NEPOOL
NEW ENGLAND POWER POOL
Sebastian Lombardi
Secretary

July 25, 2024

VIA E-MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of August 1, 2024 Participants Committee Teleconference Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the August 2024 meeting of the Participants Committee will be held **via teleconference/Webex on Thursday, August 1, 2024, at 10:00 a.m.** for the purposes set forth on the attached agenda and posted with the meeting materials at nepool.com/meetings/. The dial-in number, to be used only by those who otherwise attend NEPOOL meetings and approved guests, is **866-803-2146; Passcode: 7169224.** To join Webex, click this link and enter the event password **nepool**.

Looking ahead, the September Participants Committee meeting is scheduled to be held ***Thursday, September 5, 2024, at the Westin Portland Harborview, 157 High Street, Portland, ME***. Rooms at the Westin Portland Harborview for the September meeting will be available at the rate of $325.00 per night, on a first-come, first-served basis. If you wish to take advantage of these arrangements, please contact Jaki or Pat on or before ***Tuesday, August 6***.

We hope all of you are enjoying your Summer. Looking forward to touching base virtually on August 1.

Respectfully yours,

/s/
Sebastian Lombardi, Secretary

FINAL AGENDA

1. To approve the draft minutes of the June 25-26, 2024 Participants Committee meeting. A copy of the draft minutes is included and posted with this supplemental notice. Please provide us with any comments on those draft minutes no later than noon, **Wednesday, July 31, 2024**.

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

2A. To consider and take action, as appropriate, on an FCA19 delay conforming update to the Financial Assurance Policy's Non-Commercial Capacity Financial Assurance Amount Multiplier. Background materials and a resolution are included and posted with this supplemental notice.

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

4. To receive a report from the ISO Chief Operating Officer. The monthly (July) Operations Report will be circulated and posted in advance of the meeting.

5. 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.

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

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

7. Administrative matters.

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

Protocols. The NEPOOL general business portions and plenary sessions of the meeting will be recorded, as are all the NEPOOL Participants Committee meetings. NEPOOL meetings, while not public, are open to all NEPOOL Participants, their authorized representatives and, except as otherwise limited for discussions in executive session, consumer advocates that are not members, federal and state officials and guests whose attendance has been cleared with the Committee Chair. All those participating in this meeting must identify themselves and their affiliation at the meeting. Official records and minutes of meetings are posted publicly. No statements made in NEPOOL meetings are to be quoted or published publicly.

PRELIMINARY

The 2024 Summer Meeting of the NEPOOL Participants Committee was held at the Omni Mount Washington Hotel, Bretton Woods, New Hampshire, on Tuesday, June 25, and Wednesday, June 26, pursuant to notice duly given, followed on Thursday, June 27, 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. 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 25, 2024 SESSION

The June 25, 2024 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, Ms. Bresolin invited, and those around the table each proceeded to, introduce themselves and identify the Entity on whose behalf they were participating in the meeting.

APPROVAL OF MAY 2, 2024 MEETING MINUTES

At the conclusion of those introductions, Ms. Bresolin referred the Committee to the preliminary minutes of the May 2, 2024 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 seven items unanimously recommended for Participants Committee support or approval by the respective Technical Committees. Following motion duly made and seconded, the Consent Agenda was unanimously approved as circulated, with an abstention by Mr. Lamson noted.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), referred the Committee to the summaries of the ISO Board and Board Committee meetings, which had been circulated and posted in advance of the meeting, and invited questions. In response to a question regarding the report given to the ISO Board by Mr. Fintan Slye, Executive Director and Chairman of the Board of the United Kingdom (UK) Electricity System Operator (ESO), Mr. van Welie explained that Mr. Slye had been invited to speak to the ISO Board given certain operational complexities and commonality of issues facing both the UK and New England. Mr. van Welie highlighted the similarities between the ESO's interconnections to the European continent and ISO-NE's interconnections with Canada, ESO's and ISO's shared dependency on natural gas, particularly the role of liquefied natural gas (LNG), and significant investments to support the clean energy transition. Mr. van Welie opined that the UK ESO's experiences offered both a potential window into New England's future and many potentially important lessons.

Responding to additional questions, he explained that discussion around private placement funding to support the ISO's capital budget, discussed by both the Board's Audit and

Finance Committee and the full ISO Board, addressed a renewal of the ISO's market arrangements, rather than new arrangements.

Acknowledging comments on the challenges, and particularly the cost, of incorporating off-shore wind into the system, Mr. van Welie noted the important role that off-shore wind would play in the decarbonization process. He added that, because of current contractual agreement constructs, those costs were likely to surface on the retail, rather than on the wholesale, side of the bill. Accordingly, it would be incumbent upon the States to inform and educate consumers of the costs. He also noted other options that could alter price impacts of decarbonization, like net carbon pricing.

ISO COO REPORT

Dr. Vamsi Chadalavada, ISO Chief Operating Officer, began by noting that his June 2024 report (with May data) had been circulated and posted earlier in the month and his July 2024 report (with June data) would be circulated and posted early in July. He then highlighted a few operations-related items for May and June.

For May, he stated that the month was relatively uneventful -- slightly warmer and more humid than in past years. There was one event, a geomagnetic disturbance from May 10-12, that caused one line to trip, but that line reclosed very quickly and the trip was of short duration. Outside of that event, no geomagnetic disturbances had induced currents that compromised any transformers and the system held together really well. In May, the system peaked on May 22, during hour-ending 17:00 (17,328 MW as measured by Revenue Quality Meter data; 16,896 MW as measured by Real-Time telemetered data).

For June, Dr. Chadalavada noted the previous week's heat wave, during which peak load hit approximately 24,100 MW on June 20, hour ending 17:00. He also described a capacity scarcity event that occurred on June 18 just prior to the peak hour. Providing details and a narrative, he explained how the system experienced and recovered from a 30-Minute Operating Reserve deficiency that day. The system performed well in the days that followed, with load approaching but not reaching the forecasted peaks, and operations eased by increased self-scheduling that anticipated possible additional scarcity events. Dr. Chadalavada confirmed that the recovery on June 18 was entirely market-based and did not rely on emergency assistance arrangements. In response to further questions, he explained how scarcity events would, as a practical matter given the market design, be of short duration, triggered on days of tight supply by the loss of a large resource close to the peak hour, when operators have very little time or flexibility to commit the next unit in (or even out of) merit to make up for the deficiencies resulting from actions in response to the loss of the resource. Specific data related to the June 18 scarcity event, including penalties and balancing ratios, was not yet, but would soon be, available.

Dr. Chadalavada provided a bit more insight into the correlation between weather and load forecasting and the determination of balancing ratios. He added that the ISO provides certain Real-Time information that confirms that there is a scarcity event, but had been unable to identify how to reasonably provide information or notices to the market as circumstances unfold through the day specifically portending a scarcity event.

When asked to provide a bit more insight into the status of and next steps regarding the ISO's evaluation of tie benefits, Dr. Chadalavada explained that, following the evaluation that surveyed the practices of peer ISOs/RTOs, reviewed the ISO's GE MARS model, and the inputs into that model, no specific modeling gaps or deficiencies had been identified. However, among the next steps identified by the ISO related to tie benefit evaluation were (i) opportunities to better harmonize how energy constraints are reflected in the models used by the ISO and neighboring Control Areas (on which discussions with those Areas had already begun) and (ii) the segue to segmentation of tie benefits from annual to summer and winter tie benefits (which would be part of the prompt-seasonal capacity market design discussions). Dr. Chadalavada also identified the potential inclusion of tie benefits-related matters (e.g. expectations on the performance of tie benefits in terms of Pay-For-Performance (PFP) and modeling impacts of reduced surpluses of, and increased reliance on, assistance by neighboring Control Areas) in the 2025 and/or future Annual Work Plans.

Touching on planned outages, Dr. Chadalavada stated that there was one to note, an outage on Line 392 (Coopers Mills to Maine Yankee) from the end of May through the end of June. He expected that outage to have a marginal impact on the New England to New Brunswick interface, as well as a limited impact on the Orrington South constraint.

ISO CFO REPORT: 2025/2026 ISO PRELIMINARY BUDGETS

Mr. Robert Ludlow, the ISO’s Chief Financial Officer (CFO) and Compliance Officer, referred the Committee to the “top down” presentation of the ISO’s 2025 and 2026 preliminary Operating and Capital Budgets (Budgets) included with the materials posted in advance of the meeting. He stated that the preliminary budget presentation provided an opportunity for stakeholder review and feedback prior to presentation in August of the proposed detailed Budgets reflecting that feedback. He expanded on how budget development reflected the ISO’s strategic planning process, and identified among the areas of focus the pace of the clean energy transition and ensuring that the wholesale markets incent/attract the investment necessary to maintain a reliable power system. He reported that he had also shared and reviewed the preliminary budget information with New England Sate officials earlier in the month.

Mr. Ludlow discussed the following key drivers causing the proposed increase over the 2024 Operating Budget: (i) increases in headcount; (ii) additional investments in information technology (IT) infrastructure and licensing, cybersecurity, and the transition to cloud-based infrastructure; and (iii) inflationary and continued operational increases, including inflationary increases to salaries and benefits. He projected that the proposed 2025 Operating Budget would reflect an overall increase, before true-up, of approximately $30 million, a 10.5% increase over 2024, or an additional 16 cents/month on a per consumer basis.

The proposed 2025 Capital Budget was $40 million, a $5 million increase over the 2024 Capital Budget. Areas driving capital costs included increases to interest income, major reliability-related efforts, cyber security, IT asset and infrastructure replacement, and efforts to further attract, develop and retain talent. With growth in the ISO workforce, there would be a need to expand the physical campuses. He said that the ISO was looking to acquire property adjacent to its Holyoke, MA location, and optimize the use of its Windsor, CT campus over the next few years, generally keeping its consolidated workforce at the Holyoke campus. He explained that, to support the future capital program, the ISO would have to secure, as noted in the CEO Report, roughly $75 million in private placement notes.

In response to questions, Mr. Ludlow confirmed that the ISO employed outside consultants to analyze compensation and headcounts, which were consistent with other ISOs and RTOs. He explained that the additional headcount proposed was additive to the increases proposed in the prior few years. Overall headcount, he estimated, would increase to approximately 750, up roughly 200 from when the ISO began RTO Operations. He added that, although the ISO had experienced challenges attracting and retaining additional employees (or FTEs), it was working to mitigate the risk factors and requirements associated with retention and onboarding of additional FTEs. In addition to evaluating and fine-tuning compensation levels, the ISO planned to leverage benefits of its internship program (which focused on economists and planning and software engineers), as well as increased contingency funds to allow the ISO the flexibility to hire short-term talent to keep the workload on track.

To that end, Mr. van Welie added that, because the work that was being created and the demand for the skills required to do that work, was at, and was expected to remain at, an all-time high, but with an imbalance/deficit in the supply of the required skill sets to complete that work, the ISO was facing some critical choices as to how to move forward. One path forward, consistent with past practice, could be the retention of outside consulting help, though that approach would depend on the availability of consultants as well as internal ISO resources to supervise consultant efforts. Another consideration would be how best to adjust to the “turn over” challenges being experienced – addressing turn over as a short-term condition that could be ridden out, or addressing it as a more long-term challenge to be improved through changes in hiring and training practices. Mr. van Welie added that Participants could also expect increased variability in the ISO’s headcount estimates, at least until the scope of the work required for future projects could be determined with more precision. Although budget and staffing levels were expected to be sufficient to get through activities planned for 2025 and into 2026, should FTE shortages persist, prioritization would become increasingly central to setting and achieving future work plan items.

In response to further questions, comments and requests, Mr. Ludlow confirmed the total FTEs to be added for 2025, indicated that more detailed information on those additions would be provided in future presentations, agreed to consider presenting additional detail regarding budget impacts on retail electricity rates, and identified certain rate and other information that, as in past years, would be provided in later budget presentations as information for 2025 was finalized and came more sharply into focus.

LITIGATION REPORT

Mr. Lombardi referred the Committee to the June 24 Litigation Report that had been circulated and posted in advance of the meeting. He highlighted the following developments:

(i) The United States (U.S.) Senate had confirmed as new FERC Commissioners David Rosner, Lindsay S. See, and Judy W. Chang, with Commissioner Rosner sworn in the previous week and Commissioners See and Change to be sworn in in due course;

(ii) Transmission Owner (*TO*) *Initial Funding Show Cause Order (EL24-83)*. The FERC instituted a Section 206 proceeding on June 13, 2024, finding that the ISO tariff appears to be unjust and unreasonable because it includes provisions for TOs to unilaterally elect to fund network upgrades required by an interconnection. A more fulsome summary by NEPOOL counsel was provided to and available on the website for the Transmission Committee. The ISO's response to the Show Cause Order would be due on or before September 11, 2024;

(iii) *FERC Order 1920: Transmission Planning & Cost Allocation Reforms (RM21-17).* The FERC issued on May 13, 2024 *Order 1920*, its final rule on proposed reforms to existing transmission planning and cost allocation requirements. More than 50 parties had requested clarification or rehearing of that Order. A detailed summary had been provided to and was available with the posted materials for the Transmission Committee; and

(iv) *Order 2222 Compliance Filings* (ER22-983). Metering data submission revisions required by the FERC's April 11, 2024 order, supported as part of the meeting's Consent Agenda, had already been filed by the ISO. Comments reporting on the Committee's support for those revisions would be filed shortly following the meeting. Related, but separate revisions to specify in the Tariff itself sub-metering requirements for DER Aggregations' participation as sub-metered Alternative Technology Regulation Resources, directed as part of the FERC's May 23, 2024 order on rehearing, would similarly be filed by the ISO as directed, but ahead of Participants Committee action. The Participants Committee would act on those changes at its August meeting, with NEPOOL comments summarizing that action to be submitted shortly thereafter.

Mr. Lombardi encouraged anyone with questions on these highlights or on the full Report to reach out to him or any of NEPOOL counsel.

COMMITTEE REPORTS

Markets Committee (MC). Mr. William Fowler, the MC Vice-Chair, reported that the MC would hold its Summer Meeting on July 9-10 at The Ocean's Edge Resort in Brewster, MA on Cape Cod. The MC would receive highlights from the Internal Market Monitor (IMM) on its 2023 Annual and 2024 Winter Quarterly Markets Reports and would consider changes in response to the FERC's May 23, 2024 order on rehearing as discussed in the Litigation Report, proposed hourly tracking changes to the Generation Information System (GIS), and a discussion on potential ways to manage PFP credit risks.

Reliability Committee (RC). Mr. Robert Stein, the RC Vice-Chair, reported that the RC would next meet on July 16, 2025 at the DoubleTree in Westborough, MA. Among the items to be considered would be *Order 2023* conforming changes to Planning Procedure 5-6 (PP 5-6) (changes to interconnection requirements) and revisions to the load power factor process. Discussion on PP 5-6 would continue at a virtual meeting scheduled for July 25, 2024.

Transmission Committee (TC). Mr. David Burnham, the TC Vice-Chair, reported that the July 24, 2024 TC meeting had been cancelled. The TC would meet next at the joint RC/TC Summer Meeting on August 13-14, 2024 at the Water's Edge Resort in Westbrook, CT. Looking ahead, discussion on the *Order 1920* compliance process would be on TC's September meeting agenda.

Budget & Finance (B&F) Subcommittee. Mr. Thomas Kaslow, B&F Chair, reported that the next B&F meeting would be July 29, 2024 to discuss the ISO's proposed financial assurance (FA) changes for PFP-related credit risk. Noting that potential PFP-related Market Rule changes being considered by the MC could be considered together with the FA changes, he encouraged members interested in that topic to attend both the MC and B&F meetings.

Membership Subcommittee. Mr. Brad Swalwell, Membership Subcommittee Chair, reported that the Subcommittee was next scheduled to meet on July 15.

NESCOE REPORT

Ms. Heather Hunt, Executive Director, reported on two items of potential interest (each available on the NESCOE website). The first was an educational primer addressing the emergence of data centers and their implications on power systems in other RTOs. The second was a white paper prepared with and by DayMark Energy Advisors related to inter-regional planning. The white paper was intended to highlight the processes that proposed inter-regional transmission projects would have to go through in New England, New York and PJM, and to discuss the benefits of and challenges to the development of such projects. She welcomed feedback on those materials.

NECPUC REPORT

Mr. George Twigg, Executive Director, reported on the ongoing NECPUC efforts related to retail demand response and load flexibility. NECPUC had completed its series of informational webinars and would next be turning to stakeholder meetings and discussions. He encouraged all those interest to reach out to him and to provide input.

FERC STAFF INTRODUCTIONS & COMMENTS

After a break for lunch, Ms. Bresolin welcomed members and guests back to the meeting. She also welcomed, introduced and thanked the following FERC representatives for their attendance and participation: Mr. Eric Jacobi, Ms. Emma Brin, Mr. Brandon Ward, Mr. Aaron Siskind, and Ms. Mary Wierzbicki. 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.

Ms. Brin and Mr. Ward, each an Analyst in the Office of Energy Market Regulation (OEMR)-East, said that they had been at the FERC for three years. Their group was the lead group for processing Section 205 filings and waiver requests. Ms. Brin and Mr. Ward, with others in their group, regularly listened in to New England stakeholder meetings, and had enjoyed the chance to put names to faces during the Summer Meeting. Ms. Brin stated that members could also come to her for help with facilitating a pre-filing meeting with FERC staff.

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 almost 20 years. He highlighted his involvement in the 2004 Cold Snap, locational installed capacity (LICAP), and most other capacity-related proceedings over the last 10 years. Although New England and eastern RTO market focused, he enjoyed staying abreast of other developing policy issues. He said that he was looking forward to upcoming efforts on Resource Capacity Accreditation (RCA).

Thanking the FERC staff representatives for their introductions, Ms. Bresolin encouraged members to take advantage of the opportunities prior to the formal Sector meetings later that week to get better acquainted with these FERC representatives and, if and to the extent appropriate, explore with them in a bit more depth some of the current issues facing the region.

Ms. Bresolin then introduced Ms. Mary Wierzbicki, who had been with the FERC for 20 years, and who serves as Director of OEPI's Division of Energy Market Assessments (DEMA). Ms. Wierzbicki introduced in a bit more detail the role and work of both OEPI and DEMA. She identified and provided background regarding the three market assessments published each year and presented at Commission meetings and to state officials (the *Winter and Summer Market and Reliability Assessments* and DEMA's annual *State of the Markets* report). She commended to members DEMA's *Energy Primer: A Handbook on Energy Market Basics*, which DEMA routinely updates, as providing a wealth of introductory information, not only on electric and gas markets (how they work and what vocabulary/terminology is used in the various regions of the country) and what the FERC does in connection with each, but also foundational information on gas-electric coordination. She also highlighted the regular calls that DEMA staff holds with the market monitors of each of the FERC-jurisdictional ISO/RTOs to discuss market performance, the recommendations from the market monitor reports, and their views on issues/proposals being discussed within respective regional stakeholder processes. Ms. Wierzbicki also highlighted DEMA's leading efforts with respect to the 2022 and 2023 New England Winter Gas-Electric Forums, and the FERC's recent Order 1920 and Order 2023 rulemakings.

In response to questions, Ms. Wierzbicki explained the methodology behind the numbering of rulemaking orders, which were typically incremented, but for major orders, could be assigned an out-of-sequence number by and at the discretion of the FERC Chairman. She confirmed that the FERC continued to consider and work on gas-electric coordination issues. Staff was aware of and evaluating the recommendations by NAESB, Joint RTOs, EPSA/INGAA/NGSA, and others, but particularly given the fact that next steps did not appear to lend themselves to simple solutions, the FERC remained in the "figuring it out" stage. She welcomed any thoughts members might have on these issues.

Ms. Wierzbicki concluding by sharing some insights and recommendations with respect to the ways and frequency with which stakeholder thoughts could be relayed, whether through pre-filing meetings, direct contact with or from OEPI, or group meetings with appropriate FERC staff that could be organized. Ms. Bresolin thanked Ms. Wierzbicki for that helpful information and encouraged members to begin those conversations during the Sector meetings with Ms. Wierzbicki and her colleagues on Thursday.

EMM 2023 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 2023 Markets Report (EMM Annual Report), which had been circulated and posted in advance of the meeting. He began by opining that the New England Markets performed competitively in 2023, but noted that the EMM Annual Report nevertheless recommended improvements.

Cross-Market Comparison

Dr. Patton began by discussing the "all-in" prices on a dollar per megawatt-hour (MWh) 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 other markets (with the exception of ERCOT), which he explained could be attributed to New England's higher natural gas prices. His presentation also showed that New England's 2023 capacity prices were comparable with most organized markets, observing the cross-market variation was due to differences in surplus and market designs. In response to a question, Dr. Patton confirmed that the all-in price chart did not include costs of the Mystic Cost of Service Agreement.

Next, Dr. Patton discussed transmission congestion costs. As in past years, he showed New England ~~has~~ experiences just a fraction (about 1/10th) of the congestion tha~~n~~t other RTOs experience. A related, ~~The~~ concomitant experience ~~result~~ is that the New England region has the highest transmission rates in the nation (roughly~~at~~ $22/MWh). Dr. Patton opined that over the last 10 years or so, New England has built transmission more vigorously than other RTOs to address transmission security issues. That said, he noted that other RTOs had begun ~~are starting~~ to follow New England's lead, albeit possibly for different reasons, e.g., building transmission for ~~the~~ anticipated increases in intermittent resources.

