions
  - Developments support substantial decarbonization of electric sector by 2040
- Increasing grid complexity, proliferation of behind-the-meter solar (BTMPV) and new grid technologies drive need for progressive market products, enhanced forecasting and IT capabilities

Executive Summary

- The 2026 budget also contains funding for operational costs associated with:
  - Attracting and retaining our highly skilled workforce with competitive salaries and benefits:
    - In recent years detailed compensation review work was completed and targeted increases were made to ensure our salaries were competitive, especially in the areas of System Planning engineers, Market Development economists and analysts, and Information Technology staff
    - We want to remain competitive and continue to develop and retain our existing staff understanding the costs and lost productivity of high turnover
  - Information technology, including staffing and computer service costs for maintenance and support related to the operationalization of market, transmission, and emerging technology initiatives; Information Technology costs include those associated with:
    - Cloud Infrastructure and Data Management costs
    - Software Licensing and Subscription Fees
    - Inflation, Supply Chain Disruptions, and Tariffs
    - Modernization of Legacy Systems and Natural Hardware Refresh Cycles
    - Governance and Compliance Requirements
- The 2026 budget includes “placeholder” funding for Asset Condition Review work that will only be used for this purpose, and if not needed will not be reallocated for use elsewhere

Executive Summary *(cont.)*

- For the 2026 budget, ISO is proposing adding 25 FTEs[(1)] driven by:
  - IT support for Information and Cyber Security for Cloud Computing transition including architecture, service delivery, and IT forecasting tool support
  - Information Technology and Advanced Technology for bringing ISO-NE developed advanced technologies into the operating environment to increase our situational awareness capabilities and for migration of applications to the cloud
  - System Planning positions for supporting Long-Term Transmission Planning RFPs, NERC and NPCC requirements for energy assessments and planning, long-term forecasting, power system modeling advancements, and Transmission Planning for increased effort to support system assessments with increased penetration of inverter-based resources
  - Program Management positions as a result of increasing capital project work requiring more highly skilled personnel to manage
  - System Operations engineering support for increasing requirements related to new generation interconnections and Electromagnetic Transient (EMT) studies
  - Other positions providing organizational support including Participant Relations and Services, Legal, and Finance

(1) The Proposed 2026 Budget includes 1 additional FTE, compared to the 2026 Preliminary Budget. Funding for the additional position was offset by reductions included in the 2026 Proposed Budget.

THE STRATEGIC PLANNING PROCESS

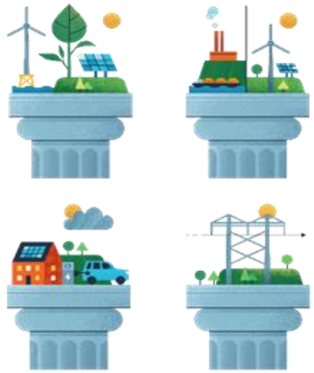
ISO-NE's integrated business and strategic planning framework

Annual Process – Business and Strategic Planning

ISO-NE is guided by a purposeful and integrated business planning approach that drives focus towards a common target that the entire organization can align behind, with the aim of creating value for ISO stakeholders

Our Guidepost: The ISO New England Vision Statement

The ISO-NE Vision Statement is an explicit statement about our intent to support the states' policy goals to achieve a reliable transition to clean energy, utilizing competitive markets and transmission planning



Vision Statement:

To harness the power of competition and advanced technologies to reliably plan and operate the grid as the region transitions to clean energy

The ISO's Vision represents the company's commitment to work with FERC, the states, and market participants to support the region's grid transition within the limits of our jurisdiction

Our Responsibility to the Region: ISO's Mission

The ISO-NE Mission Statement outlines the core role and responsibilities of the ISO's daily operations

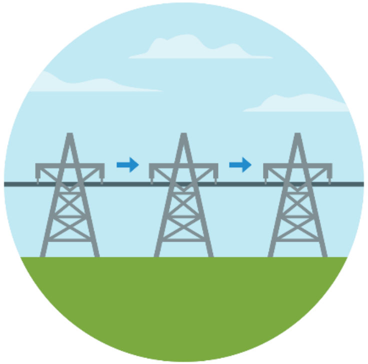
Mission Statement:

Through collaboration and innovation, ISO New England plans the transmission system, administers the region's wholesale markets, and operates the power system to ensure reliable and competitively priced wholesale electricity

Core Functions Within ISO Jurisdiction

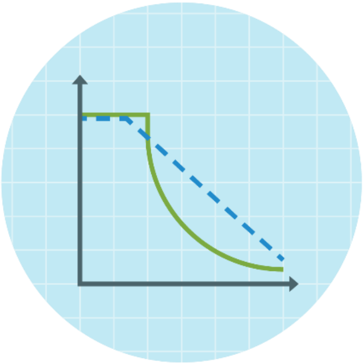
Grid Operation

Coordinate and direct the flow of electricity over the region's high-voltage transmission system



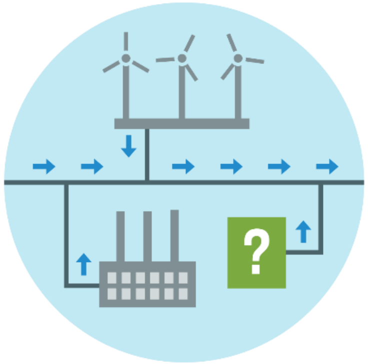
Market Administration

Design, run, and oversee the markets where wholesale electricity is bought and sold



Transmission System Planning

Study, analyze, and plan to ensure the transmission system will be reliable over the next 10 years



Functions Outside of ISO Jurisdiction

The ISO does not...

- Handle retail electricity
- Own power grid infrastructure
- Have a stake in companies that own grid infrastructure
- Have jurisdiction over fuel infrastructure
- Have control over siting decisions
- Plan the resource mix

GRID TRANSITION AND ISO-NE'S BUDGET

The region continues to experience substantial changes on the grid which effect the nature and volume of work for ISO-NE

The 2026 Budget Represents the Ongoing Support of the Stakeholder-Supported Workplan

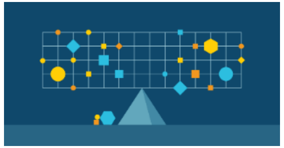
- The operationalizing of market, transmission, and emerging technology initiatives put in place through 2025 and 2026 requires ongoing support through increased headcount to service new tools and the needed technology stack associated with them
- The resource mix and customer use patterns in New England have and will continue to change independent of federal & trade policy, inflation, or permitting restrictions

Overview of ISO-NE Initiatives to Support the Region as the Grid Transitions

- Continue capacity market reforms to better ensure power system reliability and cost-efficiency as New England's resource mix evolves
- Advance long-term transmission planning to support interconnection of new resources and address evolving system needs
- Collaborate with stakeholders to operationalize Regional Energy Shortfall Threshold (REST) and provide multi-year outlook
- Enhance collaboration with NEPOOL, state agencies, and other stakeholders to ensure inclusive and transparent decision-making
- Inform policymakers about the role of retail market designs in mitigating price volatility and promoting resource development
- Invest in advanced technologies and analytics to improve system operations and planning capabilities to improve forecasting and situational awareness around changing resource mix
- Strengthen cybersecurity measures and infrastructure to safeguard grid reliability
- Develop new framework to conduct independent reviews of asset condition projects

Key Trends Informing Our Budget

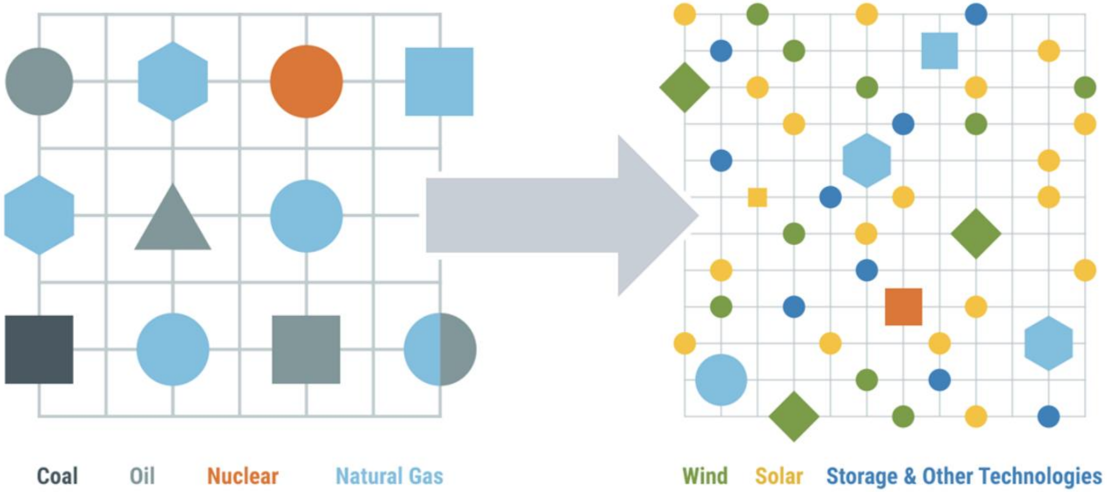
More renewable energy and storage on the New England grid by 2030



Increasing complexity due to electrification and growth of inverter-based resources

New England's seasonal operating risks

Two Dimensions to the New England Energy Transition that Contribute to Increased Grid Complexity by 2040

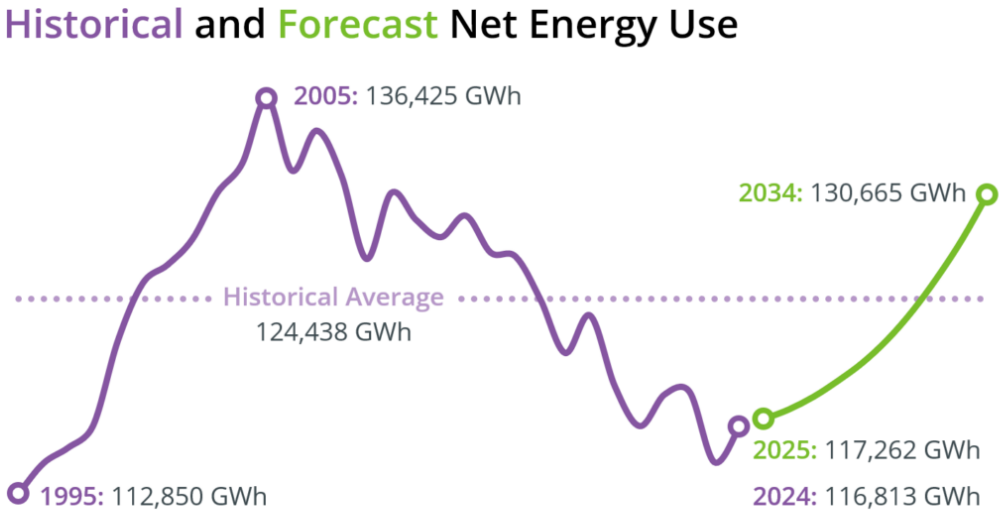


1. A shift from centrally dispatched generation to distributed resources

2. A shift from conventional generation to weather-dependent renewable generation

Increased Electrification is Expected to Drive Steady Growth in Net Annual Energy Use

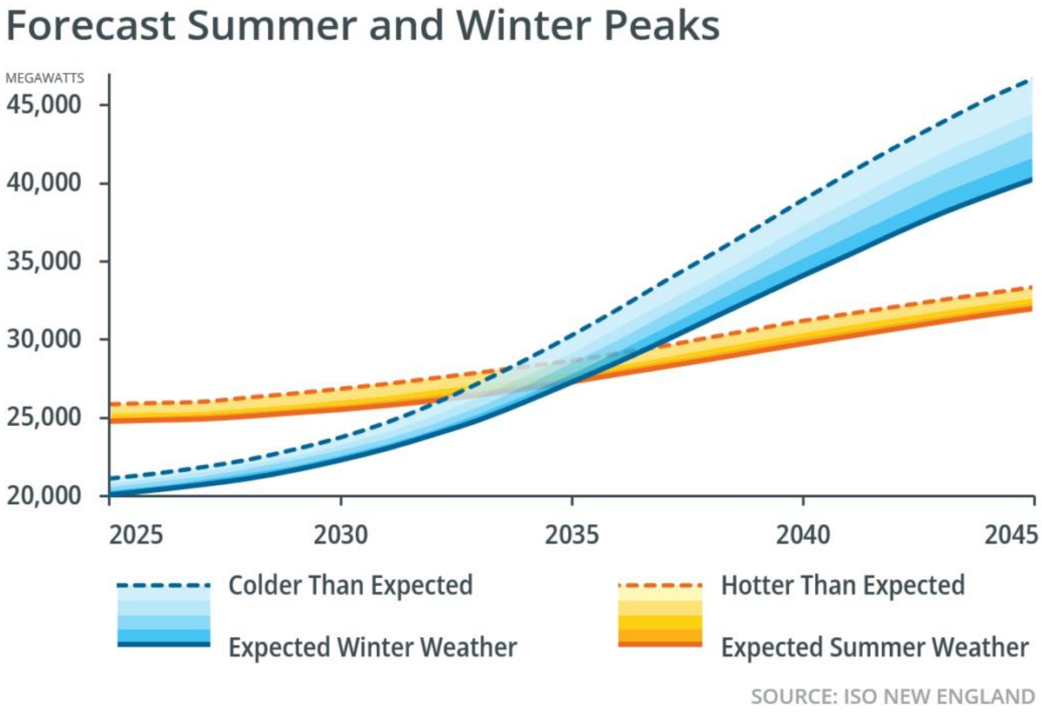
Following two decades of decreased net energy via state policies incentivizing solar PV and energy efficiency



- Net annual energy use in New England grew steadily between 1995 and 2005
- Since 2005, net annual energy use has trended downward mainly due to an increase in energy efficiency
- ISO New England is predicting steady growth in net annual energy use over the next decade

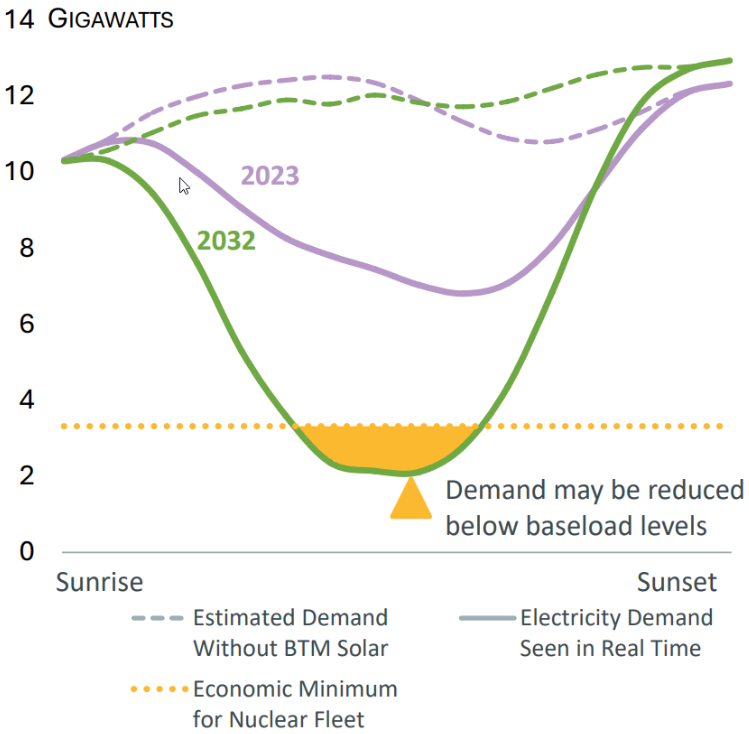
Source: ISO New England 2024-2033 Forecast Report of Capacity, Energy, Loads, and Transmission (2025 CELT Report) (May 2025)

Changes in Timing of Daily Peaks has Necessitated Advanced Modeling Methodologies



- By the mid-2030s, the ISO projects that peak demand will occur during the winter rather than the summer
- The timing of daily peaks is also expected to change coincident to increasing demand
  - Currently, peak demand occurs in the early evening
  - Heating electrification is expected to result in morning peaks during winter
- In the later 2040s, both winter and summer could see peaks around 10 p.m. as overnight electric vehicle charging becomes more of a factor

Small, Distributed Energy Resources Continue to Drive Low-Load Conditions



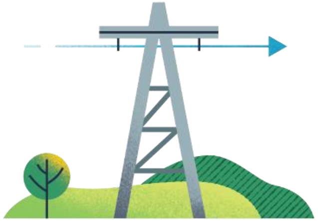
- New England reached a new low daytime load with no disruption to grid operations
- Preliminary data shows that power system demand fell to 5,318 megawatts (MW) on the afternoon of April 20, 2025
  - It was the fourth year in a row the grid set a record low
  - More than 1,200 MW lower than the previous record of 6,596 MW set in April 2024
- Demand reached a daily peak of ~11,800 MW as solar production waned
- Other resources including natural-gas-fired generators, wind, and hydroelectric facilities supplied more electricity to the grid to meet the evening peak

SUPPORTING THE FOUR PILLARS

ISO Initiatives to bolster the four pillars

Four Pillars of Supporting a Successful Energy Transition

When the ISO looks toward the future, these are the objectives the ISO, states, market participants, and regulators need to advance in order to support the grid transition



1

Significant amounts of clean energy to power the economy with a greener grid in line with States' policy objectives

2

Balancing resources that keep electricity supply and demand in equilibrium

3

Energy adequacy a dependable energy supply chain and/or a robust energy reserve to manage through extended periods of severe weather or energy supply constraints

4

Robust transmission to integrate renewable resources and move clean electricity to consumers across New England

Clean Energy Pillar – ISO Initiatives

ISO activities to support clean energy pillar include initiatives across our strategic goals and Implementing FERC Orders

2025

- ISO identifies points of interconnection in NE that can accommodate up to 9600MW of offshore wind without significant upgrades
- Implementing Order 2023 to streamline interconnection queue
- Integrating electromagnetic transient (EMT) tools into operational analyses to better account for storage, solar & wind facilities
- Designing Capacity Auction Reforms (CAR) to appropriately compensate resources for capacity available to address reliability (implementation 2028)
- Order 841 implementation

2026

- Explore enhancing probabilistic forecasting to improve evaluating BTMPV, along with other weather dependent resources
- Implement FERC Order 2222 to promote participation of aggregated distributed resources in wholesale electric markets
- Complete Transitional Cluster Study, per Order 2023

Balancing Resources Pillar – ISO Initiatives

ISO is supporting the balancing resources pillar through innovative market design work

2025

- Implement Day-Ahead Ancillary Services Initiative (DASI) to create pricing incentives for specific energy and reserve capabilities needed for reliability as regional supply and demand transform
- Designing Capacity Auction Reforms (CAR) to appropriately compensate resources for capacity available to address reliability (implementation 2028)
- Complete prompt and deactivation design for CAR – Including final tariff review and vote
- CAR Seasonal/Accreditation
  - Key directional design decisions
  - Potentially preview early design concepts
  - Begin conceptual/detailed design
- Begin CAR directional qualitative impact analyses

2026

- Implement FERC Order 2222 to promote demand response participation in wholesale electricity markets; continue to support operating reserves
- CAR Impact Analysis: Publish estimate of regional cost impacts and revenue effects by resource class
- Complete design of Seasonal Accreditation

Energy Adequacy Pillar – ISO Initiatives

ISO is supporting the energy adequacy pillar through innovative operational and planning analyses, stakeholder outreach as well as exploring potential market design improvements

2025

- Defining an acceptable REST with stakeholders
- Designing Capacity Auction Reforms (CAR) to appropriately compensate resources for capacity available to address reliability (implementation 2028)
- Implementing DASI and begin assessing further market reforms to support flexible reserves for those resources that can respond to operational uncertainty and higher ramp rates
- Evaluate Potential Tie Benefits Winter Modeling Improvements
  - Report to stakeholders in Q3/Q4 2025, in alignment with CAR stakeholder schedule on seasonal tie benefits

2026

- Complete conceptual and detailed design of CAR – Seasonal/Accreditation
  - Tariff review and vote
- Begin discussions on a specific proposal for Flexible Response Services
  - Qualitative and quantitative impact analysis information
- Explore using Probabilistic Energy Adequacy Tool (PEAT) analyses to support outage coordination management

Transmission Pillar – ISO Initiatives

The ISO has completed work on the 2050 Transmission Study, outlining the needs and considerations for the region and is continuing to work with stakeholders regarding transmission.

2025

- ISO identifies points of interconnection in NE that can accommodate up to 9600MW of OSW without significant upgrades
- First Competitive Solicitation for Longer-Term Transmission Planning (LTTP) Solution
  - Administer RFP for transmission to integrate Northern Maine
- Transmission Sizing for the Energy Transition
  - Discussions to establish “right-sizing” guidelines are expected to begin after the states and Transmission Owners complete their asset condition process improvements initiative
  - **ISO considering “Asset Condition Reviewer” Role that could inform the "right-sizing" discussion**

2026

- **TBD:** Supporting states and transmission owners on how to handle asset condition list projects
- Longer-Term Transmission Planning Phase 3
  - Stakeholder discussions are targeted to begin after Order 1920 filing, and a “lessons-learned” assessment of completing the First Competitive Solicitation for LTTP Solution
- Further Inclusion of Grid Enhancing Technologies (GETs) Into Transmission Planning
- Implement Order 881 for managing transmission line ratings

2026 BUDGET OVERVIEW

Drivers of 2026 Budget Increases

- In 2026, many market and energy adequacy initiatives; FERC orders; cloud modernization initiatives; and forecasting/modeling improvements become operational and require ongoing support
- **Driver:** Salaries for FTE additions necessary for servicing the workplan
- **Driver:** Merit and promotion increases to remain competitive in what is still a tight labor market for the unique, in-demand skill sets needed at the ISO
- **Driver:** Computer services, including support costs for capital projects that have gone into operation; much of these support costs are driven by third party vendor cost increases
- There will continue to be emergent needs associated with the changing resource mix that will require ISO resources to address FERC Orders, increasing system complexity, new markets and technologies

2026 Budget Overview

- The 2026 Proposed Budget reflects the resources needed to support the region as it continues to experience an evolving resource mix and customer use patterns, to continue progress on the stakeholder supported workplan, and to continue to attract and retain our highly skilled workforce to carry out this important work
- The net revenue requirement with prior year true-ups is an increase of $3.1M or 1.0% year-over-year
  - The proposed 2026 revenue requirement, before true-up is $330.0M, an increase of 7.7% over 2025
    - Included in the above amounts is a $1M "placeholder" funding for Asset Condition Review work that will only be used for this purpose, and if not needed will not be reallocated for other uses

Note: Throughout the presentation some schedules may appear inconsistent due to rounding.

2026 Budget Overview *(cont.)*

Changes Compared to Preliminary (Top-Down) Budget presented in June

- The proposed 2026 budget presented today is the bottom-up detailed budget (prepared with input from each ISO business unit and refinements to preliminary estimates), compared to the top-down budget presented in June (that included preliminary estimates); the detailed bottom-up budget resulted in a $0.9 million decrease compared to the preliminary top-down version:
  - Decreases included changes in Salary and Overhead estimates with savings related to lower new hire salaries, lower incentive compensation, and other small $ estimate refinements with some offset as a result a lower budgeted vacancy rate for 2026; and lower Depreciation Expense due to changes in planned capital projects and/or $ amounts and estimated completion date
  - Increases were largely for Professional and Legal Services including funding for research and implementation of enhanced workforce security best practices, Capacity Auction Reforms support, Transmission Planning work, and external regulatory counsel fees

Resources to Manage the Changing Resource Mix and Continue to meet Operational Needs for 2026

There are two main factors, in addition to the change for the revenue requirement true-up, impacting the 2026 ISO budget and revenue requirement.

1. Adding resources to directly address work related to the changing resource mix/customer use patterns and for other support areas
   - Includes additional investment for Capacity Auction Reforms, maintenance and support of new market features and applications, and information technology (IT) investment to address cybersecurity, and the transition to cloud-based infrastructure
2. Attracting and retaining staff and other operational increases:
   - Attracting and retaining our highly-skilled workforce with competitive salaries and benefits
   - On-going support for servicing new tools and the needed technology stack, for IT infrastructure and licensing, and inflationary and various other costs
3. Net change in the annual revenue true-up

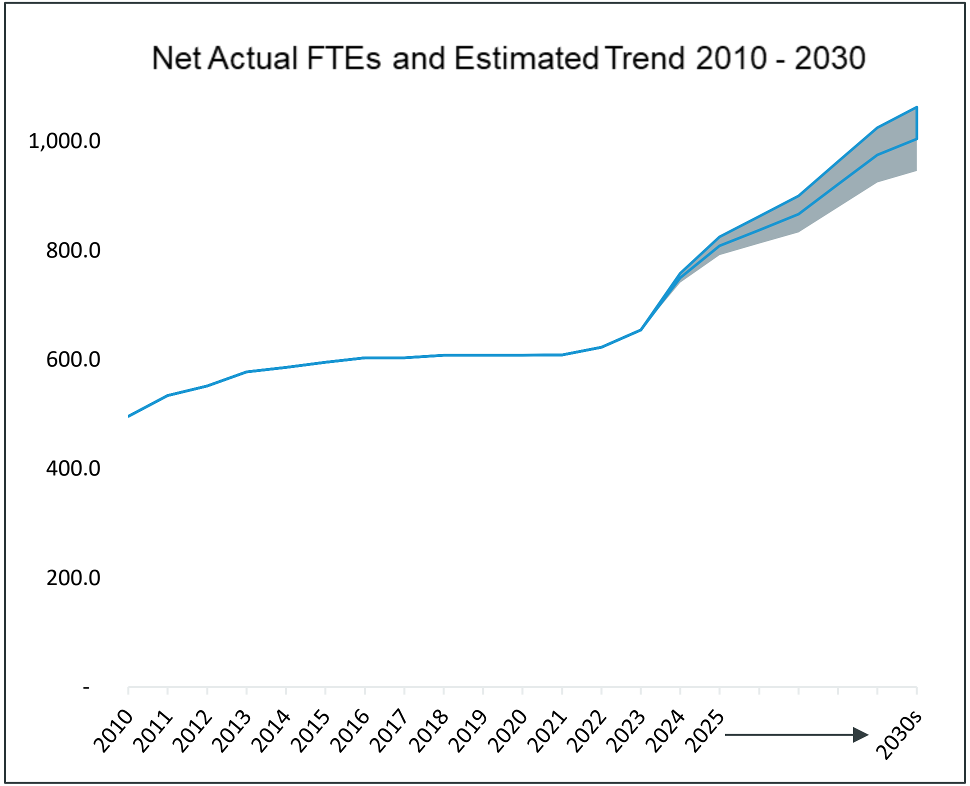
Factor	% Increase	$ Amount	$KWh Rate	Average Monthly Consumer Cost Impact *
Changing Resource Mix/Customer Use Patterns	5.4 %	$17,026,400	$ 0.00014	$ 0.11
Attract/Retain Staff and Operational Increases	2.1%	$ 6,520,800	$ 0.00006	$ 0.04
Net Change in Rev Req True-Up	(6.5)%	$(20,445,300)	$(0.00017)	$(0.13)
Total Change in Revenue Req for 2026:	**1.0 %**	**$3,101,900**	**$0.00003**	**$0.02**

**Average Monthly Consumer Cost Impact* is based on average consumption of 750 kWh per month.

After Years of Flat Headcount, in 2023, ISO-NE Began Plan to Increase Hiring to Address the Complexity of the Grid Transition

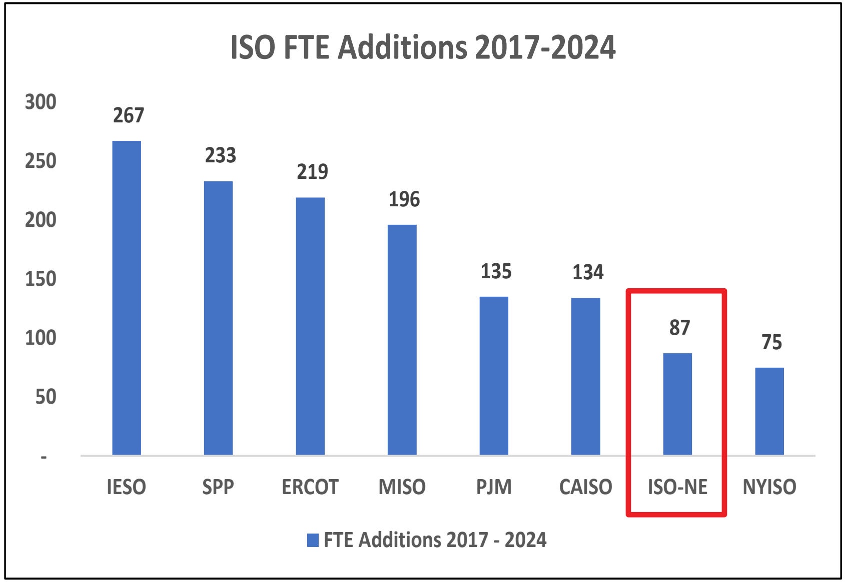
Electric grid transition driving FTE needs:

- Increasing number of resources to be interconnected, studied, and incorporated into modeling and forecasting
- New roles for the ISO including assisting states with transmission RFPs
- Increasing compliance needs to address FERC orders, and assess their impacts on operations – 2222, 841, 881, 901, 1920, and 2023
- Emergent needs to collect data for Distributed Energy Resources (DER) to address tripping and low-loads
- New and enhanced skills to work with changing technology stack, new data streams, and operationalizing new applications
- Personnel to communicate increasingly complex information to stakeholders and the public
- Increased support needs to assist the growing and distributed workforce

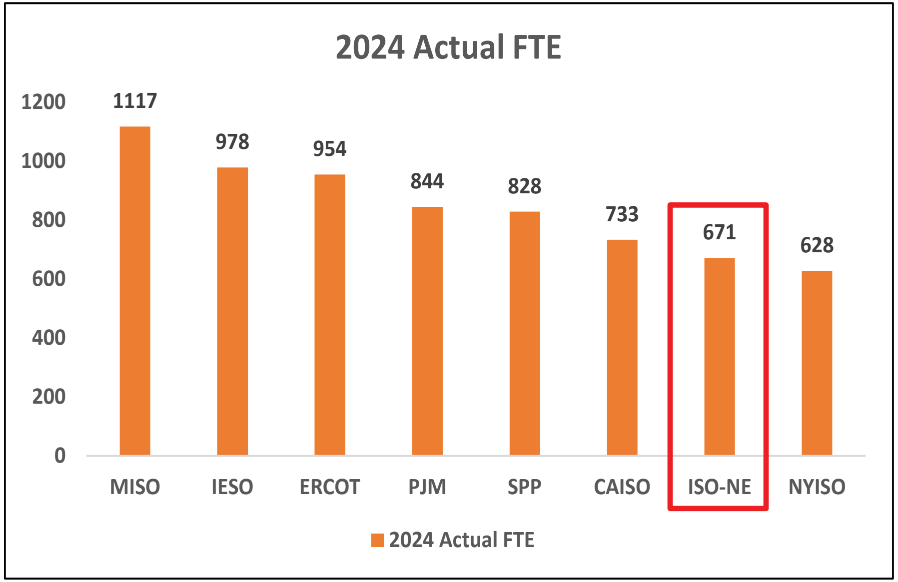


ISO-NE's Incremental and Actual Headcount in Comparison to other ISO/RTOs'

Other ISOs had already begun ramping up their hiring prior to ISO-NE



ISO-NE is still relatively small compared to other multi-state ISOs



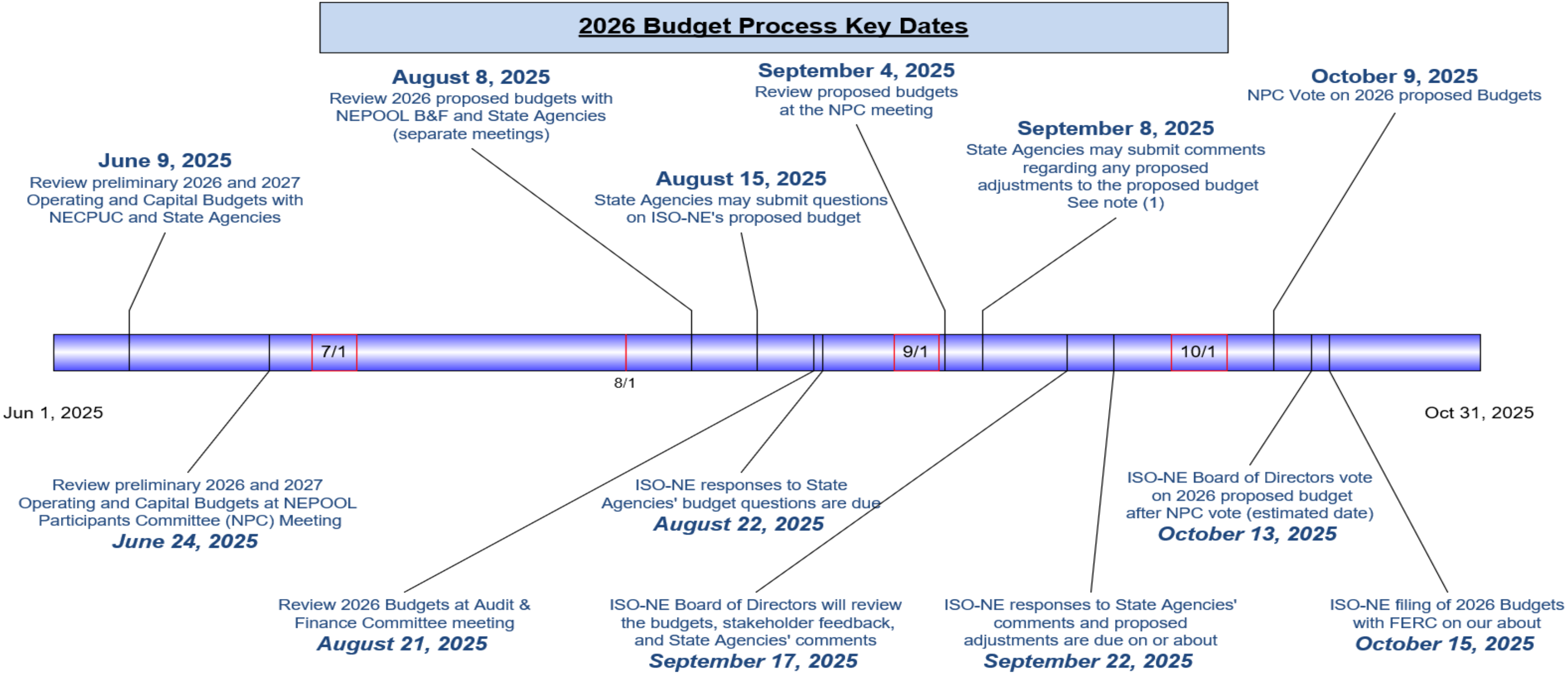
Note: FTE additions and totals are based on actual FTE amounts on 12/31 of the applicable year.

2026 Proposed Capital Budget Overview

The 2026 Capital Budget is also presented in summary form

- The 2026 Capital Budget is consistent with the 2025 Capital Budget at $42.5M
  - Capital budget increases over the past several years have been driven by three primary drivers as explained in further detail on slides 58 to 62
  - Capital budget spending is expected to increase in the foreseeable future
    - In addition, ISO is considering additional expansion of building space which would be funded by tax-exempt bonds, if approved
  - The increased capital spending will result in higher interest expense costs and depreciation expense in future years as capital projects go into service and are included in operating budgets and rates
- The 2026 proposed capital budget of $42.5M is provided with a list of projects by strategic goal that are currently chartered and on-going or in planning/conceptual design (See slides 65 to 68)

2026 Budget Process – Key Dates



(1) According to the budget settlement agreement, State Agencies must submit comments on the proposed budgets five weeks after the August meeting which is September 12, 2025. However, we are requesting comments by September 8, 2025 to allow for timely distribution to the Board when meeting materials are mailed. This is consistent with the acceleration agreed to in 2015.

2026 Budget – 5 Year Comparison

(Budget Amounts are in Millions)	2026	% Change	2025	% Change	2024	% Change	2023	% Change	2022
Operating Budget Before Depr and Regulatory Fees	$281.8	8.3%	$260.2	10.1%	$236.3	17.0%	$201.9	10.6%	$182.6
Capital Budget	42.5	0.0%	42.5	21.4%	35.0	4.5%	33.5	4.7%	32.0
Total Cash Budget	**$324.3**	**7.1%**	**$302.7**	**11.6%**	**$271.3**	**15.2%**	**$235.4**	**9.7%**	**$214.6**
Operating Budget Before Depr and Regulatory Fees	$281.8	8.3%	$260.2	10.1%	$236.3	17.0%	$201.9	10.6%	$182.6
Depreciation and Regulatory Fees	48.2	4.2%	46.2	13.8%	40.6	6.1%	38.3	17.9%	32.5
Revenue Requirement Before True-up	330.0	7.7%	306.4	10.7%	276.9	15.3%	240.2	11.7%	215.1
True up	(15.6)		4.8		(3.0)		(14.6)		1.1
Revenue Requirement	**$314.4**	**1.0%**	**$311.2**	**13.6%**	**$273.9**	**21.4%**	**$225.6**	**4.4%**	**$216.1**
Forecast – TWhs (1)	**124.7**	**0.9%**	**123.6**	**1.7%**	**121.5**	**(0.0)%**	**121.5**	**0.1%**	**121.4**
$/KWh Rate	**$0.00252**	**0.1%**	**$0.00252**	**11.7%**	**$0.00225**	**21.4%**	**$0.00186**	**4.3%**	**$0.00178**
Average Monthly Consumer Cost (2)	**$1.89**		**$1.89**		**$1.69**		**$1.39**		**$1.34**

(1) 2026 and 2025 forecast amounts are based on May 2025 CELT Report (Schedule 1.5.2 - Net Annual Energy - Gross (without reductions)). 2022 through 2024 use weather normalized annual energy without reduction for BTMPV which is an equivalent basis for May 2025 CELT report *Net Annual Energy - Gross (without reductions),* and is being displayed in this manner due to a change in the 2025 CELT Report presentation of amounts. The May 2025 CELT Report can be found at *https://www.iso-ne.com/static-assets/documents/100023/2025_celt.xlsx* , and the weather normalized annual energy can be found at *https://www.iso-ne.com/static-assets/documents/100023/forecast_data_2025.xlsx* (Schedule 5 Weather Normal)

(2) Based on average consumption of 750 kWh per month.

Note: Throughout the presentation some schedules may be inconsistent due to rounding.

2026 Detailed Budget Changes by Strategic Goal

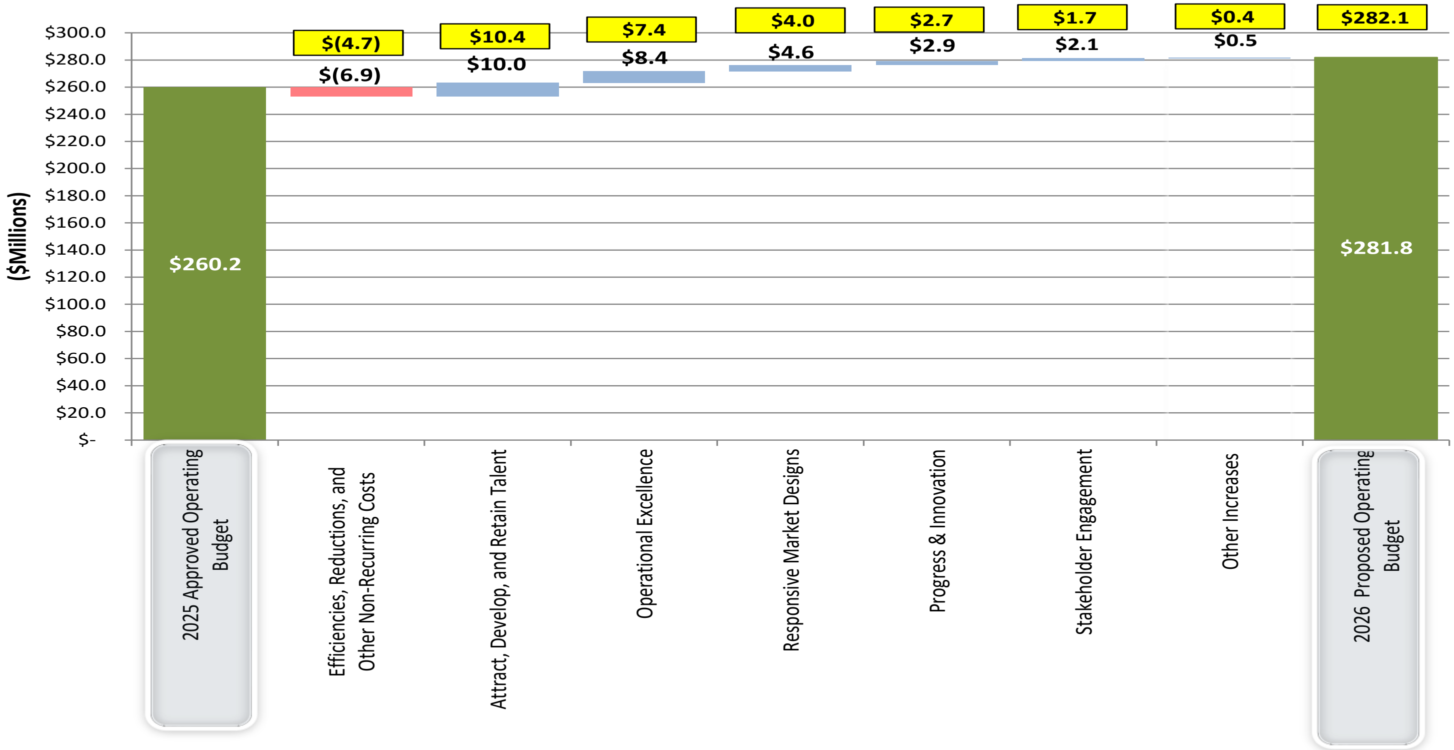
2026 ISO-NE Strategic Goals

The ISO ties its annual budget to resource requirements by Goals, Objectives, and Initiatives

Responsive Market Designs:	Advance the competitive wholesale markets to support the investment and new services required for a reliable energy transition
Progress and Innovation:	Expand capabilities to support increasing grid complexity brought about by new technologies and changes to supply mix and customer use
Operational Excellence:	Focus on high quality business operations, prioritize high impact projects, and mitigate implementation risks
Stakeholder Engagement:	Collaboratively understand and anticipate needs, demonstrate thought leadership through high-quality analysis and communication, and nurture productive relationships with regulators and stakeholders in supporting the four pillars of the clean energy transition
Attract, Develop, and Retain Talent:	Continue to promote our Culture, Mission, Vision, and Goals; develop and position the workforce to support the evolving needs of the organization; recognize and reward employees’ success and innovation; tailor programs to retain and attract critical, in-demand skills; and foster an inclusive culture that values diversity of career and life experiences

2026 Budget

Changes in budget by Strategic Goal



Note: Items in yellow above represent the estimate that was included in the 2026 preliminary budget presented in June 2025.

2026 Budget Details

Efficiencies, Reductions, and Other Non-Recurring Costs

Reductions include: ($6.9M)

- Lower salary rates and related incentive compensation due to employee turnover and retirements
- Reductions for consulting professional fees for 2025 studies or other non-recurring work including:
  - Completion of regional study work with PJM and NYISO for 1,200MW single source contingency limit appropriateness and to determine upgrades required to support 2,000MW single source limit
  - Transmission planning system assessment under NERC Transmission Planning Standard TPL-001
  - Funding of Medium-Term Energy Adequacy related work
  - Wind, Solar, and Generation dataset information that will be obtained via other sources
  - Reduction in Advanced Technology Solutions outside Research & Development support
  - Lower Relocation Expense reimbursement
  - Other miscellaneous reductions
- Reduction for no expected borrowing on working capital funds based on projections for 2026

2026 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2026 Initiatives

Changes in budget for Attract, Develop, and Retain Talent: $10.0M

- Merit and Promotion increases: for annual merit (4.0%) and for standard and targeted promotion/adjustments (1.5%) ($6.0M)
- An increase for the reduction of employee vacancy from 6.0% to 5.0% based on projected hiring ($1.6M)
- Increases in employee benefit costs, primarily for medical trend, and increased number of employees in Defined Contribution Benefit Plan ($1.5M)
- Employees fees related to the relocation of approximately 90 employees to the Windsor campus ($0.4M)
- Consulting services, data, and research to support critical HR initiatives ($0.2M)
- Board of Director search fees to recruit for position scheduled for turnover ($0.2M)
- Increase in Board of Director retainer fees ($0.1M)

2026 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2026 Initiatives

Changes in budget for Operational Excellence: $8.4M

- Computer service and leasing increases for: cyber security (security log management, network detection and response tool, zero trust access and protection, and cloud monitoring); network collaboration software; leasing of servers as part of data center refresh; computing and storage capacity application; licensing for System Planning and Operations applications; and inflationary and vendor increases across our portfolio of computer service products ($3.7M)
- Funding for 15.0 FTEs* for System Operations and System Planning to address technical challenges and perform system assessments and studies with the continued installation of Inverter Based Resources and for NERC/NPCC requirement responsibilities; for Information and Cyber Security for Cloud Computing transition including architecture, service delivery, and IT forecasting tool support; for project management support due to increased number and sophistication of capital projects; for Finance and Market Credit Risk to support the growth in these areas to support the organization ($3.0M)
- Consulting support to provide research, recommendations, and implementation of enhanced security best practices for ISO workforce (including senior management) ($0.5M)
- Increase in regulatory counsel fees for FERC Order filings and responses to supplement ISO-NE Legal staff ($0.5M)

* FTE totals and related funding on slides 44-49 reflect partial funding for 2026 positions (18.5 FTEs), as well as a partial carryover for 2025 positions (16 FTEs).

2026 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2026 Initiatives

Changes in budget for Operational Excellence: *(cont.)*

- Network Operations increases for transition of communication lines to new technologies, for data redundancy, and for inflationary and communication line increases ($0.3M)
- Data services subscriptions for Market Monitoring utilization and for vendor third party risk assessment ($0.2M)
- Consultant funds to perform audits or assist ISO-NE Internal Audit group with various engagements including systems and cyber security related work ($0.2M)

2026 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2026 Initiatives

Changes in budget for Responsive Market Designs: $4.6M

- Funding for 6.5 FTEs* related to this goal includes: Market Development in design of market overhauls including prompt seasonal capacity market, resource capacity accreditation, and flexible response services; Operations Training and Integration to design and support training needs of Operations and Market Administration staff for new market features; Information Technology and Advanced Technology staffing to support and integrate new market features into applications and tools; and Planning and Transmission Services that will continue to be heavily involved with new market designs, identifying enhancements to existing reliability modeling and researching and developing modeling techniques for emerging technologies ($1.3M)
- Information Technology and System Planning support for resource adequacy and capacity market modeling, which is essential to the redesign of the capacity market under the Capacity Auction Reforms project ($1.2M)
- Support in Advanced Technology Solutions and Market Development for Capacity Auction Reforms work including gas modeling and other analysis ($0.9M)
- Increase for nGEM vendor support with the Real-Time Market Clearing Engine application that is higher cost than the legacy Real-Time application ($0.5M)

* FTE totals and related funding on slides 44-49 reflect partial funding for 2026 positions (18.5 FTEs), as well as a partial carryover for 2025 positions (16 FTEs).

2026 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2026 Initiatives

Changes in budget for Responsive Market Designs: *(cont.)*

- Funding for commencement of work on tariff required Net CONE (Cost of New Entry) recalculation ($0.5M)
- Market Monitoring support for technology assessment and Artificial Intelligence development for use in detection and mitigation of energy market activity ($0.2M)

2026 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2026 Initiatives

Changes in budget for Progress and Innovation: $2.9M

- Funding for 9.5 FTEs* including Information Technology and Advanced Technology for bringing ISO-NE developed advanced technologies into the operating environment to increase our situational awareness capabilities and for migration of applications to the cloud; System Operations and System Planning positions for forecasting and energy analysis across different timespans as the system's resource mix continues to evolve, for modeling and electromagnetic transient analyses for market and reliability operating limits of Inverter Based Resources, for expansion of both short-term and long-term forecasting needs, and to support the continued growth and development of Power System Computer Aided Design (PSCAD) modeling capability (including database development and maintenance) for inverter-based resources ($2.3M)
- Computer service-related costs for NERC CIP Synchrophasor compliance ($0.5M)
- Photovoltaic Data and Forecasting service-related costs ($0.1M)

* FTE totals and related funding on slides 44-49 reflect partial funding for 2026 positions (18.5 FTEs), as well as a partial carryover for 2025 positions (16 FTEs).

2026 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2026 Initiatives

Changes in budget for Stakeholder Engagement: $2.1M

- Asset Condition Review work that will only be used for this purpose, and if not needed will not be reallocated for use elsewhere ($1.0M)
- Funding for 2.5 FTEs* in Participant Relations and Services for project services (gathering, managing, and supporting the assessment of participant requests), to provide technical readiness and real-time support on corporate initiatives (FERC Orders 2222, 881, 2023), and for support on Capacity Auction Reforms to support this multi-component initiative impacting many ISO-NE teams, and coordinating with participants ($0.6M)
- Funding for 0.5 of an FTE* in Legal to support RFP proposals under Long-Term Transmission Planning (LTTP) rules for which proposals are expected to be made annually ($0.2M)
- Consulting support for LTTP proposals and other Transmission Planning work ($0.2M)
- Funding for 0.5 of an FTE* in System Planning to perform economic evaluations in support of the new LTTP process and potential RFP solution reviews as well as to accommodate requests from NESCOE/States for various supporting analyses ($0.1M)

* FTE totals and related funding on slides 44-49 reflect partial funding for 2026 positions (18.5 FTEs), as well as a partial carryover for 2025 positions (16 FTEs).

2026 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2026 Initiatives

Other Increases: $0.5M

- Increases in Building Service costs due to cyclical maintenance items that are due for completion in 2026, higher utility expense largely for delivery service fees at Windsor facility, and inflationary and other small increases across line items ($0.4M)
- Lower forecasted Interest Income due to projecting lower operating cash balance from expected withdrawals under FERC Order 2023 partially offset by higher miscellaneous revenue ($0.1M)

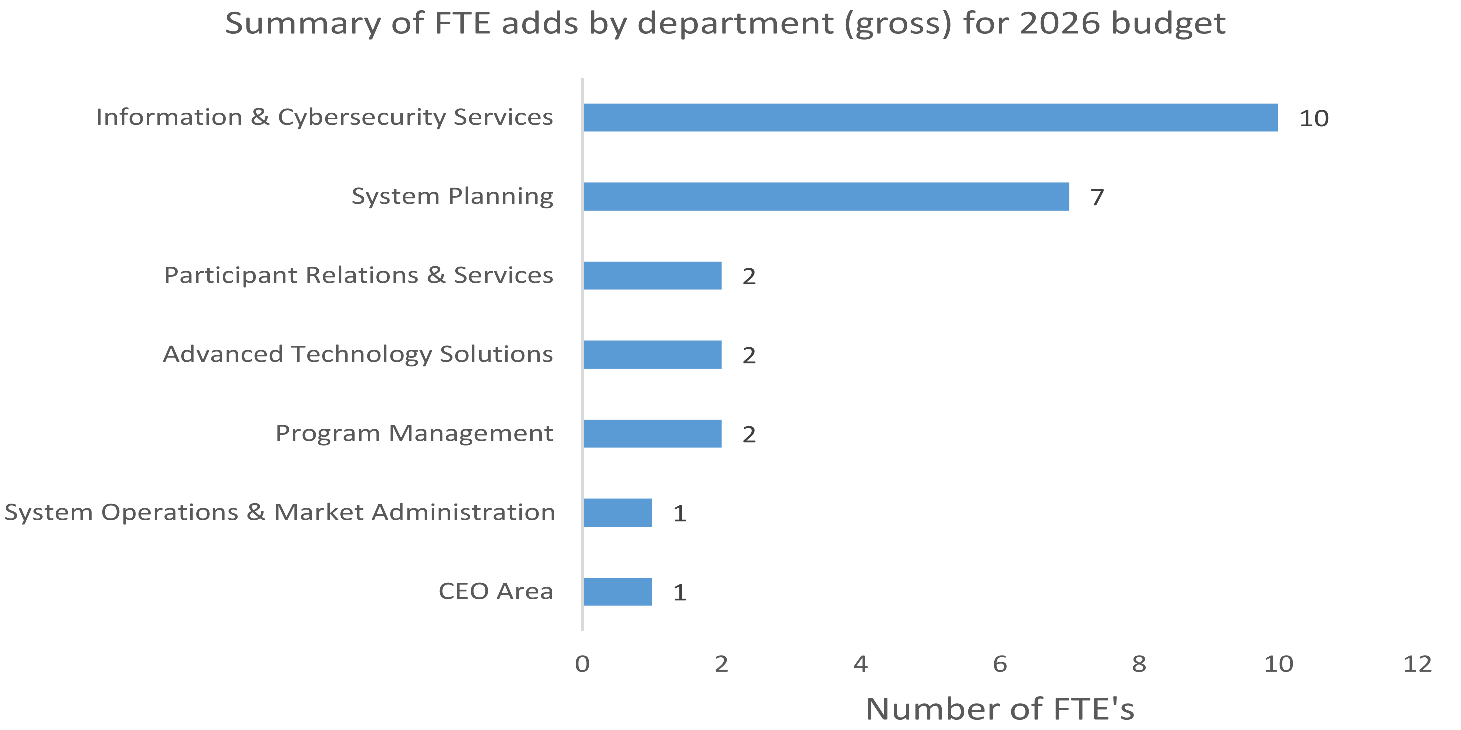
2026 BUDGET RESOURCING NEEDS

2026 Budget Resourcing Needs

Repurposed Positions

- The ISO evaluates each position that becomes vacant to determine the continued need in that area and for possible repurposing for use in other areas of the organization
  - Since 2018 this has resulted in 48 positions, including 4 to-date in 2025, being repurposed for other work where a more urgent need existed
  - Positions repurposed since 2018 include: 10 for Information Technology for Software Development, Cyber Security, Power System Modeling, Application Support, Infrastructure and Digital Transformation; 8 for System Operations & Market Administration for Energy Security, Asset Registration & Auditing, Control Room Operations, and Operations Training; 7 for Human Resources for recruiting and training support and intern conversion to full time technical roles; 6 for Market Development analysis and market design work; 2 for Advanced Technology Solutions; 2 for Market Monitoring; 2 for Market & Credit Risk; 2 for Participant Support; 2 for Corporate, Media, and Digital Communications; 2 for Finance; 1 for Load Forecasting to replace a contract position; 1 for Resource Studies & Assessments; 1 for External Affairs, 1 for Settlements; and 1 for Corporate Strategy

Requested Additional Headcount for 2026



Note: CEO Area headcount additions include those for Legal, Human Resources, and Finance (1 each for a total of 3) less the relinquishing of 2 positions bring net CEO area change to 1 additional FTE

2026 Budget Resourcing Needs *(cont.)*

In 2026 there are 25 FTE (gross) additions as follows:

FTEs	Area / Description	Clean Energy Pillar(s) (*)	Strategic Goal(s)
10.0 FTEs	**Information and Cyber Security Services**		
	Resources to support network infrastructure services supporting Enterprise, Markets and Planning business functions across on-premises and cloud environments, shared infrastructure technologies, IT Technician personnel supporting Control Room Operations, Energy Operating Analytics Team (ATS Applications), Cyber Security, and new market initiative testing (4 FTEs Support the Energy Transition associated with the evolving resource mix)	Energy Adequacy, Clean Energy Resources	Operational Excellence; Responsive Market Designs; Progress and Innovation
7.0 FTEs	**System Planning**		
	Resources to support economic evaluations in support of the new Long-Term Transmission Planning process, increased workload due to NERC and NPCC responsibilities, continued response to long-term forecast needs driven by increased complexity, the continued growth and development of PSCAD modeling capability, the development of power flow, stability, and geomagnetic disturbance base cases for various ISO groups, and to continue to meet increasing Transmission Planning responsibilities (7 FTEs Support the Energy Transition associated with the evolving resource mix)	Energy Adequacy; Robust Transmission	Progress and Innovation; Operational Excellence; Stakeholder Engagement; and Responsive Market Design
2.0 FTEs	**Participant Relations & Services**		
	Resources to support the Capacity Auction Reforms initiative, and providing stakeholders with better translations of technical information into content they can understand and take action on (2 FTEs Support the Energy Transition associated with the evolving resource mix)	Clean Energy Resources; Energy Adequacy; Balancing Resources; Robust Transmission	Responsive Market Designs; Operational Excellence; Progress and Innovation; Stakeholder Engagement

(*) See the Four Pillars of the Clean Energy Transition on Slide 24

2026 Budget Resourcing Needs *(cont.)*

In 2026 there are 25 FTE (gross) additions as follows: (cont.)

FTEs	Area / Description	Clean Energy Pillar(s)	Strategic Goal(s)
2.0 FTEs	**Advanced Technology Solutions**		
	Resources to accurately model the protection and controls of Inverter Based Resources in the Electromagnetic domain; and design and develop Capacity Market clearing engine (for prompt seasonal and monthly reconfiguration auctions) as part of CAR project (2 FTEs Support the Energy Transition associated with the evolving resource mix)	Clean Energy Resources; Energy Adequacy	Progress and Innovation, and Responsive Market Designs
2.0 FTEs	**Program Management**		
	Resources to support Capital project work that has increased dramatically in the past few years and requires skilled personnel to manage these initiatives (2 FTEs Support the Energy Transition associated with the evolving resource mix)	Clean Energy Resources	Operational Excellence
1.0 FTEs	**System Operations & Market Administration**		
	Resources to support the fast-evolving power grid and high penetration of inverter-based renewable resources and address the resulting technical challenges to operating the grid in a reliable and economic manner (1 FTEs Support the Energy Transition associated with the evolving resource mix)	Clean Energy Resources	Operational Excellence
1.0 FTE	**CEO Area** (1)		
	Resources in Legal to support on-going RFP submissions under Long-Term Transmission Planning, in Enterprise Learning for a dedicated individual to implement and manage Information Technology and Cyber Security related education that has been identified as a need; and in Finance to augment existing staff in Accounting/Accounts Payable (1 FTE Supports the Energy Transition associated with the evolving resource mix)	Robust Transmission, Other	Stakeholder Engagement, Progress and Innovation, and Operational Excellence

25.0 FTE's Total 2026 Proposed FTE Additions

(1) While 3 FTEs are being included in CEO additions, 2 of the positions are being covered by the reallocation of existing positions within the CEO area

Questions

Forward Looking Capital Budget Spending

Forward Looking Capital Budget Spending

- The capital budget over the next five years and beyond will continue to support the Company's strategic goals with specific focus on three primary drivers with the fourth wrapping up in 2026:
  - nGem platform (replacing the current market system) set to finish in 2026
  - Major market and reliability related efforts
  - Cyber security
  - IT asset and infrastructure replacement
- In order to achieve these goals, ISO has increased the capital spending over the last few years with spending of $35M in 2024; $42.5M in 2025 and remains $42.5M in 2026 with the potential to increase upwards of $55M in future years; the capital costs are dependent on various factors, including regulatory orders and approvals and the use of professional services or internal staff
  - The ISO will continue with its current practice of providing a rolling two-year look-ahead window

Forward Looking Capital Budget Spending *(cont.)*

nGEM Platform Replacement (*)

- The nGEM program (next Generation Markets Management) has upgraded the core market software by supporting a system with a growing number and type of grid assets, new and more complex market features, ever multiplying security threats, and advancing IT technologies
  - GE Solutions developed nGEM in collaboration with ISO-NE, MISO, and PJM; the portion of the software upgrade unique to each ISO will be shouldered by each ISO individually
- With the completion of the infrastructure and the day ahead version of the new market clearing engine (MCE) in 2023, the ISO is continuing work on the complex processes for customizing and implementing the next phases, which include the infrastructure and real-time version of the MCE; this work is expected to continue until 2026 with an estimated cost of $15M; this last phase will wrap up the work on the nGem platform

(*) nGEM Platform Replacement is a multi-year initiative that will advance multiple strategic goals, including Responsive Market Designs, Progress and Innovation, and Operational Excellence. The initiative will require significant investment ($15M) and, as such, is being flagged consistent with the enhanced process for Board overview of significant and multi-year capital projects.

Forward Looking Capital Budget Spending *(cont.)*

Major Market and Reliability Related Efforts

- The capital budget supports ISO's market design objectives regarding clean energy, balancing resources, energy adequacy, and robust transmission
- Many of these projects are complex efforts that will have long lead times to complete and have dependencies of stakeholder and regulatory approval; the following projects have been identified for 2026 and beyond but may fluctuate depending on stakeholder/FERC priorities:
  - Significant Capacity Market Reforms: The ISO is currently recommending the move from a forward capacity auction construct to a prompt and seasonal capacity auction construct; this is a substantial scope of work that will better position the ISO to mitigate energy adequacy risks as the power system evolves
    - Capacity Auction Reforms (CAR) is currently proposed in 3 phases over the next 2-3 years: CAR – Prompt/Deactivation; CAR – Seasonal/Accreditation; and CAR – Impact/Analysis
  - Software systems to integrate distributed energy resources into the wholesale markets

Forward Looking Capital Budget Spending *(cont.)*

Major Market and Reliability Related Efforts *(cont.)*

- Transmission Line Ratings Enhancements: This project is in response to recent FERC orders and will require substantial IT and database work to collect and appropriately use data in planning and operations
- Market Simulator, 21 Day Energy Simulator, Inverter-Based Resource Modeling: There are various research and development efforts at the ISO that are expected to result in significant improvements to ISO modeling capabilities and situational awareness
- Stakeholder Priorities: The ISO has embarked on an improved prioritization process with stakeholders; each year, the ISO expects stakeholders to highlight three key priorities; some of these priorities will require the development of new software and associated applications
- Other Market Design Projects Identified in the ISO's Multi-Year Work Plan: The ISO plans to continue to make improvements to existing ancillary services, and design new ancillary services products; new ancillary products may include replacement reserves and ramping products

• Based on the complexity of the projects, the ISO expects the cost for market and reliability efforts will range from approximately $40M - $60M over the next five plus years

Forward Looking Capital Budget Spending *(cont.)*

Cyber Security & IT Asset and Infrastructure Replacement

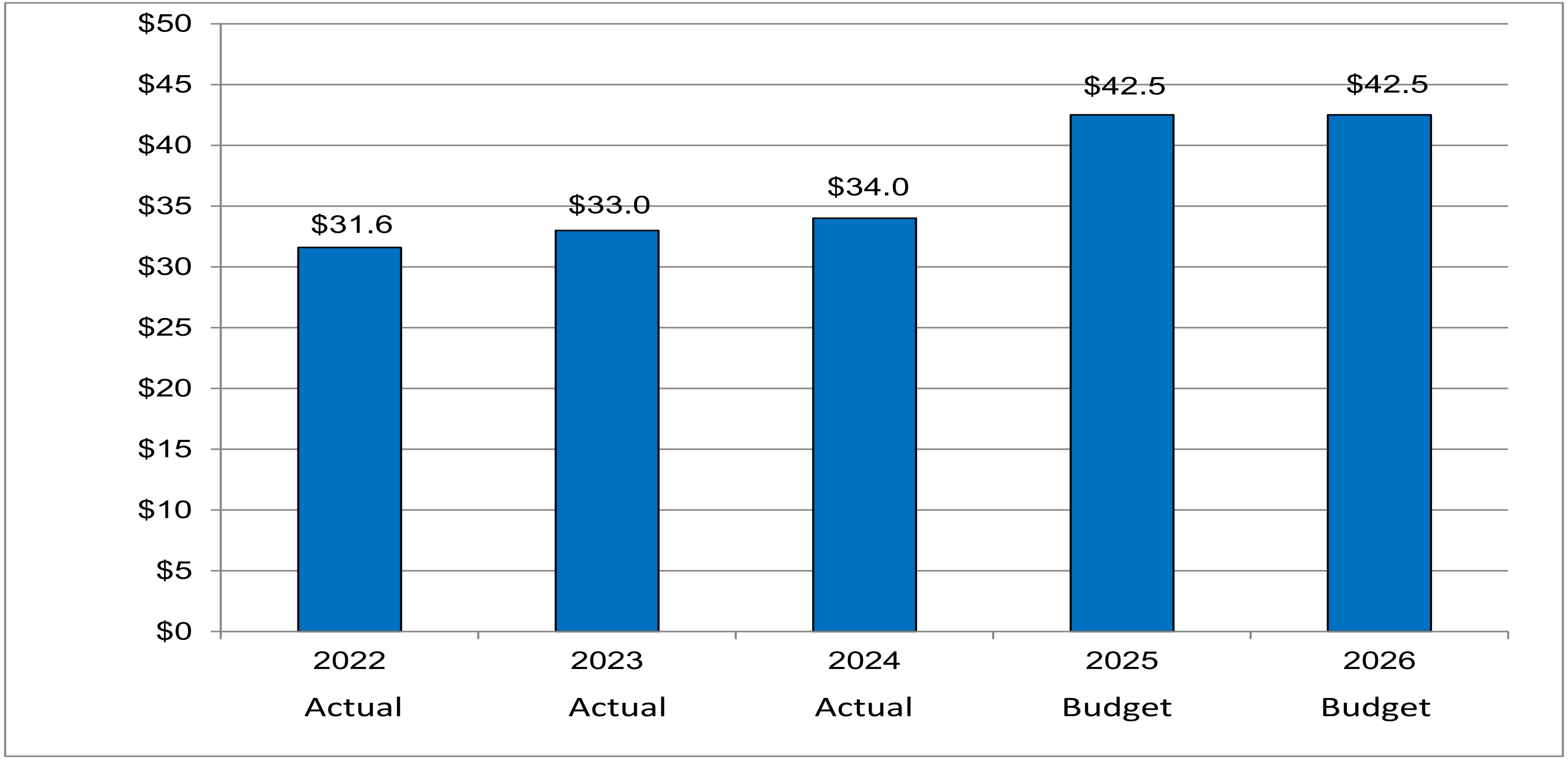
- Capital spending on improvements to cyber security and IT assets and infrastructure will support the ISO's strategic goals of Operational Excellence and Progress and Innovation
- ISO's cyber security maturity level has been a major investment for a few years and will continue over the next 3-5 years; ISO has greatly benefited from these earlier investments and as such is now able to layer improved defense, network segmentation, email and web filtering to improve monitoring, detection, and recovery tools to keep pace with increasingly sophisticated attack threats
- The ISO's transition to a cloud environment began in 2022 and is expected to be a major capital effort over the next several years
  - Reliability of operating a modern system comprised of renewable and storage resources requires the processing, transfer, and storing of vast amounts of data; in multiple phases, the ISO will be implementing cloud-computing infrastructure and virtualization technology to enable more dynamic expansion of computing capability, while maintaining reliability
- The cost for IT and cyber security initiatives will vary depending on the use of professional services or internal staff; the cost will range from approximately $20M - $40M over the next several years

CAPITAL BUDGET SUMMARY

Capital Budget

Historical Comparison Capital Expenditures

Average +/- $36.7M



Capital Budget
2026 Expenditures

Goal: Responsive Market Designs

Project	2026 Budget	Total Project Cost	Estimated Completion Date	Project Stage
EMP 3.5 Upgrade - GridOS	$3.5 M	$6.9 M	09/2027	Conceptual Design
GridOS Connect	$1.5 M	$2.0 M	12/2026	Conceptual Design
Storage as Transmission Only Asset	$0.5 M	$1.0 M	10/2026	Conceptual Design
Enterprise Core Network Refresh	$0.1 M	$2.1 M	08/2026	In Development
Total:	**$5.6 M**			

Goal: Progress and Innovation

Project	2026 Budget	Total Project Cost	Estimated Completion Date	Project Stage
Single Interval MCE Improvements (SIMI)	$5.0 M	$13.2 M	06/2028	Conceptual Design
nGEM Real-Time Market Clearing Engine Implementation	$3.2 M	$14.8 M	05/2026	In Development
Advanced Technology Initiatives	$2.0 M	$4.0 M	12/2026	Conceptual Design
Day Ahead Market Simulator	$1.8 M	$1.9 M	12/2026	Conceptual Design
Total:	**$ 12.0 M**			

Capital Budget
2026 Expenditures *(cont.)*

Goal: Operational Excellence

Project	2026 Budget	Total Project Cost	Estimated Completion Date	Project Stage
. Distributed Energy Resources - Order 2222	$2.6 M	$5.4 M	11/2026	In Development
. MW Dependent Fuel Price Adjustment	$2.5 M	$2.6 M	12/2026	Conceptual Design
. Atlassian Cloud Migration	$2.0 M	$2.3 M	12/2026	Conceptual Design
. Oracle Platform Replacement	$1.2 M	$1.8 M	09/2026	Conceptual Design
. Managing Transmission Line Ratings	$1.0 M	$8.7 M	12/2026	In Development
. Adoption of NERC CIP Compliance of Synchrophaser Systems	$1.0 M	$2.1 M	08/2026	In Development
. Tie Line Telemetry and PCEC Upgrade Phase II	$0.5 M	$0.7 M	10/2026	Conceptual Design
. Replace Employee & Pager Application	$0.5 M	$0.6 M	12/2026	Conceptual Design
. Solar Do Not Exceed Dispatch Phase III	$0.5 M	$0.5 M	12/2026	Conceptual Design
. Circuit Inventory Management Platform Phase 2	$0.5 M	$0.5 M	10/2026	Conceptual Design
. Operations Document Management System MS 365 Conversion	$0.3 M	$0.3 M	10/2026	Conceptual Design
. CIP ESP Phase 3	$0.3 M	$1.3 M	05/2026	Conceptual Design
. EMS CFE Refresh	$0.1 M	$0.8 M	06/2026	In Development
. Centralized Application Security	$0.1 M	$0.2 M	02/2026	In Development
. Non-Project Capital Expenditures	$5.5 M	$5.5 M		
Total:	**$18.5 M**			

Capital Budget
2026 Expenditures *(cont.)*

Goal: Stakeholder Engagement

Project	2026 Budget	Total Project Cost	Estimated Completion Date	Project Stage
. Order 2023 Interconnection Reforms	$2.0 M	$2.1 M	09/2026	Conceptual Design
Total:	**$2.0 M**			

Capital Budget
2026 Expenditures Summary

- 2026 Capital Budget Expenditure Summary

Allocation Category	2026 Budget
Goal:Operational Excellence	$18.5 M
Goal: Progress and Innovation	$12.0 M
Goal: Responsive Market Designs	$5.6 M
Other Emerging Work	$3.2 M
Goal: Stakeholder Engagement	$2.0 M
Capital Interest	$1.2 M
Total:	**$42.5 M**

CAPITAL STRUCTURE AND CASH FLOW

Capital Structure

- The ISO increased its working capital line from $20M to $40M in March of 2024; the working capital line, which will expire on March 1, 2028, covers the ISO's operational needs and cash flow risks, including lower than projected load driving decreased Tariff collections, a continued increase in budgetary needs over the next 3 - 4 years, and more recently the issuance of FERC Order 2023 which may increase withdrawals of system impact studies
- Capital project costs are largely funded by $75M in Private Placement Notes that were increased in 2024, from $50M, and require interest only payments until full payment of principal in 2034
  - As noted in last year's budget materials, the private placement note increase in 2024 was to support increased capital spending, that has occurred over the past several years, and longer lead times to complete projects resulting in a greater period of time from when the ISO spends capital funds to tariff recovery through depreciation expense of these projects
- For the six months ended June 30, 2025, the ISO's total weighted average cost of capital was 4.45%, excluding fees charged on the various debt financing; fees ranged from .075% to .38%

Capital Structure and Cash Flow *(cont.)*

	2025 Forecast	2026 Budget	2027 Forecast	2028 Forecast	2029 Forecast
Cash flows from operating activities:					
Operating Cost Recovery *	$ 271,432	$ 275,524	$ -	$ -	$ -
Non Cash Items:					
Depreciation, Amortization & G/L on Disposals	35,341	38,213	43,853	44,660	47,276
Amortization Term Loan Fees	91	129	129	129	129
Chg in Accrued Expenses & Deferred Revenue-Depreciation	(23,057)	-	-	-	-
Interest Expense	(4,254)	(3,639)	-	-	-
Operating Expenses *	(259,341)	(287,972)	-	-	-
Net cash provided by operating activities	20,212	22,255	43,982	44,789	47,405
Cash flows from investing activities:					
Capital expenditures	(42,500)	(42,500)	(44,500)	(46,500)	(48,500)
Net cash used in investing activities	(42,500)	(42,500)	(44,500)	(46,500)	(48,500)
Cash flows from financing activities:					
Net Proceeds/(Repayment) - Revolving Credit Line	-	-	3,000	5,000	4,000
Net Proceeds/(Repayment) - Revolving Capital Credit Line	-	-	-	-	-
Repayment of Principal - Private Placement	-	-	-	-	-
Proceeds - Private Placement	-	-	-	-	-
Repayment of Principal - Tax Exempt Bonds	(3,180)	(3,180)	(3,180)	(3,180)	(3,180)
Net cash provided by (used by) financing activities	(3,180)	(3,180)	(180)	1,820	820
Net increase/(decrease) in cash	(25,468)	(23,425)	(698)	109	(275)
Cash & Cash Equivalents on Hand - Beginning of Period	49,960	24,492	1,067	369	478
Change in Cash & Cash Equivalents Available	(25,468)	(23,425)	(698)	109	(275)
Cash & Cash Equivalents on Hand - End of Period	$ 24,492	$ 1,067	$ 369	$ 478	$ 203
Debt Maturity Schedule					
Tax Exempt Bond - BCC	1,360	1,360	1,360	1,360	1,360
Tax Exempt Bond - MCC	1,820	1,820	1,820	1,820	1,820
Total Year Repayment	$ 3,180	$ 3,180	$ 3,180	$ 3,180	$ 3,180

*= Operating Cost Recovery for 2025 has increased by an under collection in 2023 of $4,844 which was not amortized in 2024 but included in the 2025 tariff. The over collection of $15,601 for 2024 will be filed with the 2026 tariff and will be reflected in the Operating Cost Recovery for 2026. The Operating Cost Recovery for 2027-2029 is projected to offset Operating Expenses for 2027-2029. The Operating Cost Recovery amount for 2027-2029 has not yet been established at this point.

Questions

APPENDIX 1: COMPENSATION

Process for Establishing Salary Budget Increases

- ISO-NE contracts with Mercer, an independent compensation consulting firm to provide job specific benchmark data to inform our market competitiveness. This data provides insight into median pay and relative pay ranges for similar jobs in the national market enabling us to evaluate our salaries relative to companies with whom we compete for talent
  - Initial evaluation complete in 2025 with planned annual updates
- ISO-NE reviews comprehensive salary budget planning data compiled by nationally-recognized compensation consulting firms
  - These surveys are typically published later in the fall and reflect planned salary budget increases of over 2,300 employers, including more than 100 utility companies
- ISO-NE will also review expected salary increases of other ISOs/RTOs

Process for Establishing Salary Budget Increases *(cont.)*

- Merit Increases
  - Merit pools are the percentage of total employee salaries that companies intend to use for broad-based salary increases in the coming year
    - At ISO-NE, this pool funds the annual performance-based increases for eligible non-bargaining unit employees
    - Individual percentage increases vary based on employees' performance, with some receiving less than and some receiving more than the budget percentage
- Promotion and Adjustment Increases
  - Promotion and adjustment equity pools are used to fund promotions and base salary adjustments required to attract and retain talent throughout the year
    - At ISO-NE, this pool funds all promotions and any required salary adjustments required to remain competitive so that we can attract and retain the talent required to achieve our objectives

Process for Establishing Salary Budget Increases *(cont.)*

- In 2022, to address competitive challenges related to the grid transition and evolving resource mix, particularly those specified on Slides 77 and 78, ISO engaged a compensation consulting film to conduct more discrete, 1-for-1 job-specific benchmarking to establish competitive rates of pay for our highly skilled and in-demand workforce
- Supplementing the salary budget survey data with job-specific benchmarking allows us to better ensure that we are providing competitive rates of pay to our current employees, as well as attracting the necessary talent to be successful in the future
- Initial job specific benchmarking will be complete in 2025 and will be updated each year going forward to ensure our salary budget supports our ability to maintain competitive rates of pay
- A summary of the survey results and managements' recommendation is presented to the Compensation and Human Resources Committee of the Board of Directors for approval

Competitive Challenges

- As described in industry literature and shared with NEPOOL in the past, ISO-NE and utility employers face significant challenges associated with the retirement of a seasoned, technical workforce
  - Approximately 19% of the ISO-NE workforce is retirement-eligible

- The significant increase in demand for System Planning Engineers as a result of continued high levels of regional and interregional transmission expansion planning, large volumes of new generation and data center interconnection activity and overall resource adequacy concerns, has influenced salary requirements for these roles requiring higher pay to attract and retain this talent

- Addressing the grid transition and evolving resource mix is impacting all aspects of industry nationwide, leading to a tight labor market and inflation on new and existing employees' compensation expectations

Competitive Challenges *(cont.)*

- One third of ISO-NE's workforce is comprised of IT professionals who are in increasingly high demand
  - Software development and cyber security skills are the most sought after as organizations invest in newer, faster technology and mobile networks; compensation for these professionals is escalating
- This competition will only intensify as the region becomes increasingly involved with new and emerging technologies
  - More employees, with different skill sets will be needed to address the volume of market design changes and operational/planning complexities
  - Major investments in new technologies to create and support the core business applications and processes, including increased computational capacity to deal with increased grid complexity, will require the requisite staff to complete this work
- For all of these reasons, it is essential that we maintain competitive compensation; doing so is a cost-effective measure that will help prevent additional turnover and ensure the Company does not experience vacancies that will hinder implementation of major initiatives or impact efficient operation of its systems and markets

Competitive Challenges *(cont.)*

- With our current job specific competitive position for many specialized roles still lagging the market median, the limited national survey information currently available, and insights from other ISO's, we are currently budgeting 4.0% for merit and 1.5% for promotions and adjustments for 2026

Merit and Promotion/ Adjustment History	2022	2023	2024	2025	2026
Merit	3.0%	4.0%	4.0%	4.0%	4.0%
Promotion/Adjustments	0.5%	1.75%	4.0%	2.0%	1.5%
Total	**3.5%**	**5.75%**	**8.0%**	**6.0%**	**5.5%**

Executive Compensation

- As a tax-exempt organization, ISO-NE's Board of Directors is required by the Internal Revenue Code Section 4958 to ensure that executive compensation falls within a reasonable range of compensation practices among functionally comparable positions at similarly-situated organizations, both taxable and tax-exempt
- ISO-NE's Board of Directors contracts with Mercer, an independent compensation consulting firm, to study each executive's total compensation for "reasonableness"
  - The analysis includes examining data from other ISOs, utilities, and as appropriate, the general industry
  - Considerations such as the complexities of the markets, the significance of maintaining the grid, and the multi-billion dollars in settlements handled by ISO-NE are also factored into the review
  - Following its analysis, Mercer issues a Reasonableness Opinion
- The Mercer Reasonableness Opinion has consistently concluded that ISO-NE's executive compensation is within the appropriate competitive range

Executive Compensation *(cont.)*

- The Compensation and Human Resources Committee of the Board of Directors and the full Board of Directors review the Mercer Reasonableness Opinion and use it to finalize their decisions regarding each executive's compensation
- Executive compensation is reported in ISO-NE's annually filed IRS Form 990
  - This public filing is required for all tax-exempt companies and depicts officer compensation in detail
  - In addition to annual compensation, the data includes incremental increases in accrued pension benefits and other potential future compensation not yet received by the executive
- 2026 Budget for Executive Salaries $5.4M
  - Executive Salaries comprise the base salaries of the officers on the IRS Form 990

Pension and Defined Contribution Benefit Plans in 2026

- Defined Contribution Pension Plan: In 2014, ISO-NE changed its retirement plan offering from a Defined Benefit Pension Plan (Pension Plan) to a Defined Contribution Pension Plan (DC Plan) for employees hired after 12/31/13 and closed its Pension Plan to new participants; the DC Plan provides predictable cost and reduced balance sheet liability, with no investment risk and minimal cost volatility for ISO-NE

Pension and Defined Contribution Benefit Plans in 2026 *(cont.)*

- Defined Benefit Pension Plan: Consistent with the 10-year approach adopted in 2016, the 2026 Pension Plan expense will follow a level funding approach, rather than including the expense amount as calculated under FASB's Compensation – Retirement Benefits (ASC Topic 715)
  - The level funding approach will reduce the year over year volatility of the Pension Plan expense while still providing reasonable assurance that the Pension Plan is sufficiently funded
  - The level funding amount for the 2026 Pension Plan is unchanged at the $10,000,000 level
  - In 2024 ISO's actuaries, Segal Consulting performed a detailed Asset Liability Modeling ("ALM") study to refresh the original analysis with current economic conditions; the study results confirmed the Company's level funding approach and the amount of level of funding was still appropriate
  - The Pension Plan expense that is included in the 2026 budget is $10,000,000 compared to the projected FAS expense of $5,300,000

Postretirement Medical Benefit Plan in 2026

- In 2014 ISO-NE looked at making changes to its benefit plan offerings; to better align with the industry, the decision was made to close the Postretirement Benefit Plan to new hires, effective January 2016; in addition, a modification was made to the criteria for when this benefit could start for those employees in the plan prior to January 1, 2016; the age and years of service requirements were increased, thereby reducing future benefits that could be paid
- Consistent with previous years' budgets, ISO-NE's actuaries prepared estimated 2026 Financial Accounting Standards (FAS) Expense for the Postretirement Benefit Plan
- Actuaries utilized the FTSE Pension Discount curve, and reflected the change in discount rates as of May 31, 2025 to estimate the discount rate used in the calculation of the Postretirement Benefit Plan; current rates approximate the forward curve rates
  - Discount Rates Selected Postretirement Benefit Plan 5.45%
  - Salary Scale assumption (weighted Avg.) 3.00%
  - Projected 2026 annual earnings rate 6.00% (approximately)
- The calculated FAS expense amount for the Postretirement Benefit Plan of $883,000 is included in the 2026 budget

APPENDIX 2: 2026 OPERATING BUDGET RISKS

2026 Operating Budget Risks

- Additional funding may be required to enhance new models to study extreme weather and contingencies; to conduct new studies related to the integration of variable resources and emerging technologies; for completing requirements on implementing Capacity Auction Reforms; and for long-range transmission planning studies including request for proposals (RFP) process for finding competitive solutions to identified transmission needs in the region
- Resources may be needed as operations evolve (e.g., energy forecasting, load management) due to the changing resource mix
- Information Technology software licensing and maintenance costs, and cloud migration costs may each require additional funding
- Insurance policy renewals may be higher than estimated as ISO is not immune to overall increases from the insurance industry due to recent natural disasters
- Interest Rates may impact the ISO floating rates on tax-exempt debt, pension and post-retirement benefit plans liability costs, and interest income on settlement float balance
- Legal costs from material litigation that may arise during the course of the year would pose a risk to the ISO’s ability to operate within the approved budget
- Federal and state policy directives/changing could result in additional cost associated with new requirements
- Workforce sourcing and related pay rates and supply chain disruption may each have budgetary impacts

APPENDIX 3: 2024 DELIVERABLES AND SELECT METRICS

ISO Tracks Metrics to Monitor Progress and Efficiency in Upholding its Regional Responsibilities

- To carry out the ISO's mission and keep track on its strategic goals, the organization tracks a number of metrics to gauge progress; those metrics are listed in the subsequent slides
- ISO-NE Five Strategic Goals:
  – Responsive Market Designs
  – Progress and Innovation
  – Operational Excellence
  – Stakeholder Engagement
  – Attract, Develop, and Retain Talent

Mission Statement:

Through collaboration and innovation, ISO New England plans the transmission system, administers the region's wholesale markets, and operates the power system to ensure reliable and competitively priced wholesale electricity

Delivering Market Initiatives to Address the Changing Resource Mix – Responsive Market Designs

These 2024 deliverables address the clean energy and balancing resources pillars

Capacity Auction Reforms (CAR)

- Successfully pivoted to secure stakeholder support for significant capacity market reforms to align with the evolving resource mix
  - Filed capacity market structure proposals with the Commission in April, with a focus on transitioning to a prompt, seasonally-based market
  - Secured broad support for delaying the forward capacity auction by two years (approved in May)
  - Completed substantial internal work, including inter-departmental task teams, GE contracting, and modeling system-wide gas supply constraints for winter

- Conducted five months of stakeholder discussions, ensuring key elements are included in the 2028 auction design

- **2025:** Plan to Complete prompt and deactivation design for CAR – Including final tariff review and vote

Ancillary Services

- Advanced Day-ahead Ancillary Services Initiative (DASI), completing factory-acceptance testing and ongoing automated testing for MCE; Filed and received approval for Tariff changes to support DASI's implementation

- **2025:** Commenced implementation of DASI and begin assessment of further market reforms to support flexible reserves for those resources that can respond to operational uncertainty and higher ramp rates

2024 Initiatives to Enhance the ISO's Ability to Integrate Emerging Grid Technologies – Progress and Innovation

These 2024 deliverables address the clean energy and balancing resources pillars

Real-Time Market Clearing Engine (RT MCE)

- Delivered the preliminary RT MCE as part of the Next Generation Electricity Market (nGEM) initiative
  - In 2023, implemented nGEM Day Ahead Market Clearing Engine (MCE) as a critical step in transitioning the market clearing system from legacy to modern technology
  - In 2024, GE delivered a stand-alone version of RT MCE for initial debugging and testing, which was later integrated with Market Database and Market Operator Interface.
  - The RT MCE will support the ISO's Real-Time Unit Commitment (RTUC) mode and provide a foundation for final deployment and integration by the end of 2024