Addressing virtual transactions, Dr. Patton explained that, as in prior years, New England's Day-Ahead Energy Market was less liquid than the Day-Ahead Energy Markets of other RTOs due to lower virtual trading levels. Looking ahead, however, Dr. Patton believed that the FERC-approved Day-Ahead Ancillary Services Initiative (DASI), when coupled with a requirement to schedule physical resources to meet the regions' forecasted load, should address his concern because it would negate the need to allocate Net Commitment Period Compensation (NCPC) payments to virtual transactions.

Navigating the Clean Energy Transition

Dr. Patton then turned to the clean energy transition. Based on experiences in other ISO/RTOs, he noted that the increase in intermittent resources on the grid would create a higher uncertainty in energy output. He explained that it was incredibly challenging to forecast the energy output for intermittent resources, adversely impacting ISO energy output ~~resulting in a~~ forecasts~~ error~~. Energy output forecast errors increased as ~~with more~~ intermittent resources on the system increased. Given intermittent resource ~~the~~ energy output fluctuations, the system would see a greater demand for resources that can ramp up or down. Relatedly, the uncertainty in energy output leads to uncertainty in transmission flows because intermittent generation tends to be clustered in a region. Thus, the possibility existed that transmission~~s~~ constraints would be violated. Moreover, Dr. Patton reported that he had seen situations where intermittent resources did not respond reliably to curtailment instructions. He added, however, that he was not too concerned with renewable resources setting negative prices. From his perspective, flexible resources would set prices in most hours when renewable resources could not meet demand. Additionally, Dr. Patton suggested~~offered~~ that dispatchable resources would likely see a larger revenue impact from an increase in the frequency of reserve shortages.

Dr. Patton opined that New England's markets could ~~can~~ address these challenges. He pointed to two critical market design elements: (1) efficient shortage pricing and (2) marginal capacity accreditation. With the former, Dr. Patton noted that shortage pricing could ~~can~~ signal dispatchable resources as a revenue source. With the latter, he stated that some resources would~~will~~ become less critical from a reliability standpoint as the system transitions. Thus, an accreditation methodology must provide positive ~~the~~ signals to resources that provide reliability. Dr. Patton observed that, despite initial concerns about how the ISO was thinking of accrediting gas-only resources, the ISO's ongoing RCA ~~resource capacity accreditation~~ project was attempting to re-design the region's accreditation regime to offer the right signals. Dr. Patton recommended evaluating a look-ahead dispatch model that optimizes dispatching resource hours in the future rather than the current model that does it 10 or 15 minutes ahead.

Responding to questions concerning tie benefits, Dr. Patton agreed that the assumptions underlying tie benefits should be evaluated and that the ISO's RCA project offered an excellent opportunity to do so. Regarding gas modeling and resource flexibility, he noted that no

ISO/RTO had a model that could address resource lead time for accreditation purposes. Accordingly, transmission building should be undertaken economically so that it does not undermine market-based investments that solve the same problem at a lower cost.

Out-of-Market Commitments and Operating Reserve Prices

Referencing his presentation, Dr. Patton reported on the Day-Ahead commitments for Ten-Minute Spinning Reserves (TMSR). He noted that, on average, out-of-market commitments happened about 25 to 40 percent of the yearly hours to meet the system's TMSR Requirement. As a result, the prices in the Day-Ahead market are affected. He noted that DASI is going to address this issue.

Dr. Patton addressed what he viewed as a flaw in the fast-start pricing logic for Operating Reserves. After offering a high-level overview of this aspect of the market (further elaborated in the EMM Annual Report), he noted that when a fast-start resource is set at its Economic Minimum (EcoMin) for pricing purposes, it cannot set the marginal price. Consequently, the available MW below a resource's EcoMin is undervalued. Thus, the fast-start pricing logic raises energy and reserve prices because the system appears short.

Assessment of the July 5, 2023 PFP Event

Dr. Patton ~~started by~~ observed~~ing~~ that PFP events, though to date infrequent, were likely to increase in frequency. He addressed the July 5, 2023 PFP event~~ that occurred on July 5, 2023~~. He explained that, during the event, the region lost import capability from Canada, and although exports to New York were then curtailed, New England was approximately 200 MW short of capacity for about 30 minutes. Dr. Patton noted that, although the reliability implications were almost negligible, the PFP rate remained an issue. Referring to his presentation, he showed that the units not committed in the Day-Ahead Market, e.g., steam and conventional units, had PFP charges. These resources, though essential for winter reliability, were at risk of inefficient retirement due to the exposure caused by a high, flat PFP rate. As detailed in the EMM Annual Report, he believed that the PFP rate should be a dynamic, sloped rate commensurate with the severity of the reliability event.

Following his comments, the Committee directed questions to the EMM related to his concern that exports are not charged the PFP rate ($3,500/MWh). Referring to a chart in his presentation, Dr. Patton noted that, if exports had been charged the PFP rate, exports would have been charged around $1.2 million during the July 5 event. He said that not charging exports but paying imports the PFP rate was a flaw in the PFP design and could create inefficient incentives and encourage gaming, such as a strategy to simultaneously schedule imports and exports at the New England/New York border in a scarcity event. In this scenario, no power would flow into either market, but the imports would receive a credit while the exports would not receive a charge at the PFP rate. Thus, Dr. Patton opined that exports were receiving a windfall. In response, a Committee member suggested that the EMM consider whether the Balancing Ratio should be revised, which he agreed to consider. Relatedly, the EMM offered (without formally recommending) that the PFP construct would be better served if it was in the energy market to reflect the value of energy and prevent the need to self-schedule in some instances. In response, a participant stated that doing so could remove incentives for capacity resources to perform, a point the EMM acknowledged but countered by saying that a PFP construct in the energy markets could include a forward construct that mimics the current design's obligation to perform.

Winter Reliability in the FCA

Dr. Patton then provided an overview of the EMM Annual Report's section on winter reliability. He bean ~~started his comments on this section~~ by noting his belief ~~that he believes~~ that winter presents the biggest reliability concerns for the region. Thus, his team spent significant effort understanding and modeling the problem to offer insights on structuring the markets to address the reliability issues. He explained that winter presents a unique challenge because of the possibility of a long cold snap that consumes the region's fuel inventory and, thus, impacts the system's ability to produce sufficient energy. He highlighted ISO-NE's Probabilistic Energy Adequacy Tool (PEAT) as particularly helpful in addressing the winter reliability issue.

Next, he turned to several charts that illustrated Potomac Economics' simulation of the winter reliability risk by 2031–2032 using inputs from the PEAT study, the 2024 ~~CELT~~ forecast of capacity, energy, loads, and transmission (CELT Report), and the FCA-18 results. As detailed in the EMM Annual Report, the simulation indicated that ~~the amount of LNG and oil inventories significantly impacted the~~ winter reliability risk in New England was significantly impacted by the amount of available LNG and oil inventories. Accordingly, ~~The import is that~~ Market Participants' fuel procurement decisions have significant ~~big~~ reliability implications, and the market design must therefore ~~should develop the appropriate construct to~~ incentivize the efficient procurement of fuel for the winter season. Moreover, Potomac Economics' model also analyzed sensitivity cases assessing the possible impact of (i) delayed offshore wind development and (ii) delayed offshore wind development but with higher penetration of two-hour energy storage resources. From the analysis, Dr. Patton opined that the amount of offshore wind operating on the system significantly impacted the winter reliability risk issue, but the entry of energy storage resources~~ESRs~~ did not.

Dr. Patton answered questions about the model and noted the importance of capturing the available LNG amount in the system because it wa~~i~~s not an exogenous amount that could ~~can~~ be treated as a random variable. In response to a guest's comment about the EMM's conclusions on offshore wind's impact on winter reliability, Dr. Patton emphasized that offshore wind provides a certain amount of reliability, particularly during the winter period, and should be compensated for the reliability. Importantly, and more generally, Dr. Patton explained that every resource class provides some reliability and should be compensated accordingly.

Continuing the discussion on winter reliability, Dr. Patton, referencing his presentation, compared the 12-day LNG in reliability models and historical data. He opined that the ISO's prior assumption of LNG in the system was too optimistic and was hopeful that, in the future, those assumptions~~it~~ would be more conservative. Next, the EMM shifted his presentation to discuss the importance of dispatch logic in models. The gist of his comments was that the models must be realistic to capture opportunity costs and accurately quantify winter risk for accrediting resources. Finally, Dr. Patton provided a chart that showed Potomac Economics' estimates of the marginal capacity value for various resources using a model that included inventoried fuel versus one that did not. The key takeaway wa~~i~~s that, if the ISO's model used for accreditation does not model the available fuel inventory in the system, then the model ~~it~~ may not ensure that the market aligns with the winter reliability of each type of resource.

From this portion for the presentation, a couple of members asked clarifying questions. Dr. Patton confirmed his belief ~~that he believes~~ that the ISO's model should consider modeling inventoried fuels in the next two years. In response to a member's request, the EMM said he would consider adding this suggestion to his official recommendations. Dr. Patton also addressed questions concerning how the Potomac Economics model incorporated ~~ed~~ energy storage resources, noting how those resources contribute to winter reliability, particularly in a two-week cold snap.

JUNE 26 SESSION

The Summer Meeting reconvened at 9:30 a.m. on June 26, 2024.

HOST STATE (MIKE HARRINGTON) WELCOME REMARKS

Ms. Bresolin welcomed members and guests back to the meeting. She then introduced New Hampshire State Representative Michael Harrington, who offered some welcoming remarks as a representative of the host state of New Hampshire. Representative Harrington began by encouraging all to take advantage of the great things that New Hampshire had offer. He reflected on distinctive characteristics of New Hampshire, including its legislative body, its state motto and the pride displayed in living up to that motto, as well as its commonality of interest with the rest of the New England States for a reliable electric system at a reasonable price. He also noted the related importance of investigating advanced technologies and processes, citing as an example his experience with New Hampshire's inquiry into the implementation of next generation nuclear reactor technology. He concluded by wishing all an enjoyable time in New Hampshire.

MARKETS COMMITTEE SUMMER MEETING UPDATE

Providing an update to his Markets Committee report from the day before, Mr. Fowler announced that the ISO, having accelerated some internal processes in response to Participant requests, was prepared to discuss at the Wednesday session of the MC's July Summer Meeting some preliminary thoughts on the scoping of the upcoming capacity accreditation/reforms work. He emphasized that the ISO was interested in Participant feedback and encouraged all those interested to participate.

RECOGNITION OF BOB ETHIER

On behalf of NEPOOL, Ms. Bresolin asked Mr. Tom Kaslow to say a few words on the occasion of the impending retirement of Mr. Bob Ethier, the ISO's Vice President of System Planning. Mr. Kaslow thanked Mr. Ethier for his years of close collaboration and dedicated service to the region, developing and monitoring the markets, planning for the future system and helping to keep the lights on. He commended Mr. Ethier's 360° view of planning, markets, and mitigation, highlighting Mr. Ethier's communication skills and personal approach to discerning stakeholder perspectives and seeking opportunities to reach mutually-supported outcomes. In recognition and appreciation of Mr. Ethier's more than 24 years of service, Mr. Kaslow presented Mr. Ethier with a token of NEPOOL's gratitude, the inscription on which Mr. Ethier himself read at Mr. Kaslow's request. Mr. Ethier reflected on the progress made over his time working with NEPOOL, his eagerness to follow the progress to be made going forward, but above all, thanked all for the pleasure and privilege of working in partnership on the really interesting work that the regional arrangements entailed.

REMARKS BY BCSE PRESIDENT LISA JACOBSON

Ms. Lisa Jacobson, President of Business Council for Sustainable Energy (BCSE), opened by recognizing NEPOOL's diversity of stakeholders and its culture of collaboration and thanking the Committee for the opportunity to offer remarks. She introduced the BCSE, a broad-based trade organization, founded over 30 years ago, with a mission to influence public policy to improve air quality and achieve better energy efficiency, reliability, affordability, and sustainability. She explained the BCSE focuses its efforts on advancing policies that will infuse capital into the energy industry and on advocacy at the federal level. She noted also that the

BCSE participates at both the state and local levels (though without engaging in active legislative lobbying).

Ms. Jacobson explained that the BCSE played an active role in the formation of the Regional Greenhouse Gas Initiative (RGGI) in New England and actively participates in international energy initiatives. She noted one example of the organization's work on an international level wa~~i~~s its participation in the Rio Earth Summit in 1992, from which four treaties emerged, with one focused on climate change.

Ms. Jacobson's presentation focused on a piece of the information contained in the annual *Sustainable Energy in America Factbook* (*Factbook*) that the BCSE creates in partnership with Bloomberg New Energy Finance (BloombergNEF). She noted that the 13th edition of the *Factbook* was released in March, 2024. She explained that the *Factbook* was a resource geared towards policymakers and~~,~~ was accessible to the broader public at no cost. The 2024 *Factbook* contained historical data, as well as up-to-date commentary and data trends related to energy and emerging technologies in the U.S.

Reflecting on recent economic challenges such as the COVID-19 pandemic, and high inflation and interest rates, Ms. Jacobson acknowledged a resilient and encouraging performance in the energy sector. However, she stressed the need for progress to continue and to accelerate if climate goals we~~a~~re to be reached.

Ms. Jacobson noted that, at the conclusion of 2023, the nation's energy productivity (the combination of energy consumption and U.S. Gross Domestic Product (GDP)), was high and supporting significant growth in the U.S. economy. She highlighted as significant three pieces of federal legislation, the Chips and Science Act, the Inflation Reduction Act (IRA), and the Infrastructure Investment and Jobs Act (IIJA), noting the particular effectiveness of the IRA and

IIJA. She underscored record-breaking global investments in renewable energy, both in terms of output levels and percentage of generation.

Ms. Jacobson noted the importance of policy maker understanding as to the integration of natural gas in the U.S. ~~our nation's~~ economy, especially increased activity in LNG exports and exports to Mexico. She stated that, given the contribution by natural gas to the national economy, there should be focus on how to decarbonize the natural gas sector. Turning to transportation, Ms. Jacobson stated that electric vehicles (EVs) unsurprisingly experienced a record-breaking year in 2023, with a significant jump in ownership from prior years attributable in part to the increased number of choices in EVs. She emphasized that renewable natural gas and biofuels offered an incredible opportunity to help decarbonize the transportation and natural gas sectors.

Because a main goal of the BCSE is to support decarbonization efforts, Ms. Jacobson explained that much of the data in the *Factbook* focused on Green House Gas (GHG) emissions. She stated that, at end of 2023, the U.S. was about 16% below 2005 GHG levels (measured in million metric tons of CO_2 equivalent). To achieve the goal for reductions set by the Biden ~~current presidential~~ administration, she added, would require annual reductions of six percent. Ms. Jacobson underscored that the buildings sector and industrial sector particularly offered significant potential for reductions, and would need to be an area of focus moving forward.

Ms. Jacobson concluded her presentation by thanking NEPOOL for facilitating productive discussions and collaboration on these critical energy and environmental issues. She also responded to several questions from members. In response to one~~a question~~, she confirmed that the U.S. economy had a relative advantage in energy efficiency per ~~Gross Domestic Product~~ ~~(~~GDP~~)~~ output. Elaborating, she stated that the BCSE endorsed a bipartisan bill introduced in the

U.S. Senate called the “PROVE IT~~rove it~~” Act, which capitalizes on ~~the~~ U.S. advantages. She also explained that, because the U.S. did not have a carbon border policy, the BCSE supported a current piece of legislation that would provide for data collection over the next couple of years that could be used to establish a carbon border adjustment. Ms. Jacobson affirmed that the energy transition was well underway and identified viable economic signals as important to progress on decarbonization, including energy efficiency-~~-~~related support, tax code changes and carbon pricing.

REMARKS BY BLOOMBERG~~-~~NEF LEAD ANALYST TARA NARAYANAN

Ms. Tara Narayanan centered her presentation on latest data trends and future projections relating to decarbonization efforts. Ms. Narayanan noted that BloombergNEF had historically been known for its work in the renewables and power sectors, but BloombergNEF had ~~now~~ expanded to encompass all sectors experiencing disruption from decarbonization.

Ms. Narayanan began by noting that the end point for BloombergNEF’s analysis was typically ~~ends with~~ 2050, because 2050 represented the time by which ~~this is when we should have met~~ certain climate goals should have been met. She stated that the central question in her analysis wa~~i~~s how these goals could ~~can~~ be achieved at the lowest cost~~s~~. She stated that, if ~~we let~~ least cost economics were permitted to play out, and the status quo maintained~~leave things as they are~~, increased future demand would lead to ~~we are set to see~~ a 40% climb in emissions with increased future demand. Acknowledging the current ongoing transition and recognizing the challenge of balancing cost-effectiveness with emission reduction targets, Ms. Narayanan stressed the urgency of investing in lower emission technologies to align supply with ~~our~~ growing demand projections.

Based on charts in her presentation, Ms. Narayanan projected rapid growth in solar and wind energy to support electricity consumption, which will displace oil and gas and drive down emissions. She noted that the U.S. likely hit ~~our~~ its peak ~~of~~ oil and coal use in the 2010s. Ms. Narayanan also acknowledged the economic effect of the natural gas industry. She explained~~remarked~~ that, under~~in the~~ base case assumptions, ~~there is an expectation for an increase in~~ natural gas use was expected to increase and emphasized that the ~~conversation regarding the~~ future use of natural gas would be ~~is~~ critical to reaching decarbonization/net-zero emissions goals.

Ms. Narayanan noted that BloombergNEF's predictions we~~a~~re based on extrapolations that incorporated~~s~~ tax credits; however, she also noted that ~~these~~ those predictions would~~ill~~ be adjusted to remove tax adjustments under the IRA because it wa~~i~~s not desirable or realistic to endlessly subsidize these technologies.

Ms. Narayanan concluded by responding to a question addressing~~at~~ the end of her presentation. ~~The~~ A member noted the significant use of oil, coal and natural gas even under the net zero scenario, suggesting the need for carbon capture and sequestration, and raising questions~~. They inquired~~ about ~~the~~ risks given the current absence of carbon capture technology. Ms. Narayanan emphasized that the U.S. wa~~i~~s a leader in carbon capture technology and had been used by the oil and gas industry~~ has been using it~~. She described carbon capture technology~~it~~ as a mature and well-understood, ~~technology~~ but acknowledged that it had~~is~~ not yet achieved a ~~set up to~~ scale needed ~~yet~~ to sustain a decarbonized world. Ms. Narayanan identified a lack of infrastructure as the biggest risk, a risk ~~s an issue of a lack of infrastructure,~~ similarly faced by ~~to~~ transmission ~~or~~ and other technologies. Elaborating, she stated that ~~we need~~ pipelines to transport the carbon and ~~a~~ way to store carbon were needed~~it~~, but ~~there are risks with that~~ the development ~~as well~~of each of those presented their own set of risks.

PANEL DISCUSSION – ENERGY SECTOR PERSEPECTIVES & REFLECTIONS "BEYOND NEW ENGLAND"

The panel discussion was moderated by Ms. Jacobson and featured as panelists Ms. Sapna Gheewala Dowla, Associate Vice President of Policy & Research at the Alliance to Save Energy (the Alliance); Mr. Rob Mosher Rob Mosher, Vice President of Government Affairs, Interstate Natural Gas Association of America (INGAA); and Mr. Anthony Fratto, Senior Director, Research & Analytics, American Clean Power Association (ACP). Ms. Jacobson opened the discussion by asking the panelists to introduce themselves and share their initial reactions for the discussion. The questions in the discussion were framed around the challenges and opportunities of the transition towards cleaner, cheaper, and more efficient and reliable energy sources.

After introducing themselves, Mr. Mosher began by emphasizing the magnitude of the task ahead in meeting clean energy goals by 2050, characterizing it as both daunting and exciting. Ms. Dowla highlighted the potential better use of energy efficiency measures that could alone help to achieve demand reductions of about 60%~~ of our demand~~. She noted the availability of existing technologies and emphasized the challenge of scaling them effectively. Mr. Fratto emphasized the pivotal role that natural gas will play as a key component to changing our energy economy and an instrumental part of the transition. He noted that natural gas consumption wa~~i~~s rising and demand wa~~i~~s increasing due to factors such as artificial intelligence ~~AI~~ and data centers.

Ms. Jacobson asked the panelists to identify what they viewed as the biggest opportunities and challenges ~~are~~ to catalyzing~~e~~ investment in~~to~~ support of the energy transition. Mr. Mosher stated that the biggest challenge is getting through the state and federal processes required to develop and build the infrastructure needed to support new energy systems, including the~~to~~ integration~~e~~ of new renewable resources. He highlighted the massive amounts of new transmission that wa~~i~~s expected to be needed, and ~~followed up with asking the question of how do we~~ the challenge to ensuring~~e~~ customers receive~~are getting~~ reliable, cost-effective energy. Mr. Fratto echoed Mr. Mosher's statement that the main challenge wa~~i~~s infrastructure-~~-~~related, encompassing~~including~~ everything from siting, permitting and environmental approval process challenges. Ms. Dowla noted the importance of continued work to keep policymakers adequately informed and educated on these complex issues.

Ms. Jacobson then posed a question about offshore wind and battery storage. Mr. Mosher emphasized that, with no discernible~~ there is no~~ 'silver bullet' solution to achieve a clean energy future, ~~and that~~ a mix of resources would~~ill~~ be needed. Acknowledging that offshore wind wa~~i~~s a comparatively more developed technology~~ compared to other emerging energy technologies~~, he noted regional variations in offshore wind feasibility, due in part to geographic differences, as well as ~~and~~ cost and inflation challenges, especially in the Northeast.

Ms. Jacobson followed up by asking about demand-side ~~matters~~ management and virtual power plants.

Ms. Dowla said the Alliance had~~s~~ two initiatives focused~~ing~~ on next generation energy efficiency and virtual power plants. She noted that the Alliance ha~~s~~d put together working groups to tackle the challenges of virtual power plants and how to best implement them. She said~~acknowledged~~ that virtual power plants we~~a~~re all over the U.S. and that, given the ~~each~~

~~region has~~ different regulation and priorities in each region, identifying ~~so pulling together~~ best practices would be~~is~~ very important and helpful. She further noted that virtual power plants were ~~it is~~ still a new technology, presenting both ~~but the Alliance sees it as a~~ challenge and opportunity.

Ms. Jacobson asked about natural gas infrastructure needs and how to ensure flexible fuel and storage options. Mr. Mosher noted that the largest fuel source for electricity generation, over 40%, wa~~i~~s natural gas and ~~that~~ projections were for that percentage ~~continues~~ to increase. He explained ~~highlighted that we are at a~~ the “flashpoint” faced due to ~~because~~ infrastructure development ~~is~~ not keeping pace with consumption. He stressed the~~at~~ continuing~~we~~ need for natural gas to serve~~provide~~ as a backstop to~~n~~ renewables. He noted ~~also acknowledged~~ that ~~we are seeing~~ renewables were experiencing~~have~~ the same issues with permitting delays ~~at a federal level for permitting~~ as natural gas. He stressed~~highlighted~~ that broad ~~we will need to build~~ infrastructure investment and development would be needed~~broadly~~.

Ms. Jacobson concluded her set of questions by asking Mr. Fratto for his thoughts on batteries. Mr. Fratto elaborated on trends in battery storage, noting regional differences in deployment strategies. He contrasted~~noted that in~~ California, which w~~h~~as home to ~~a lot~~ more battery storage than other states, where ~~mostly~~ long-~~-~~term batteries we~~a~~re more useful given the state’s level of solar-powered energy to ~~; while in~~ Texas, which ha~~s~~d ~~a much more open competitive market, you see~~ more short-~~-~~term, 1 hour batteries given the structure of its competitive markets. Mr. Fratto discussed the importance of long-term battery storage solutions and development for uses beyond ~~when the market has met its battery saturation for~~ ancillary services needs.

~~Members asked several questions of the panelists as well and~~ Ms.~~Chair~~ Bresolin joined Ms. Jacobson on stage to moderate members questions of the panelists. Regarding the potential effects of a lower inflation rate on the adoption of renewable energy technologies, Mr. Mosher stated ~~responded by acknowledging~~ that, while lower inflation might spur increased investment in technologies like solar, it would also necessitate restructuring Power Purchase Agreements (PPAs) and Renewable Energy Certificates (RECs). He expressed concerns about heightened uncertainty in project timelines due to permitting challenges, which could result in~~lead to~~ stalled projects and missed opportunities for linear infrastructure development across various sectors. He added~~also acknowledged~~ that a decreasing inflation rate would create more market uncertainty.

Another question raised concerns about ~~utilities facing~~ the pressure utilities faced ~~from consumers~~ to invest in future-proof infrastructure amidst uncertain long-term projections. In response, Mr. Fratto said ~~addressed this by encouraging~~ utilities should be encouraged to mitigate risks associated with infrastructure investments by~~to~~ employing best-case assumptions in their planning processes and conducting thorough analyses that consider two bookend scenarios ~~to mitigate risks associated with infrastructure investments~~. Mr. Fratto also emphasized the critical role that~~of~~ utilities would play in evaluating future needs ~~with precision and foresight~~.

Ms. Dowla noted ~~the~~ policy lag as a significant challenge in crafting a balanced energy mix that aligns with evolving technological advancements and consumer demands. She underscored the importance of energy advocates, such as the Alliance, actively engaging with policymakers to ensure that regional energy policies are adaptive and involve energy efficiency measures.

Ms. Jacobson brought attention to the IRA~~'~~’s role in~~goal of~~ making ~~our~~ policy goals more affordable and assessable in more areas~~different parts~~ of the country. She acknowledged the difficulty in planning for an uncertain future, but stressed the importance of garnering community support and establishing~~setting~~ regional signals to guide collaborative efforts with local communities.

The final question related to the different collaboration efforts among the panelists’ respective organizations. Mr. Mosher stated that INGAA participates in bipartisan caucuses and roundtables. Ms. Dowla discussed the Alliance's approach of unified messaging among diverse member companies and prioritizing federal policy advocacy. She emphasized the Alliance’s involvement in shaping initiatives like the IRA and the IIJA to ensure that energy efficiency remains a cornerstone of federal energy policy such as through the ‘Solar for All’ program. Mr. Fratto highlighted upcoming initiatives focused on addressing future load growth, particularly in response to the rising prominence of data centers, and invited collaboration from interested organizations to shape tho~~e~~se policies.

There being no other business (other than the recognition of Mr. Dave Cavanaugh later that evening), the meeting adjourned at 11:45 a.m.

Respectfully submitted,

Sebastian Lombardi, Secretary

RECOGNITION OF DAVE CAVANAUGH

During the banquet that evening, the Committee endorsed by acclimation the following resolution of appreciation for the immediate-past Chairman of the Committee, Mr. Cavanaugh:

WHEREAS, Mr. David A. Cavanaugh was elected Chair of the New England Power Pool (NEPOOL) Participants Committee, and led NEPOOL, for three years, from 2021 through 2023, following two years serving as the elected Vice-Chair of the Publicly Owned Entity Sector, many more years as a NEPOOL representative and thought leader, and before that as a trusted colleague in ISO market operations; and

WHEREAS, Dave has been an unwavering advocate for NEPOOL's role in influencing and guiding the trajectory of New England's competitive wholesale power markets and its operations by working candidly, respectfully, and collaboratively with members, state and federal officials, and ISO colleagues; and

WHEREAS, Dave guided the operation of the NEPOOL Participants Committee, then nearly one year into, through to the end of, the unprecedented COVID-19 pandemic, and to the return to in-person meetings, strengthening the fundamental pillars of candor, respect and collaboration upon which the success of NEPOOL, and its relationship with ISO New England, New England State and federal officials, as well as between and among its members, is founded and sustained; and

WHEREAS, Dave's leadership and his hallmark empathy, positivity, and warm and steady style have skillfully advanced NEPOOL's mission and the interests of the many Participants he has represented through the years; and

WHEREAS, Dave has exemplified collaboration, not only through his professional participation and leadership, but in the organization of, and camaraderie forged over, many 18-hole pursuits, including his fair share of birdies and bogies for the formidable foursomes of which he was a part.

NOW, THEREFORE, the Participants Committee of the New England Power Pool, on behalf of the NEPOOL Participants, hereby expresses its sincere appreciation to Dave for his three years of service as its Chair and looks forward to continuing to work with him through the challenges ahead on the path to New England's energy future.

Signed and presented by the Chair of the NEPOOL Participants Committee on behalf of the NEPOOL Participants this 26th day of June, 2024, in Bretton Woods, New Hampshire.

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
JUNE 25-26, 2024 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	Transmission	Alan Trotta	Jason Rauch	
Bath Iron Works Corporation	End User			Gus Fromuth; 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	
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		
Connecticut Office of Consumer Counsel (CT OCC)	End User		Jamie Talbert-Slagle	Chelsea Mattioda
Conservation Law Foundation (CLF)	End User	Phelps Turner (tel)		
Constellation Energy Generation	Supplier	Gretchen Fuhr	Bill Fowler	
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Dominion Energy Generation Marketing	Generation	Wes Walker		
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	Brett Kruse Alex Chaplin	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	Joe Dalton	
Eversource Energy	Transmission	James Daly	Dave Burnham	Vandan Divatia
FirstLight Power Management, LLC	Generation	Tom Kaslow	Peter Rider	
Galt Power, Inc. (Galt)	Supplier	José Rotger		
Garland Manufacturing Company	End User	Gus Fromuth		Bill Short
Generation Bridge Companies	Generation		Bill Fowler	
Generation Group Member	Generation	Dennis Duffy	Abby Krich	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Granite Shore Companies	Generation			Bob Stein
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	Bob Stein	
Hammond Lumber Company	End User	Gus Fromuth		Bill Short
Hanover, NH	End User			Bill Short
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	

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PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN JUNE 25-26, 2024 SUMMER MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Holden Municipal Light Department	Publicly Owned Entity	Matt Ide	Dan Murphy	
Holyoke Gas & Electric Department	Publicly Owned Entity	Matt Ide	Dan Murphy	
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		Nancy Chafetz	Dan Pierpont
Jupiter Power	AR-RG		Frank Swigonski	
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 (tel)		
Maine Public Advocate’s Office (Maine OPA)	End User	Drew Landry		
Mansfield Municipal Electric Department	Publicly Owned Entity	Matt Ide	Dan Murphy	
Marblehead Municipal Light Department	Publicly Owned Entity	Matt Ide	Dan Murphy	
Mass. Attorney General’s Office (MA AG)	End User	Jacquelyn Bihrle	Kelly Caiazzo	Jamie Donovan
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Department of Capital Asset Management	End User		Paul Lopes (tel)	Nancy Chafetz
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Matt Ide	Dan Murphy	
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			Gus Fromuth; Bill Short
Narragansett Electric Co. (d/b/a RI Energy)	Transmission	Brian Thomson		Janell Fabiano
Natural Resources Defense Council	End User	Claire Lang-Ree		
Nautilus Power, LLC	Generation		Bill Fowler	
New Hampshire Electric Cooperative	Publicly Owned Entity			Brian Forshaw
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	
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
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Pawtucket Power Holding Company LLC	Generation	Dan Allegretti	Kevin Telford	
Paxton Municipal Light Department	Publicly Owned Entity	Matt Ide	Dan Murphy	
Peabody Municipal Light Department	Publicly Owned Entity	Matt Ide	Dan Murphy	
Princeton Municipal Light Department	Publicly Owned Entity	Matt Ide	Dan Murphy	
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
RI Division (DPUC)	End User	Paul Roberti		
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity	Matt Ide	Dan Murphy	
Saint Anselm	End User	Gus Fromuth		Bill Short
Shell Energy North America (US)	Supplier	Jeff Dannels		
Shipyard Brewing LLC	End User	Gus Fromuth		Bill Short

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PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
JUNE 25-26, 2024 SUMMER MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Shrewsbury Electric & Cable Operations	Publicly Owned Entity	Matt Ide	Dan Murphy	
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	
Sunrun Inc.	AR-DG			Pete Fuller
SYSO Inc.	AR-DG	Doug Matheson (tel)		
Tangent Energy Inc.	AR-LR	Brad Swalwell		
Taunton Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity	Matt Ide	Dan Murphy	
Tenaska Power Services Co.	Supplier		Eric Stallings	
Union of Concerned Scientists	End User			Francis Pullaro
Vermont Electric Cooperative	Publicly Owned Entity		Dan Potter	
Vermont Electric Power Company (VELCO)	Transmission	Frank Ettori		
Vermont Energy Investment Corporation	AR-LR		Stefan Koester	
Vermont Public Power Supply Authority	Publicly Owned Entity	Matt Ide	Dan Murphy	
Versant Power	Transmission	Dave Norman		
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity	Dave Cavanaugh		
Vitol Inc.	Supplier	Seth Cochran		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity	Matt Ide	Dan Murphy	
Walden Renewables Development LLC	Generation			Abby Krich
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		Gus Fromuth	Bill Short

CONSENT AGENDA

Markets Committee (MC)

From the previously-circulated notice of actions of the MC's ***July 9-10, 2024 Summer Meeting****, dated July 11, 2024.*[1]

1. Revisions to Market Rule 1 (Additional *Order 2222*-Related Compliance)

Support the proposed revisions to Market Rule 1 to add into the Tariff the submetering requirements for Alternative Technology Regulation Resources (ATRRs), including Distributed Energy Resource Aggregations (DERAs) participating as ATRRs, as recommended by the MC at its July 9-10, 2024 Summer Meeting, together with such further non-material changes as the Chair and Vice-Chair of the MC may approve.

The motion to recommend Participants Committee support was approved unanimously, with one abstention in each of the Generation and the End User Sectors.

Reliability Committee (RC)

From the previously-circulated notice of actions of the RC's ***July 16, 2024 meeting****, dated July 16, 2024].*[2]

2. New Planning Procedure No. 12 (Data Collection for Distributed Energy Resources)

Support the creation of a new ISO New England Planning Procedure No. 12 (Procedure for Distributed Energy Resource Data Collection), as recommended by the RC at its July 16, 2024 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was approved unanimously.

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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 Actions.

[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.

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: NEPOOL Counsel

DATE: July 25, 2024

RE: ISO's Proposed Updates to the Non-Commercial Capacity Financial Assurance Amount Multiplier

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At the August 1, 2024 Participants Committee meeting, you will be asked to vote on ISO-proposed updates to the Financial Assurance Policy's (FAP) Non-Commercial Capacity Financial Assurance (NCCFA) Amount Multiplier to conform with the delay of the nineteenth Forward Capacity Auction (FAP Updates). The vote on the FAP Updates had been deferred pending FERC action on the now-accepted further delay of FCA19. This memorandum provides an overview of the Updates and summarizes the stakeholder review process to date. Included with this memorandum are the following materials:

- Attachment A: ISO's April 24, 2024 Presentation
- Attachment B: ISO's Redlined FAP Sheets

BACKGROUND & OVERVIEW OF THE FAP UPDATES

Under the current Forward Capacity Market rules, non-commercial capacity that receives a Capacity Supply Obligation (CSO) must provide NCCFA. This amount is calculated pursuant to a formula set forth in the FAP. The formula contains a multiplier that increases if a resource has not achieved commercial operation (Multiplier).

In January 2024, the FERC accepted the ISO's filed proposal to delay holding FCA19 by one year. Subsequently, the ISO and NEPOOL jointly submitted an additional filing to further delay FCA19 (including its pre-auction activities) by an additional two years beyond the previously accepted one-year delay (or until 2028). The FERC approved this request on May 20. 2024.

To account for the additional two-year delay for FCA19, the ISO identified and is now proposed targeted conforming updates to the FAP's NCCFA Amount Multiplier, which are explained in further detail in ISO-sponsored materials included with this memorandum (*see* Attachment A.

STAKEHOLDER PROCESS TO DATE

The ISO presented its proposed FAP Updates at the March and April Budget & Finance (B&F) Subcommittee meetings. At the March meeting, a number of members offered feedback on the ISO's initial proposal, and in light of the feedback received, the ISO modified its proposal, as reflected in the FAP revisions included as Attachment B.

At its April meeting, no Subcommittee member objected to the ISO's FAP Updates proposal. Because the ISO/NEPOOL filing to further delay FCA19 remained pending at that time before the FERC, consideration and vote by the Participants Committee was deferred until FERC weighed in. With the FERC's acceptance of the further FCA19 delay proposal now in hand, this matter is ready for final NEPOOL action.

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

> RESOLVED, that the Participants Committee supports the updates to the Financial Assurance Policy's Non-Commercial Capacity Financial Assurance Amount Multiplier as reflected in the materials circulated to this Committee in advance of this meeting, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair of the Budget & Finance Subcommittee.

APRIL 24, 2024

FCA 19 Delay FAP Redlines

Update to the Financial Assurance Policy regarding Non-Commercial Capacity Financial Assurance

NEPOOL Budget & Finance Subcommittee Meeting

Zachary Shell

LEAD RISK ANALYST

The ISO recommends expanding the Pre-Auction NCC FA formula to include the multiplier in order to align with the Post-Auction NCC FA

FAP Updated Pre-Auction NCC FA Formula

Current FAP Pre NCC FA Formula

- Non-Commercial Capacity Financial Assurance Amount = (NCC x NCCFA$) – FCM Deposit
- NCC = Non-Commercial Qualified Capacity
- NCCFA$ = Net CONE

Recommended FAP Pre NCC FA Formula

- Non-Commercial Capacity Financial Assurance Amount = (NCC x NCCFA$ x Multiplier) – FCM Deposit
- NCC = Non-Commercial Qualified Capacity
- NCCFA$ = Net CONE
- Multiplier = one if the auction occurs within 40 months of the commencement of the Capacity Commitment Period for which the NCC has qualified; two if the auction occurs within 28 months of the commencement of the Capacity Commitment Period for which the NCC has qualified; and three if the auction begins within 16 months of the commencement of the Capacity Commitment Period for which the NCC has qualified.

The recommended change to the FAP definition of the NCC FA pre-auction formula keeps the level of the pre-auction NCC FA as closely in line with the post-auction NCC FA as possible with the information available prior to completion of the auction

The ISO recommends updating the Financial Assurance Policy (FAP) definition of the Non-Commercial Capacity (NCC) Financial Assurance (FA) Amount Multiplier to conform with the delay of FCA 19

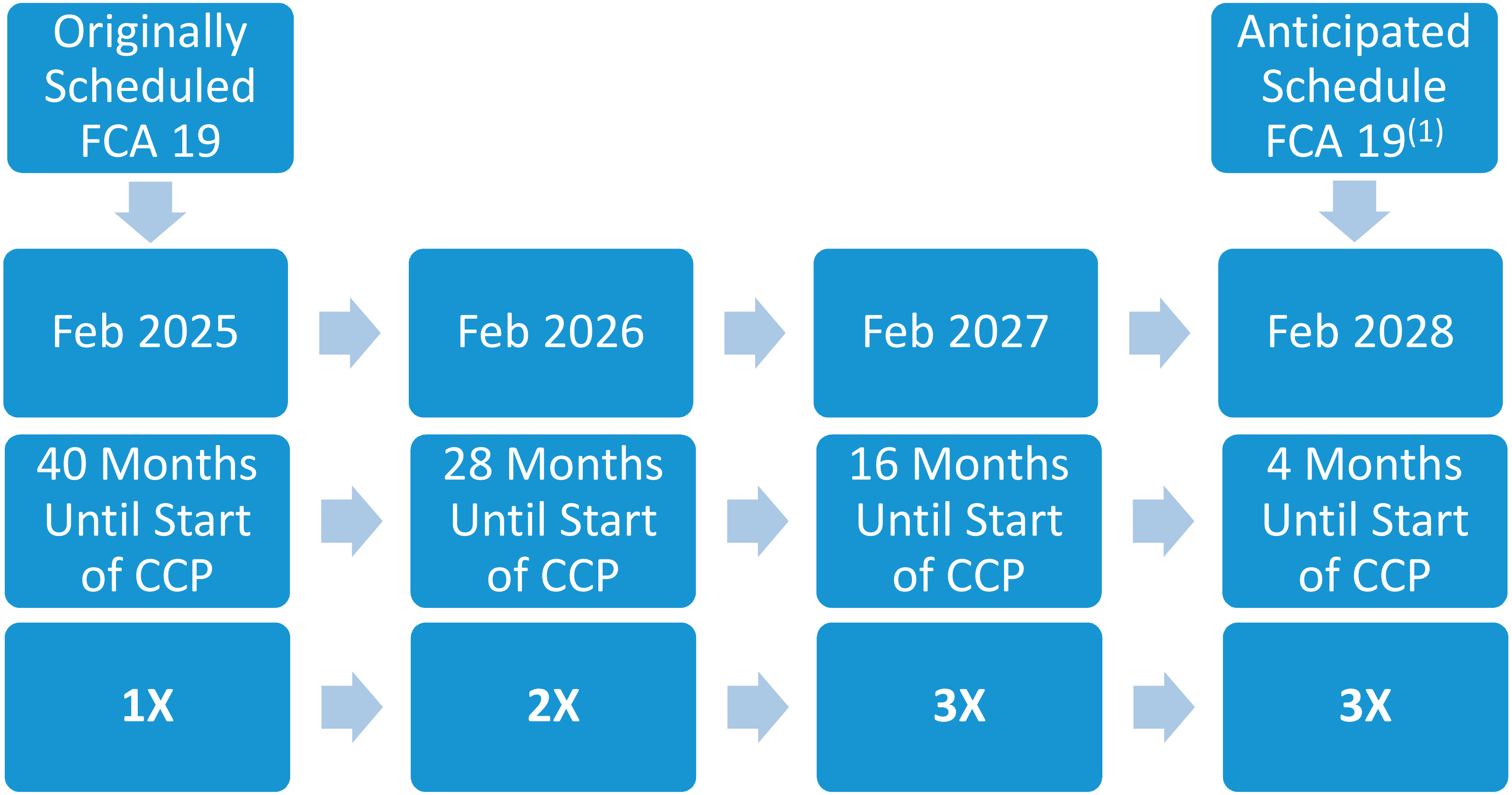
FAP Updated NCC FA Amount Multiplier Definition

Current FAP NCC FA Multiplier Definition	Recommended FAP NCC FA Multiplier Definition
• Multiplier = one at the completion of the Forward Capacity Auction in which the Capacity Supply Obligation was awarded; two beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the next Forward Capacity Auction after the Forward Capacity Auction in which the Capacity Supply Obligation was awarded; and three beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the second Forward Capacity Auction after the Forward Capacity Auction in which the Capacity Supply Obligation was awarded.	• Multiplier = one beginning at 8 a.m. (Eastern Time) on the first business day occurring within 40 months of the commencement of the Capacity Commitment Period for which the Capacity Supply Obligation was awarded; two beginning at 8 a.m. (Eastern Time) on the first business occurring within 28 months of the commencement of the Capacity Commitment Period for which the Capacity Supply Obligation was awarded; three beginning at 8 a.m. (Eastern Time) on the first business day occurring within 16 months of the commencement of the Capacity Commitment Period for which the Capacity Supply Obligation was awarded.