Electromagnetic Transient (EMT) Modeling for Inverter-Based Resources (IBRs)

- Developed a guideline for the EMT modeling process and model repository to facilitate reliable integration of inverter-based resources (IBRs) into the grid

EMT Modeling for IBRs *Cont'd*

- The guideline outlines best practices for conducting EMT studies, especially for generation interconnections and operational analyses

- Focused on the need for EMT studies due to the complex controls of IBRs and their reliability challenges

- System Planning is also developing a system to collaboratively manage EMT model data throughout the lifecycle of IBR projects, involving Generator Owners, Transmission Owners, and ISO Staff

- **2025:** Integrating electromagnetic transient (EMT) tools into operational analyses to better account for storage, solar & wind facilities

Improving Operational Efficiency

Improving the ISO's technology infrastructure to support the changing resource mix and ensuring compliance with regulatory mandates

Infrastructure/Compliance and Regulatory Improvements

- Sandbox Installation for Order 881 Compliance
  - **2025:** Completed the installation of the "Limit Exchange Portal" for implementing ambient-adjusted ratings as required by Order 881 for transmission system operation
- Assessment of Tie-Line Benefits Methodology
  - **2025:** Completed an assessment of the current tie-line benefits methodology, concluding that no changes to the existing methodology were necessary
- Successfully completed the refresh of foundational network infrastructure supporting enterprise and market IT and business functions

Cloud Computing and Migration to MS 365

- Completed a Cloud Transformation project focused on Office 365 adoption and cloud desktops:
  - **2025:** Delivered the implementation design for Office 365 features, with the pilot phase initiated for cloud desktops
  - Engaged in migration efforts for technologies like Active Directory, Exchange, SharePoint, and network file storage to a centralized cloud offering, reducing infrastructure costs and improving employee productivity
- Microsoft 365 Service Adoption Project
  - Including integration of new cybersecurity tools
- Executed a pilot to explore the viability of using cloud virtual desktops

Delivering Increased Reliability to ISO Stakeholders

2024 deliverables focused on improving energy adequacy, enhancing the ability to manage extreme weather events, and increasing transparency in energy reliability assessments across regional systems

Interconnection Queue and Energy Adequacy

- Order 2023 Compliance: addressed the interconnection queue backlog and filed rules for extended term/longer-term transmission planning as part of Order 2023 compliance
  - **2025:** Implementing Order 2023 to streamline interconnection queue
- Energy Adequacy Promotion
  - Led efforts within NERC to develop a new standard for Energy Reliability Assessments, improving transparency regarding energy adequacy risks across neighboring areas
  - Supported NPCC's New England/New York Gas Electric Study, providing PEAT-based studies to inform the analysis
  - Implemented the second year of the Inventoried Energy Program, contributing to efforts aimed at ensuring reliable energy supply amidst decreasing reserve margins and increasing intermittent resources
  - **2025:** Evaluate Potential Tie Benefits Winter Modeling Improvements
- Regional Energy Shortfall Threshold (REST) Initiative
  - Completed the work on defining a "regional energy shortfall threshold" to assess energy adequacy during extreme weather
  - Developed dual metrics for REST, focused on both the magnitude and duration of energy shortfalls, using a "conditional expectation" approach to better estimate high-impact tail risks
  - Estimated a "manageable" energy shortfall of 245,000 MWh over 72 hours during extreme weather and used this as a reference point for defining minimum manageable metrics
- **2025:** Defining an acceptable REST with stakeholders
- **2025:** First Competitive Solicitation for Longer-Term Transmission Planning (LTTP) Solution

Key Metrics – Responsive Market Designs

Goal: Advance the competitive wholesale markets to support the investment and new services required for a reliable clean energy transition

- Wholesale energy market is structurally competitive
  - Operating reserve margins remain relatively high
  - Residual Supply Index (RSI) scores meet expectations
  - Energy market mitigation is relatively infrequent
  - Markups in RT and DA markets were close to zero or negative
  - In 2024, withheld economic capacity relatively low
- Wholesale capacity market structurally competitive
  - RSI and Pivotal Supplier Test scores: no pivotal suppliers
  - Overall competitiveness increased with decrease in SENE zonal load forecast & increase in import capability limit

Key Metrics – Progress and Innovation

Goal: Expand capabilities to support increasing grid complexity brought about by new technologies and changes to supply mix and customer use

- Improve day-ahead load forecasting accuracy
  - Average accuracy for peak hours of the month meets ISO's standards, but average accuracy across all hours of month does not. See Monthly COO report to NEPOOL for detail
- Enhance programs to incorporate state policy objectives
  - Reflect state energy efficiency goals; PV and electrification growth in long-term forecasting methodology. See NEPOOL Load Forecast Committee & Planning Committee working groups
  - In 2025, ISO began implementing a project to enhance longer-term transmission planning program
- Interconnect and register new resources to meet FERC established timeframes
  - Order 2023 Reporting metrics (to be implemented)
  - Streamlined DER process through transferring all distribution system interconnection to state processes

Key Metrics – Operational Excellence

Goal: Continuously improve operations and processes, with a focus on prioritizing project scope and implementation, business results, and continuity of reliable operations

- Maintain NERC Standards compliance
  - Operate bulk electric system reliability, e.g., within frequency limits; to avoid instability, cascading outages or uncontrolled separation
  - Maintain accurate planning models and update planning studies
  - Oversee facility interconnection studies
- Accurately settle markets with no errors
  - Administer hourly market operations with minimal LMP corrections and zero provisional DAM results adjustments
  - Maintain IT uptime and ensure business continuity
- Continuous assessments of cyber security threats and risks against CIP Standards; NIST Framework; DHS Known Exploited Vulnerabilities; phishing attempts
- Maintain accurate quarterly budget forecasts, comparing projected costs/revenues against actual financial results

Key Metrics – Stakeholder Engagement

Goal: Collaboratively understand and anticipate needs, demonstrate thought leadership through high-quality analysis and communication, and nurture productive relationships with regulators and stakeholders, including the public, in supporting the four pillars of the clean energy transition

- Address public policy concerns
  - Assess regional policy requests
  - Administer stakeholder prioritization process
  - Hired for position to focus on environmental policies and community outreach in 2024
- Annually survey stakeholder satisfaction with ISO services
  - Overall service quality
  - Market Participant training course satisfaction
- Over past several years, ISO has delivered products responsive to New England States' 2020 Vision and policy initiatives:
  - Request to evaluate clean energy pricing (Pathways report)
  - Updated economic planning study methodology
  - Request to conduct longer-term transmission planning (Future Grid Reliability Study; 2050 transmission study)
  - Enhancement to longer-term transmission planning process
  - Technical support on States' RFP efforts

APPENDIX 4: CYBER SECURITY AND CIP COMPLIANCE HISTORY AND COSTS

Cyber Security and CIP Compliance

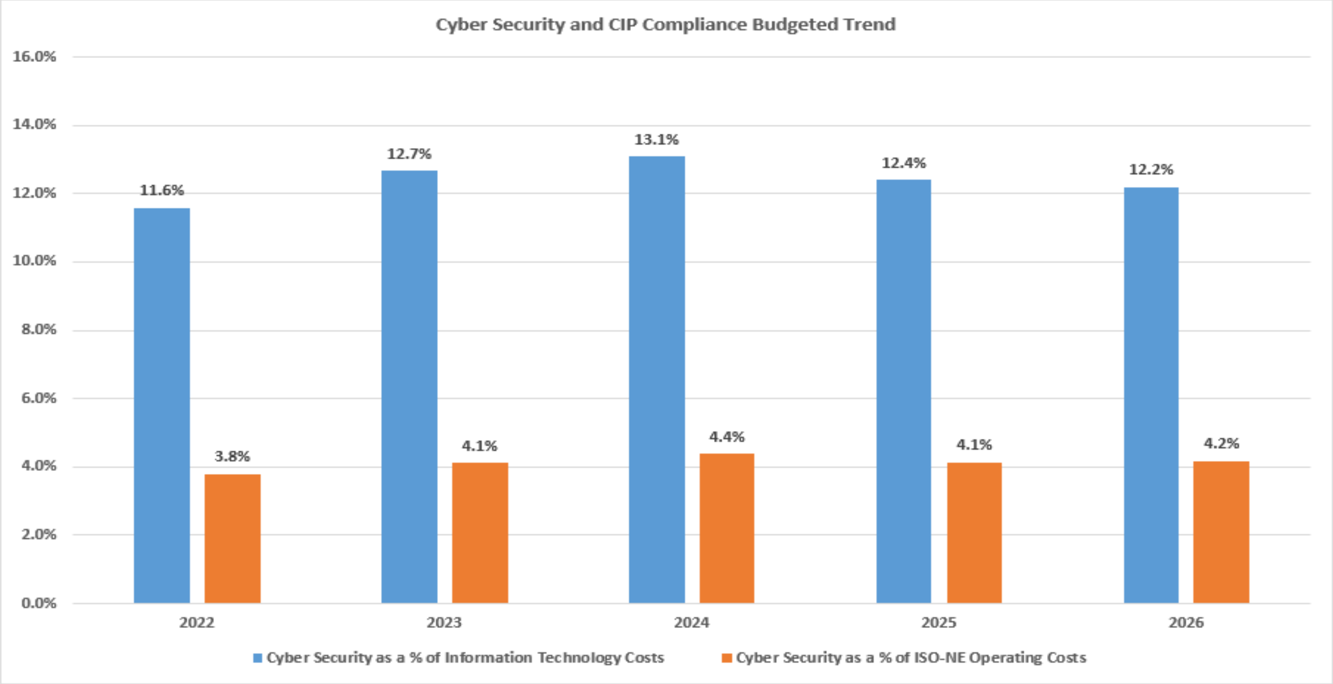
- Background
  - Information technology has become an indispensable tool for efficiently and reliably operating the increasingly complex regional power system, administering the billion-dollar markets where wholesale electricity is bought and sold in New England, and engaging and collaborating with our stakeholders
  - The energy sector faces significant risk of attempted cyber intrusion; ISO-NE is committed to making sure power grid and market operations remain secure and will continue to build on our already extensive process controls, advanced detection and response systems, and redundancy in systems and control centers
  - Our Security Operations Center monitors the ISO-NE environment and multiple new state-of-the-art cyber security capabilities were deployed in 2022, including best in class endpoint detection and response, network detection and response, software vulnerability detection, and cyber threat hunting
  - A prominent corporate objective requires all ISO-NE employees to participate in annual cyber security training; ISO-NE has tightened security controls for cyber assets and visitors to ISO facilities in compliance with revised NERC CIP cyber security standards
  - ISO-NE developed and implemented a third-party cyber security risk management program that includes compliance with CIP-013 related to Supply Chain Cyber Security Risk

Cyber Security and CIP Compliance *(cont.)*

- A CIP and Systems Compliance Operations Group provide day-to-day support of highly complex infrastructure and cybersecurity compliance functions required by North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) standards - Version 5
- During 2022 ISO-NE also procured additional software to enhance our capability to visualize, detect, and respond to threats and vulnerabilities from industrial control systems and technology that interfaces with the physical world (e.g., distributed control systems, SCADA); and software to improve ISO-NE's ability to recognize and block phishing attempts, as these attempts have increased exponentially and become more sophisticated in the past several years; additional alerts and automations to increase the reach and productivity of Security Operations Center staff continue to be developed
- During 2023 ISO-NE began to incorporate "immutable" technology that prevents modifications to data written to disk for both enterprise storage applications and system backups providing greater resiliency and protection for ransomware-style attacks; in the same year, ISO-NE deployed a technology framework to identify and fix known vulnerabilities more rapidly and to protect applications from emerging threats
- In June 2024, ISO-NE completed its periodic NERC CIP compliance audit with NPCC resulting in zero potential non-compliance (PNC) items, zero areas of concern (AOC), and four positive observations shared jointly with the Operations review
- In 2025, ISO-NE extended the adoption of "immutable" storage technology to include all servers and workstation backups and even protects active storage for some key services

Cyber Security and CIP Compliance *(cont.)*

To ensure robust cyber security defenses against ongoing sophisticated threats and to ensure compliance with CIP standards, ISO-NE has increasingly invested in these areas which have trended higher of our Information Technology and Overall Operating Expense Budgets



APPENDIX 5: ISO/RTO FINANCIAL COMPARISON

Financial Results Summary

ISO/RTO Financial Summary - 2024 Actual Results

Operating Expense and Capital Expenditures for Calendar Year 2024, and Outstanding Debt as of December 31, 2024 [1]

(Amounts in Millions)

	ISO-NE [2]	PJM	NYISO	CAISO	IESO [3]	MISO	SPP	ERCOT
Operating Expense - 2024	$ 264.6	$ 498.1	$ 256.2	$ 288.5	$ 299.4	$ 515.7	$ 285.6	$ 330.0
Less: Amortization & Depreciation	(31.6)	(38.7)	(22.1)	(27.4)	(25.6)	(35.0)	(17.8)	(43.6)
Regulatory Fees	(8.0)	(111.4)	(18.3)	-	-	(76.1)	(36.2)	-
Grant Expenses	-	-	-	-	-	-	-	-
Net Operating Expense - 2024	$ 225.0	$ 348.0	$ 215.8	$ 261.1	$ 273.8	$ 404.7	$ 231.5	$ 286.5
Other Financial Data								
Capital Expenditures for 2024	$ 29.6	$ 45.6	$ 14.8	$ 35.1	$ 79.3	$ 35.4	$ 23.4	$ 48.6
Outstanding Debt as of 12/31/24	$ 108.3	$ 2.2	$ 81.5	$ 147.9	$ 277.0	$ 274.4	$ 101.3	$ 2,457.0
Actual full-time equivalent headcount as of 12/31/24	670.5	844.0	628.0	733.0	978.0	1117.0	828.0	954.0

(1) Applicable amounts were taken from each entity's 2024 audited financial statements.

(2) ISO-NE Amortization & Depreciation and Capital Expenditures are presented on a cash-flow basis

(3) Amounts are in Canadian dollars

Questions

5.b 2026 NESCOE Budget

Sep 4, 2025
Meeting

NEPOOL
NEW ENGLAND POWER POOL
Participants Committee

New England States
Committee on Electricity

2026 Budget Presentation

NEPOOL Budget & Finance Subcommittee

August 8, 2025

Background: Budget Review

Term Sheet Provision: "… the annual review of its [NESCOE's] proposed budgets by at least the NEPOOL Participants Committee will be limited to considerations of accounting and reconciliation, so long as spending remains within the boundaries established by those frameworks….. NESCOE will develop an operating budget recommendation for each year in consultation with NEPOOL, the PTO Administrative Committee and ISO-NE within the boundaries of the then-approved five year budget framework …"

- ✓ Proposed 2026 budget conforms to:
  - Boundaries of 5-year pro forma (2023-2027) reviewed by Budget & Finance
  - NESCOE commitment not to seek an increase over pro forma budget of more than 10% in any 1 year: 2026 proposed budget is less than 2026 5-year pro forma budget
- ✓ Following calendar year 2024, independent auditor concluded NESCOE books conform to generally accepted accounting principles

Background: Policy Priorities

Term Sheet Provision Governing Identification of Policy Priorities:

"Each year NESCOE will produce a ***Report to the New England Governors*** that will document its accomplishments from the preceding year and its projected policy priorities for the coming two years. This report will include a full accounting of spending by NESCOE during the preceding year and proposed budgets for each of the upcoming two years."

Consistent with Term Sheet, 2024 *Report to the New England Governors*:

- ✓ Reviewed work in 2024
- ✓ Projected policy priorities
- ✓ Provided spending from prior year
- ✓ Projected budget information for upcoming two years

Projected Policy Priorities

- ✓ NESCOE provided to the Governors the ***2024 Annual Report to New England Governors***

- ✓ Report simultaneously released to NEPOOL & ISO-NE & circulated to the Participants Committee

- ✓ NESCOE identified forward looking policy priorities at Section V, pages 16

Report in "Resource Center"

www.nescoe.com

Projected Policy Priorities

Transmission has a strong presence in forward-looking priorities. This includes, but is not limited to:

- ✓ Asset Condition Project Review and Oversight
- ✓ Operationalizing long-term transmission analysis, including evaluating the first solicitation for longer-term transmission solicitation and ways to further enhance longer-term transmission planning
- ✓ Procedures to ensure timely and effective consideration of advanced transmission technologies to get the most out of the existing system and new investments
- ✓ FERC's efforts to reform transmission planning through Order 1920, including state law-based transmission planning and cost allocation.

Wholesale Market Reforms. Continued engagement on capacity market reforms and understanding the market and consumer implications of Day Ahead Ancillary Services design.

Resource Adequacy. Engage in (1) ISO-NE's Economic Studies and provide input into their development, particularly with respect to assumptions about state laws; and 2) ISO-NE's Probabilistic Energy Adequacy Tool analysis, including, for example, providing assumptions and requesting scenarios to assess risks and options as the resource mix evolves pursuant to state laws and policies

NESCOE Organization & Misc.

Employees

- ✓ Retain and attract diversity in academic training, skills; blend of private & public sector experience
- ✓ In 2025, retained experienced staff member at reduced hours

Office Space

- ✓ No office leases at this time; renting meeting space as needed

Other Organization Matters

Technical Consultants

Technical consultants assist NESCOE in the regular course of business in analyzing ISO-NE studies and data.

Continue work with technical consultants to conduct independent analysis to inform state officials' decisions on key issues, including, for example:

- ✓ Wilson Energy Economics
- ✓ MP Energy LLC
- ✓ RLC Engineering
- ✓ Stickney Brook Consulting
- ✓ GDS Associates
- ✓ Oxford Power Systems
- ✓ Daymark Energy Advisors
- ✓ Apex Analytics

Legal Counsel

Litigation is not the primary means by which NESCOE seeks to accomplish its objectives & thus, greater resource and focus has historically, and thus far in 2025, been on technical consulting. Further, while NESCOE produces most legal pleadings and analysis internally, the frequency and type of litigation brought by others influences the extent to which NESCOE engages outside counsel.

- ✓ Primary FERC Counsel: Phyllis G. Kimmel Law Office PLLC

5-Year Pro Forma

Proposed 2026 budget conforms to 2026 budget in 5-year Pro Forma Framework

✓ 2026 Projected Budget in 5-Year Pro Forma:	$3,065,753
✓ 2026 Proposed Budget:	$2,731,108
✓ 2025 Budget, for reference:	$2,707,893

The 2026 Proposed Budget reflects:

- ✓ Continued emphasis on technical consultants (vs. outside legal services)
- ✓ Continued inflationary pressures
- ✓ No office rent or utilities
- ✓ More travel for meetings

5-Year Pro Forma, for reference

NESCOE
PRO FORMA BUDGET 2023-2027*

Expense Category	Year 16 (2023)	Year 17 (2024)	Year 18 (2025)	Year 19 (2026)	Year 20 (2027)
Salaries and Wages					
Salaries	1,311,718	1,377,304	1,446,169	1,518,478	1,594,401
Payroll Taxes	131,172	137,731	144,617	151,848	159,440
Health and Other Benefits	110,098	115,603	121,383	127,452	133,825
Retirement §401(k)	52,469	55,092	57,847	60,739	63,776
Total, Salaries and Wages	**1,605,457**	**1,685,730**	**1,770,016**	**1,858,517**	**1,951,443**
Direct Expenses - Consulting					
Technical Analysis	342,933	353,221	363,818	374,732	385,974
Legal (FERC)	342,933	353,221	363,818	374,732	385,974
Total, Direct Expenses, Consulting	**685,866**	**706,442**	**727,635**	**749,464**	**771,948**
General and Administrative					
Rent		12,000	12,360	12,731	13,113
Utilities		2,500	2,575	2,652	2,732
Office and Administrative Expenses	50,000	51,500	53,045	54,636	56,275
Professional Services	41,500	42,745	44,027	45,348	46,709
Travel/Lodging/Meetings	60,000	61,800	63,654	65,564	67,531
Total General and Administrative	**151,500**	**170,545**	**175,661**	**180,931**	**186,359**
Capital Expendiures & Contingencies					
Computer Equipment	8,666	8,926	9,194	9,470	9,754
Contingencies	244,682	252,022	259,583	267,371	275,392
Capital Expenditures & Contingencies	**253,348**	**260,948**	**268,777**	**276,840**	**285,145**
TOTAL EXPENSES**	**2,696,171**	**2,823,665**	**2,942,090**	**3,065,753**	**3,194,896**

*Projected 5% salaries and wages annual adjustment, and projected 3% annual adjustment on all other items. Line items and categories subject to increase greater than, or decrease from, amounts projected. Any such changes will be subject to review, input, and recommendations by the NEPOOL Participants Committee (and/or its designees).

**At no time during this 5-year period will NESCOE seek a budget increase of more than 10% in any 1 year of more than 30% on a cumulative basis.

2026 Proposed Budget

NESCOE
Proposed 2026 Budget

	2026
Salaries and Wages	
Salaries	1,154,640
Payroll Taxes	115,464
Health and Other Benefits	140,000
Retirement §401(k)	46,186
Total, Salaries and Wages	**1,456,290**
Direct Expenses - Consulting	
Technical Analysis	550,000
Legal (FERC)	200,000
Total, Direct Expenses, Consulting	**750,000**
General and Administrative	
Rent	-
Utilities	-
Office and Administrative Expenses	54,535
Professional Services	60,000
Travel/Lodging/Meetings	150,000
Total General and Administrative	**264,535**
Capital Expend. & Contingencies	
Computer Equipment	12,000
Contingencies	248,283
Capital Expend. & Contingencies	**260,283**
TOTAL EXPENSES	**2,731,108**

2024 & 2025 Spending & Implications for 2026

Unspent funds in any year credited toward future year

2024 Total Spending:	$1,692,408*
2025 Spending to end of June:	$896,285
2025 Projected Year End:	$2,115,965*

*Cumulative prior years' true up, including 2023, was reflected in the 2025 revenue requirement and rates. The 2024 true up will be reflected in the 2026 revenue requirement and rates (see next slide). Any 2025 true up will be reflected in the 2027 revenue requirements and rates.

2026 Projected Billing Rate

With thanks to ISO-NE for calculations -

2026 Budget:	$2,731,108
Less 2024 True Up:	($933,127)
Total Revenue Recovery:	$1,797,981
Divided by Total Network Load:	222,552,617

(total network load from 2025 ISO-NE tariff; no escalation or reduction used in calculation)

2026 Schedule 5 Estimated **Rate $0.00808 per kW-month**

Thank you.

Questions?

6 IMM 2024 Annual Markets Report Highlights

Sep 4, 2025
Meeting

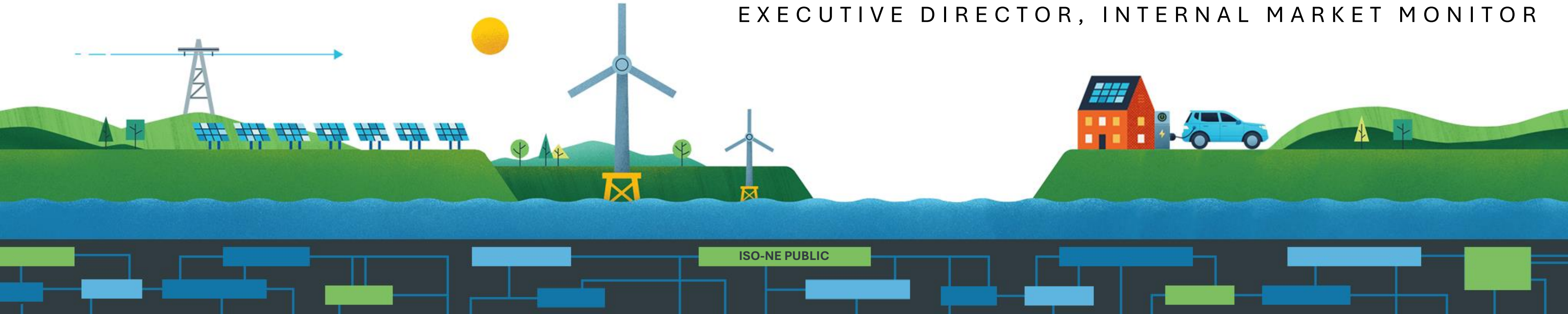
SEPTEMBER 4, 2025 | NEPOOL PARTICIPANTS COMMITTEE, BOSTON, MA

IMM Annual Markets Performance Report

Highlights of the 2024 Report

Dave Naughton

EXECUTIVE DIRECTOR, INTERNAL MARKET MONITOR



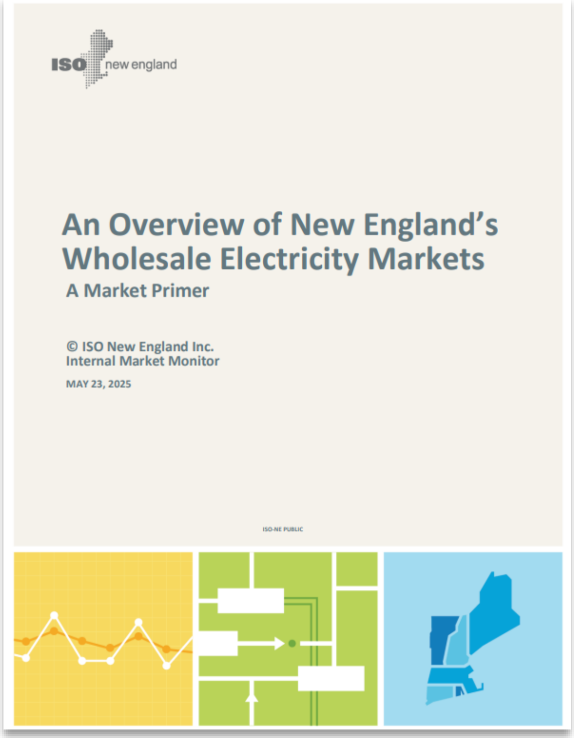
About the Internal Market Monitor

- The IMM is an independent group within ISO-NE with five core functions:
    1. Monitor Market Performance & Participant Behavior
    2. Report on Market Performance and Competitiveness
    3. Assess and Refer Potential Market Violations
    4. Administer the Market Power Mitigation rules
    5. Evaluate New and Existing Market Rules
- The IMM is composed of economists, market analysts, data scientists, business managers and legal counsel

Accompanying Market Primer Document

- Provides an overview of products procured through the wholesale markets: product definitions, procurement mechanisms, settlements

- Latest edition includes Day-Ahead Ancillary Services content



See IMM section of ISO-NE website or click on document image

At a Glance: High-level Market Statistics

Demand (MW)	2020	2021	2022	2023	2024	% Change '23 to '24	Sparkline
Load (avg. hourly)	13,305	13,561	13,576	13,096	13,294	2%	
Weather-normalized load (avg. hourly)[a]	13,242	13,419	13,514	13,132	13,226	1%	
Peak load (MW)	25,121	25,801	24,780	24,043	24,871	3%	
Generation Fuel Costs ($/MWh) [b]							
Natural Gas	16.34	36.07	72.57	23.76	23.83	0%	
Coal	37.82	67.77	144.87	69.19	58.89	-15%	
No.6 Oil	89.42	138.21	221.17	164.97	154.96	-6%	
Diesel	112.07	184.50	331.99	253.42	217.37	-14%	
Hub Electricity Prices: LMPs ($/MWh)							
Day-ahead (simple avg.)	23.31	45.92	85.56	36.82	41.47	13%	
Real-time (simple avg.)	23.37	44.84	84.92	35.70	39.50	11%	
Day-ahead (load-weighted avg.)	24.57	48.30	91.36	39.19	44.52	14%	
Real-time (load-weighted avg.)	24.79	47.34	91.13	38.25	42.47	11%	
Estimated Wholesale Costs ($ billions)							
Energy	3.0	6.1	11.7	4.5	5.6	24%	
Capacity[c]	2.7	2.3	2.0	1.8	1.4	-22%	
Uplift (NCPC)	0.03	0.04	0.05	0.03	0.03	1%	
Ancillary Services[d]	0.1	0.1	0.1	0.2	0.2	7%	
Regional Network Load Costs	2.4	2.7	2.8	2.7	3.0	11%	
Total Wholesale Costs	**8.1**	**11.2**	**16.7**	**9.2**	**10.2**	**11%**	
Supply Mix [e]							
Natural Gas	42%	45%	45%	48%	50%	2%	
Nuclear	22%	22%	23%	20%	22%	2%	
Imports	20%	16%	14%	13%	9%	-4%	
Hydro	7%	6%	6%	8%	7%	-1%	
Other[f]	5%	5%	4%	4%	5%	0%	
Wind	3%	3%	3%	3%	3%	0%	
Solar	2%	2%	3%	3%	4%	0.6%	
Coal	0%	0%	0%	0%	0.2%	0.04%	
Oil	0%	0%	2%	0%	0.3%	-0.01%	
Battery Storage	0%	0%	0%	0%	0.3%	0.10%	