The recommended change to the FAP definition of the NCC FA Amount Multiplier keeps the level of the multiplier consistent with the current level of the multiplier with regards to the length of time until the start of the Capacity Commitment Period

The NCC FA Amount Multiplier remains consistent with the length of time until the start of the CCP regardless of the scheduled timing of auctions occurring after the CSO is obtained

NCC FA Amount Multiplier Timeline



Originally Scheduled FCA 19			Anticipated Schedule FCA 19(1)
Feb 2025	Feb 2026	Feb 2027	Feb 2028
40 Months Until Start of CCP	28 Months Until Start of CCP	16 Months Until Start of CCP	4 Months Until Start of CCP
1X	**2X**	**3X**	**3X**

(1) Changes to the scheduled timing of auctions will not impact the calculation or timing of the FCM Deposit

The ISO proposes the following language change to the Financial Assurance Policy regarding the Pre-Auction NCC FA formula

FAP Redlines – Pre-Auction Collateral

Non-Commercial Capacity Participating in the ~~Ninth~~ Forward Capacity Auction ~~and All Forward Capacity Auctions Thereafter~~ (1)

A Designated FCM Participant offering Non-Commercial Capacity into the ~~ninth~~ Forward Capacity Auction ~~and all Forward Capacity Auctions thereafter~~ must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction an amount calculated according to the following formula ~~equal to the difference between the Net CONE associated with the Forward Capacity Auction in which the Capacity Supply Obligation was awarded (adjusted as described in Section III.13.2.4) times the Non-Commercial Capacity qualified for such Forward Capacity Auction and the FCM Deposit.~~

Non-Commercial Capacity Financial Assurance Amount = (NCC x NCCFCA$ x Multiplier) – FCM Deposit

Where:

NCC = the amount of Qualified Capacity qualified for the Designated FCM Participant for the Forward Capacity Auction minus any Commercial Capacity

NCCFCA$ = the Net CONE associated with the Forward Capacity Auction for which the NCC has qualified (adjusted as described in Section III.13.2.4).

Multiplier = one if the auction occurs within 40 months of the commencement of the Capacity Commitment Period for which the NCC has qualified; two if the auction occurs within 28 months of the commencement of the Capacity Commitment Period for which the NCC has qualified; and three if the auction begins within 16 months of the commencement of the Capacity Commitment Period for which the NCC has qualified.

FCM Deposit = $2/kW times the Non Commercial Capacity qualified for such Forward Capacity Auction by such Designated FCM Participant

(1) Language in section VII.B.2(a)-(b) referencing auctions up to and including the eight FCA is proposed to be removed from the FAP

The ISO proposes the following language change to the Financial Assurance Policy regarding the Post Auction NCC FA Amount Multiplier

FAP Redlines – Post Auction Collateral

Non-Commercial Capacity Financial Assurance Amount = (NCC x NCCFCA$ x Multiplier) + NCC Trading FA

Where:
NCC = the Capacity Supply Obligation awarded to the Designated FCM Participant in the Forward Capacity Auction minus any Commercial Capacity

For Capacity Supply Obligations acquired in Forward Capacity Auctions up to and including the thirteenth Forward Capacity Auction, NCCFCA$ = the Capacity Clearing Price from the first run of the auction-clearing process of the Forward Capacity Auction in which the Capacity Supply Obligation was awarded. For Capacity Supply Obligations acquired in the fourteenth Forward Capacity Auction and all Forward Capacity Auctions thereafter, NCCFCA$ = the Net CONE associated with the Forward Capacity Auction in which the Capacity Supply Obligation was awarded (adjusted as described in Section III.13.2.4).

Multiplier = one ~~at the completion of the Forward Capacity Auction in~~ beginning at 8 a.m. (Eastern Time) on the first business day occurring within 40 months of the commencement of the Capacity Commitment Period for which the Capacity Supply Obligation was awarded; two beginning at 8 a.m. (Eastern Time) on the ~~tenth Business Day prior to the next Forward Capacity Auction after the Forward Capacity Auction in~~ first business day occurring within 28 months of the commencement of the Capacity Commitment Period for which the Capacity Supply Obligation was awarded; and three beginning at 8 a.m. (Eastern Time) on the ~~tenth Business Day prior to the second Forward Capacity Auction after the Forward Capacity Auction in~~ first business day occurring within 16 months of the commencement of the Capacity Commitment Period for which the Capacity Supply Obligation was awarded.

Further FAP Revision Considerations

FERC Filing	FERC Accepts	FERC Rejects
2 year further delay to FCA 19	The proposed language outlined in this presentation will be filed with FERC and will be revisited for review once the Prompt/Seasonal model is filed and accepted/reject by FERC	The proposed language outlined in this presentation will generally still serve its intended purpose, but will be further evaluated consistent with outcomes at FERC
Prompt/Seasonal	ISO will review the FAP for all necessary changes	At this point in time the proposed language outlined in this presentation will have already been approved by FERC but will be further evaluated consistent with outcomes at FERC

Stakeholder Schedule

Stakeholder Committee and Date	Scheduled Project Milestone
Participants Committee June 25-26, 2024	Vote on updated FAP language related to NCC FA
Q4 2024	Effective Date

EXHIBIT IA

ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY

Table of Contents

value will be used for new and existing resources until actual performance data is available.

SF (scaling factor) is a month-specific multiplier, as follows:

June and December	2.000;
July and January	1.732;
August and February	1.414;
All other months	1.000.

B. Non-Commercial Capacity

Notwithstanding any provision of this Section VII to the contrary, a Designated FCM Participant offering Non-Commercial Capacity for a Resource that elected existing Resource treatment for the Capacity Commitment Period beginning June 1, 2010 will not be subject to the provisions of this Section VII.B with respect to that Resource (other than financial assurance obligations relating to transfers of Capacity Supply Obligations).

1. FCM Deposit

A Designated FCM Participant offering Non-Commercial Capacity into any upcoming Forward Capacity Auction must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, beginning at 8 a.m. (Eastern Time) on the fifth (5th) Business Day after its qualification for such auction under Market Rule 1, an amount equal to $2/kW times the Non-Commercial Capacity qualified for such Forward Capacity Auction by such Designated FCM Participant (the “FCM Deposit”).

2. Non-Commercial Capacity in Forward Capacity Auctions

a. **[Reserved for Future Use]**~~**Non-Commercial Capacity Participating in a Forward Capacity Auction Up To and Including the Eighth Forward Capacity Auction**~~

~~For Non-Commercial Capacity participating in a Forward Capacity Auction up to and including the eighth Forward Capacity Auction, a Designated FCM Participant that had its supply offer of Non-Commercial Capacity accepted in a Forward Capacity Auction~~

~~must include in the calculation of its Financial Assurance Requirement under the ISO New England Financial Assurance Policy the following amounts at the following times:~~

~~beginning at 8 a.m. (Eastern Time) on the fifth (5th) Business Day following announcement of the awarded supply offers in that Forward Capacity Auction, an amount equal to $5.737(on a $/kW-month basis) multiplied by the number of kW of capacity awarded to that Designated FCM Participant in that Forward Capacity Auction (such amount being referred to herein as the "Non-Commercial Capacity FA Amount");~~

~~beginning at 8 a.m. (Eastern Time) on the tenth (10th) Business Day prior to the next annual Forward Capacity Auction after the Forward Capacity Auction in which such supply offer was awarded, an additional amount required to make the total amount included in the calculation of the Financial Assurance Requirement with respect to that Non-Commercial Capacity equal to two (2) times the Non-Commercial Capacity FA Amount; and~~

~~beginning at 8 a.m. (Eastern Time) on the tenth (10th) Business Day prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which such supply offer was accepted, an additional amount required to make the total amount included in the calculation of the Financial Assurance Requirement with respect to that Non-Commercial Capacity equal to three (3) times the Non-Commercial Capacity FA Amount.~~

b. Non-Commercial Capacity Participating in ~~the Ninth Forward Capacity Auction and All~~ Forward Capacity Auctions ~~Thereafter~~

A Designated FCM Participant offering Non-Commercial Capacity into the ~~ninth~~ Forward Capacity Auction ~~and all Forward Capacity Auctions thereafter~~ must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction an amount calculated according to the following formula: ~~equal to the difference between the Net CONE associated with the Forward Capacity Auction in which the Capacity Supply Obligation was awarded (adjusted as described in Section III.13.2.4) times the Non-Commercial Capacity qualified for such Forward Capacity Auction and the FCM Deposit.~~

Non-Commercial Capacity Financial Assurance Amount = (NCC x NCCFCA$ x Multiplier) – FCM Deposit

Where:

NCC = the amount of Qualified Capacity that the ISO has qualified for the Designated FCM Participant for the Forward Capacity Auction minus any Commercial Capacity

NCCFCA$ = the Net CONE associated with the Forward Capacity Auction for which the NCC has qualified (adjusted as described in Section III.13.2.4).

Multiplier = one if the auction occurs within 40 months of the commencement of the Capacity Commitment Period for which the NCC has qualified; two if the auction occurs within 28 months of the commencement of the Capacity Commitment Period for which the NCC has qualified; and three if the auction begins within 16 months of the commencement of the Capacity Commitment Period for which the NCC has qualified.

FCM Deposit = $2/kW times the Non Commercial Capacity qualified for such Forward Capacity Auction by such Designated FCM Participant

Upon completion of the Forward Capacity Auction, the Non-Commercial Capacity Financial Assurance Amount shall be recalculated according to the following formula:

Non-Commercial Capacity Financial Assurance Amount = (NCC x NCCFCA$ x Multiplier) + NCC Trading FA

Where:

NCC = the Capacity Supply Obligation awarded to the Designated FCM Participant in the Forward Capacity Auction minus any Commercial Capacity

For Capacity Supply Obligations acquired in Forward Capacity Auctions up to and including the thirteenth Forward Capacity Auction, NCCFCA$ = the Capacity Clearing Price from the first run of the auction-clearing process of the Forward Capacity Auction in which the Capacity Supply Obligation was awarded. For Capacity Supply Obligations acquired in the fourteenth Forward Capacity Auction and all Forward Capacity Auctions thereafter, NCCFCA$ = the Net CONE associated with the Forward Capacity Auction in which the Capacity Supply Obligation was awarded (adjusted as described in Section III.13.2.4).

Multiplier = one ~~at the completion of the Forward Capacity Auction in~~ beginning at 8 a.m. (Eastern Time) on the first Business Day occurring within 40 months of the commencement of the Capacity Commitment Period for which the Capacity Supply Obligation was awarded; two beginning at 8 a.m. (Eastern Time) on the first ~~tenth~~ Business Day occurring within 28 months of the commencement of the Capacity Commitment Period for ~~prior to the next Forward Capacity Auction after the Forward Capacity Auction in~~ which the Capacity Supply Obligation was awarded; and three beginning at 8 a.m. (Eastern Time) on the ~~tenth~~first Business Day occurring within 16 months of the commencement of the Capacity Commitment Period for ~~Day prior to the second Forward Capacity Auction after the Forward Capacity Auction in~~ which the Capacity Supply Obligation was awarded.

In the case of Non-Commercial Capacity that fails to become commercial by the commencement of the Capacity Commitment Period associated with the Forward Capacity Auction in which it was awarded a Capacity Supply Obligation, the Non-Commercial Capacity Financial Assurance Amount shall be recalculated as follows: beginning at 8 a.m. (Eastern Time) on the first Business Day of the second month of the Capacity Commitment Period associated with the Forward Capacity Auction in which the Capacity Supply Obligation was awarded, the Multiplier in the recalculation of the Non-Commercial Capacity Financial Assurance Amount shall be four. The Multiplier in the recalculation of the Non-Commercial Capacity Financial Assurance Amount shall increase by one every six months thereafter until the Non-Commercial Capacity becomes commercial or the Capacity Supply Obligation is terminated.

For Capacity Supply Obligations acquired in Forward Capacity Auctions up to and including the twelfth Forward Capacity Auction, NCC Trading FA = zero. For Capacity Supply Obligations acquired in the thirteenth Forward Capacity Auction and all Forward Capacity Auctions thereafter, NCC Trading FA shall be zero until the start of the

Summary of ISO New England Board and Committee Meetings

August 1, 2024 Participants Committee Meeting

Since the last update, the Compensation and Human Resources Committee, and the Information Technology and Cyber Security Committee met on June 24. The Markets Committee and the System Planning and Reliability Committee both met on June 25. The Nominating and Governance Committee, and the Board of Directors, met on June 26. All of the meetings were held in Bretton Woods, New Hampshire in conjunction with the NEPOOL Participants Summer Meeting.

The Compensation and Human Resources Committee was provided with an annual summary of the Company's retirement plans in connection with its oversight role of the Company's benefits and benefit plans. The summary covered the plan features, highlights of the financial education program, changes related to federal laws, and potential new retirement benefit opportunities which would result in no additional cost to the Company. The Committee also reviewed the Company's three year strategy for health and wellness benefits for its employees. The Committee noted that negotiations for the higher than anticipated medical and dental renewals were still in progress, and that the separation of life insurance rates for active employees and retirees resulted in an overall cost savings. The Committee was informed that compensation survey data is not yet available for 2025. Next, the Committee discussed a potential amendment to the Company's Code of Conduct to expand the Code's restrictions regarding spousal employment to include live-in partners. The Committee agreed to consider proposed wording changes at a future meeting. The Committee reviewed its charter for compliance and agreed to add the words "and competitive" to references to oversight of reasonable compensation, and to recommend that the Board approve the changes. The Committee agreed to expand the delegation of authority to management to make administrative changes to the Company's 401(k) plan, so long as those changes do not implicate fundamental plan changes, such as benefit levels, and agreed to recommend that the Board approve the expanded delegation. Finally, in executive session, the Committee discussed succession management and transition planning for officers, and reviewed the results of its self-evaluation.

The Information Technology and Cyber Security Committee was provided with an update on the Company's three-year cyber security work plan, including progress made on several projects and their costs and benefits. The Committee considered the agenda for discussion at the annual cyber security "deep dive" for the full board in September and concurred that the format would include a guest speaker to conduct a briefing on artificial intelligence. The Committee then performed its annual review of the Company's IT-related business continuity plan and disaster recovery plans. During executive session, the Committee reviewed the results of its self-evaluation.

The Markets Committee was presented with highlights of the draft External Market Monitor's Annual Report, and discussed the market monitoring review of market performance related to Spring 2024. In executive session, the Committee reviewed the results of its self-evaluation.

The System Planning and Reliability Committee received updates on system forecasting, economic and special study requests, long-term transmission planning, the Commission's Order No. 2023 compliance, and planned activities for the second half of 2024. The Committee received an update on the system operations outlook for summer 2024, and reviewed updates to the Regional System Plan project list, noting changes in project costs. The Committee then considered its compliance with the Committee's charter, and suggested that management propose further changes to clarify its oversight on various initiatives. The Committee received a summary of the Commission's recent Order No. 1920, and discussed system planning staffing turnover and strategies for recruitment and retention. During executive session, the Committee reviewed the results of its self-evaluation.

The Nominating and Governance Committee discussed Board leadership, state liaison and committee assignments, and adopted a recommendation to present to the full Board in September. The Committee reviewed a gap analysis summary regarding environmental, social and governance reporting, and discussed the recommended areas in which to enhance and expand reporting. Those areas include data security, cyber security and customer centricity. The Committee discussed opportunities to highlight this enhanced reporting on the ISO's corporate website. The Committee also discussed recent meetings with state commission members, and recent activities of the Consumer Liaison Group.

The Board of Directors received a report from the CEO covering the Company's progress toward corporate goals. The Board noted the impact on the budget metric of lower-than-predicted spending on salaries, which is due to challenges in filling open positons. The Board reviewed operations during the recent heat wave, and was also informed that all three appointees to the Federal Energy Regulatory Commission had been approved by the U.S. Senate and are in the process of being sworn in. Next, the Board prepared for its meetings with the NEPOOL sectors and reviewed the discussion topics that were submitted in advance by the sectors. The Board discussed transmission-related items, and issues related to the Commission's Order No. 1920 regarding long-term policy planning. The Board then discussed matters related to the Resource Capacity Accreditation project and the transformation of the capacity market. The Board particularly considered stakeholder concerns about price suppression associated with the retention of units seeking to retire. The Board then recognized Robert Ethier's upcoming retirement, and the promotion of Alan McBride, and congratulated them both. Next, the Board discussed the 2025 ISO/RTO Board Conference, which is to be hosted by ISO New England, and reviewed and approved its meeting dates for 2025. The Board received reports from the standing committees, and reviewed the Company's Form 990 for 2023 to be filed with the Internal Revenue Service. Finally, during executive session, the Board discussed the results of its self-evaluation.

NEPOOL Participants Committee Report

August 2024

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Regular Operations Report - Highlights

Data through July 24th (unless otherwise noted)

Highlights: July 2024

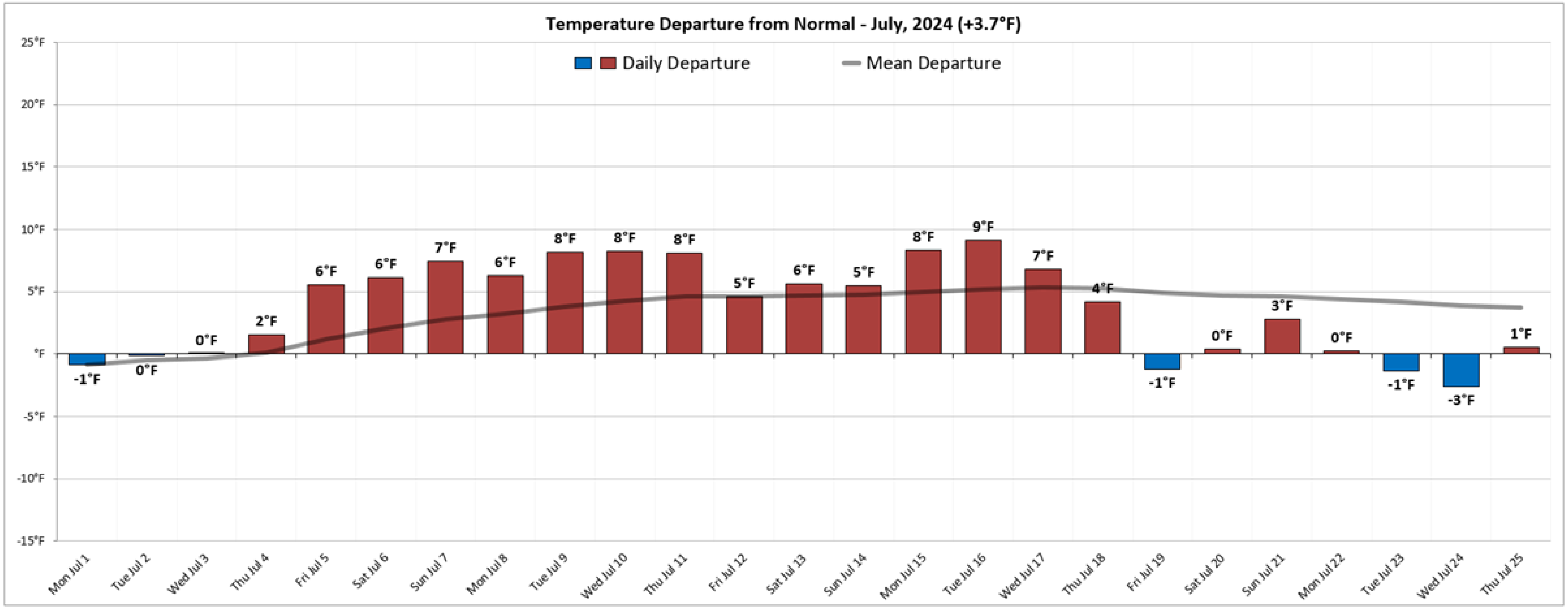
- **Peak Hour** on July 16
  - 24,816 MW system peak (Revenue Quality Metered/RQM); hour ending 6:00 P.M.
- **Average Pricing**
  - Day Ahead (DA) Hub Locational Marginal Price (LMP): $49.33/MWh
  - Real Time (RT) Hub LMP: $43.73/MWh
  - Natural Gas: $1.86/Mmbtu (MA Natural Gas Avg)
- **Energy Market** value $572M down from $579M in July 2023
  - Ancillary Markets* value $13.5M down from $22.8M in July 2023
  - Average DA cleared physical energy** during the peak hours as percent of forecasted load was 101.7% during July, up from 101.0% during June
  - Updated June Energy Market value: $428M
- **Net Commitment Period Compensation (NCPC)** total $6.3M
  - First Contingency $5.8M
    - Dispatch Lost Opportunity Cost (DLOC) - $448K; Rapid Response Pricing (RRP) Opportunity Cost - $620K; Posturing - $0; Generator Performance Auditing (GPA) - $0
    - $274K paid to resources at external locations, up $64K from June
      - $49K charged to Day Ahead Load Obligation (DALO) at external locations, $225K to RT Deviations
  - Distribution $480K
  - 2nd Contingency and Voltage were both zero
- **Forward Capacity Market (FCM)** market value $119.6M
- **M/LCC 2 Implementations:** July 9th (7 p.m.-10 p.m.) and July 15th (2 p.m.-10 p.m.)

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 and Net Imports cleared in the DA Energy Market

July Temperatures Were Above Normal

- Daily average temperatures were consistently above normal through the first half of the month; through July 25, the 23-city weighted average temperature departure from normal was +3.7°F
  - Dew points in New England have generally been above normal this summer and were ~2°F above normal for the month of July, through July 25



Year-to-Date Peak Load* Statistics

- Telemetered System Peak Load: **24,310 MW**
  - Hour Ending 19:00 on Tuesday, July 16
- RQM System Peak Load: **24,816 MW** (initial)
  - Hour Ending 18:00 on Tuesday, July 16
- FCM Peak Load: **24,366 MW** (preliminary & subject to change)
  - Hour Ending 18:00 on Tuesday, July 16
  - At this hour, the capacity zone-level FCM peak loads were 3,296 MW in Northern New England, 1,919 MW in Maine, 9,096 MW in Rest-of-Pool, and 10,054 MW in Southeast New England.

*Telemetered loads are those seen in RT by the Control Room. RQM loads are of settlement quality and reflect the contribution of Settlement Only Generation (SOG). These values can occur on different days and/or hours. FCM system load is the sum of active load assets that are non-dispatchable and that are included in the FCM settlement and excludes losses

Highlights

- 2050 Transmission Study
  - The ISO expects to discuss the results of the offshore wind point of interconnection screening and constraint identification analysis at the August 21 PAC meeting
- EPCET Pilot Study draft report will be issued in August 2024
- Improvements to the long-term load forecast will be discussed with stakeholders and implemented as part of the CELT 2025 forecast cycle

Forward Capacity Market (FCM) Highlights

- CCP 15 (2024-2025)
  - The ISO held the third annual reconfiguration auction (ARA3) over March 1-5 and posted the results on April 3
- CCP 16 (2025-2026)
  - The ISO will hold the second annual reconfiguration auction (ARA2) over August 1-5 and will post the results no later than September 3
- CCP 17 (2026-2027)
  - The ISO held the first annual reconfiguration auction (ARA1) over June 3-5 and posted the results on July 2

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP 18 (2027-2028)
  - The ISO filed the auction results with FERC on February 21 and, on June 18, FERC issued an order accepting the results effective June 20
- CCP 19 (2028-2029)
  - The ISO filed market rule changes to delay FCA 19 for two additional years with FERC on April 5
    - On May 20, FERC issued an order accepting the additional delay to FCA 19
  - The Show of Interest submission window for the 2024 interim RA qualification process opened on April 17 and closed on April 30
  - The New Capacity Qualification Package submission window opened on June 13 and closed on June 21

June 18, 2024 OP-4 Event and Capacity Scarcity Condition

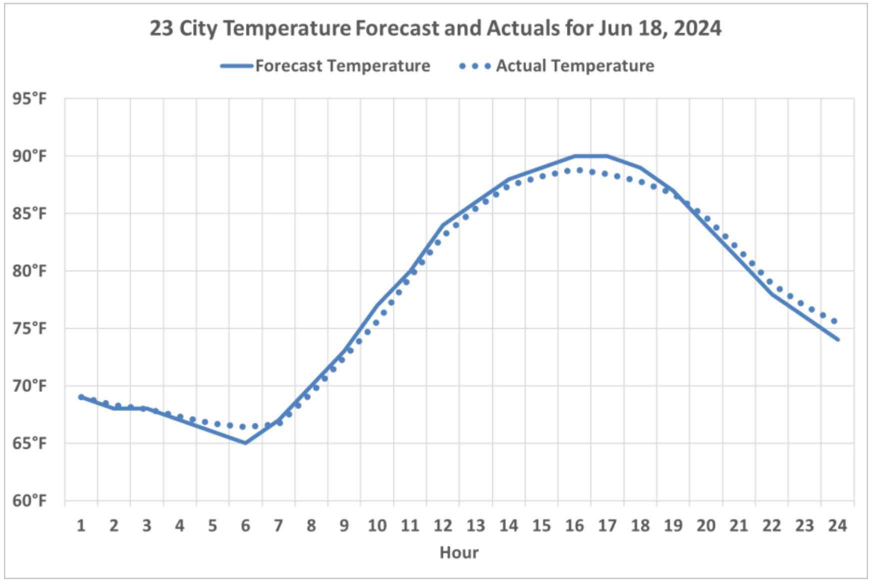
OP-4 and Capacity Scarcity Condition Tuesday, June 18, 2024

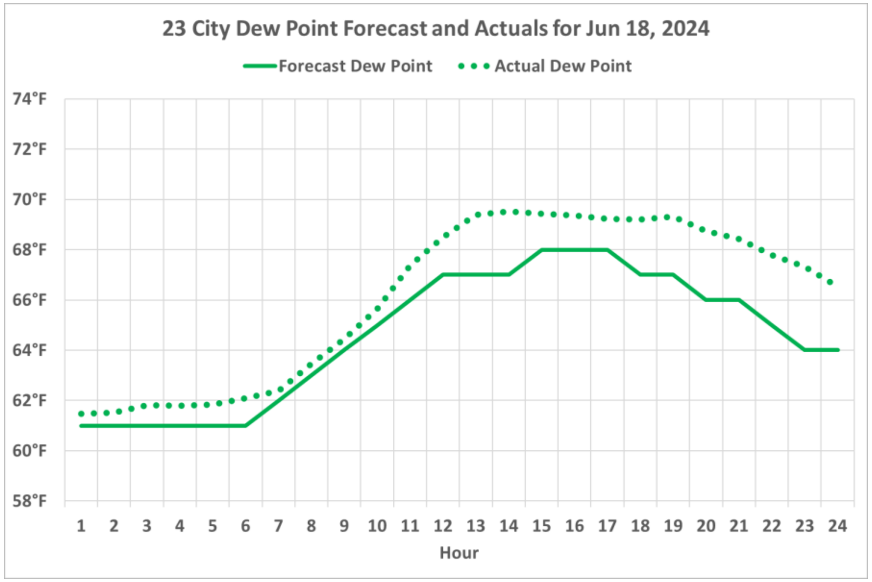
- The primary factor leading to the implementation of OP-4 and the Capacity Scarcity Condition was generator outages and reductions totaling ~1,600 MW
  - In addition, net interchange at the time of OP-4 implementation was ~100 MW less than day ahead expectations
- 30-minute Reserve Constraint Penalty Factor (RCPF) violated for the following 5-minute intervals: 17:50 – 18:15
  - $1,000/MWh RCPF
- System conditions required the implementation of M/LCC 2 and OP-4
  - M/LCC 2, Abnormal Conditions Alert: 6/18 17:30 - 6/20 22:00 (remained in effect for the duration of the heat wave)
  - OP-4 Actions 1 and 2: 17:40 – 22:00
- Telemetered system load* for the peak hour (HE19) was 22,049 MW

* Telemetered system loads are those seen in real-time by the Control Room

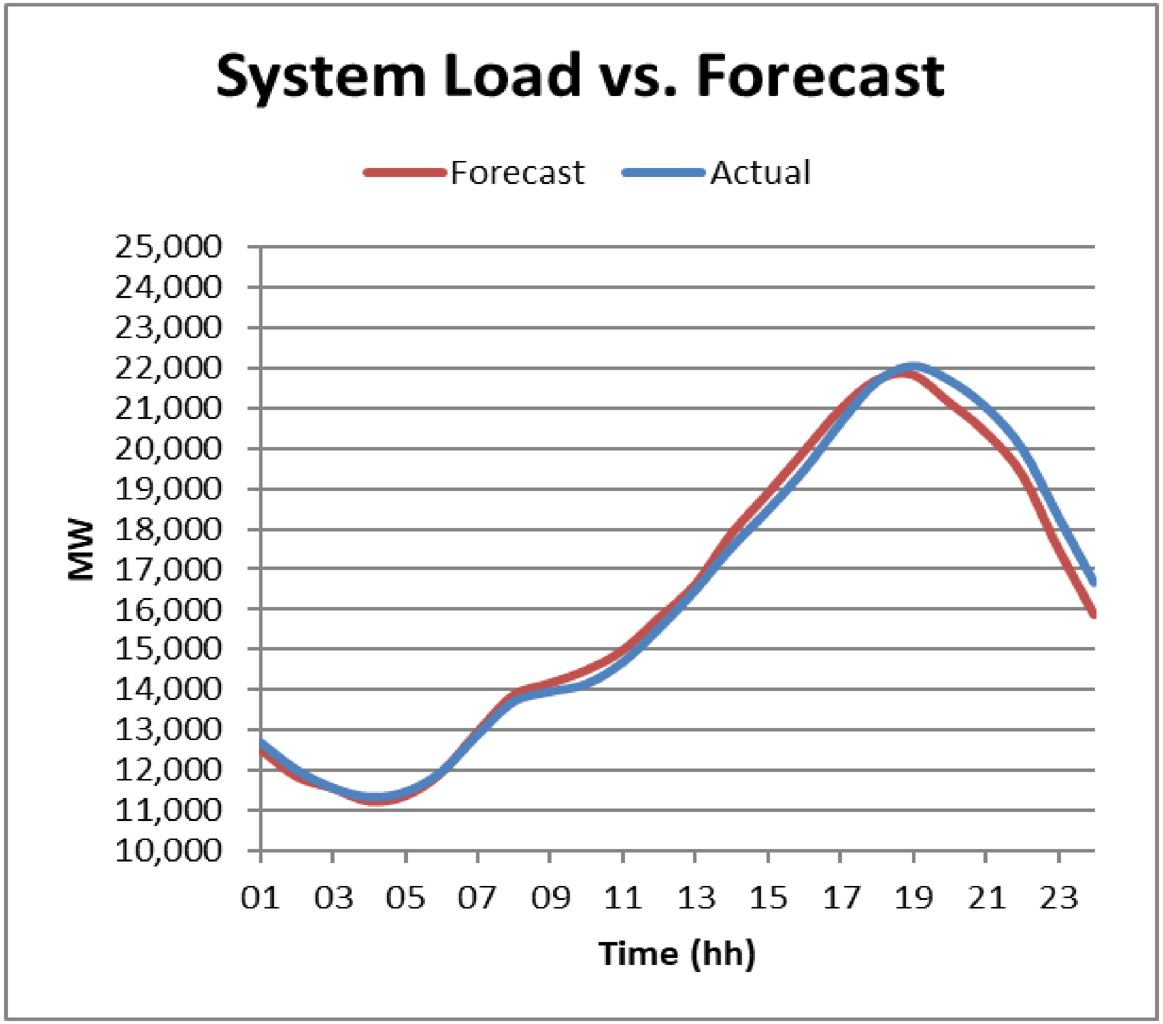
Temperatures Were Warm, But Not Extreme

- The 23-city weighted high temperature during the peak hour (HE19) was 86.7°F, ~1°F below the forecast
- The 23-city weighted dew point during the peak hour (HE19) was 69.3°F, ~2.4°F above the forecast





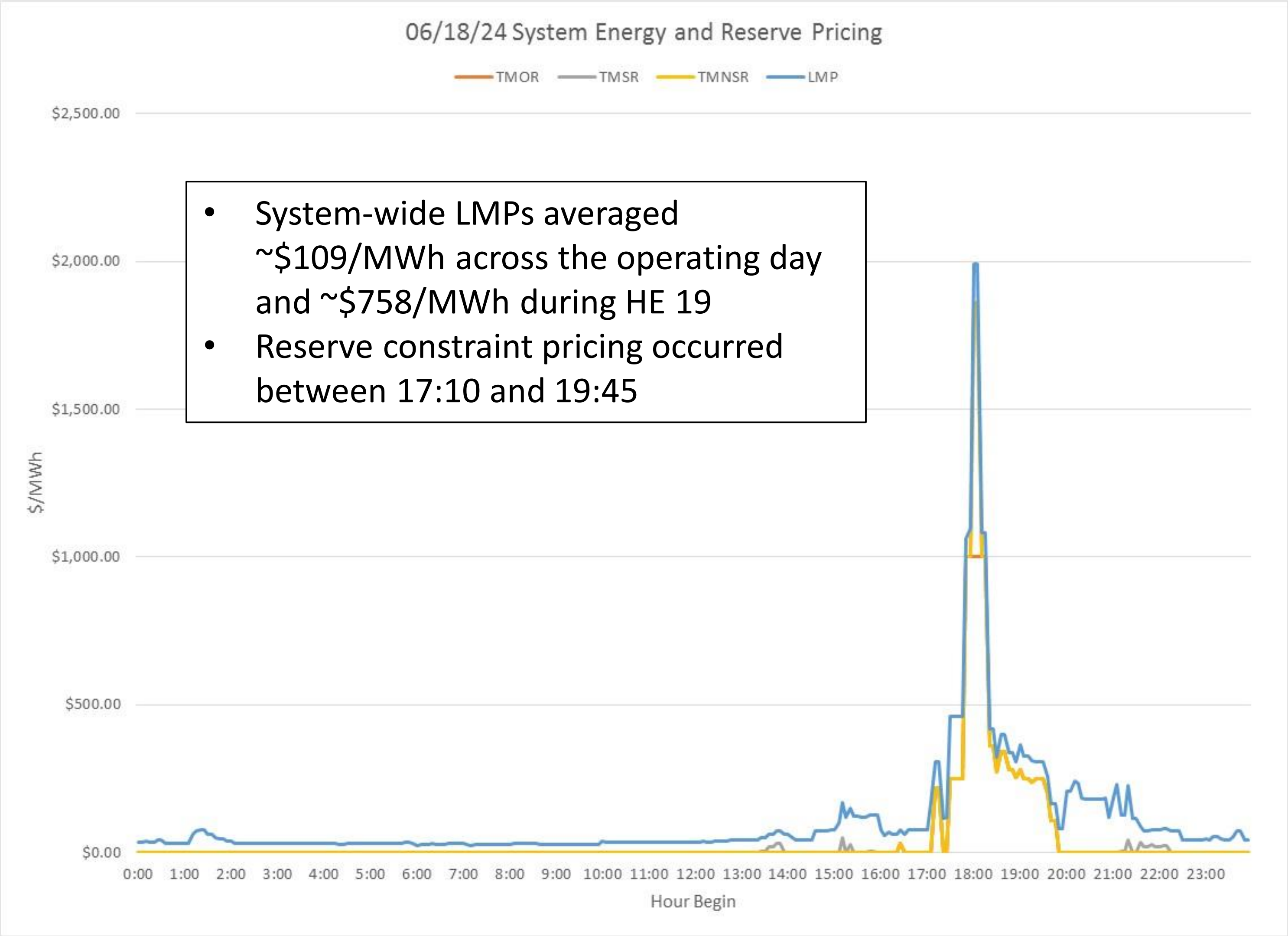
ISO's Load Forecast Was Highly Accurate; ~1% Forecast Error During the Peak Hour



Peak Hour Generator Capacity and Energy Imports Were Less Than Anticipated

- ~1,600 MW of generator outages and reductions occurred throughout the day prior to OP-4 implementation
  - Contributing factors included reductions due to ambient temperatures and various mechanical issues during startup
  - Approximately 50% of these outages and reductions occurred prior to noon, the remainder occurred between HE16 and HE18
- A ~600 MW resource tripped offline around 17:30
- At the time of OP-4 implementation, imports to New England were ~100 MW below day ahead expectations
  - System operators implemented the curtailment (~30 MW) of Real-Time Only export contracts in HE18 & 19

Real-Time System Energy and Reserve Pricing



- System-wide LMPs averaged ~$109/MWh across the operating day and ~$758/MWh during HE 19
- Reserve constraint pricing occurred between 17:10 and 19:45

Summary of Capacity Scarcity Condition Intervals

5-Minute Intervals	System 30 Min Reserve Constraint Penalty Factor ($1,000 MW/hr)	System 10 Min Reserve Constraint Penalty Factor ($1,500 MW/hr)
17:50 (1 Interval)	**Violated**	Binding
17:55 (1 Interval)	**Violated**	N/A
18:00 – 18:05 (2 Intervals)	**Violated**	Binding
18:10 – 18:15 (2 Intervals)	**Violated**	N/A

- A Capacity Scarcity Condition results from the **violation** of the System 30 Minute Operating Reserve constraint or the System 10 Minute Operating Reserve constraint in any one 5-minute interval

Pay for Performance Summary

- **Pay for Performance (PFP) Event on June 18:**
  - TMOR Triggered for 6 intervals (17:50-18:15)
  - Avg. Balancing Ratio (BR): **86.5%**
    - BR = (Load Requirement + reserve requirement) / CSO (excluding Energy Efficiency resources)
      - Avg. Load Req't :~23,600 MW
      - Avg. Reserve Req't: ~2,260 MW
      - CSO: 29,900 MW (excludes Energy Efficiency CSO)
  - Capacity Performance Payment Rate: **$5,455/MWh**
    - Effective as of June 1st for current Commitment Period
  - *Initial* settlements*:
    - PFP charges to underperforming FCM resources: **$14.0M**
    - Balancing Fund: **$312K** (surplus collection)
      - Difference between payments and charges
  - Initial settlements were distributed July 11, 2024 and reflect adjustments for Capacity Performance Bilateral Contracts

*Results are subject to change in subsequent settlements

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (2.1°F) Max: 95°F, Min: 62°F Precipitation: 1.16" – Below Normal Normal: 2.94"	Hartford	Temperature: Above Normal (4.4°F) Max: 96°F, Min: 58°F Precipitation: 2.38" – Below Normal Normal: 3.72"

Peak Load:	24,310 MW	July 16, 2024	19:00 (ending)

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

Procedure	Declared	Cancelled	Note
M/LCC 2	7/9/2024 09:00	7/9/2024 22:00	Capacity
M/LCC 2	7/15/2024 14:00	7/15/2024 22:00	Capacity

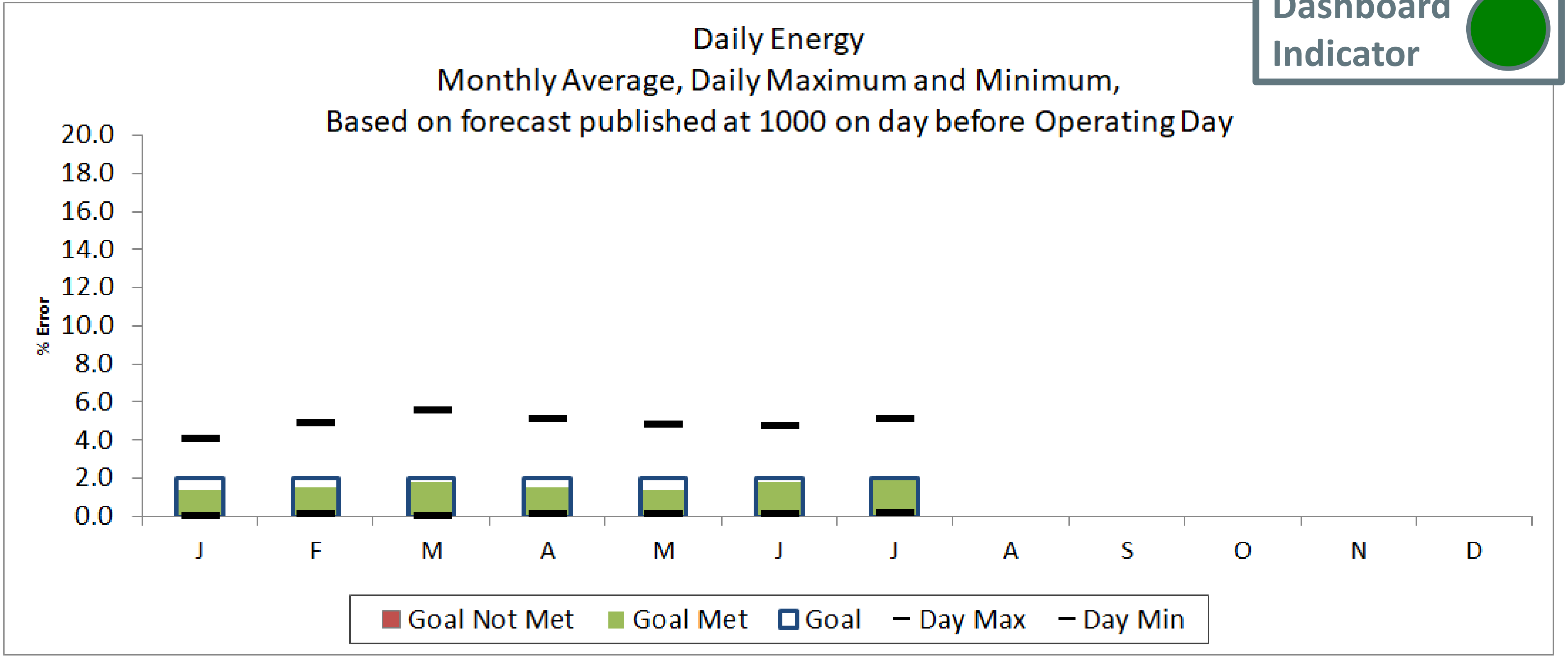
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
7/3/2024	IESO	900
7/8/2024	NYISO	980
7/8/2024	PJM	700
7/11/2024	NYISO	525
7/13/2024	IESO	900
7/14/2024	NYISO	531
7/14/2024	NYISO	900
7/25/2024	ISO-NE	500