- Capacity, energy, and ancillary service markets performed well and exhibited competitive outcomes in 2024; energy price changes were consistent with fuel prices, electricity demand and the supply mix
- Notable factors impacting the cost of supply were higher CO_2 prices from the Regional Greenhouse Gas Initiative (RGGI) program and lower net imports from Quebec

PUBLIC

WHOLESALE COSTS

- **Wholesale costs** totaled $10.2bn, up by $1bn year-over-year on higher energy costs (up $1.1bn) and transmission costs (up $0.3bn); capacity costs down by $0.4bn

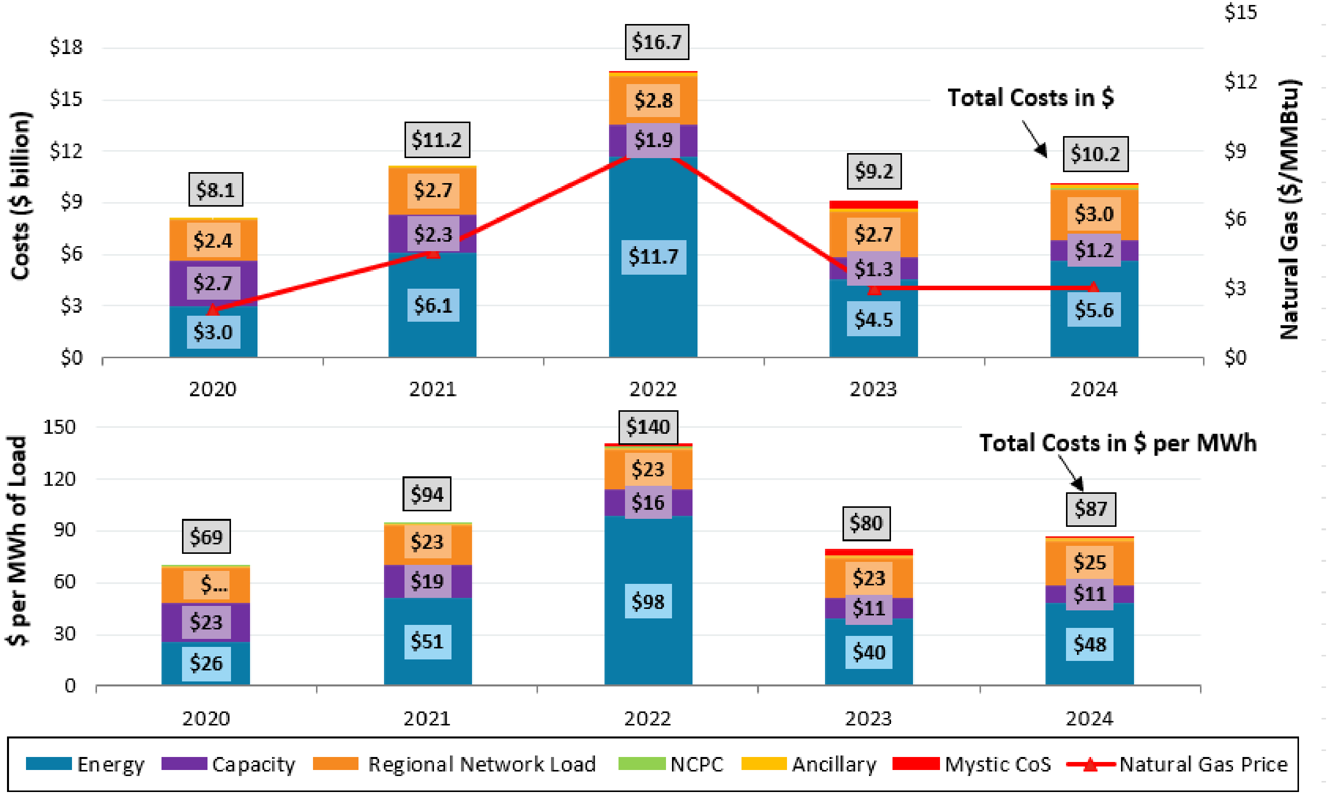
– **Energy costs** of $5.6bn (~55% of total costs) and energy price increase ($41.47/MWh, up 13%); change driven by higher CO2 prices from the Regional Greenhouse Gas Initiative (RGGI) program and lower net imports

– **Capacity costs** based on rates of $2.00 and $2.61/kW-mo in FCA 14 and 15, reflecting surplus capacity of over 1,300 MW relative to NICR

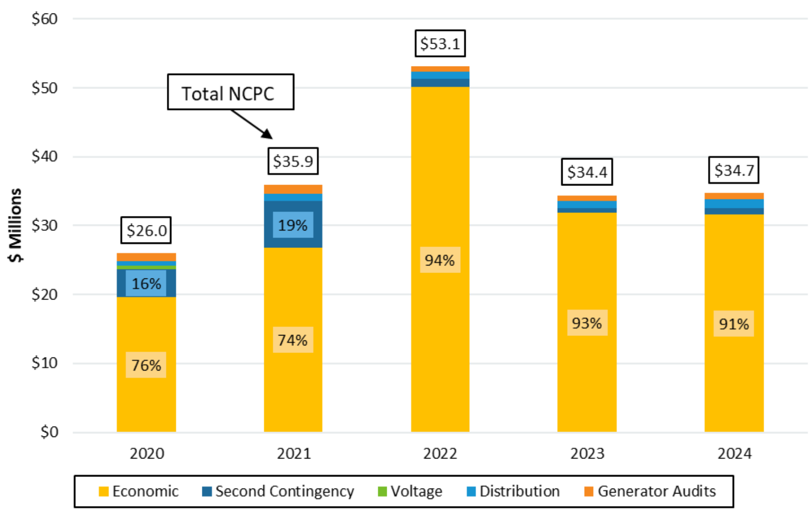
– **Uplift** of $34.7m of (0.6% of energy costs) primarily covered economic commitments. Supplemental payments under the Mystic reliability agreement for fuel security were significantly higher at $139m

– **Transmission costs** increased due to reliability-needs and asset condition projects, as well as inflationary pressure on transmission equipment; **Congestion** costs of $36.9m (0.7% of energy costs) were modest with export constrained flows at the main interface with New York, and northern New England continuing to be the significant drivers

Higher energy costs drove an overall $1 billion increase in wholesale costs due to higher CO_2 prices and fewer net imports; transmission costs also up



Uplift payments totaled nearly $35 million this year, 91% of which was economic NCPC



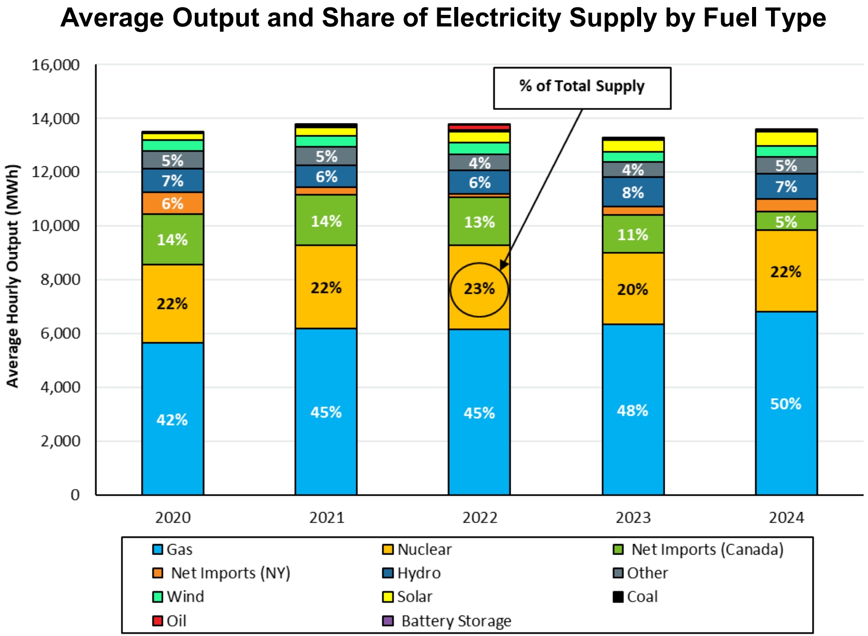
Energy and Uplift Payments

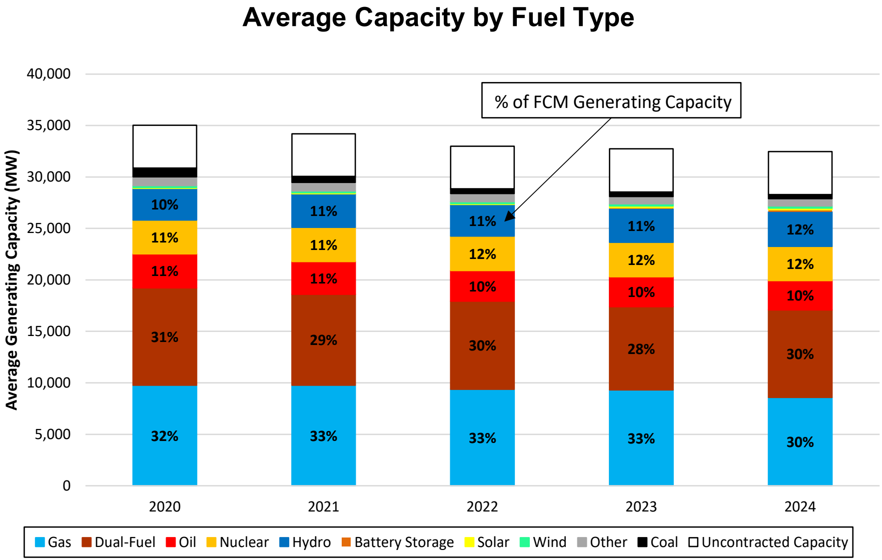
	2020	2021	2022	2023	2024
Energy Payments ($ millions)	$ 2,996	$ 6,099	$ 11,712	$ 4,537	$ 5,624
NCPC Payments ($ million)	$ 25.95	$ 35.94	$ 53.08	$ 34.39	$ 34.72
NCPC in $/MWh	$ 0.22	$ 0.30	$ 0.45	$ 0.30	$ 0.30
NCPC as % Energy Payments					
Day-Ahead NCPC	0.3%	0.3%	0.1%	0.1%	0.1%
Real-Time NCPC	0.5%	0.3%	0.3%	0.7%	0.5%
Total NCPC as % Energy Costs	**0.9%**	**0.6%**	**0.5%**	**0.8%**	**0.6%**

SUPPLY AND DEMAND CONDITIONS

- **Energy and capacity mix** trends show reduced imports and declining overall capacity
- **Profitability and net revenue metrics** show market conditions remain below the cost of new conventional generation. Net revenues for existing resources vary widely, with steam turbine generators relying heavily on capacity revenues
- **Demand** has been relatively steady in recent years, but heating and transportation driven demand expected to drive average and peak demand growth
- The pace of the **energy transition** and impact on wholesale operational and market metrics is gradual to date; most significant impact is on load and pricing profiles due to solar generation
  - In this report we establish a framework for assessing trends in market and operational issues identified in long-term studies such as EPCET and Pathways

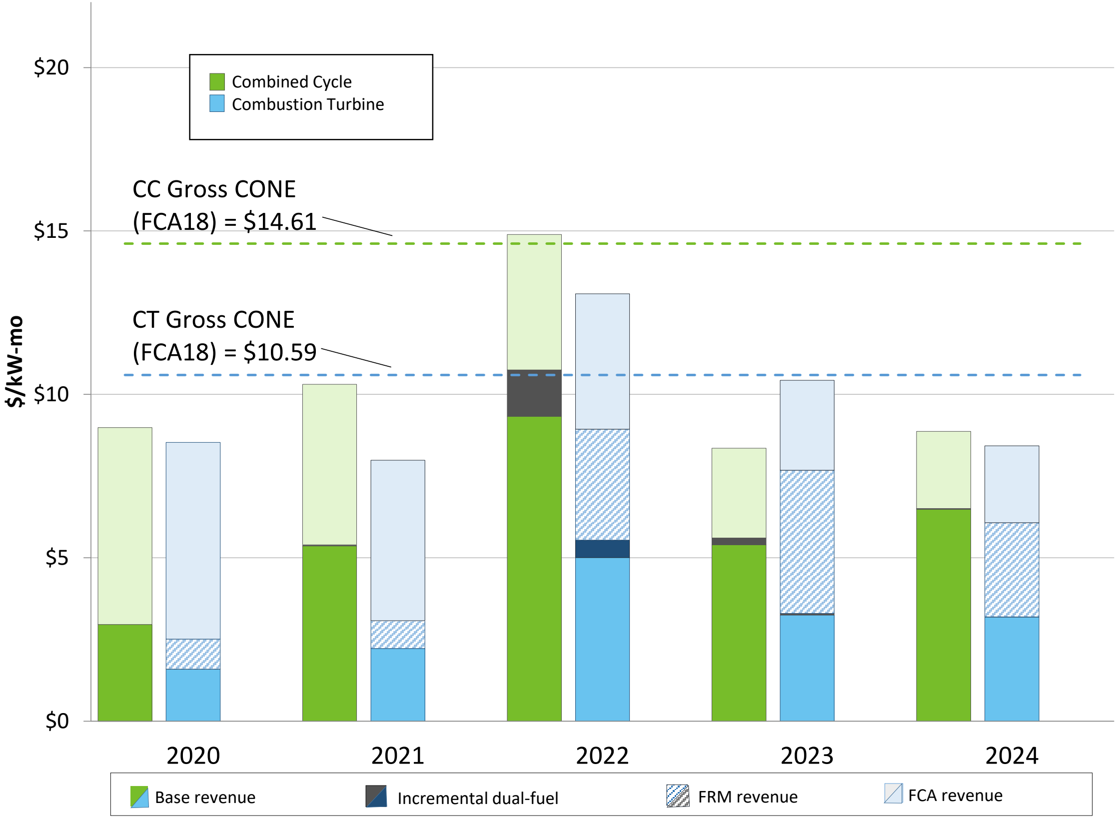
Trends in energy and capacity mix show fewer imports, declining overall capacity





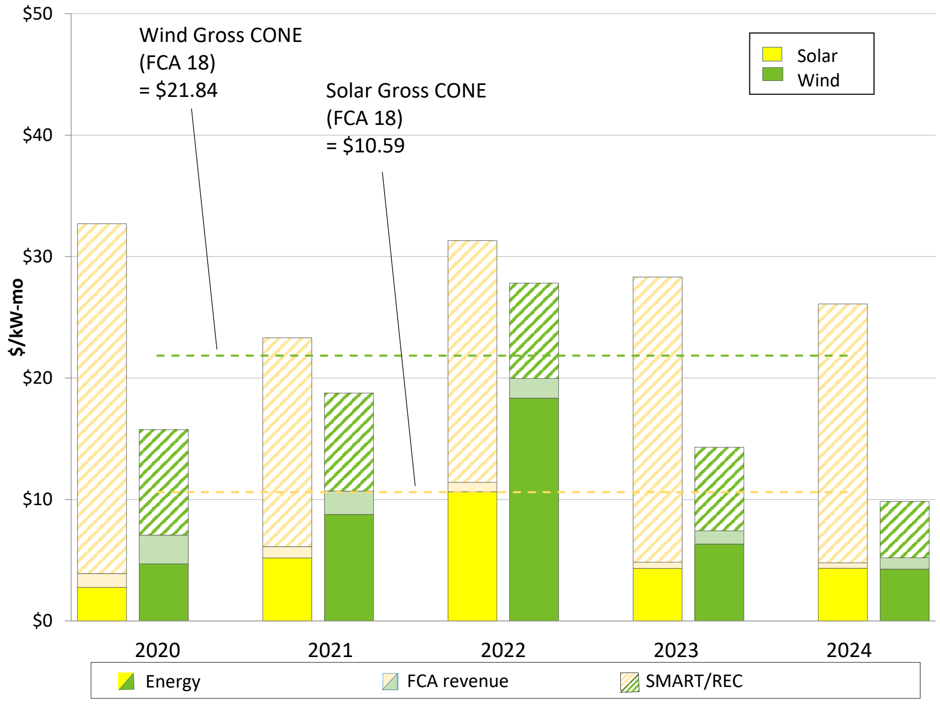
The “Other” category includes active capacity demand response, landfill gas, methane, refuse, steam, and wood.

Market-based revenues in 2024 were below the going-forward costs of new entrant gas-fired generators

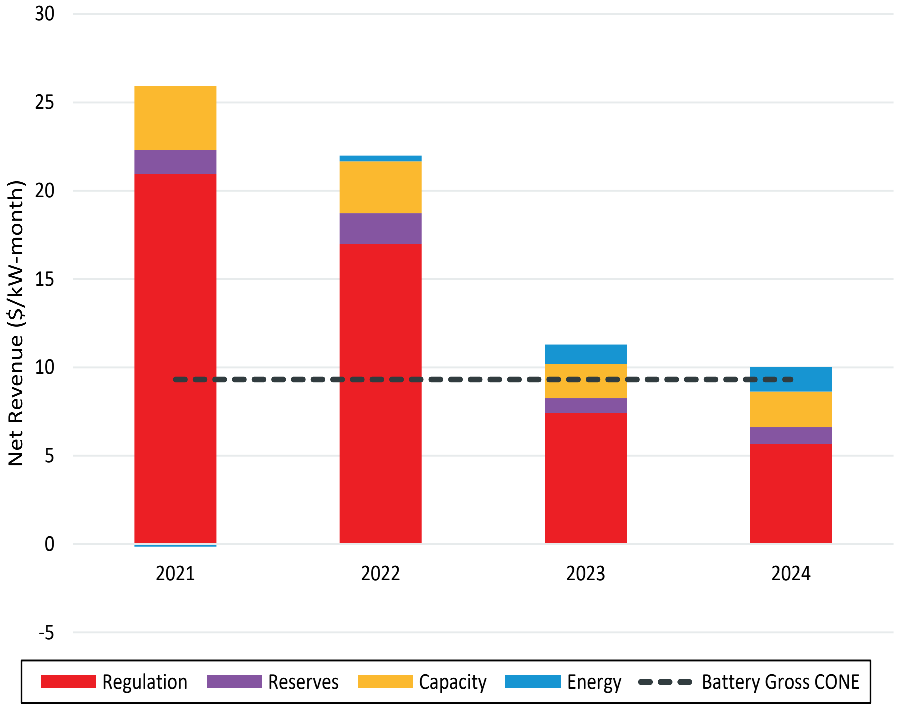


Profitability of most new entry technologies intricately linked with state policies; wholesale market revenues falling for energy storage

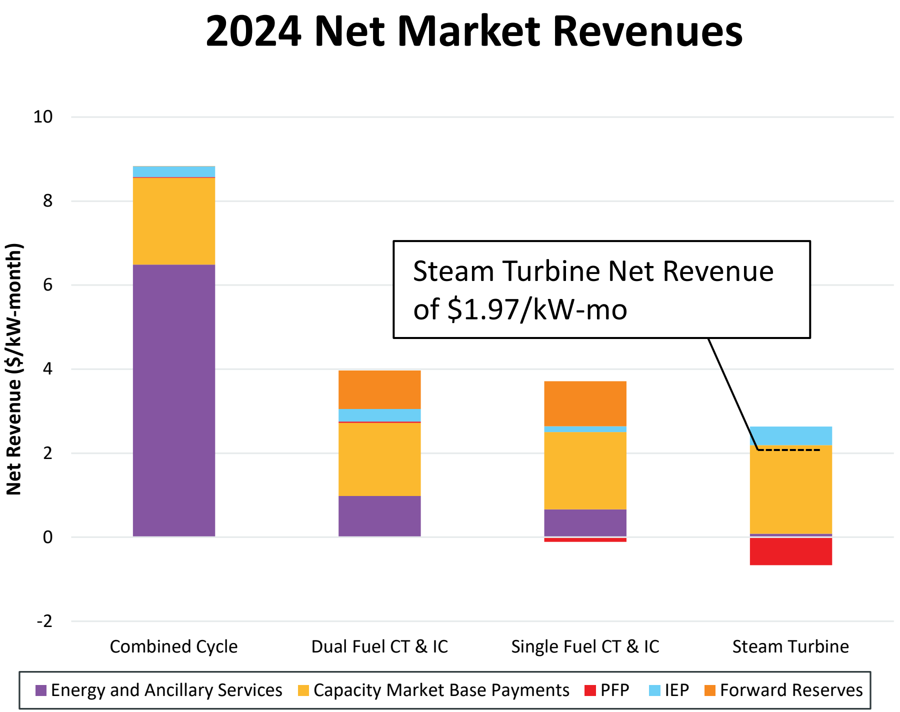
Net Revenue for Solar- and Wind-Powered Units

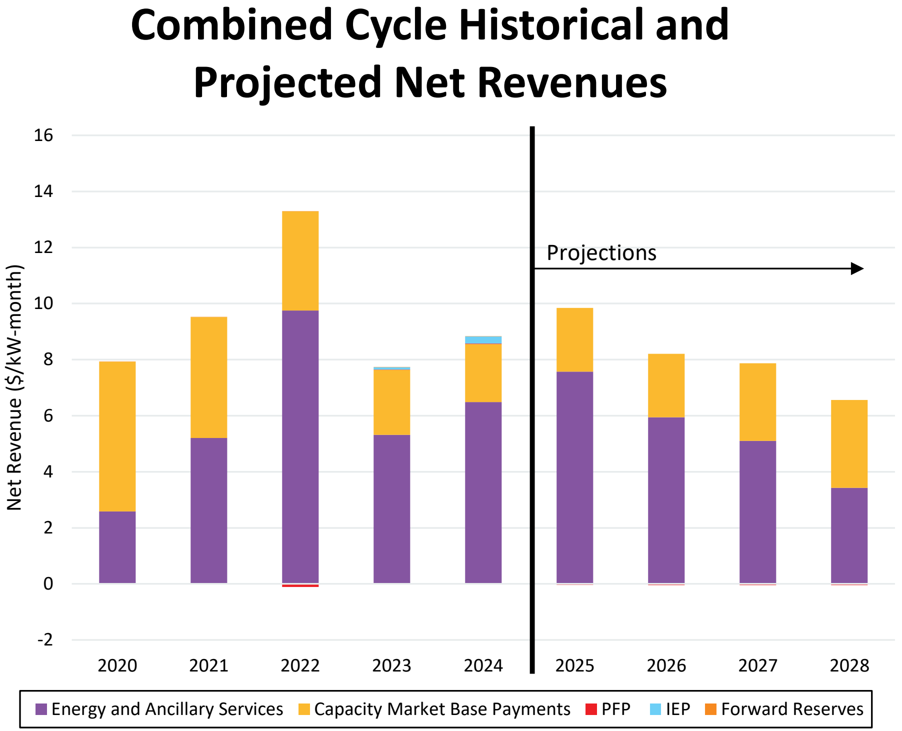


Net Revenues for Battery Resources



Net market revenues for existing resources highlight the varied levels and sources of revenues



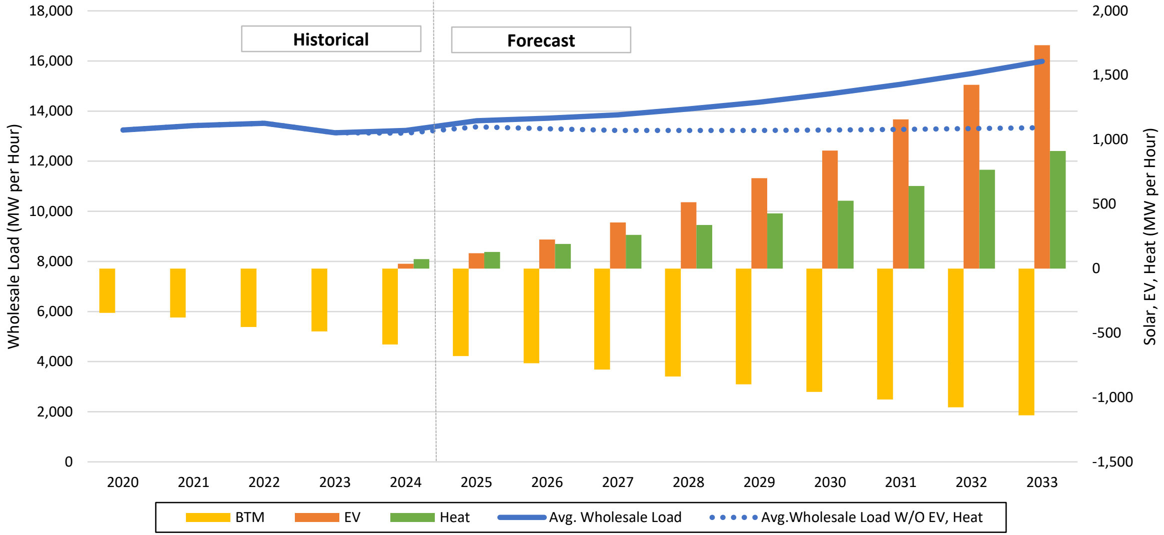


Note: Energy margin projections utilize forward power and natural gas prices, capacity based on FCA prices.