2024 System Operations - Load Forecast Accuracy cont.

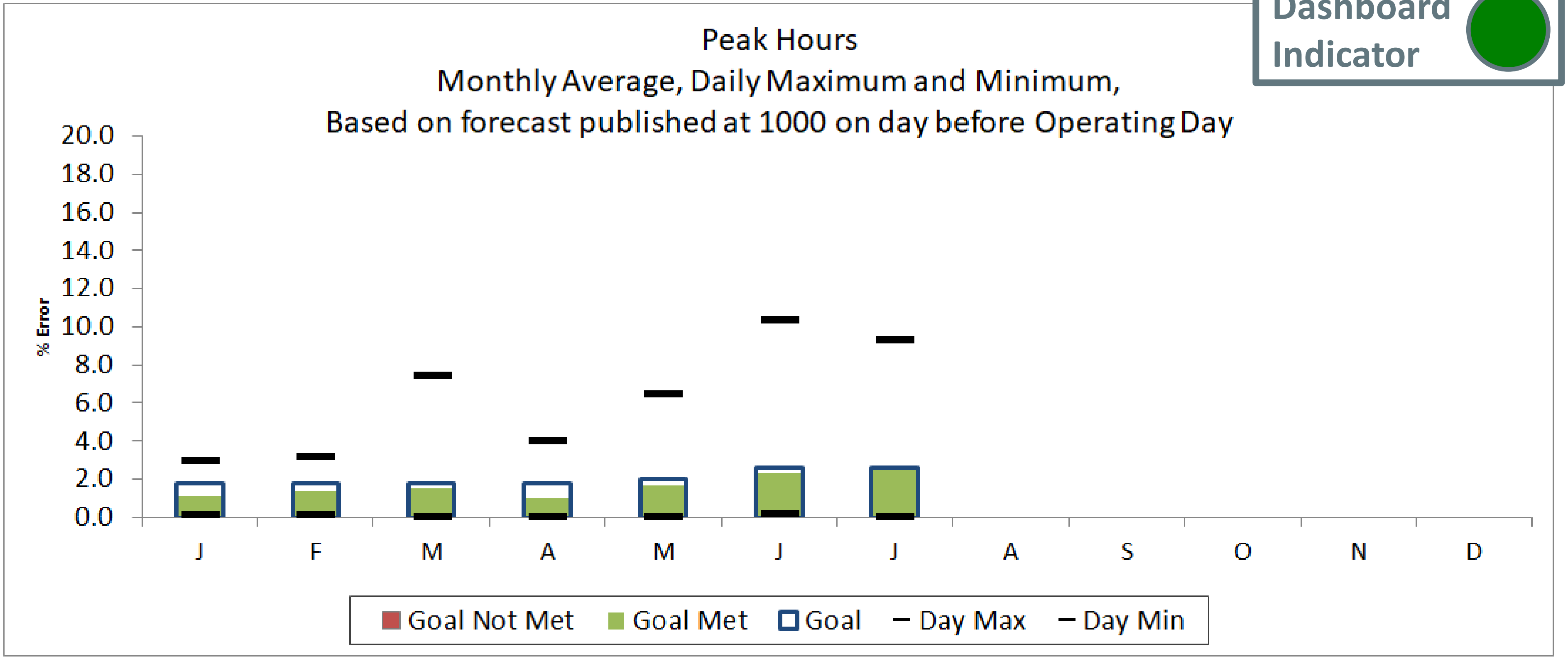
Dashboard Indicator ●



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.02	4.89	5.56	5.09	4.84	4.73	5.13						5.56
Day Min	0.00	0.12	0.02	0.09	0.07	0.11	0.19						0.00
MAPE	1.38	1.54	1.82	1.52	1.40	1.79	1.95						1.63
Goal	2.00	2.00	2.00	2.00	2.00	2.00	2.00						

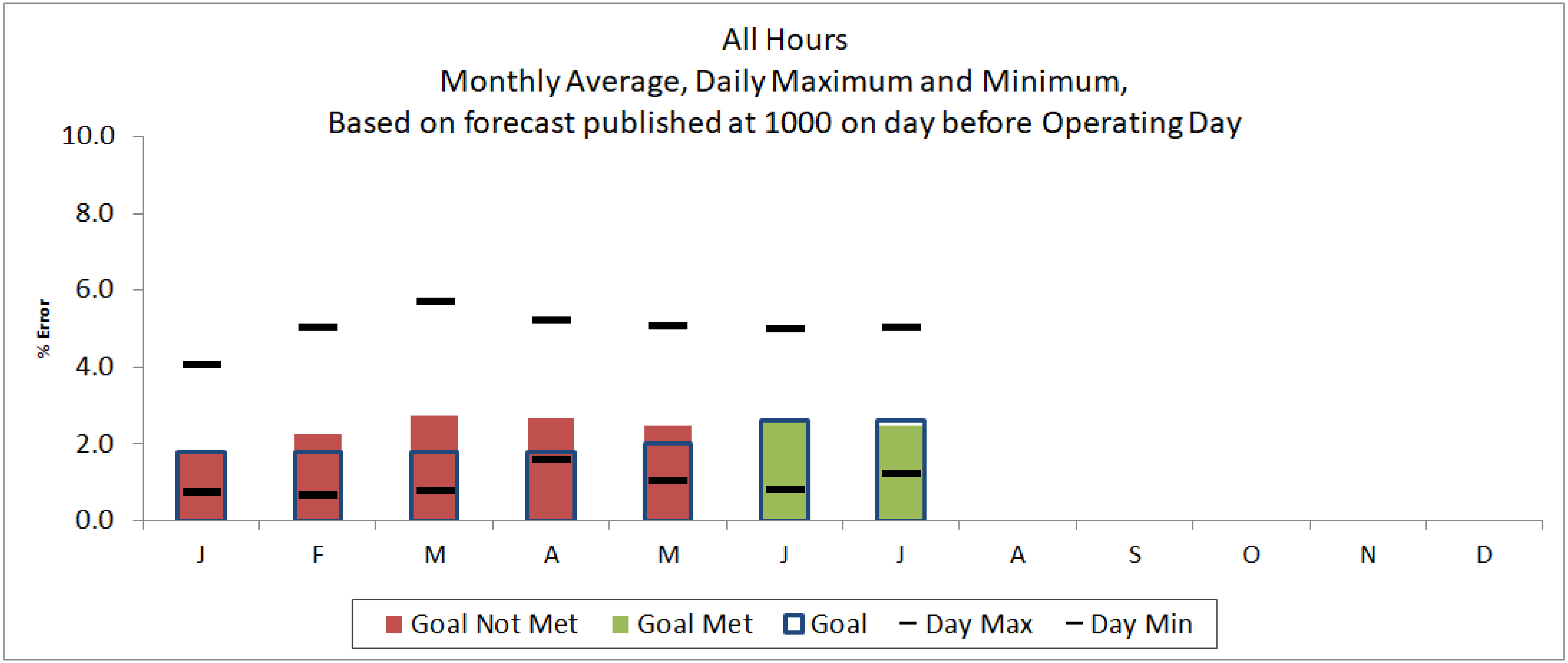
2024 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator ●



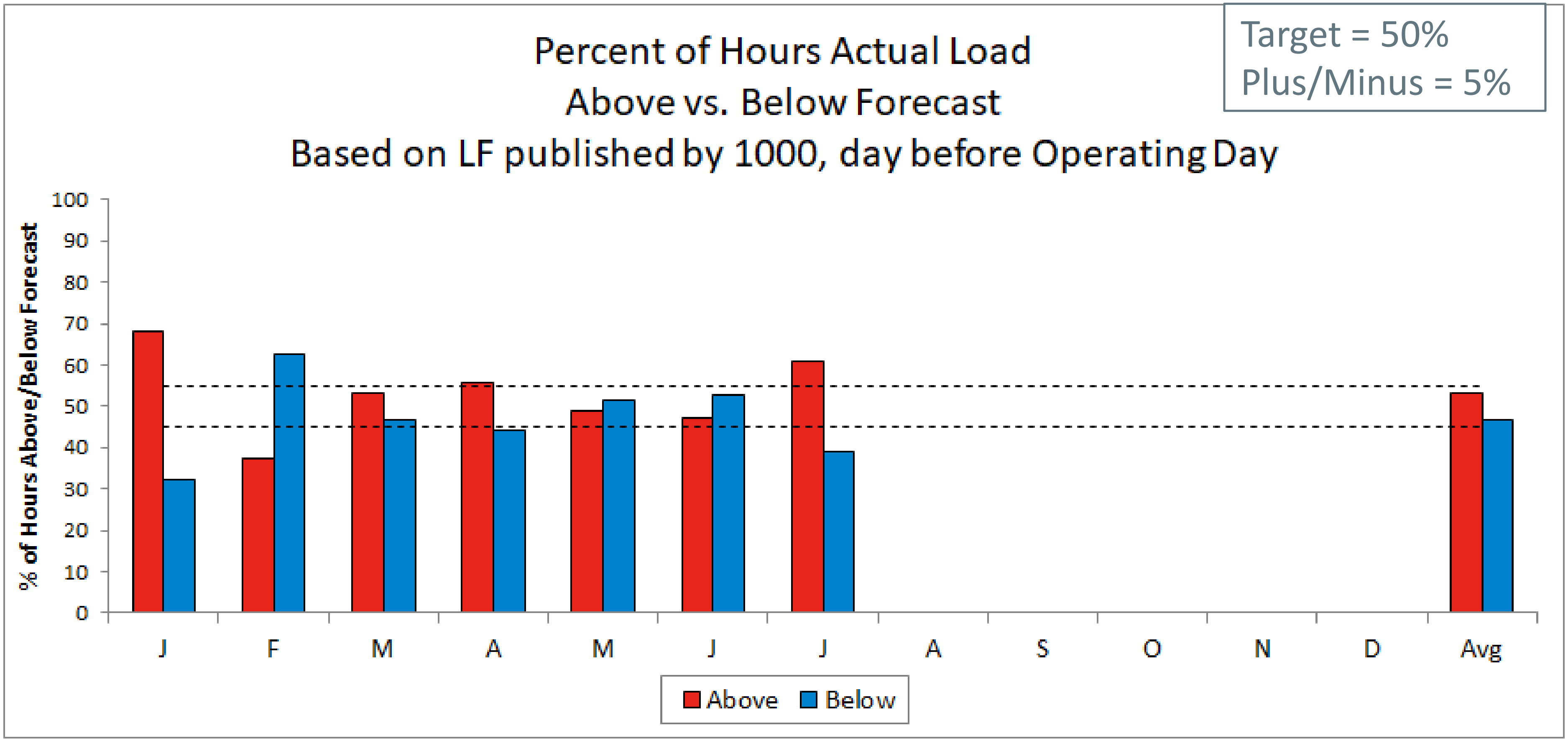
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	2.90	3.17	7.45	3.99	6.46	10.30	9.30						10.30
Day Min	0.08	0.10	0.02	0.03	0.01	0.14	0.00						0.00
MAPE	1.10	1.39	1.54	1.02	1.66	2.32	2.47						1.64
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60						

2024 System Operations - Load Forecast Accuracy



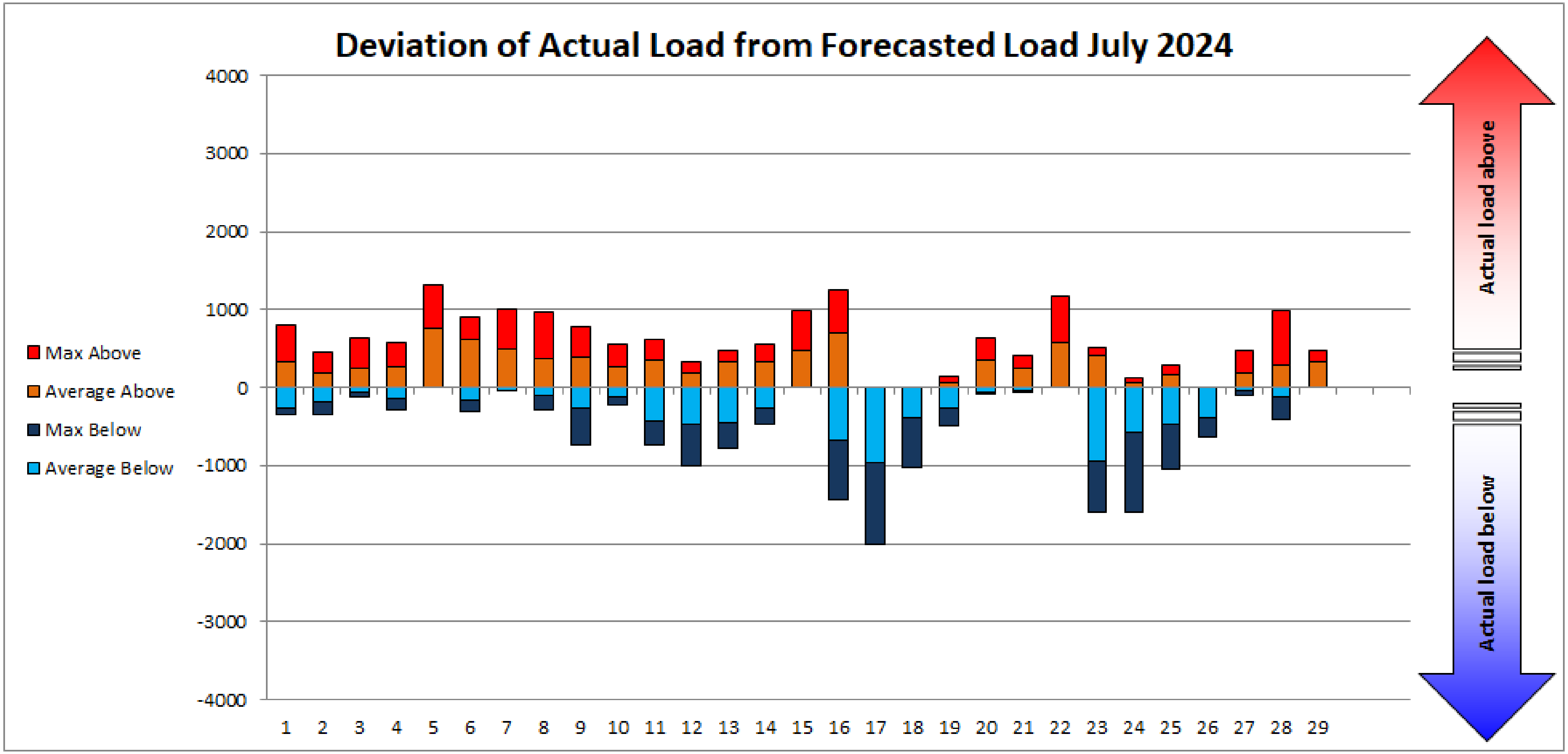
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.03	5.00	5.67	5.18	5.04	4.99	5.02						5.67
Day Min	0.73	0.64	0.76	1.59	1.00	0.81	1.20						0.64
MAPE	1.83	2.24	2.72	2.66	2.46	2.57	2.48						2.42
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60						

2024 System Operations - Load Forecast Accuracy cont.



	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	67.9	37.4	53.3	55.8	48.7	47.2	60.8						53
Below %	32.1	62.6	46.7	44.2	51.3	52.8	39.2						47
Avg Above	260.5	155.2	254.6	254.9	245.5	267.4	287.8						288
Avg Below	-155.5	-292.3	-253.5	-239.2	-223.2	-265.6	-255.6						-292
Avg All	132	-130	39	38	11	-16	64						21

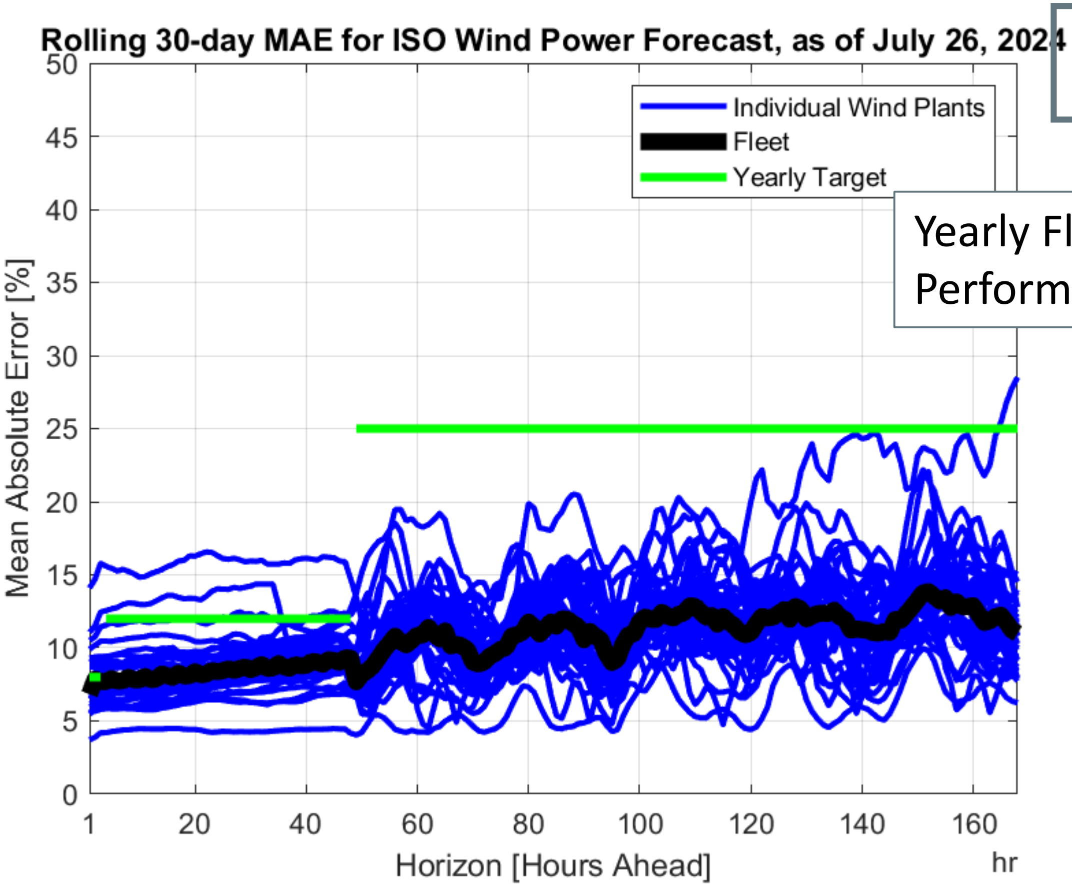
2024 System Operations - Load Forecast Accuracy cont.



Note on Wind and Solar Forecast Error Statistics

- With the launch of solar do-not-exceed dispatch in December 2023, the ISO is now able to provide the same forecast error statistics for do-not-exceed dispatchable generator (DDG) solar resources as it does for DDG wind resources
- The next 8 slides review the wind data as well as the newly developed solar statistics
- For stakeholders' information, from now on, these monthly updates will be posted on two new pages that have been created in ISO Express:
  - ISO Express > Operations Reports > System > Wind Forecast MAE and Bias
  - ISO Express > Operations Reports > System > Solar Forecast MAE and Bias
- The ISO also provides an **annual** analysis of forecasting error statistics to the Emerging Technologies Working Group (ETWG)

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

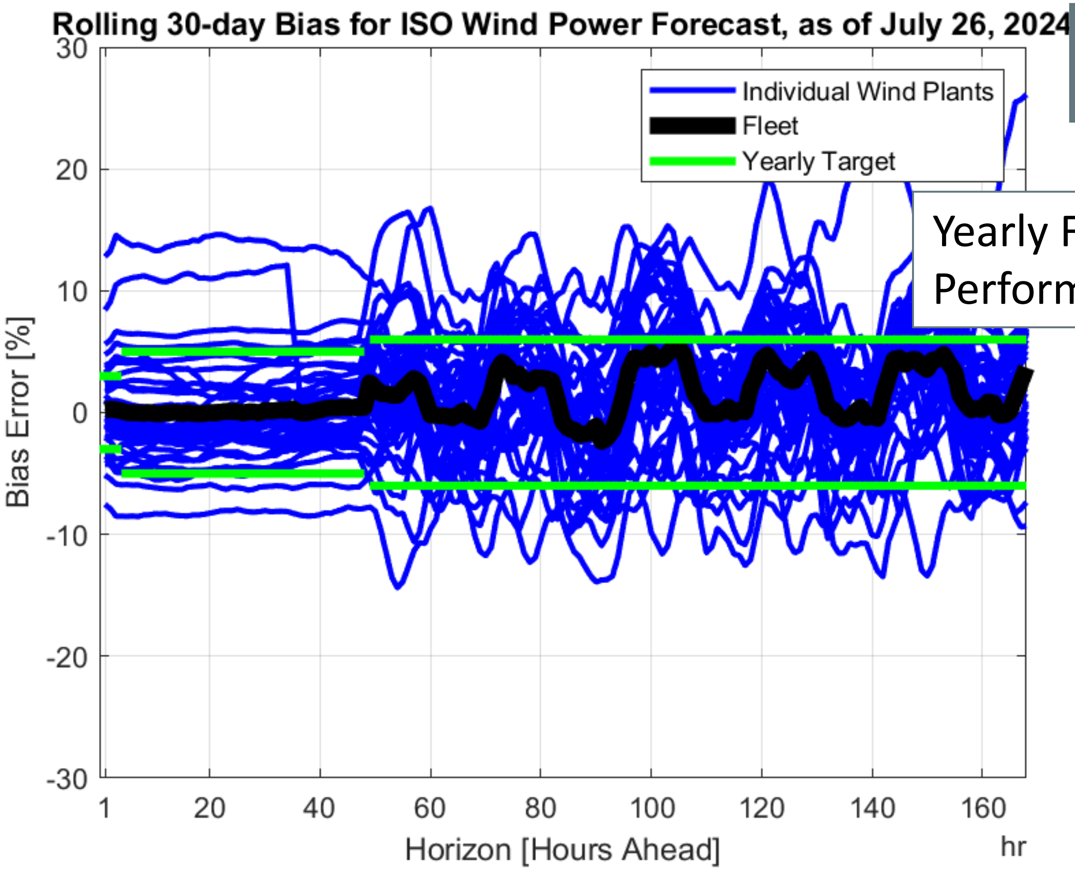


Dashboard Indicator ●

Yearly Fleet Performance targets

Ideally, MAE and Bias would be both equal to zero. As is typical, MAE increases with the forecast horizon. MAE and Bias for the fleet of wind power resources are less due to offsetting errors. Across all time frames, the ISO-NE/DNV forecast is very good compared to industry standards; and monthly MAE is within the yearly performance targets for all hours.

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

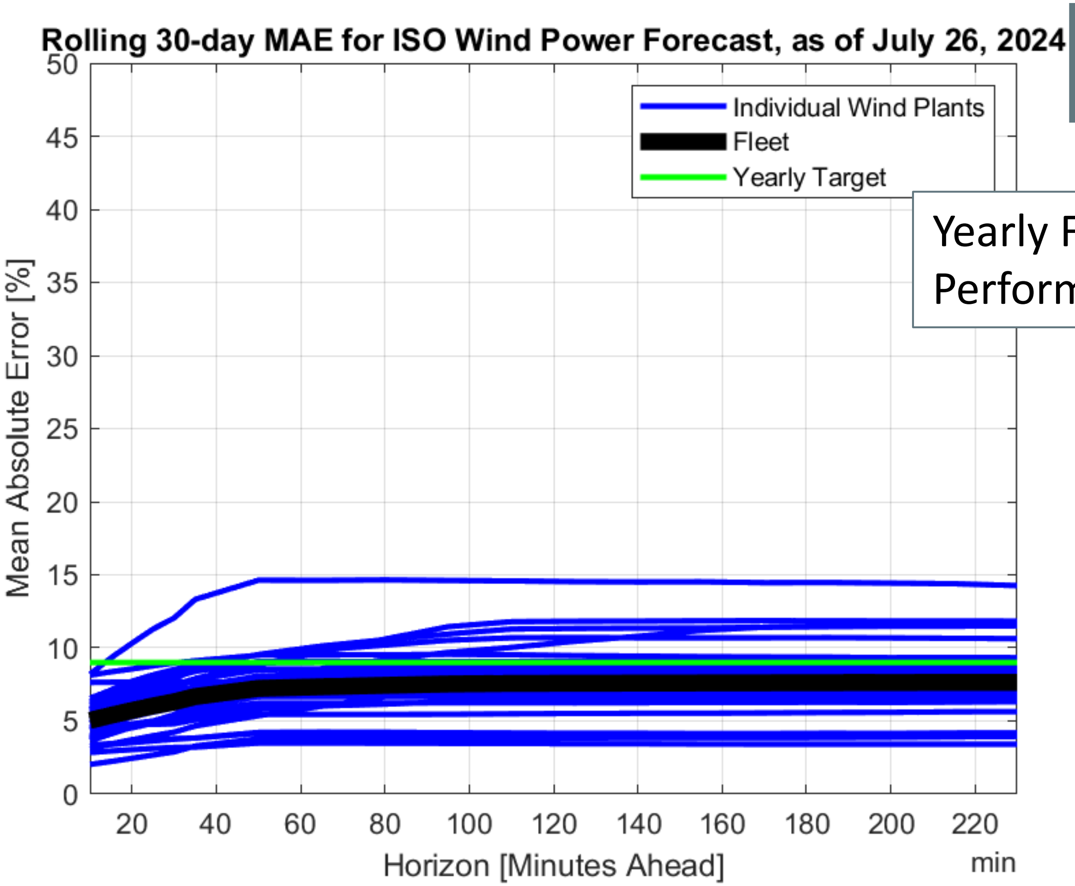


Dashboard Indicator ●

Yearly Fleet Performance targets

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

Wind Power Forecast Error Statistics: Short Term Forecast MAE



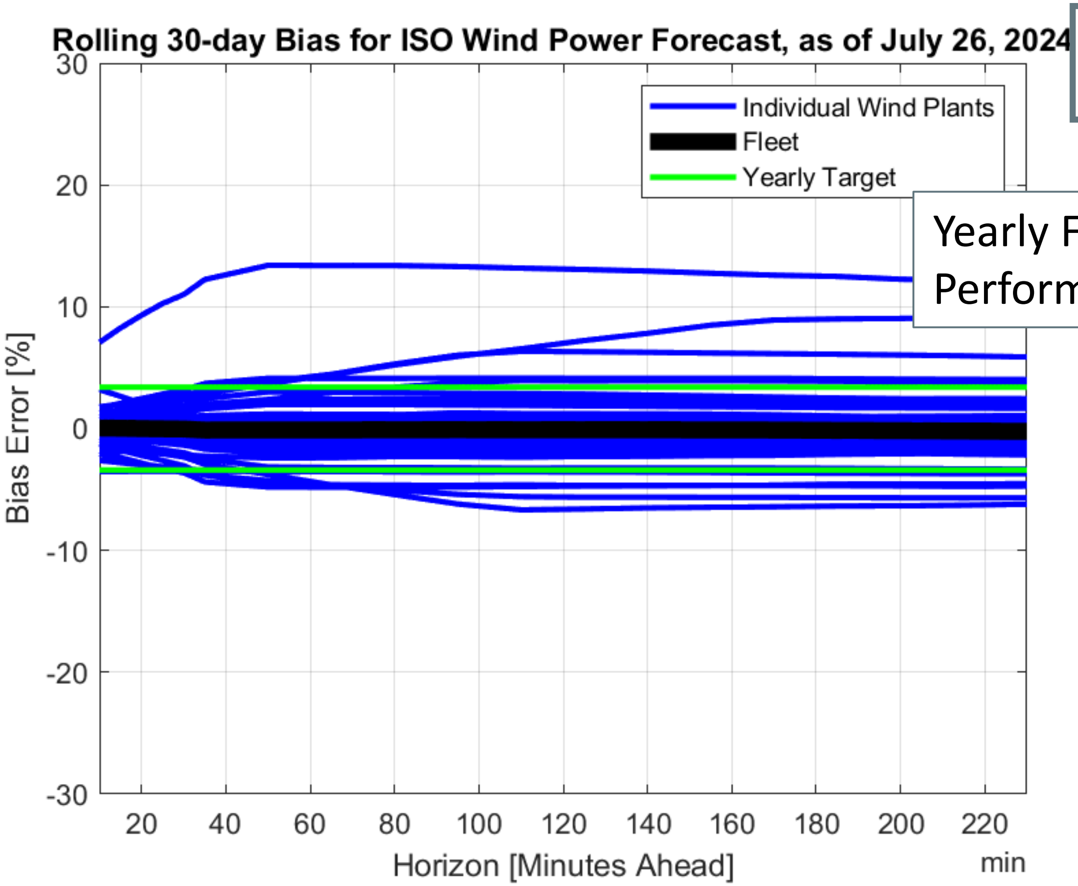
Dashboard Indicator ●

Yearly Fleet Performance targets

Ideally, MAE and Bias would be both equal to zero. As is typical, MAE increases with the forecast horizon. MAE and Bias for the fleet of wind power resources are less due to offsetting errors. Across all time frames, the forecast compares well with industry standards, and monthly MAE is within yearly performance targets.

Wind Power Forecast Error Statistics: Short Term Forecast Bias

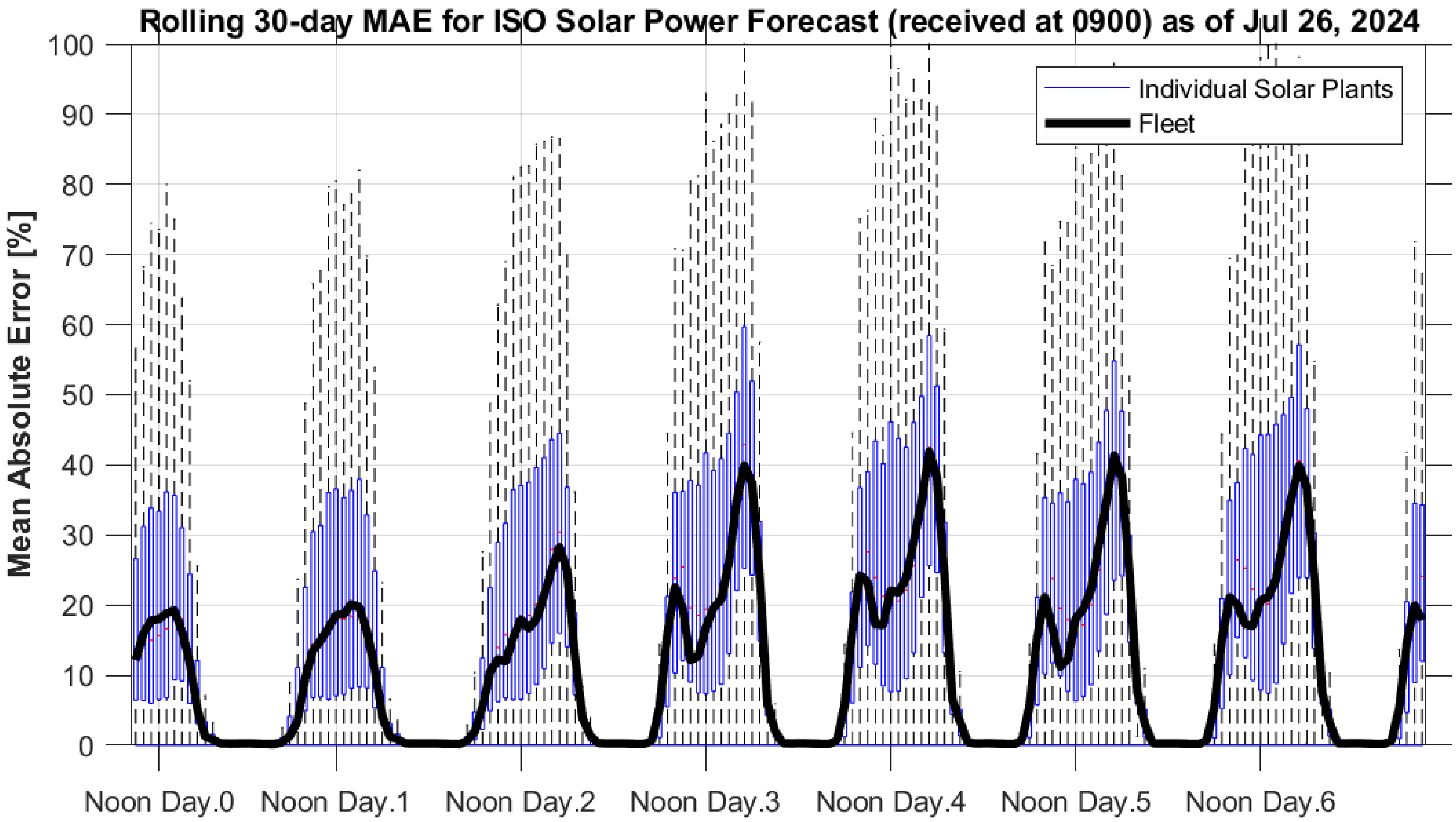
Dashboard Indicator ●



Yearly Fleet Performance targets

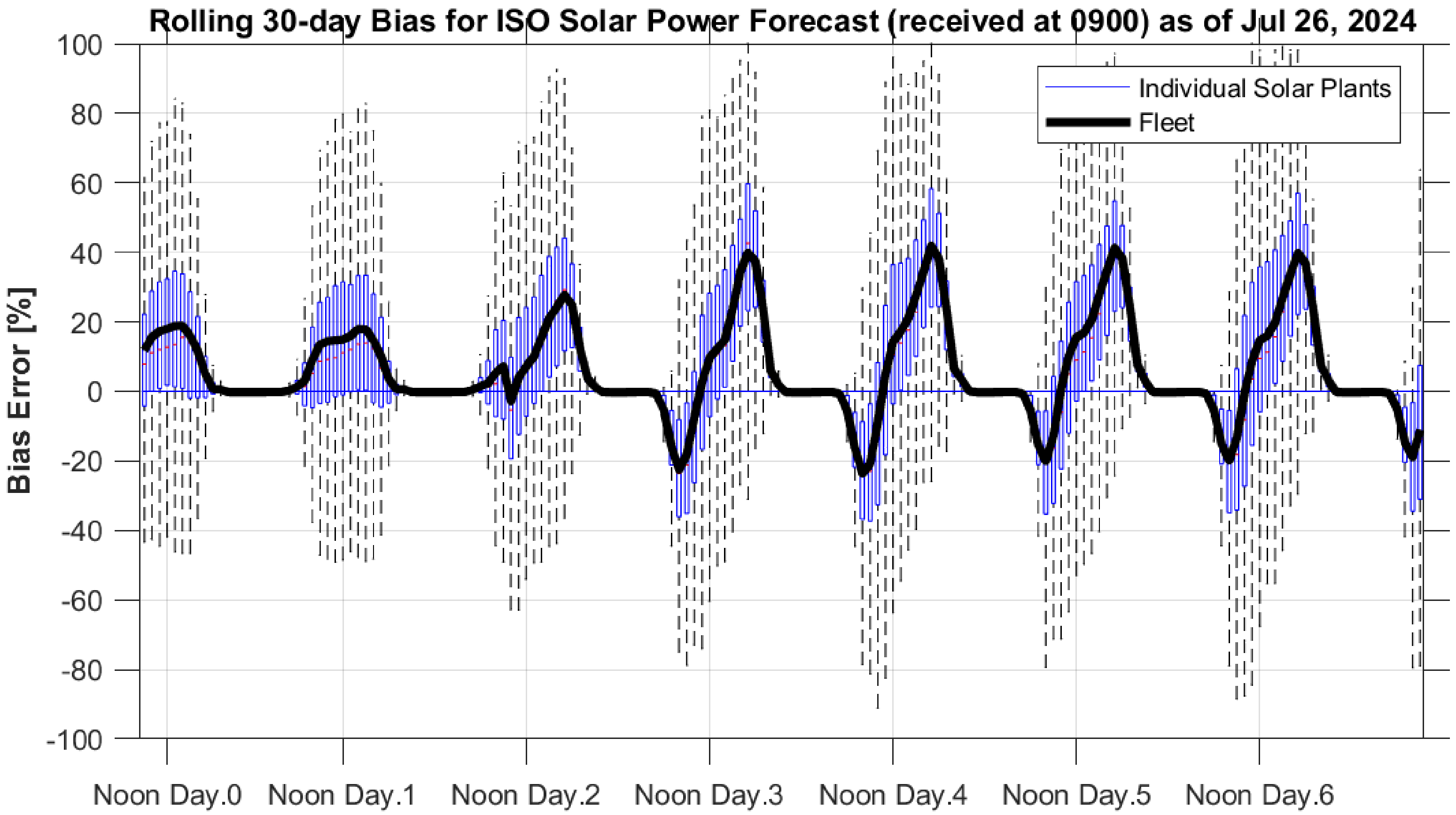
Ideally, MAE and Bias would be both equal to zero. Positive bias means less windpower was actually available compared to forecast. Negative bias means more windpower was actually available compared to forecast. Across all time frames, the ISO-NE/DNV forecast compares well with industry standards, and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

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



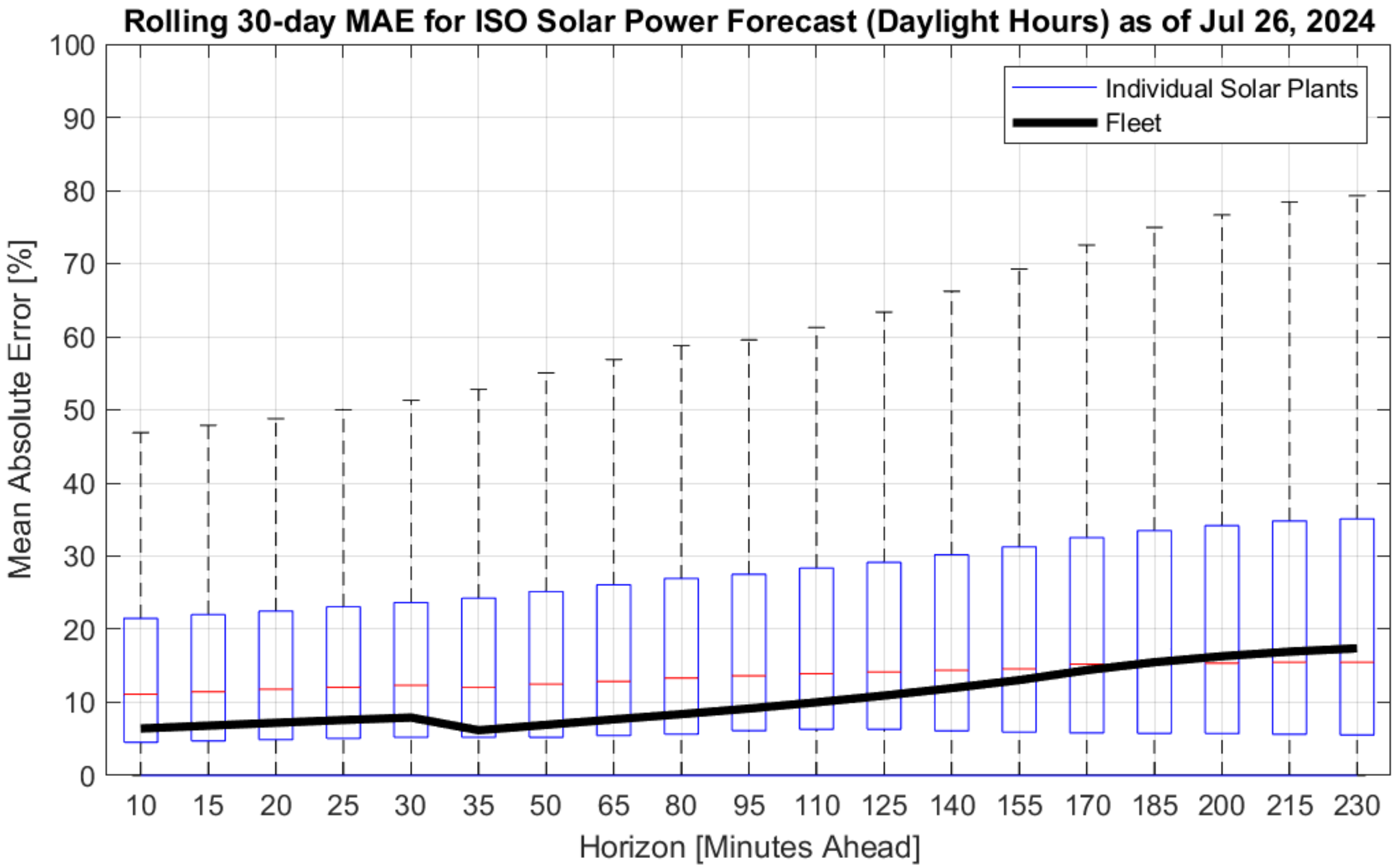
Ideally, MAE and Bias would be both equal to zero. As is typical, MAE increases with the forecast horizon. MAE and Bias for the fleet of solar power resources are less due to offsetting errors.