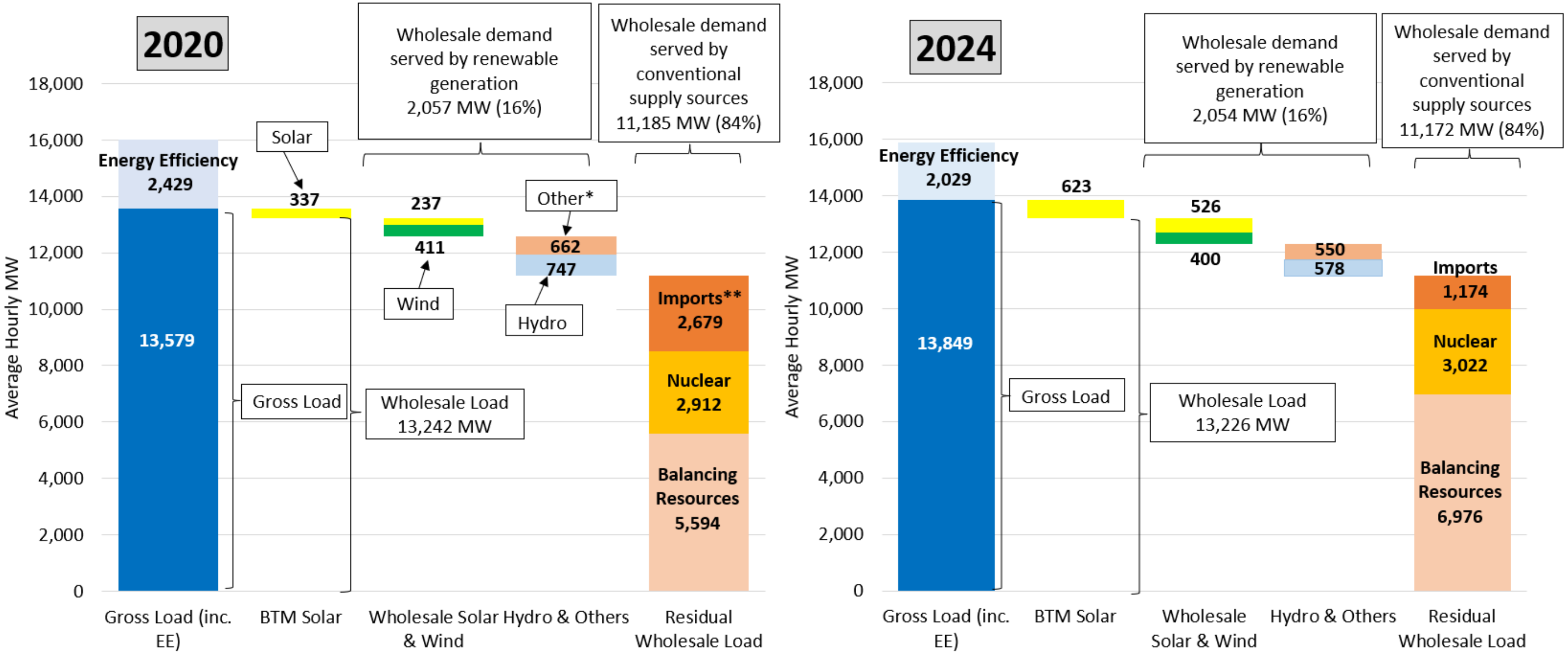
Stable load in past five years, with an expected 17% increase between 2023 and 2033 (note: forecast since revised down to 9% in 2025 CELT)

Demand (MW)	2020	2021	2022	2023	2024	% Change '23 to '24	Sparkline
Load (avg. hourly)	13,305	13,561	13,576	13,096	13,294	2%	
Weather-normalized load (avg. hourly)	13,242	13,419	13,514	13,132	13,226	1%	
Peak load (MW)	25,121	25,801	24,780	24,043	24,871	3%	
Minimum load (MW)	8,392	8,646	8,694	8,617	8,775	2%	

Historical and Forecast Average Hourly Load and Major Drivers (BTM solar, EV, and Heat)

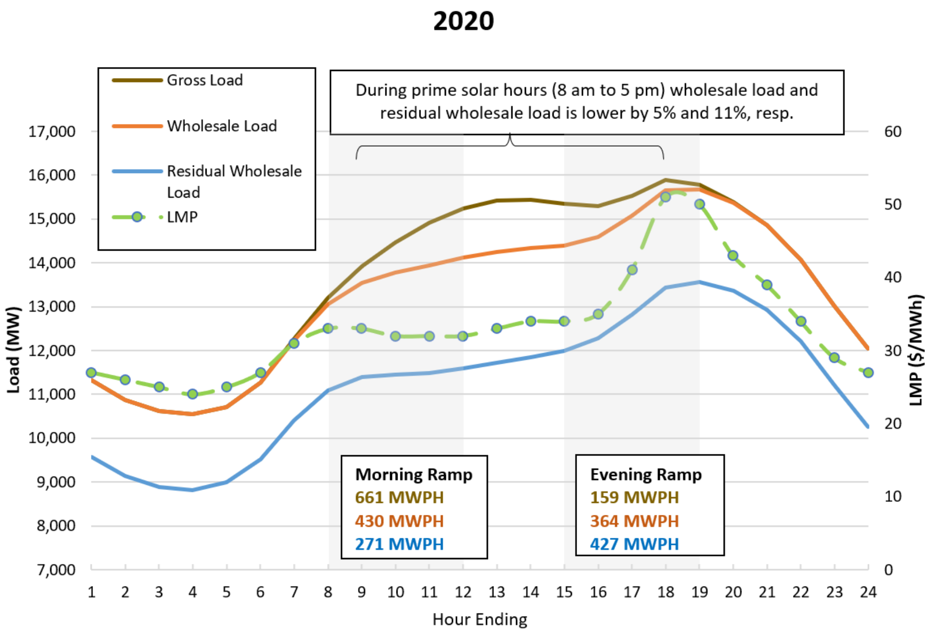


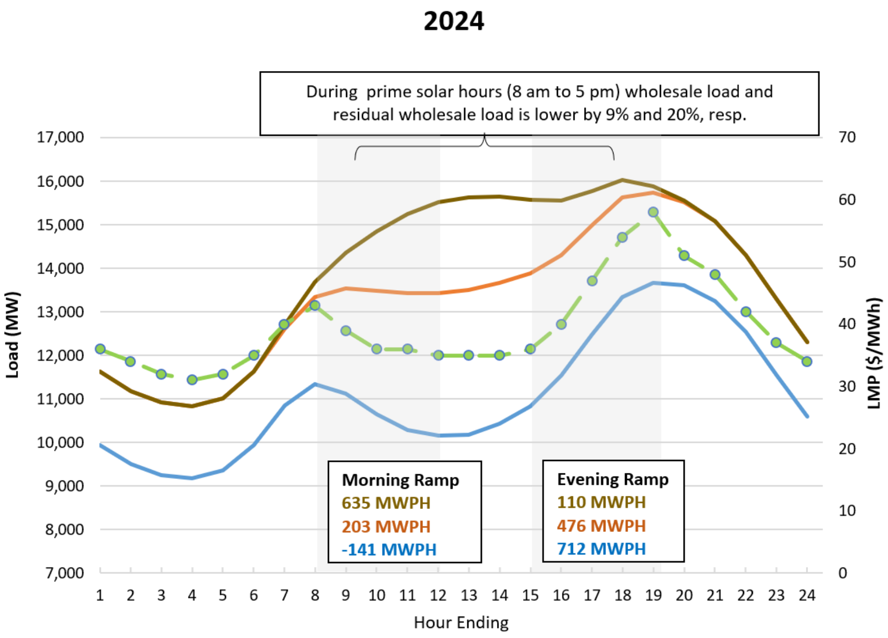
Energy transition demand and supply changes are gradual to date



* Other renewable sources include biomass, wood waste, refuse, landfill gas and methane.
** The net import value includes imports backed by renewable forms of generation.

Impact of renewable generation on load and pricing profiles



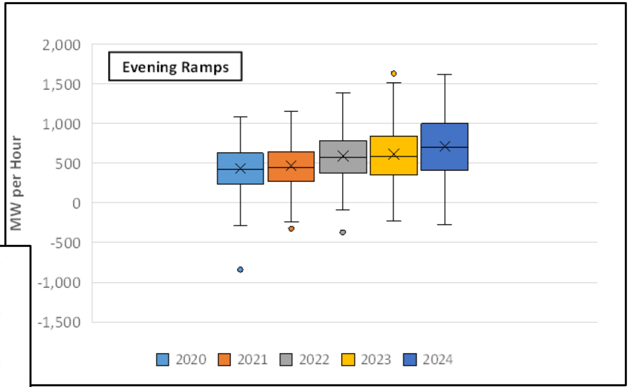


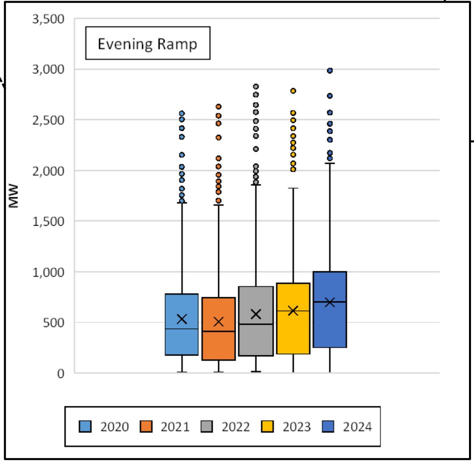
Note: The hourly average 2020 LMP is adjusted by the ratio of 2024 average natural gas price to the 2020 average gas price to allow for a more direct comparison

Metrics on anticipated operational/market impacts on the clean energy transition indicate gradual change

Metric	Trend
Seasonal/Annual Load Variability	↔
Morning and Evening Load Ramps (down and up)	↑
Downward Flexibility of Supply	↔
Fast-Start Generator Utilization	↑
Load Forecast Error	↔
Negative Energy Prices	↔
Negative Priced Offers	↔
Energy Price Level	↑
Energy Price Volatility	↑

Significant differences between winter loads expected as temperature-dependent heating demand increases [EPCET]





ENERGY AND ANCILLARY SERVICES MARKETS

- Avg. **natural gas price** ($3.06/MMBtu) was comparable to 2023; prices tracked historically low Henry Hub and Marcellus prices during non-winter months, while elevated pricing occurred during winter months

- **Day-ahead and real-time energy prices** increased in 2024 (11%-13%) from 2023 levels, reflecting increase in emissions costs, and a greater reliance on natural gas-fired generators due to fewer net imports, as well as dispatch in more expensive upper ranges of gas-fired capacity during hot summer conditions

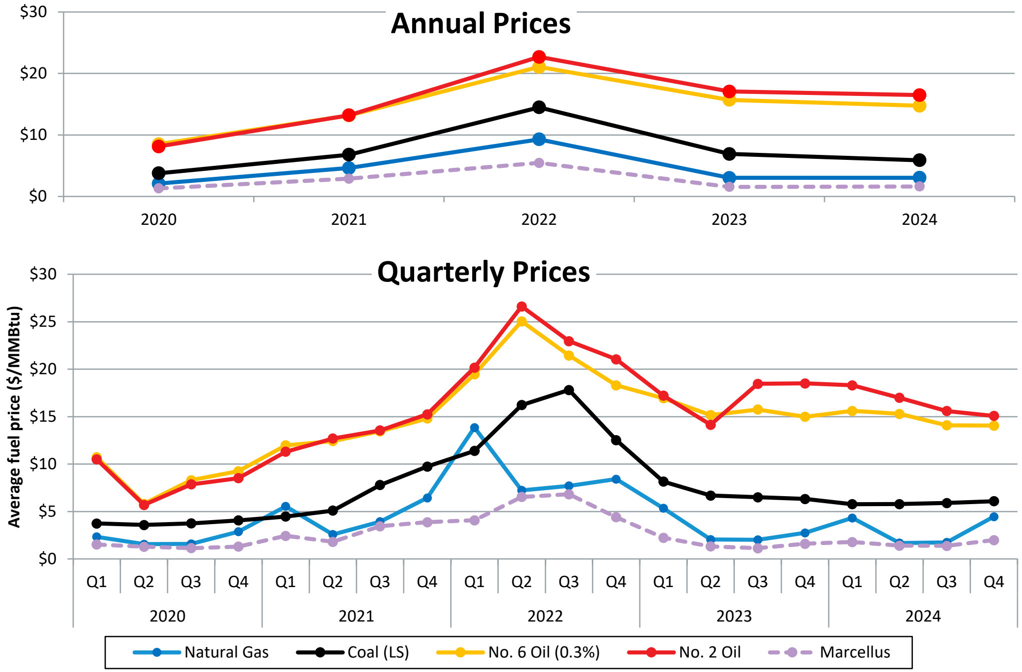
- **RGGI and MA EGEL** CO_2 cap-and-trade program costs added an estimated ~$8/MWh to the avg. load-weighted energy price and contributed about $910m to total energy costs

- **Net imports** (1,175 MW per hour) at lowest level since 2011, meeting 9% of demand; dry weather and reduced hydro generation in Quebec drove a ~50% decrease in imports from Canada (from 1,426 MW to 693 MW per hour); higher natural gas and nuclear generation offset reduction

- **Operations:** there were few capacity shortage events (2.3hrs), reliability commitments, and low levels of transmission congestion

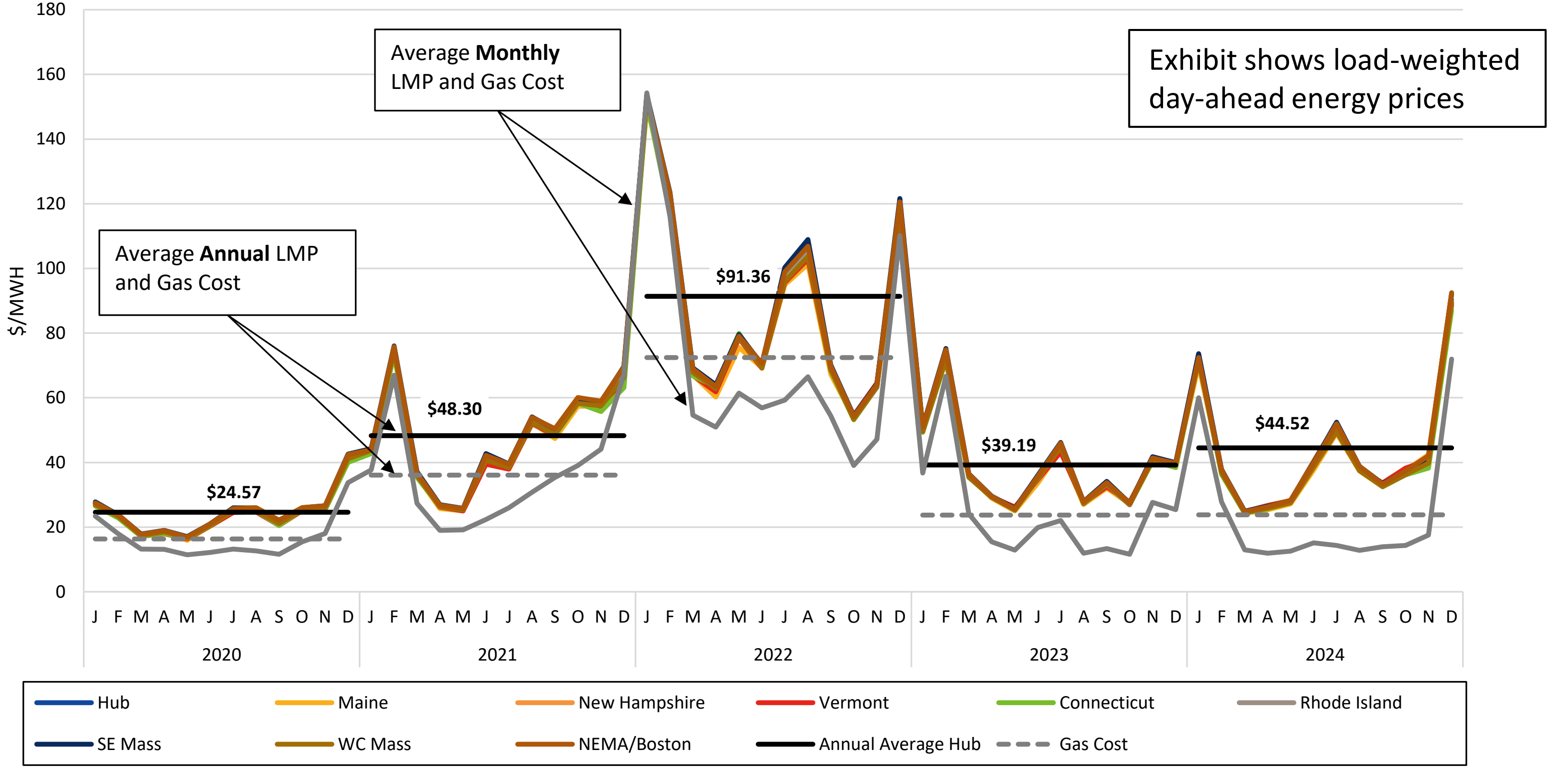
- **Recommendations** to address observed issues related to tie-breaking rule for scheduling external transactions, Pay for Performance Rate for export transactions, and real-time supply offers for renewable generation

Natural Gas prices averaged $3.06/MMBtu, which was relatively unchanged from the prior year



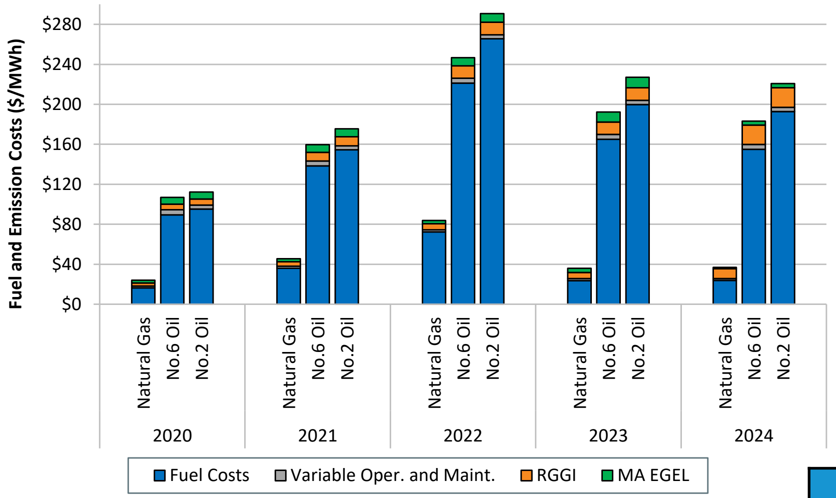
- Winter natural gas prices in New England are strongly influenced by cold temperatures
  - **Winter 2023-2024**: Mild weather and lack of cold snaps kept prices low
  - **Winter 2024-2025**: Higher prices due to colder weather starting in December 2024 and continuing through the winter

Natural gas continues to be the significant driver of energy prices, but annual changes driven by other supply factors (supply mix and CO_2 prices)



Carbon allowance costs made up a larger share of total fossil fuel generation costs compared to prior years, driven by rising RGGI prices

Annual Estimated Average Costs of Generation and Emissions



Related 2024 Key Figures

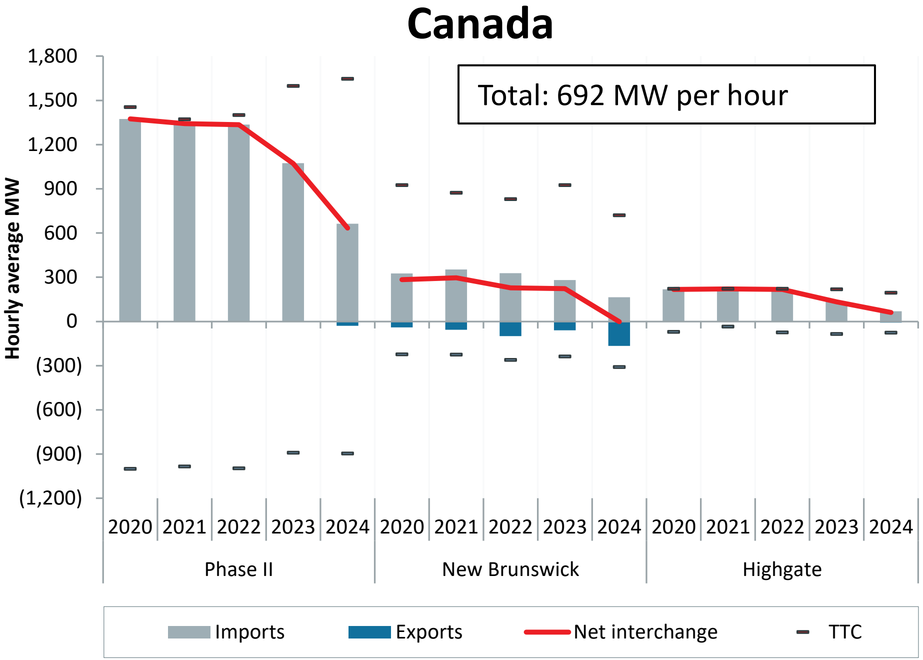
- **Generator CO_2 Compliance Costs:** $509 million
- **Estimated Impact on Energy Costs:** $910 million
- **Energy Efficiency Savings (Avoided energy costs):** $757 million

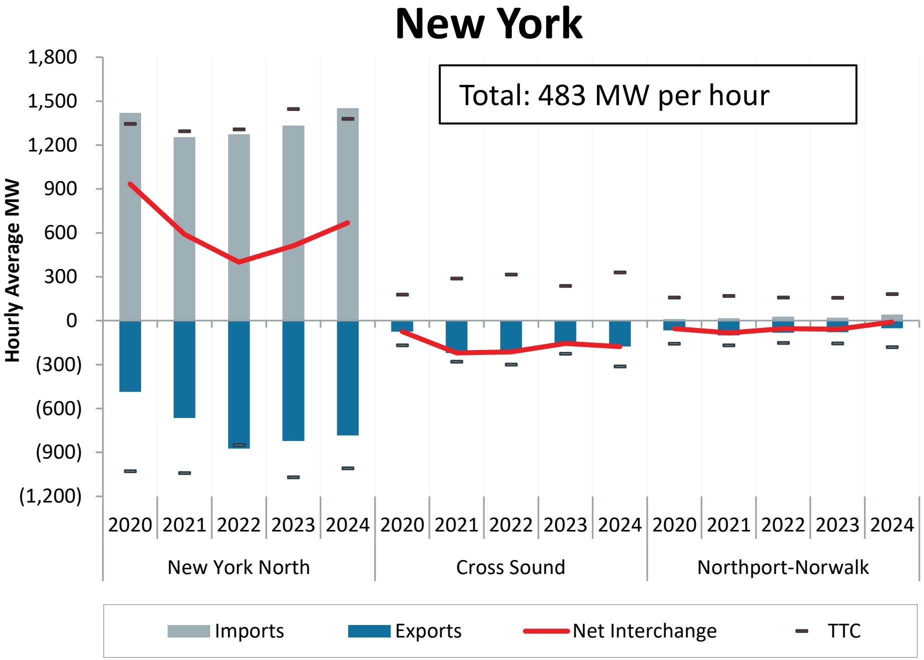
2024 Estimated Average Costs of Emissions and Percent Contribution of Generation Costs

Fuel Type	RGGI Costs ($/MWh)	MA EGEL Costs ($/MWh)	RGGI % of Generation Costs	Total CO_2 % of Generation Costs
Natural Gas	$9.59	$1.62	27%	30%
No. 6 Oil	$19.20	$3.96	11%	13%
No. 2 Oil	$19.80	$4.08	9%	11%

Note: Standard generator heat rates and fuel emission rates are used to convert $/ton CO2 prices to $/MWh generation costs.

Net interchange between New England and Canada fell substantially for the second consecutive year, while flows from New York offset some of the decline





Despite the overall decline, net imports remained a critical supply source during high-load periods, averaging nearly 2,700 MW per hour on days when load exceeded 20,000 MW

Recommendation: ISO-NE should re-evaluate non-CTS external interface clearing rules

- Participants use virtual demand bids at the Highgate interface to try and secure clearing priority for real-time imports when multiple import transactions are submitted
  - Virtual demand bids provide counter-flow, enabling >225 MW of DA imports
  - Real-time priority awarded based on:
    1. Real-time price
    2. Day-ahead cleared award
    3. Time-of-submission
    4. Pro-rata
  - The time-of-submission tiebreaker encourages participants to submit external transactions 40 days prior without changes
  - In the DA A/S market, DA cleared imports also receive Forecasted Energy Requirement credits – even if they exceed the interface's capacity

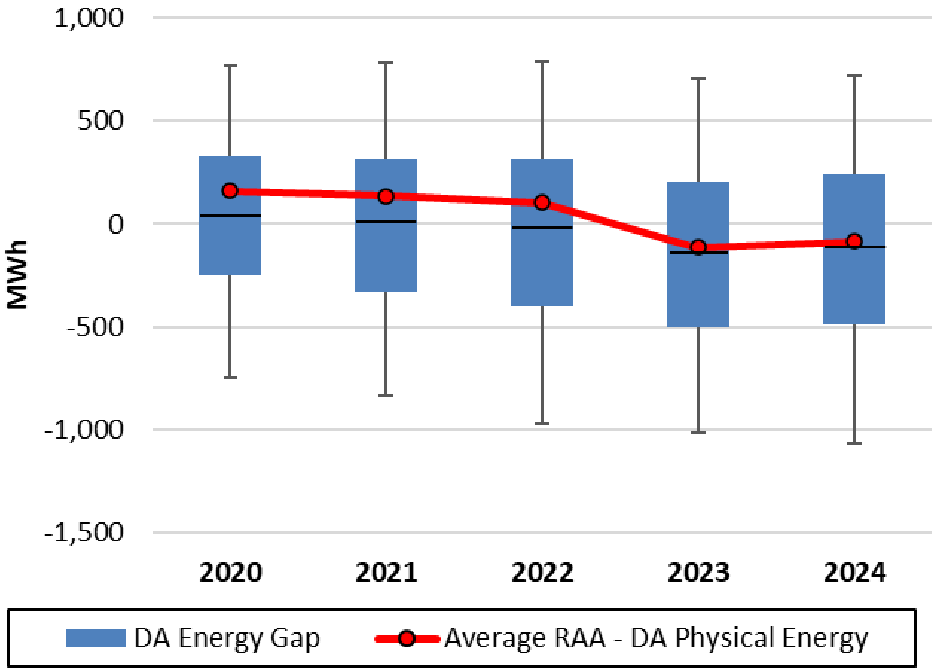
- We recommend ISO-NE revise these rules to better align external bids with expected quantities and the cost or value of the underlying energy

Recommendation: Pay-for-Performance Treatment of Export Transactions

- Issue: Unequal treatment of imports vs. exports during Capacity Scarcity Condition (CSC) events
  - Imports receive LMP + PFP rate
  - PFP netting rules exist for participants with exports and imports; however, exporting-only participants are only charged the LMP
  - Over-incentivizes procuring imports vs. reducing exports, which have the same reliability value
- Risk: Market Gaming Opportunity
  - Related entities could import and export equal amounts during a CSC event
  - Net settlement would be positive without real energy delivered
  - No such behavior observed to date, but risk exists
- Recommendation: Apply PFP charges to exports during CSC events, in line with EMM's 2023 recommendation
  - Ensures consistent incentives for reliability
  - Closes potential loophole and strengthens market efficiency

Reliable operations in 2024 with few reserve deficiency events and out-of-market reliability actions

- Day-ahead market generally secured enough physical supply to meet anticipated real-time load – as of March 2025, generation to meet the Load Forecast is procured and priced (DA A/S)
- Reliability commitments remained low (avg. 10 MW per hour)
- No resource posturing in 2024
- Uplift mostly covered economic commitments (total $35m, or $0.30/MWh)



Recommendation: Provide option For Real-Time-Specific Offer Schedules to Automatically be Used in Real-Time Energy Dispatch

- Currently, if a resource clears in the day-ahead market, that schedule is automatically used in real-time unless the participant re-offers
  - For wind and solar generators, **day-ahead offers** often include **higher prices** due to volumetric risk
  - In contrast, **real-time offers** are typically **low or negative,** reflecting their low marginal cost
- When participants do not update their high day-ahead offers with lower real-time ones, low-cost resources may only be dispatched at high prices
- We recommend that the ISO revise/enhance the bidding software to allow low-cost resources to more easily submit real-time specific offers

MARKET STRUCTURE AND COMPETITIVENESS ASSESSMENT

- **Energy Market:** Market power indices indicative of competitive outcomes, despite pivotal suppliers in 33% of real-time hours. There are very few pivotal suppliers in the day-ahead market and the estimated impact of above-cost offers was relatively modest
- **Capacity Market:** We recommend that the ISO incorporate a Conduct & Impact mitigation framework for seller-side mitigation in the capacity market and eliminate the current pivotal supplier test

Energy market outcomes were competitive overall, and the exercise of market power was generally not a concern

- No significant change to structural indices such as market share, Residual Supply Index and Pivotal Supplier Test (33%)

- Although our simulations indicate that price-cost markup metrics in both the day-ahead and real-time markets were higher than in previous years, they remained well below the tightest mitigation threshold of 10%

Energy Market Price-Cost Markup, %

Year	Day-Ahead Price-Cost Markup	Real-Time Price-Cost Markup
2020	0.9%	-3.1%
2021	-0.6%	0.2%
2022	-1.8%	-1.7%
2023	-2.2%	-3.6%
2024	2.4%	6.8%

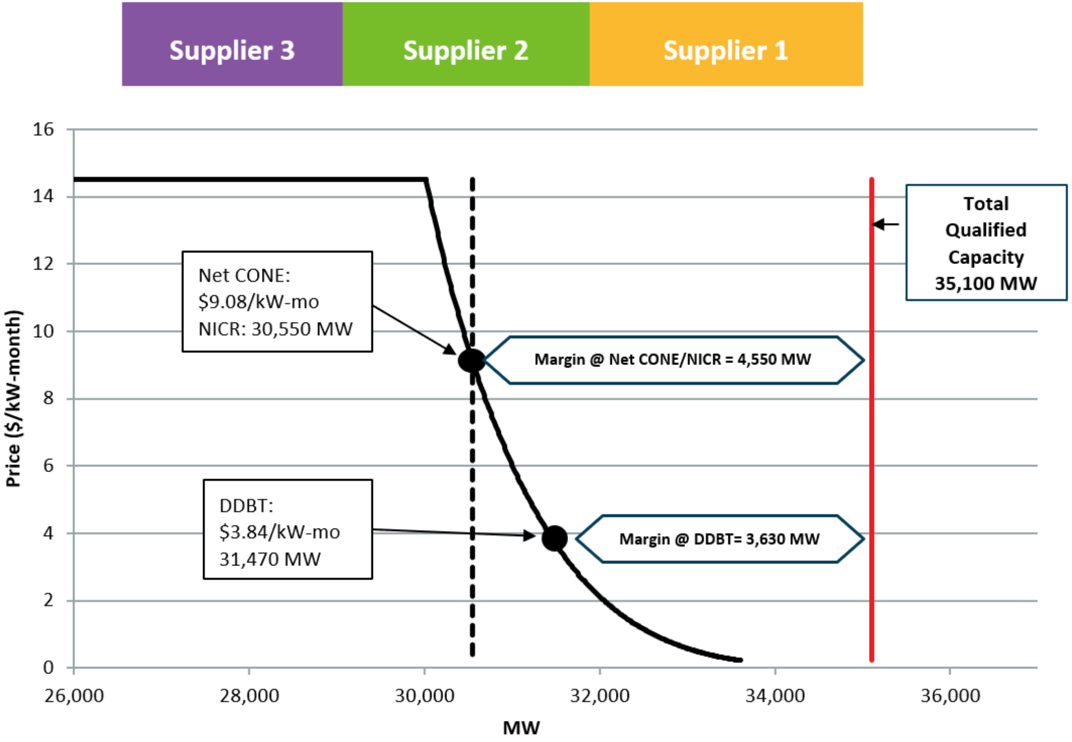
- Withheld capacity due to above-cost bidding remained in line with prior years (below 2%)

- Supply offer mitigation remained low (0.03% of all asset hours); however, we continue to recommend a review of mitigation conduct and price impact thresholds

Recommendation to adopt a Conduct & Impact approach for Seller-Side Mitigation in the Capacity Market

- Current mitigation rules relies on two tests: Structural Competitiveness (Pivotal Supplier Test, PST) and Conduct Test (Cost Review)
  - Mitigation applies to a resource that belongs to a Pivotal Supplier **and** fails the Conduct Test (Offer > 1.1 * IMM Price)
- In FCA 14-18, there have been no Pivotal Suppliers at the system level; in practice, mitigation of static de-list bids has been extremely infrequent
- The PST can be an indicator of the ability and incentive to exercise market power; however, it does not measure the impact of suppliers' offer behavior
  - also prone to estimation error

Recommendation to adopt a C&I approach for Seller-Side Mitigation (2)



Qualified Capacity is calculated as FCA 18 Qualified Existing Capacity - Retirements + Cleared New Capacity (rounded to nearest 100 MW)

- PST is calculated at criterion (NICR). A supplier with a Portfolio size > Margin (4,550 MW) is considered pivotal
  - Recent auctions have cleared close to the DDBT (margin of 3,630 MW)
- Largest suppliers (3 shown here) are not pivotal and not subject to mitigation

Note: The impacts of marginal resource accreditation and seasonal demand curves are not captured in the above graph and will impact the PST calculations.

Recommendation to adopt a C&I approach for Seller-Side Mitigation (3)

- The IMM recommends that the ISO adopt a Conduct and Impact (C&I) approach to seller-side mitigation
  - a more accurate assessment of market power
  - a consistent mitigation framework (to buyer-side and deactivations)

- The C&I approach would be conceptually similar to energy market mitigation
  - Readily applied to a sealed-bid auction construct
  - Allows more flexibility with respect to supply offers; price impact determined by replacing supply offers with IMM prices (for resource failing Conduct Test)
  - Participants assuming a CSO at an expected loss should have recourse to seek cost recovery at FERC

CAPACITY MARKET AND THE CAPACITY AUCTION REFORM (CAR) INITIATIVE

- IMM is supportive of the value of the core **CAR** components of moving to a prompt auction timeline, and incorporating marginal accreditation and seasonal auctions
  - Given supply and demand uncertainties, we believe it is prudent for the CAR design to incorporate flexibility around the exit and potential re-entry of existing resources
- **Recommendations** to enhance clarity of capacity market rules to address two issues that generate compliance concerns

Capacity Auction Reforms: Lower exit (and re-entry) barriers

- Low barriers to exit and re-entry may be valuable to the region in the context of new supply and load growth uncertainties
  - Benefits of flexibility and cost-effectiveness in meeting reliability needs
- Important to remove the "repowering" rules requiring an existing resource to invest $417/kW to return to the FCM
- Beneficial to allow withdrawal of a deactivation plan should economic circumstances change materially between proposed two-year notification time and commitment period*

[*Note: since the report was published, ISO-NE is now pursuing a 1-year notification period which the IMM supports]

Capacity-related Recommendations to enhance rule clarity

- Provide clarity on the need to shed a Capacity Obligation during outage periods
  - Issue generates significant compliance concerns and discussions with participants and FERC OE, and interpretation requests of IMM; beneficial to have more clarity in the Market Rules
- Review and clarify the Time-Out Trigger for Capacity Resource Retirements and Termination of Interconnection Rights
  - A generator can "operate commercially" once every 3 years to retain its interconnection rights, but the rule lacks specificity and may not be effective at ensuring the efficient allocation of transmission capacity; has raised compliance questions from participants

Questions

7 Litigation Report

Sep 4, 2025
Meeting

NEPOOL
NEW ENGLAND POWER POOL
Participants Committee

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of September 3, 2025

The following activity, as more fully described in the attached Litigation Report, has occurred since the report dated August 6, 2025 ("last Report") was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

Executive Orders

*	1	Revolution Wind Stop-Work Order	Aug 22	BOEM issues stop-work order for Revolution Wind project; appeal deadline ***Oct 21, 2025***

I. Complaints/Section 206 Proceedings

*	5	NEPGA Balancing Ratio and Stop Loss Allocation Methodology Complaint (EL25-106)	Aug 6-25	ISO-NE IMM, AEU, Avangrid, Brookfield, Calpine, Enel, Eversource, LS Power, National Grid, RI Energy, Vistra, CPV Towantic**,** Vitol, MA DPU, NHA, Public Citizen intervene
			Aug 15	MMWEC supports Complaint
			Aug 21	Answers, comments, and protests filed by: ISO-NE, NEPOOL, Braintree/Taunton, CANE, FirstLight, LS Power, NESCOE, RENEW, Vitol, EPSA

II. Rate, ICR, FCA, Cost Recovery Filings

*	11	Bucksport CIP-IROL (Schedule 17) Section 205 Cost Recovery Filing (ER25-3233)	Aug 19	Bucksport requests recovery of ***$292,870*** in CIP-IROL Costs incurred between Apr 1, 2023 and Mar 31, 2025; comment deadline ***Sep 9, 2025***

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

*	13	Waiver Request (ISO-NE): Capacity Performance Payment Calculation & Use of Late Payment Account (ER25-3253)	Aug 20	ISO-NE requests limited waivers so that Brookfield White Pine Hydro's Harris Hydro Unit 2 is reimbursed/made whole for an approximately $68,000 Performance Payment Charge related to the June 24, 2025 CSC Event; comment deadline ***Sep 9, 2025***
			Aug 26-29	NEPOOL, Brookfield White Pine Hydro, Calpine intervene
	13	Waiver Request (Evergreen Wind Power II): Interconnection Request Requirements (ER25-3031)	Aug 18	NEPOOL intervenes

IV. OATT Amendments / TOAs / Coordination Agreements

*	15	NECEC Tariff Conforming Changes (ER25-3128)	Aug 8	ISO-NE and NEPOOL file Conforming Tariff Changes
			Aug 12-29	Calpine, Eversource, National Grid intervene
	13	CMP Att F Appendix A Revisions (ER25-3067)	Aug 22	MPUC intervenes
	14	Attachment H Updates (MEPCO) (ER25-2902)	Aug 11	Emera submits comments requesting the FERC either (i) approve the revised Attachment H confirming Emera's GTSAs are valid and in full force and effect, or (ii) direct MEPCO to provide refunds to Emera for any period in which Emera paid MEPCO for transmission service that was not available to Emera under the MGTSAs
			Aug 26	MEPCO answers Emera's comments

	15	*Order 2023* Further Compliance Changes (ER24-2009-001)	Aug 28	FERC accepts the Further *Order 2023* Compliance Changes, without change or condition, eff. *Aug 12, 2024*

V. Financial Assurance/Billing Policy Amendments

	15	FAP Changes to Issuer Eligibility, and Forms of LC, Security and BlackRock Control Agreements (ER25-2709)	Aug 26	FERC accepts FAP changes, eff. *Sep 1, 2025*

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

	15	Schedule 20B-NECEC: Reassignment /Resale of NECEC Transmission Service (ER25-2894)	Aug 7-8	HQUS files comments in support; IRH Management Committee, Eversource intervene
			Sep 2	NECEC files supplemental information
	16	Schedule 21-VTransco: Real Power Losses Calculation Clarifications (ER25-2762)	Aug 26	FERC accepts revisions to Schedule 21-VTransco that clarify the Section 10 provisions regarding the calculation of real power losses, eff. *Sep 1, 2025*

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

*	17	Capital Projects Report – 2025 Q2 (ER25-3137)	Aug 8	ISO-NE files 2025 Q2 Report
			Aug 15-25	NEPOOL files supporting comments; National Grid intervenes
*	17	ISO-NE FERC Form 3-Q (not docketed)	Aug 27	ISO-NE submits its 2025 Q2 FERC Form 3Q

IX. Membership Filings

*	17	Sep 2025 Membership Filing (ER25-3342)	Aug 29	***New Members***: energyRe Giga-Projects USA, Janus Power; ***Termination***: Windham Energy Center; and ***Name Changes***: Icetec Energy Services, LLC and Research Power Corporation; comment deadline ***Sep 19, 2025***
*	18	Suspension Notices – All Choice Energy, Berlin Station, and Hudson Energy Services (not docketed)	Aug 15	ISO-NE files notice of *Aug 13, 2025* suspension of All Choice Energy, Berlin Station, and Hudson Energy Services from the New England Markets

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

*	18	NERC Compliance Enforcement Initiative (RC11-6)	Aug 29	FERC issues Notice of Staff Review of Enforcement Programs
*	18	NERC Reliability Standards Definition Changes (GO, GOP) (RD25-10)	Aug 27	NERC files proposed changes to the definitions of “Generator Owner” (GO) and “Generator Operator” (GOP); comment deadline ***Sep 26, 2025***
			Sep 2	Calpine intervenes
	19	*Order 909*: Revised Reliability Standards: PRC-029-1 and PRC-024-4 (RM25-3)	Aug 25	ACPA/SEIA request limited clarification or *Order 909*
	20	*Order 907*: CIP-015-1 (Cyber Security – Internal Network Security Monitoring) (RM24-7)	Aug 7	FERC issues an Errata Notice for the Information Collection Statement in *Order 907* and underlying NOPR
			Aug 21	FERC issues *Order 907-A* (Order on Clarification)

*	21	2026 NERC/NPCC Business Plans and Budgets (RR25-5)	Aug 22	NERC submits proposed 2026 Business Plan and Budget for itself and its Regional Entities, including NPCC; comment deadline ***Sep 12, 2025***

XI. Misc. - of Regional Interest

	22	203 Application: CPower/NRG (EC25-102)	Aug 7 Aug 13 Aug 27 Sep 2	NRG answers PJM IMM and Joint Consumer Advocates FERC issues deficiency letter; response due ***Sep 3, 2025*** PJM IMM answers NRG's Aug 7 answer NRG answers PJM IMM's Aug 27 answer
	22	203 Application: Tomorrow Energy/Six One Commodities (EC25-98)	Aug 8 Aug 22	FERC authorizes Six One Commodities' acquisition of 100% of the interests in Tomorrow Energy Acquisition consummated
	23	203 Application: Constellation/ Calpine (EC25-43)	Aug 22	PA Office of Consumer Advocate and Public Citizen et al. submit Requests for Reh'g
*	24	Interconnection Study Agreement Cancellation: PSNH/Wok LLC (ER25-3359)	Sep 3	PSNH files notice of cancellation of its ISA with Wok; comment deadline ***Sep 24, 2025***
*	24	D&E Agreement: NSTAR/BXP (ER25-3309)	Aug 27	NSTAR files D&E Agreement; comment deadline ***Sep 17, 2025***
*	24	Amended LGIAs – ISO-NE/CMP (ER25-3187)	Aug 15	ISO-NE and CMP file amendments to LGIAs with CPV Saddleback Ridge Wind and CPV Canton Mountain Wind to reflect changes to the ownership; comment deadline ***Sep 5, 2025***
*	24	NSTAR (MMWEC) – HQUS Use Rights Transfer Agreement (ER25-3170)	Aug 13	NSTAR files for acceptance an Agreement with HQUS for the Transfer of MMWEC's Use Rights on the Phase I/II HVDC Transmission Facilities
	25	Wholesale Distribution Service Agreement: CMP/MRRA (ER25-2705)	Aug 28	FERC accepts Agreement, eff. *Sep 1, 2025*
	25	Wholesale Distribution Tariff – Versant Power (ER25-2500)	Aug 8 Aug 20	FERC issues deficiency letter requesting add'l information Versant responds to deficiency letter; comment deadline ***Sep 10, 2025***
	26	CMP ESF Rate (ER24-1177)	Sep 3	CMP submits compliance filing; comment deadline ***Sep 24, 2025***

XII. Misc. - Administrative & Rulemaking Proceedings

	27	Joint Federal- State Current Issues Collaborative (AD24-7)	Aug 25 Aug 28	FERC posts transcript of Jul 27 meeting NARUC submits notice of newly-appointed NECPUC representatives

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

*	28	Cordova Energy Stipulation and Consent Agreement (IN25-8)	Sep 3	FERC approves Agreement that resolves OE's investigation into whether Cordova, through its offers into PJM and its submissions of GADS data in eGADS, violated the PJM Tariff; Cordova agreed to ***disgorge $1,964,436*** plus interest, pay a ***civil penalty of $370,000***, and to submit compliance monitoring reports for at least two years

Natural Gas-Related Enforcement Actions

*	29	Skye MS Stipulation and Consent Agreement (IN25-9)	Aug 8	FERC approves Agreement that resolves OE's investigation into whether Skye MS violated NGPA Section 311(a)(2); Skye agreed to pay a ***civil penalty of $45,000***, and to submit compliance monitoring reports for at least two years

XIV. Natural Gas Proceedings

No Activity to Report

XV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XVI. Federal Courts

33	*Order 1920: Transmission Planning Reforms (4th Circuit – 24-1650)*	Aug 29	Appalachian Voices et al. submit opening brief
33	*Orders 2023 and 2023-A* (23-1282 et al.) (consolidated)		Oral argument scheduled for ***Sep 26, 2025*** before Judges Millett, Walker, and Childs

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: September 3, 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 September 3, 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 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. Revolution Wind may appeal the Stop-Work Order on or before ***October 21, 2025***.

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

On July 23, 2025, President Trump issued an Executive Order ("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

[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).

under the CWA or Rivers and Harbors Appropriation Act to facilitate the efficient permitting of Qualifying Projects. Additionally, the 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: 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 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.

- **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.

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).

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[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.

[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.

- **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

- **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.

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

- **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

[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").

[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

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. Since the last Report, Complainants answered the May 22 answer by "Southeast Respondents"[12] and ATC 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)**

Also on December 19, 2024, Allco Finance Limited ("Allco") filed a complaint 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

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.

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). Allco's arguments are very similar to those Allco raised in the *Order 2023* Compliance Revisions and Related Changes proceeding (*see* Section IV below). Comments on the Allco PP5 Complaint, following an ISO-requested and FERC-granted extension of time, were due on or before January 15, 2025. 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. 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 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*

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[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).

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 531-A*).[23] However, the FERC's orders were challenged, and in *Emera Maine,*[24] the U.S. Court of

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[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*")).

[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).

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*.

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

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[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).

[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

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 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

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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.

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

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

- **Bucksport CIP-IROL (Schedule 17) Section 205 Cost Recovery Filing (ER25-3233)**

On August 19, 2025, Bucksport Generation LLC ("Bucksport") requested FERC acceptance of its revised rate schedule to allow recovery of eligible Interconnection Reliability Operating Limits ("IROL") critical infrastructure protection ("CIP") costs ("CIP-IROL") under Schedule 17 of the ISO-NE Tariff, effective October 18, 2025. Bucksport seeks to recover $292,870 of CIP-IROL Costs incurred between April 1, 2023 and March 31, 2025. Comments on Bucksport's request are due on or before September 9, 2025. 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).

- **Transmission Rate Annual (2026) Update/Informational Filing (ER20-2054)**

On July 31, 2025, 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 2026. The filing reflected the charges to be assessed under annual transmission and settlement formula rates, reflecting actual 2025 cost data, plus forecasted revenue requirements associated with projected PTF, Local Service and Schedule 12C capital additions for 2025 and 2026, as well as the Annual True-up including associated interest. The PTO AC states that the annual updates results in a Pool "postage stamp" RNS Rate of

[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").

$183.75/kW-year effective January 1, 2026, a decrease of $1.53 /kW-year from the charges that went into effect on January 1, 2025. In addition, the filing includes updates to the revenue requirements for Scheduling, System Control and Dispatch Services (the Schedule 1 formula rate), which result in a Schedule 1 charge of $2.23 kW-year (effective June 1, 2025 through May 31, 2026), a $0.05/kW-year increase from the Schedule 1 charge that last went into effect on June 1, 2025.

While this filing will not be noticed for public comment, this filing triggers the commencement of an Information Exchange Period and a Review Period under the Protocols. Interested Parties have until ***September 15, 2025*** to submit information and document requests, and the PTOs are required to make a good faith effort to respond to all requests within 15 calendar days, but by no later than ***October 15, 2025***. During the Review Period, Interested Parties have until November 17, 2025 to submit Informal Challenges to the PTOs, and the PTOs are required to make a good faith effort to respond to any Informal Challenges no later than ***December 15, 2025***. Interested Parties have until ***February 2, 2026*** to file a Formal Challenge with the FERC.

- **Transmission Rate Annual (2023-24) Update/Informational Filing (ER20-2054-000)**

Formal Challenge by MOPA. As previously reported, the Maine Office of the Public Advocate ("MOPA") filed a formal challenge ("MOPA Formal Challenge") to the 2023-24 Annual Update on January 31, 2024.[39] MOPA asserted that, (i) with respect to the cost of asset condition projects placed into service in 2022, Identified TOs[40] 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. Comments on the MOPA Formal Challenge were due on or before February 21, 2024 and were filed by Consumer Advocates[41] (who supported MOPA's attempt to discover the information requested in its September 15, 2023 requests and agreed that policies, processes, and procedures related to ACP costs are discoverable pursuant to the Protocols) and Identified TOs (who urged the FERC to reject the MOPA Formal Challenge as baseless and misguided). On March 4, 2024, MOPA answered Identified TOs' comments. Identified TOs answered MOPA's March 4 answer on March 15 (as corrected on March 18, 2024).

On July 26, 2024, the FERC directed Identified TOs to provide to the FERC its responses (both public and confidential) to MOPA's questions related to general processes and procedures for asset condition project planning. The FERC stated that it needs the full information to evaluate whether the Identified TOs made "a good faith effort to respond to [the] information request[] pertaining to the Annual Update." Identified TOs' responses were filed by CMP, Eversource (CL&P, NSTAR East, NSTAR West, and PSNH), MEPCO, National Grid (Narragansett and New England Power), and VTransco (on September 6). On September 5, 2024, MOPA challenged National Grid's claim that, because it had provided copies of what it sent to MOPA originally, MOPA's Formal Challenge could be rejected without further procedures. MOPA continues to assert that the materials provided by National Grid do not constitute a "good faith response" and renewed its request for the

[39] 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.

[40] "Identified TOs" are the New England Transmission Owners with asset condition projects that are the focus of the MOPA Formal Challenge: CL&P, Maine Electric Power Company ("MEPCO"), NSTAR (East & West), National Grid, Public Service Company of New Hampshire ("PSNH"), Rhode Island Energy ("RI Energy"), and Vermont Transco LLC ("VTransco").

[41] For purposes of this proceeding, "Consumer Advocates" are the MA AG, CT OCC, NH OCA, and RI Division.

FERC to direct the Identified TOs to answer its questions concerning the investment policies and practices used to evaluate the need for a particular asset condition project, a necessary predicate to a prudence review.

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

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

On August 20, 2025, ISO-NE requested 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) to reimburse/make whole Brookfield White Pine Hydro's Harris Hydro Unit 2 ("Harris 2"). 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. ISO-NE proposed the limited waivers to ensure that the charge is excluded from Harris 2's final invoice for that operating day and the amount is returned to Harris 2 through a withdrawal from the Late Payment Account. Comments on this filing are due on or before ***September 9, 2025***. Thus far, NEPOOL, Brookfield White Pine Hydro, and Calpine have intervened doc-lessly. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

On July 30, 2025, Evergreen Wind Power II ("Evergreen") requested waiver 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 ("Waiver Request"). Evergreen states that the Waiver Request will 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. Given the timing for ISO-NE's issuance of FCA19 qualification notices, Evergreen requested that the FERC act on this pleading no later than October 16, 2025. Comments on the Waiver Request are due on or before ***August 20, 2025***. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

IV. OATT Amendments / TOAs / Coordination Agreements

- **CMP Att F Appendix A Revisions (ER25-3067)**

On August 1, 2025, CMP filed proposed revisions to certain worksheets in the transmission formula rate template contained in Appendix A to Attachment F of the OATT. The revisions will enable CMP to directly assign to the transmission or distribution function, as appropriate, (i) investments made on or after October 1, 2025 and recorded to FERC Accounts 301 through 303 ("Intangible Plant") and 389 through 399.1 ("General Plant", and together with Intangible Plant, "G&I Plant"); and (ii) depreciation reserve, amortization reserve, depreciation expense, and amortization expense associated with directly assigned G&I Plant. CMP requested an effective date of October 1, 2025. Comments on this filing were due on or before August 22, 2025; none were filed. The MPUC intervened doc-lessly. 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).

- **PBOP Collections Report, Attachment F App. A (FG&E) (ER25-3065)**

On August 1, 2025, Fitchburg Gas & Electric ("FG&E") 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 exceeded the threshold identified in OATT Attachment F.[42] No changes to the filed rate were sought. The report shows an over-recovery, after interest, of **$132,866**. If accepted, the PBOP figures will be used in FG&E's 2026 Annual Updates. Comments on this filing were due on or before August 22, 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).

- **MEPCO Attachment H Updates (ER25-2902)**

On July 21, 2025, Maine Electric Power Company ("MEPCO") filed revisions to Attachment H of the ISO-NE OATT to reflect the currently effective MEPCO Grandfathered Transmission Service Agreements ("MGTSAs") under which MEPCO provides transmission service. The filing was submitted in accordance with Section II.45.1 of the ISO-NE OATT, which requires MEPCO to periodically review and update Attachment H. An effective date of September 20, 2025 was requested. On August 11, 2025, Emera filed comments requesting that the FERC confirm the validity and continued effectiveness of two Emera Grandfathered Transmission Service Agreements ("GTSAs") that currently appear to have expired July 31, 2013 and 2014, or alternatively, direct MEPCO to provide refunds to Emera for any period in which Emera paid MEPCO for transmission service that was not available to Emera under the MGTSAs because Attachment H and/or the OASIS was not updated in a timely manner. On August 26, 2025, MEPCO answered the Emera request, asserting that it was procedurally improper and any relief sought by Emera related to past service over MEPCO or any associated charges should be pursued in a separate proceeding. 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 Filings (ER25-2654; ER25-2657)**

On June 27, 2025, in accordance with *Order 676-K*,[43] 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 March 19, 2025, ISO-NE and NEPOOL submitted revisions to Schedule 2 of the ISO-NE OATT in compliance with *Order 904* ("Reactive Power Compensation Changes"). 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 were supported by the Participants Committee at its March 6, 2025 meeting (Agenda Item #6). An effective date of 6-12 months from the date of an order accepting the filing, with an actual

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[42] 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).

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

date to be submitted one month in advance, was requested. Comments on the filing were due on or before April 9, 2025. NEPGA filed supporting comments; doc-less interventions were filed by Calpine, CPV Towantic, MA AG, National Grid, Shell, Vistra, and SEIA. 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) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

- ***Order 2023* Further Compliance Changes (ER24-2009-001)**

On August 28, 2025, the FERC accepted, without change or condition, the Further Order 2023 Compliance Changes filed by ISO-NE and PTO-AC on June 3, 2025.[44] The Further Order 2023 Compliance Changes were filed in response to the FERC's *Order 2023 Compliance Order,* which conditionally accepted most of the proposed Tariff revisions from the *Order 2023* Compliance Revisions filing (with some directives to incorporate *pro forma* language, correct minor inconsistencies and provide further description), and accepted all of the proposed tariff revisions from the *Order 2023* Related Changes filing.[45] The Further Order 2023 Compliance Changes were accepted effective as of August 12, 2024, as requested. Unless the *Further Order 2023 Compliance Changes Order* is challeneged, this *Order 2023* proceeding will be concluded. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com), Margaret Czepiel (202-218-3906; mczepiel@daypitney.com), or Joan Bosma (617-345-4651; jbosma@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

- **FAP Changes to LC Issuer Eligibility, and Forms of LC, Security and BlackRock Control Agreements (ER25-2709)**

On August 26, 2025, the FERC accepted the ISO-NE and NEPOOL's jointly filed changes to the ISO-NE Financial Assurance Policy ("FAP") that: (i) add two new circumstances under which ISO-NE may draw upon a Market Participant's letter of credit ("LC") ("Risk Mitigation Draws"); (ii) modify the eligibility criteria for banks that issue LCs to ISO-NE; and (iii) conform several other provisions regarding the forms of acceptable financial assurance.[46] The changes were accepted effective as of *September 1, 2025*, as requested. Unless the August 26 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).

VI. Schedule 20/21/22/23 Changes & Agreements[47]

- **NECEC Tariff Conforming Changes (ER25-3128)**

On August 8, 2025, ISO-NE and NEPOOL filed conforming changes to Sections I and II of the Tariff to support the operation and implementation of the New England Clean Energy Connect ("NECEC") Transmission Line as an Other Transmission Facility ("NECEC Tariff Changes"). Specifically, the NECEC Tariff Changes introduce new definitions, including "NECEC Transmission LLC", "NECEC Transmission Line" and "Schedule 20 Service Provider", incorporate the NECEC Transmission Line into Attachment C of the OATT, and make related conforming edits. The

[44] *ISO New England Inc. and Eversource Energy Srvc. Co.*, 192 FERC ¶ 61,185 (Aug. 28, 2025) ("*Further Order 2023 Compliance Changes Order*"). The Further Compliance Changes, which revised Section I.2.2, Schedules 11, 22, 23, and 25 of Section II, and Section III.13 of the Tariff, were unanimously supported by the Participants Committee at its June Summer Meeting (Consent Agenda Item #3) and supported in June 24, 2025 comments to the FERC.

[45] *ISO New England Inc. and New England Power Pool Participants Comm.*, 191 FERC ¶ 61,018 (Apr. 4, 2025) ("*Order 2023 Compliance Order*").

[46] *ISO New England Inc.*, Docket No. ER25-2709-000 (Aug. 26, 2025) (unpublished letter order).

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

NECEC Tariff Changes were supported by the Participants Committee at its August 7 meeting (Consent Agenda Item Nos. 4 through 8). An October 7, 2025 effective date was requested. Comments on the NECEC Tariff Changes were due on or before August 29, 2025; none were filed. Calpine, Eversource, and National Grid intervened doc-lessly. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Schedule 20B-NECEC: Reassignment/Resale of NECEC Transmission Service (ER25-2894)**

On July 18, 2025, as supplemented on September 2, 2025, NECEC filed proposed procedures for resale and reassignment of point-to-point transmission service over the NECEC Transmission Line (ISO-NE OATT Schedule 20B-NECEC). While resale/reassignment terms are generally addressed under Schedules 18 and 20A, NECEC proposed more detailed procedures to provide additional transparency for the NECEC Transmission Line, the U.S. portion of the 1,200 MW interconnection between New England and Québec. A September 16, 2025 effective date was requested. Comments on this matter were due on or before August 8, 2025. HQUS filed comments in support of the filing. National Grid, the IRH Management Committee, and Eversource 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).

- **Schedule 21-VTransco: Clarify Section 10 Calculation of Real Power Losses (ER25-2762)**

On August 26, 2025, the FERC accepted VTransco's revised Schedule 21-VTransco,[48] which clarified the (Section 10) provisions regarding the calculation of real power losses in accordance with VTransco's longstanding practice and interpretation of existing provisions. The changes were accepted effective as of *September 1, 2025*, as requested. Unless the August 26 order is challenged, this proceeding will be concluded. 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[49] 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. 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).

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[48] *Vermont Transco LLC*, Docket No. ER25-2762-000 (Aug. 26, 2025) (unpublished letter order).

[49] 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.

VII. NEPOOL Agreement/Participants Agreement Amendments

- **134th Agreement (ER25-2953)**

On July 23, 2025, NEPOOL filed the One Hundred Thirty-Fourth Agreement Amending New England Power Pool Agreement (the "134th Agreement"). The 134th Agreement replaces the definition of "Fuels Industry Participant" with "Associate Non-Voting Participant". An effective date of October 1, 2025 for the changes was requested. Comments on this filing were due on or before August 13, 2025; none were filed. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VIII. Regional Reports[50]

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

On August 8, 2025, ISO-NE filed its Capital Projects Report and Unamortized Cost Schedule covering the second quarter ("Q2") of calendar year 2025 (the "Report"), requesting an effective date of July 1, 2025. 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 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. Comments on this filing were due on or before August 29, 2025. NEPOOL filed comments supporting 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).

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

On August 27, 2025, ISO-NE submitted its 2025/Q2 FERC Form 3Q (quarterly financial report of electric utilities, licensees, and natural gas companies). FERC Form 3-Q is a quarterly regulatory requirement, which supplements the annual FERC Form 1 financial reporting requirement. These quarterly filings 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).

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

On August 29, 2025, NEPOOL requested that the FERC accept: (i) the following Applicants' membership in NEPOOL: energyRe Giga-Projects, LLC (Provisional Member, QTPS); and Janus Power LLC (Supplier Sector); (ii) the

[50] 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.

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.). Comments on this filing, if any, are due on or before ***September 19, 2025***.

- **Aug 2025 Membership Filing (ER25-3002)**

On July 29, 2025, NEPOOL requested that the FERC accept: (i) the following Applicants' membership in NEPOOL: Alpha Generation LLC [Related Person to the Generation Bridge companies (Generation Sector)]; Ryegate Associates (AR Sector, RG Sub-Sector, Large RG Group Seat); and TDI DevCo LLC [Related Person to Champlain VT, LLC; and (ii) the corporate name changes of ReGenerate Stratton LLC (f/k/a ReEnergy Stratton LLC); and Clearlight Energy Services LLC (f/k/a Algonquin Energy Services Inc.). This matter is pending before the FERC.

- **Suspension Notices (not docketed)**

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

Date of Suspension/ FERC Notice	***Participant Name***	***Default Type***
Aug 13, 2025	All Choice Energy NE LLC	Financial Assurance
Aug 13, 2025	Hudson Energy Services, LLC	Financial Assurance
Aug 13, 2025	Berlin Station, LLC	Financial Assurance

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

X. Misc. - ERO Rules, Filings; Reliability Standards[51]

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 Compliance Enforcement Initiative (RC11-6)**

On August 29, 2025, the FERC issued a notice of Staff's annual review of NERC's Find, Fix, Track and Report ("FFT") and Compliance Exception ("CE") programs. The notice reported that Commission Staff reviewed a sample of 32 of 232 FFTs and 33 of 1,089 CEs submitted by NERC between October 2023 and September 2024 and found that the FFT and CE programs are meeting the FERC's expectations in accordance with the FERC's *FFT and CE Orders*. Specifically, (i) all 65 FFT/CEs were remediated, with the root cause of each non-compliance clearly identified; (ii) Staff agreed with the final risk determinations; (iii) none of the 65 FFT/CEs contained any material misrepresentations by the registered entities; and (iv) the Regional Entities appropriately identified all 65 FFT/CEs as appropriate to be processed as FFTs and CEs. The notice is not subject to public comment.

- **NERC Reliability Standards Definition Changes (GO, GOP) (RD25-10)**

On August 27, 2025, NERC filed proposed revisions to the definitions of "Generator Owner" and "Generator Operator" in its Glossary of Terms[52] used in the NERC Reliability Standards, to include owners and

[51] 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.*).

[52] The "Glossary" is a comprehensive list that reflects all of the defined terms used in Reliability Standards that have been adopted by the NERC Board of Trustees. The Glossary is updated through the Reliability Standards development process, and changes to the

operators of non-Bulk Electric System Inverter-Based Resources ("IBR") that individually or collectively have an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV. Comments on this filing are due on or before ***September 26, 2025***.

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

Still pending before the FERC is NERC's proposed Reliability Standard EOP-012-3 (Extreme Cold Weather Preparedness and Operations). As previously reported, EOP-012-3 is intended to improve the efficiency and effectiveness of the Bulk-Power System ("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. Comments on EOP-012-3 were due on or before May 12, 2025, and were filed by the ISO/RTO Council ("IRC")[53] (requesting approval of the and clarification of FERC's expectation that NERC's criteria for reviewing Generator Cold Weather Constraint declarations be objectively documents with clear guidance from NERC) and by the Union of Concerned Scientists ("UCS") (suggesting the FERC adopt several modifications to the circumstances that qualify on the case-by-case list in order to remove ambiguity and possible conflicts of interest). On May 28, 2025, NERC answered UCS' comments, requesting the FERC reject the UCS-proposed modifications. Doc-less interventions only were filed by Calpine, ACPA, EPSA, and Public Citizen. As noted, EOP-012-3 is pending before the FERC.

- ***Order 909*: Revised Reliability Standards PRC-029-1 and PRC-024-4 (RM25-3)**

On July 24, 2025, in *Order 909*,[54] the FERC approved revisions to Reliability Standards PRC-024-4 (Frequency and Voltage Protection Settings for Synchronous Generators, Type 1 and Type 2 Wind Resources, and Synchronous Condensers) and PRC-029-1 (Frequency and Voltage Ride-through Requirements for Inverter-Based Resources), and a definition of "Ride-through." In *Order 909*, the FERC also directed NERC, on or before ***August 25, 2026***, to clarify documentation requirements for legacy equipment needed to support an exemption request pursuant to Reliability Standard PRC-029-1; to consider whether, and if so how, to address a total of two exception- and exemption-related issues raised by commenters; and to submit an informational filing that assesses the reliability impact of the exemptions to Reliability Standard PRC-029-1. *Order 909* will become effective *August 28, 2025*.[55] Challenges, if any, to *Order 909* were due on or before August 25, 2025.

Request for Clarification. On August 25, 2025, ACPA and SEIA submitted a request for limited clarification (that, to avoid a timing mismatch between a NERC filing deadline and the effective date of the Standard, and related risks or regulatory uncertainty for IBR developers, the FERC encourage NERC to submit its required filing by May 28, 2026, three months before *Order 909* requires). The Request for Clarification is pending before the FERC, with FERC action required on or before ***September 24, 2025***, or the request will be deemed denied by operation of law.

Glossary are sometimes proposed independent of proposed changes to Reliability Standards, as is the case in this proceeding. The Glossary is available on NERC's website.

[53] In addition to ISO-NE, the IRC includes the following ISOs and RTOs: California Independent System Operator ("CAISO"); Electric Reliability Council of Texas, Inc. ("ERCOT"); Midcontinent Independent System Operator, Inc. ("MISO"); New York Independent System Operator, Inc. ("NYISO"); PJM Interconnection, L.L.C. ("PJM"); and Southwest Power Pool, Inc. ("SPP").

[54] *Reliability Standards for Frequency and Voltage Protection Settings and Ride-Through for Inverter-Based Resources*, Order No. 909, 192 FERC ¶ 61,076 (July 24, 2025) ("*Order 909*").

[55] *Order 909* was published in the *Fed. Reg.* on July 29, 2025 (Vol. 90, No. 143) pp. 35,599-35,616.

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

On July 10, 2024, as corrected and supplemented on May 20, 2025, NERC filed for approval 11 revised Critical Infrastructure Protection ("CIP") Reliability Standards,[56] as well as 18 new or revised definitions for inclusion in NERC's Glossary,[57] to facilitate the full implementation of virtualization and to address the risks associated with virtualized environments. The proposed CIP Reliability Standards would permit Responsible Entities with more "traditional" architecture to continue with their current configurations. As of the date of this Report, the FERC still has not yet noticed a proposed rulemaking proceeding or otherwise invited public comment.

- ***Order 907*: CIP-015-1 (Cyber Security – Internal Network Security Monitoring) (RM24-7)**

On June 27, 2025, in *Order 907*,[58] the FERC approved Reliability Standard CIP-015-1 (Cyber Security – Internal Network Security Monitoring). In addition, the FERC directed NERC to develop certain modifications to CIP-015-1 to extend internal network security monitoring to include electronic access control or monitoring systems and physical access control systems outside of the electronic security perimeter. The FERC clarified the term CIP-networked environment as it is used in CIP-015-1. *Order 907* became effective *September 2, 2025*.[59]

Requests for Clarification Granted. Requests for clarification of *Order 907* were filed by NERC and Trade Associations.[60] NERC sought clarification of the scope of *Order 907* with respect to the term CIP-networked environment. Trade Associations sought clarification that *Order 907* (i) is not intended to be interpreted to extend the scope of CIP-015-1 to require monitoring of network traffic between certain assets outside of the Electronic Security Perimeter ("ESP"), specifically network traffic between corporate assets not subject to the NERC CIP Standards and certain Electronic Access Control or Monitoring Systems ("EACMS") identified as Intermediate Systems; and (ii) is intended to be interpreted to extend the scope of CIP-015-1 to require monitoring of network traffic between PACS including PACS controllers, and not a broader definition of the term "controller". The FERC granted the requests for clarification in *Order 907-A*.[61]

- **NOPR: Supply Chain Risk Reliability Standards (RM24-4)**

Also on September 19, 2024, the FERC issued a NOPR proposing to direct NERC to develop and submit for FERC approval new or modified Reliability Standards that address the sufficiency of responsible entities' supply chain risk management plans related to the identification of, assessment of, and response to supply chain risks, and applicability of Reliability Standards' supply chain protections to protected cyber assets.[62] Comments on the NOPR were due on or before December 2, 2024[63] and were filed by, among others: NERC and its Regional Entities,

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[56] 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).

[57] 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").

[58] *Critical Infrastructure Protection Reliability Standard CIP-015-1 – Cyber Security – Internal Network Security Monitoring*, Order No. 907, 191 FERC ¶ 61,224 (June 26, 2025) ("*Order 907*"), *clarif. granted*, 192 FERC ¶ 61,171 (Aug. 21, 2025).

[59] *Order 907* was published in the *Fed. Reg.* on July 29, 2025 (Vol. 90, No. 143) pp. 35,599-35,616.

[60] "Trade Associations" for the purposes of this proceeding are APPA, EEI, and NRECA.

[61] *Critical Infrastructure Protection Rel. Standard CIP-015-1 – Cyber Security – Internal Network Security Monitoring*, Order No. 907-A, 192 FERC ¶ 61,171 (Aug. 21, 2025) ("*Order 907-A*").

[62] *Supply Chain Risk Management Reliability Standards Revisions*, 188 FERC ¶ 61,174 (Sep. 19, 2024) ("*Supply Chain Risk Standards NOPR*").

[63] The *Supply Chain Risk Standards NOPR* was published in the *Fed. Reg.* on Oct. 1, 2024 (Vol. 89, No. 190) pp. 79,794-79,804.

NESCOE, BPA, APPA/LPPC, EEI, North American Transmission Forum, National Electrical Manufacturers Association, and Secure the Grid. On December 16, 2024, TAPS filed comments supporting the APPA/LPPC comments.

Notice of Supply Chain Workshop. On March 20, 2025, the FERC held a workshop focused on the "assessment" aspect of supply chain risk management ("SCRM"). Specifically, the workshop panels discussed the proposed directive in the FERC's *Supply Chain Risk Standards NOPR* to require that entities establish steps in SCRM plans to validate the completeness and accuracy of information received from vendors during the procurement process to better inform the identification and assessment of supply chain risks associated with vendors' software, hardware, or services. A transcript of the workshop is posted in the FERC's eLibrary. Post-workshop comments were due April 11, 2025 and filed by: Asset 2 Vendor, Business Cyber Guardian, National Electrical Manufacturers Association, North American Transmission Forum, MISO, APPA/LPPC/TAPS, and EEI. This matter is pending before the FERC.

- **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 August 22, 2025, NERC submitted its proposed Business Plan and Budget, as well as the Business Plans and Budgets for the six Regional Entities,[64] including NPCC, for 2026. FERC regulations require NERC to file its proposed annual budget for statutory and non-statutory activities 130 days before the beginning of its fiscal year (January 1), as well as the annual budget of each Regional Entity for their statutory and non-statutory activities, including complete business plans, organization charts, and explanations of the proposed collection of all dues, fees and charges and the proposed expenditure of funds collected.[65] NERC reports that its proposed 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. The NPCC has requested $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 proposed to allocate to NPCC $13.6 million of its 2026 assessment. Comments on this filing are due on or before ***September 12, 2025***.

[64] 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").

[65] 18 CFR § 39.4(b) (2014).

XI. Misc. - of Regional Interest

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

On July 16, 2025, Cricket Valley Energy Center ("CVEC"), among others, asked the FERC to authorize a transaction pursuant to which certain parties[66] will indirectly acquire voting interest of 10% or more in 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. When consummated, CVEC will become a Related Person to Bridgewater Power (Generation Group Seat) and Burgess BioPower (a current applicant). Comments on this application were due on or before August 6, 2025; none were filed. This matter is now pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **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. In addition, on August 13, FERC Staff issued a deficiency letter requesting additional information to process the application. NRG's responses to the Deficiency Letter are due on or before ***September 3, 2025***. 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.[67] 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).

- **203 Application: Tomorrow Energy/Six One Commodities (EC25-98)**

On August 22, 2025, Six One Commodities LLC ("Six One Commodities") acquired 100% of the equity interests of Tomorrow Energy,[68] as authorized by the FERC.[69] Six One Commodities' acquisition did not result in any change to Tomorrow Energy's Supplier Sector or individual voting status. Reporting on this matter is

[66] 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.

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

[68] *See* Notice of Consummation, *Tomorrow Energy Corp*, Docket No. EC25-98-000 (filed Aug. 26, 2025).

[69] *Tomorrow Energy Corp*, 192 FERC ¶ 62,079 (Aug. 8, 2025).

concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Kleen Energy/Alpha Gen (EC25-77)**

On June 13, 2025, the FERC authorized Alpha Gen's acquisition of Kleen Energy.[70] Pursuant to the June 13 order, Alpha Gen 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, Kleen Energy will become a Related Person to the Generation Bridge Companies.[71] If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On July 23, 2025, the FERC conditionally authorized[72] 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.[73] The requests for rehearing are pending, with Commission action required on or before ***September 29, 2025***, or the requests will be deemed denied by operation of law. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **PURPA Enforcement Petition: Allco Finance Ltd/Connecticut SCEF Program (EL25-81)**

On August 4, 2025, the FERC issued a notice[74] that it has decided not to act on the PURPA Complaint filed by Allco Finance Limited ("Allco") related to Connecticut's[75] implementation under section 210 of PURPA of its Shared Clean Energy Facility ("SCEF") Program.[76] The FERC's decision not to act means that Allco may itself bring an enforcement action against Connecticut in the appropriate federal district court.[77] Allco brought that action in

[70] *Kleen Energy Systems, LLC and Alpha Generation Kleen GP, LLC*, 191 FERC ¶ 62,163 (June 13, 2025).

[71] The "Generation Bridge Companies" are: Generation Bridge Connecticut Holdings, LLC; Generation Bridge M&M Holdings, LLC; GB II Connecticut LLC; and GB II New Haven LLC.

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

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

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

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

[76] 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.

[77] 16 U.S.C. § 824a-3(h)(2)(B).

Connecticut District Court in *Allco Finance Limited Inc. v. Dykes et al.* (case no. 3:25CV01321). If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On September 3, 2025, PSNH filed a notice of cancellation 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. The ISA is no longer required because all work pursuant to the ISA is complete and all invoices for that work paid. A September 4, 2025 effective date was requested for the cancellation notice. Comments on the ISA cancellation are due on or before ***September 24, 2025***. 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 August 27, 2025, NSTAR filed a Design & Engineering ("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. An August 28, 2025 effective date was requested. Comments on this filing are due on or before ***September 17, 2025***. 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 (ER25-3184)**

On August 13, 2025, ISO-NE and Central Maine Power ("CMP") filed a Second Revised LGIA with CPV Saddleback Ridge Wind, LLC and a First Revised LGIA with CPV Canton Mountain Wind, LLC to reflect ownership changes and revise certain Appendix details.[78] A July 30, 2025 effective date was requested for each. Comments on this filing are due on or before ***September 5, 2025***. 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 August 13, 2025, NSTAR filed for acceptance an Agreement for the Transfer of Use Rights on the Phase I/II HVDC Transmission Facilities ("Transfer Agreement") between itself and H.Q. Energy Services (U.S.) Inc.("HQUS"). 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. An effective date of October 31, 2025 was requested. Comments on this filing were due on or before September 3, 2025.I f you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On July 29, 2025, NSTAR filed for acceptance an Agreement for the Transfer of Use Rights on the Phase I/II HVDC Transmission Facilities ("Transfer Agreement") from CMMEC to Vitol. 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. An effective date of October 31, 2025 was requested. Comments on this filing are due on or before ***August 19, 2025.*** If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Revised Wholesale Distribution Access Tariff: CMP (ER24-2975)**

On July 28, 2025, CMP filed an amendment to its Wholesale Distribution Access Tariff to implement time-of-use ("TOU") rates and update the rates to be consistent with CMP's currently effective state-regulated distribution rates ("Revised WDAT"). A September 1, 2025 effective date was requested. Comments on the

[78] The FERC accepted the First Revised Saddleback LGIA and Original Canton LGIA in Docket No. ER17-1668 (by letter order dated July 13, 2017).

Revised WDAT were due on or before August 18, 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).

- **SGIA 2nd Amendment: CMP/Spruce Mountain Wind (ER25-2957)**

On July 23, 2025, CMP filed a second amendment to the Interconnection Agreement ("Amended SGIA") providing the terms and conditions for CMP's continuing provision of interconnection service to CPV Spruce Mountain Wind, LLC. CMP stated that the Amended SGIA: (i) revises the interconnection customer name from Spruce Mountain Wind, LLC to CPV Spruce Mountain Wind, LLC; (ii) updates CPV Spruce Mountain Wind's contact information; (iii) removes language contained in Article 4.2 of the agreement in conformance with the FERC's directives in the *RENEW O&M Complaint Order;*[79] and (iv) incorporates up-to-date system diagrams contained in Attachment 3 to the Amended SGIA. A June 27, 2025 effective date was requested. Comments on this filing were due on or before August 13, 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).

- **Wholesale Distribution Service Agreement: CMP/MRRA (ER25-2705)**

On August 28, 2025, the FERC accepted, effective *September 1, 2025*, a Wholesale Distribution Service Agreement ("WDSA") between CMP and Midcoast Regional Redevelopment Authority ("MRRA").[80] The WDSA provides the terms and conditions for CMP's provision of wholesale distribution service to MRRA, which will be directly connected to a CMP distribution circuit, and will take Regional Network Service ("RNS") and Local Network Service ("LNS") as a Non-Participant Transmission Customer pursuant to the ISO-NE Tariff and Schedule 21-CMP. Unless the August 28, 2025 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).

- ***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 June 12, 2025, Versant Power filed a new Wholesale Distribution Tariff ("WDT") 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. The WDT allows such customers to utilize Versant's distribution system when charging their ESS for the purpose of participating in the wholesale (New England) market. A January 1, 2026 effective date was requested. Comments on the Versant Power WDT were due on or before July 3, 2025; none were filed.

Deficiency Letter Response (-001). On August 8, 2025, the FERC issued a deficiency letter directing Versant Power to provide additional information and clarifications on whether ESFs taking service under Subschedule 1 may be dispatched by ISO-NE and, if so, why transmission charges would apply given *Order 841* and ISO-NE OATT exemptions. Versant provided that information in an August 20, 2025 response. Comments on

[79] *RENEW Northeast, Inc. v. ISO New England Inc. and New England Participating Transmission Owners*, 189 FERC ¶ 61,216 (Dec. 19, 2024) ("*RENEW O&M Complaint Order*").

[80] *Central Maine Power Co.*, Docket No. ER25-2705-000 (Aug. 28, 2025) (unpublished letter order).

Versant's response are due on or before ***September 10, 2025***. 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*,[81] 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. 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).

- **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,[82] effective August 4, 2025.[83] 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***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

XII. Misc. - Administrative & Rulemaking Proceedings[84]

- **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, 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.

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

[82] *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")).

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

[84] 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).

- **Joint Federal-State Current Issues Collaborative[85] (AD24-7)**

Third Meeting. The Collaborative held its third public meeting in conjunction with NARUC's 2025 Summer Policy Summit on July 27, 2025 at the Omni Boston Hotel. The principal topic for discussion was generic issues related to the states' role in RTO governance, including on resource adequacy issues. On August 25, 2025, the FERC posted in eLibrary a final transcript of the July 27 meeting.

New NECPUC Representatives. On August 27, 2025, NARUC provided notice of the two state commission representatives from each of the NARUC regions. MPUC Chairman Phil Bartlett and NH PUC Commissioner Pradip Chattopadhyay were elected as NECPUC representatives.

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

On June 27, 2024, the FERC issued an advanced notice of proposed rulemaking ("ANOPR")[86] seeking comments on both the need for a dynamic line ratings ("DLRs")[87] 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[88] 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,[89] TAPS, and R Street Institute. Nine sets of reply comments were filed, including from: ISO-NE, DC Energy, and the US DOE.

- ***Order 904*: Compensation for Reactive Power Within the Standard Power Factor Range (RM22-2)**

On October 17, 2024, the FERC issued *Order 904,*[90] which revises Schedule 2 of the *pro forma* OATT, § 9.6.3 of the *pro form* LGIA, and § 1.8.2 of the *pro forma* SGIA to prohibit separate compensation to generators for

[85] *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.

[86] *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.

[87] 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.

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

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

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

the provision of reactive power within the standard power factor range or "deadband."[91] The proposed change will affect revenues received by reactive power resources in New England.[92] New England's Order 904 filing was submitted on March 19, 2025 (*see* ER25-1703 in Section IV above). Challenges to *Order 904* were filed by: D. E. Shaw Renewable Investments, Invenergy Nelson, NYISO, the PSEG Companies,[93] and Vistra. On December 19, 2024, the FERC issued an "Allegheny Notice", noting that the requests for rehearing may be deemed to have been denied by operation of law, but noting that the requests will be addressed in a future order.[94] The FERC issued that order on June 6, 2025, modifying the discussion in *Order 904* but continuing to reach the same result.[95] The FERC's orders on *Order 904* have been appealed to the US Courts of Appeals for the 5th, 2nd, and DC Circuits (*see* Section XVI below). If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

- **Cordova Energy Stipulation and Consent Agreement (IN25-8)**

On September 3, 2025, the FERC approved a Stipulation and Consent Agreement with Cordova Energy Company LLC ("Cordova") to resolve OE's investigation of whether, through its offers into PJM[96] and its submissions of Generating Availability Data System ("GADS") data in PJM's electronic GADS submission program ("eGADS"),[97] Cordova violated FERC regulations and/or the PJM Tariff.[98] Under the Stipulation and Consent Agreement, Cordova agreed to ***disgorge $1,964,436*** plus interest, pay a ***civil penalty of $370,000*** to the United States Treasury, and to submit compliance monitoring reports for at least two years (a third year at OE's sole discretion). If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

[91] *Reactive Power NOPR* at PP 51-53.

[92] Generating facilities in New England are currently compensated for reactive power under a flat, inflation-adjusted rate design. In *Order 904*, the FERC rejected the requests by ISO-NE and NEPOOL for the flexibility to retain the current Schedule 2.

[93] The "PSEG Companies" are: Public Service Electric and Gas Co., PSEG Power LLC, and PSEG Energy Resources & Trade LLC, each wholly-owned, direct or indirect subsidiaries of Public Service Enterprise Group Inc.

[94] *Compensation for Reactive Power Within the Standard Power Factor Range*, 189 FERC ¶ 62,127 (Dec. 19, 2024) ("*Order 904 Allegheny Notice*").

[95] Order Addressing Arguments Raised on Rehearing, Compensation for Reactive Power Within the Standard Power Factor Range, 191 FERC ¶ 61,188 (June 6, 2025) ("*Order 904 Allegheny Order*").

[96] In Jan. 2022, Cordova had mechanical issues that necessitated a maintenance outage and a derating of Cordova's energy offers by 20 MW. Cordova resolved the maintenance issue by Mar. 28, 2022, but inadvertently continued to derate energy market offers for Cordova by 20 MW until May 19, 2022. As a result, on 22 days from Mar. 28 to May 18, 2022 ("Derated Offer Dates"), Cordova's energy offers into PJM were approximately 20 MW lower than its committed ICAP of 474.6 MW.

[97] During the Relevant Period, Cordova failed to submit complete and accurate GADS data to PJM, through eGADS, for 2,412 hours. These errors resulted in a lower calculated Equivalent Forced Outage Rate of demand ("EFORd"), which impacted the amount of capacity that Cordova was able to sell for the 2021/2022 to the 2025/2026 delivery years. Cordova's inaccurate or missing eGADS data submissions resulted in capacity market overpayments of $1,668,874 for the 2021/2022 to the 2024/2025 delivery years and will result in a capacity market overpayment of $295,562 during the 2025/2026 delivery year.

[98] *Cordova Energy Co. LLC*, 192 FERC ¶ 61,205 (Sep. 3, 2025).

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

As previously reported, the FERC issued on December 16, 2024 a show cause order[99] in which it directed American Efficient, LLC, its various subsidiary companies,[100] and its corporate parents[101] (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;[102] 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").[103] 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).[104]

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." 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).

Natural Gas-Related Enforcement Actions

- **Skye MS Stipulation and Consent Agreement (IN25-9)**

On August 8, 2025, the FERC approved a Stipulation and Consent Agreement with Skye MS LLC ("Skye") to resolve OE's investigation of whether Skye violated Section 311(a)(2) of the Natural Gas Policy Act of 1978 ("NGPA"), 15 U.S.C. § 3371(a)(2) (2023), by charging fees to transport natural gas on behalf of interstate pipelines without having approved rates or a Statement of Operating Conditions ("SOC") on file with the FERC for certain of its pipeline segments, as required by FERC regulations[105] from May 2023 to April 2025 (the "Relevant Period").[106]

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

[100] Affirmed Energy LLC, Wylan Energy L.L.C., Midcontinent Energy LLC, and Maple Energy LLC.

[101] Modern Energy Group LLC and MIH LLC.

[102] 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."

[103] 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.

[104] 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."

[105] 18 C.F.R. § 284.123.

[106] *Skye MS LLC*, 192 FERC ¶ 61,136 (Aug. 8, 2025).

Under the Stipulation and Consent Agreement, Skye agreed to pay a ***civil penalty of $45,000*** to the United States Treasury, and to submit compliance monitoring reports for at least two years (a third year at OE's sole discretion). If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **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,[107] 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,[108] 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[109] 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,[110] 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;[111] (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'

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[107] 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.

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

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

[110] *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*").

[111] 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.

request for rehearing of the FERC's January 21, 2022 designation notice.[112] This matter is pending before the FERC.

XIV. Natural Gas Proceedings

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

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

On June 18, 2025, the FERC issued a NOPR proposing to remove 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.[113] The FERC said that the proposal is "to promote and expedite efficient energy development and reduce construction delays resulting from the regulation's limitation on the issuance of construction authorizations while a rehearing request is pending." The FERC said that it would continue to consider whether additional protections are warranted in individual proceedings and that the proposal does not modify its case-by-case application of its presumptive stay policy. Comments were due on or before July 24, 2025; nearly 30 sets of comments, from a mix of companies, trade groups and natural persons, were received. This matter is pending before the FERC.

New England Pipeline Proceeding

The following New England pipeline project is currently under construction or before the FERC:

- **Iroquois ExC Project (CP20-48)**
  - 125,000 Dth/d of incremental firm transportation service to ConEd and KeySpan by building and operating new natural gas compression and cooling facilities at the sites of four existing Iroquois compressor stations in Connecticut (Brookfield and Milford) and New York (Athens and Dover).
  - Three-year construction project; service 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.[114] The certificate was conditioned on: (i) Iroquois' completion of construction of the proposed facilities and making them available for service within ***three years*** of the date of the; (ii) Iroquois' compliance with all applicable FERC regulations under the NGA; (iii) Iroquois' compliance with the environmental conditions listed in the appendix to the order; and (iv) Iroquois' filing written statements affirming that it has executed firm service agreements for volumes and service terms equivalent to those in its precedent agreements, prior to commencing construction. The March 25, 2022 order also approved, as modified, Iroquois' proposed incremental recourse rate and incremental fuel retention percentages as the initial rates for transportation on the Enhancement by Compression Project.
  - On April 18, 2022, Iroquois accepted the certificate issued in the *Iroquois Certificate Order*.
  - On June 17, 2022, in accordance with the *Iroquois Certificate Order,* Iroquois submitted its Implementation Plan, documenting how it will comply with the FERC's Certificate conditions.

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[112] *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.

[113] *Removal of Regulations Limiting Authorizations to Proceed with Construction Activities Pending Rehearing*, 191 FERC ¶ 61,208 (June 18, 2025).

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

- 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.[115]
- 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.[116] 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.[117]

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).

- ***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[118]
  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. While docketing statements and appearances have been filed, no briefing schedule has yet been established.

[115] 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.

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

[117] *Id.* at P 15.

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

- ***Order 1920*: Transmission Planning Reforms (4th Circuit – 24-1650)**
  Case Title: *Appalachian Voices v. FERC*
  Underlying FERC Proceeding: RM21-17[119]
  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*.[120] 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.

- ***Orders 2023 and 2023-A* (23-1282 et al.) (consolidated)**
  Case Title: *Advanced Energy United, et al. v. FERC*
  Underlying FERC Proceeding: RM22-14[121]
  Status: Oral Argument Scheduled for September 26, 2025

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 has been scheduled for ***September 26, 2025***. The merits panel will be comprised of Judges Millett, Walker, and Childs.

- ***CASPR* (20-1333, 21-1031) (consolidated)****
  Case Title: *Sierra Club, et al. v. FERC*
  Underlying FERC Proceeding: ER18-619[122]
  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***.

[119] *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*").

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

[121] *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).

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

- ***Opinion 531-A* Compliance Filing Undo (20-1329)**
  Case Title: *Central Maine Power Company, et al. v. FERC*
  Underlying FERC Proceeding: ER15-414[123]
  Petitioners: TOs (CMP et al.)
  Status: Being Held in Abeyance

On August 28, 2020, the TOs[124] 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*[125] 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 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.

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

[124] 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.

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

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