Solar Power Forecast Error Statistics: Medium and Long Term Forecasts Bias



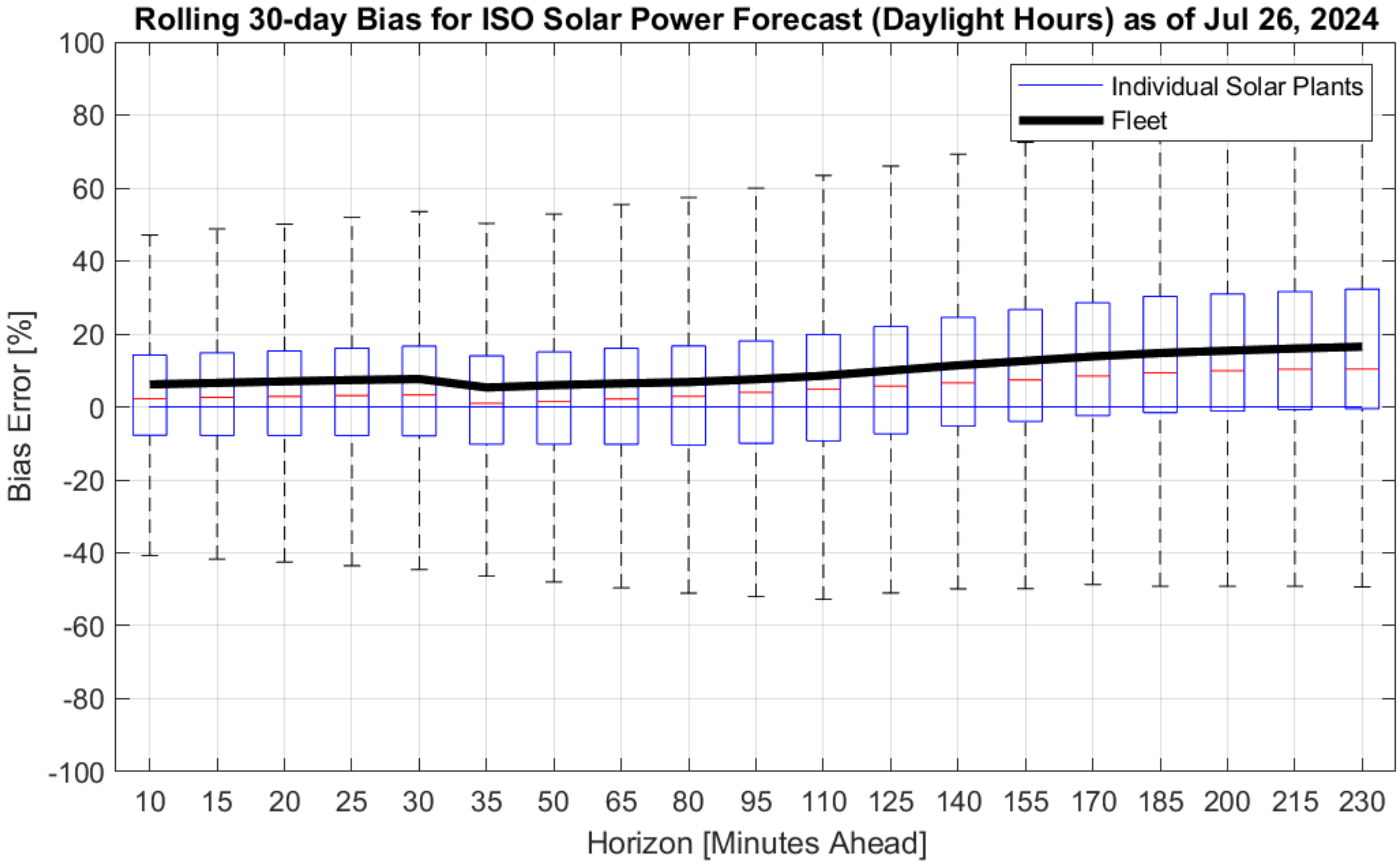
Ideally, MAE and Bias would be both equal to zero. Positive bias means less solar power was actually available compared to forecast. Negative bias means more solar power was actually available compared to forecast.

Solar Power Forecast Error Statistics: Short Term Forecast MAE



Ideally, MAE and Bias would be both equal to zero. As is typical, MAE increases with the forecast horizon. MAE and Bias for the fleet of solar power resources are less due to offsetting errors.

Solar Power Forecast Error Statistics: Short Term Forecast Bias

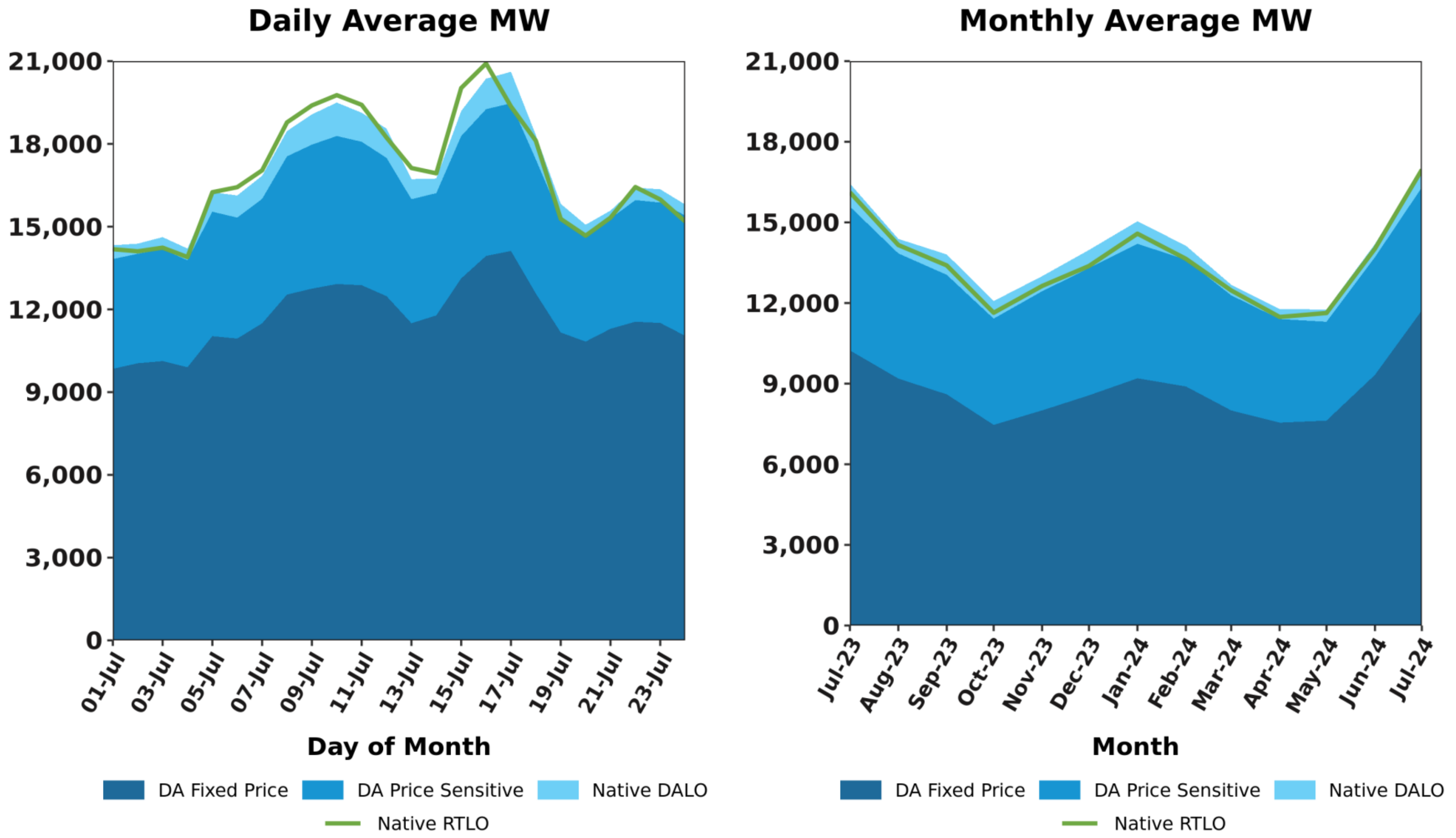


Ideally, MAE and Bias would be both equal to zero. Positive bias means less solar power was actually available compared to forecast. Negative bias means more solar power was actually available compared to forecast.

MARKET OPERATIONS

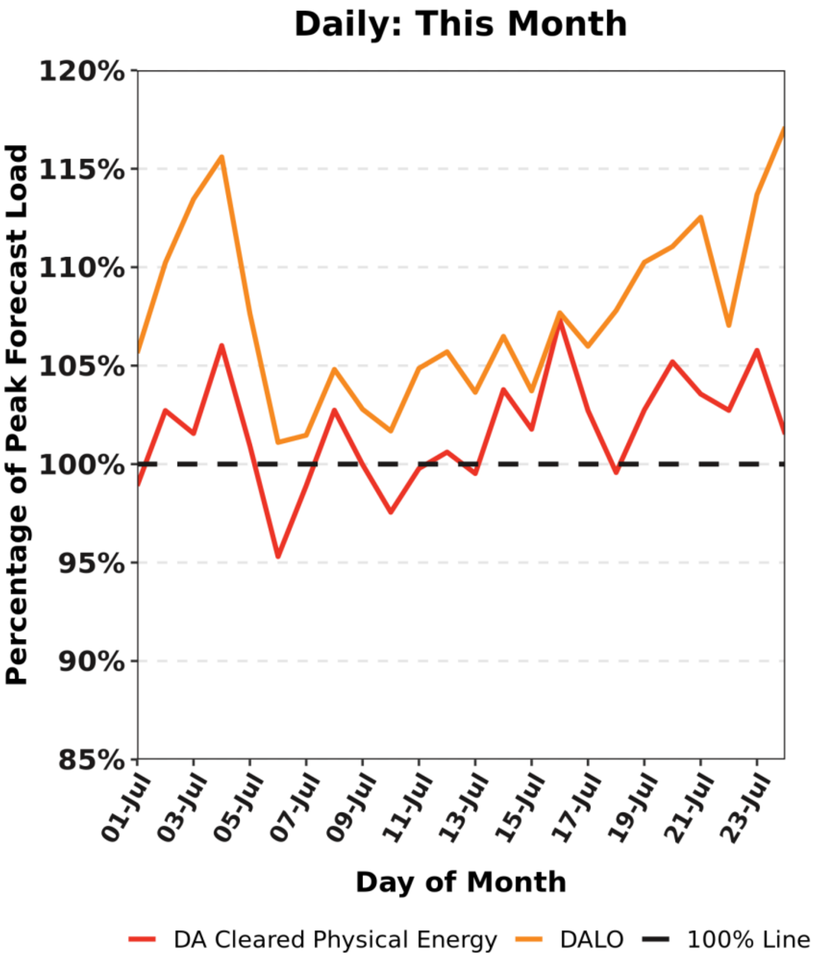
SUPPLY AND DEMAND VOLUMES

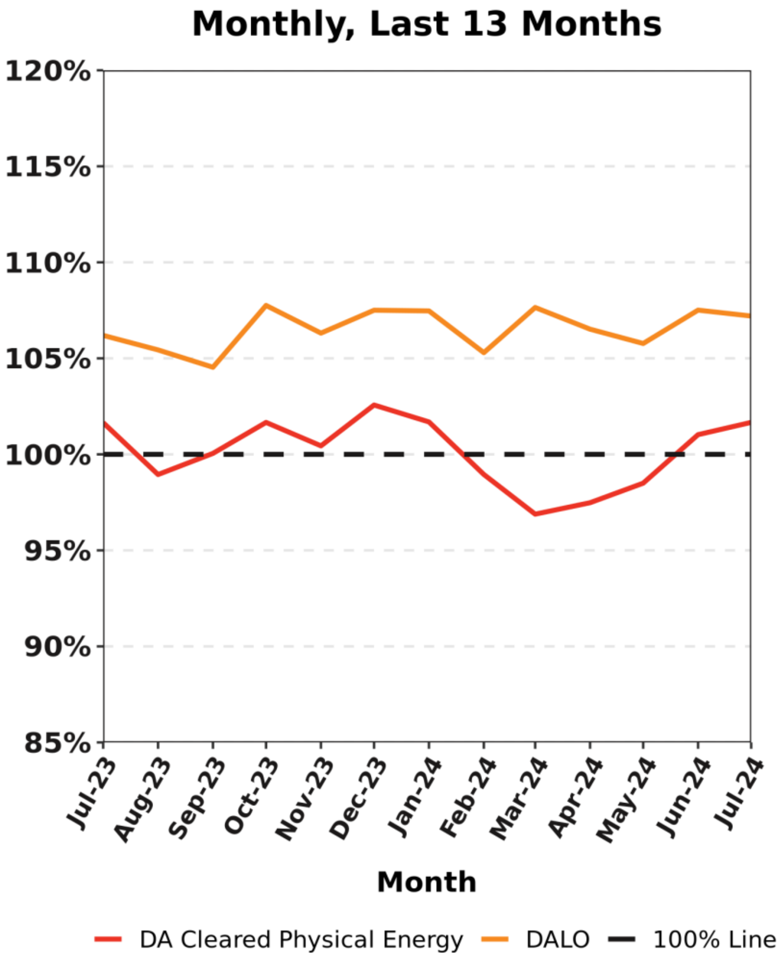
DA Cleared Native Load by Composition Compared to Native RT Load



Native Day-Ahead Load Obligation (DALO) is the sum of all day-ahead cleared load, excluding modeled transmission losses and exports
Native Real-Time Load Obligation (RTLO) is the sum of all real-time load, excluding exports

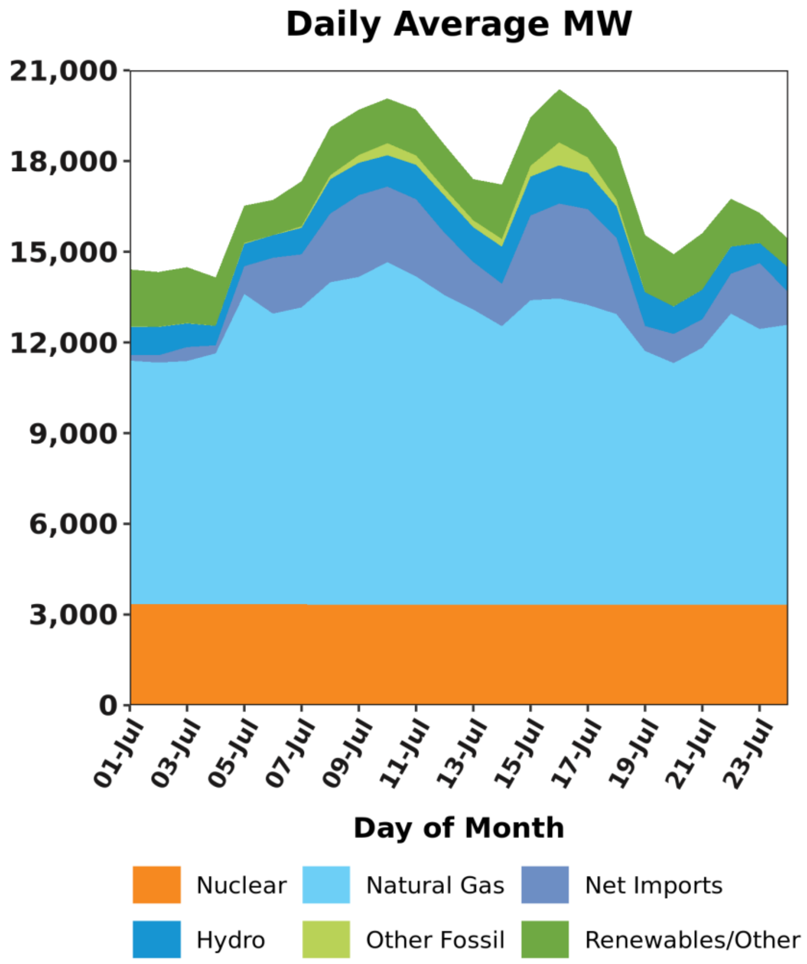
DA Volumes as % of Forecast in Peak Hour

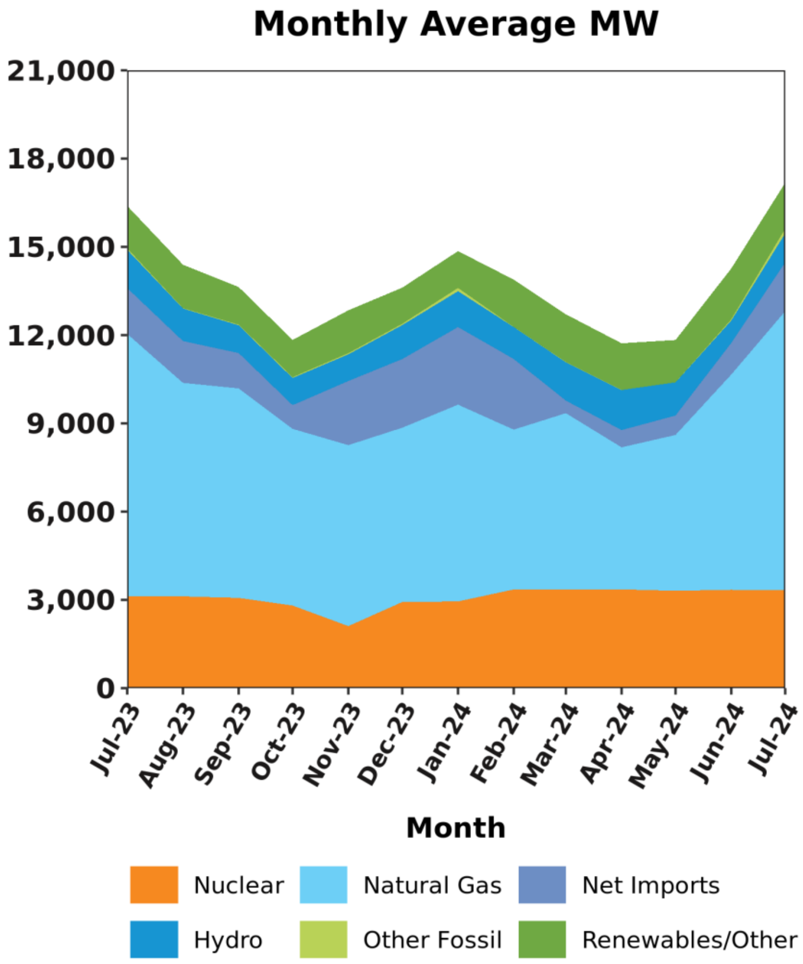




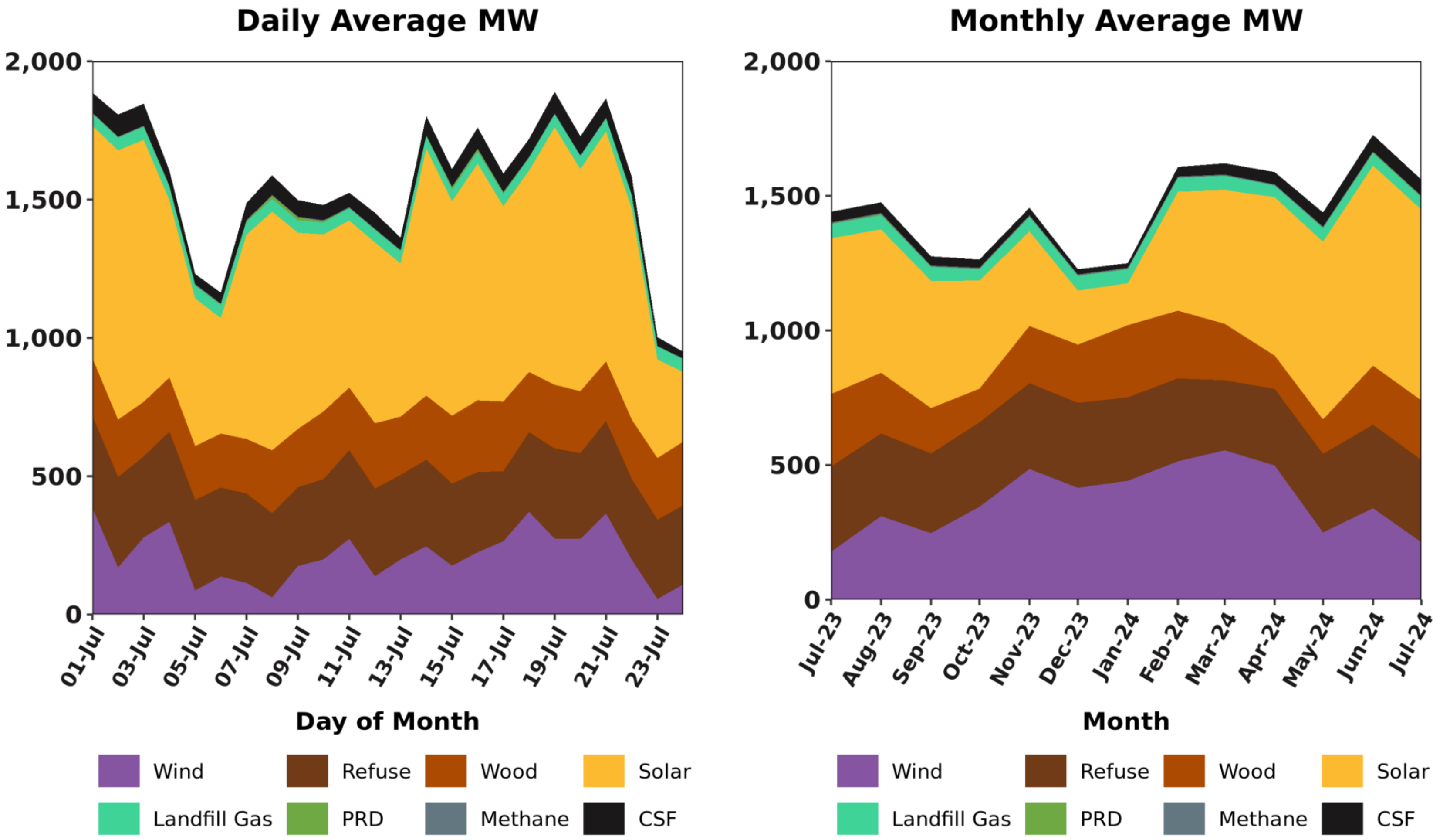
The number of system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) period during the month was: none

Resource Mix



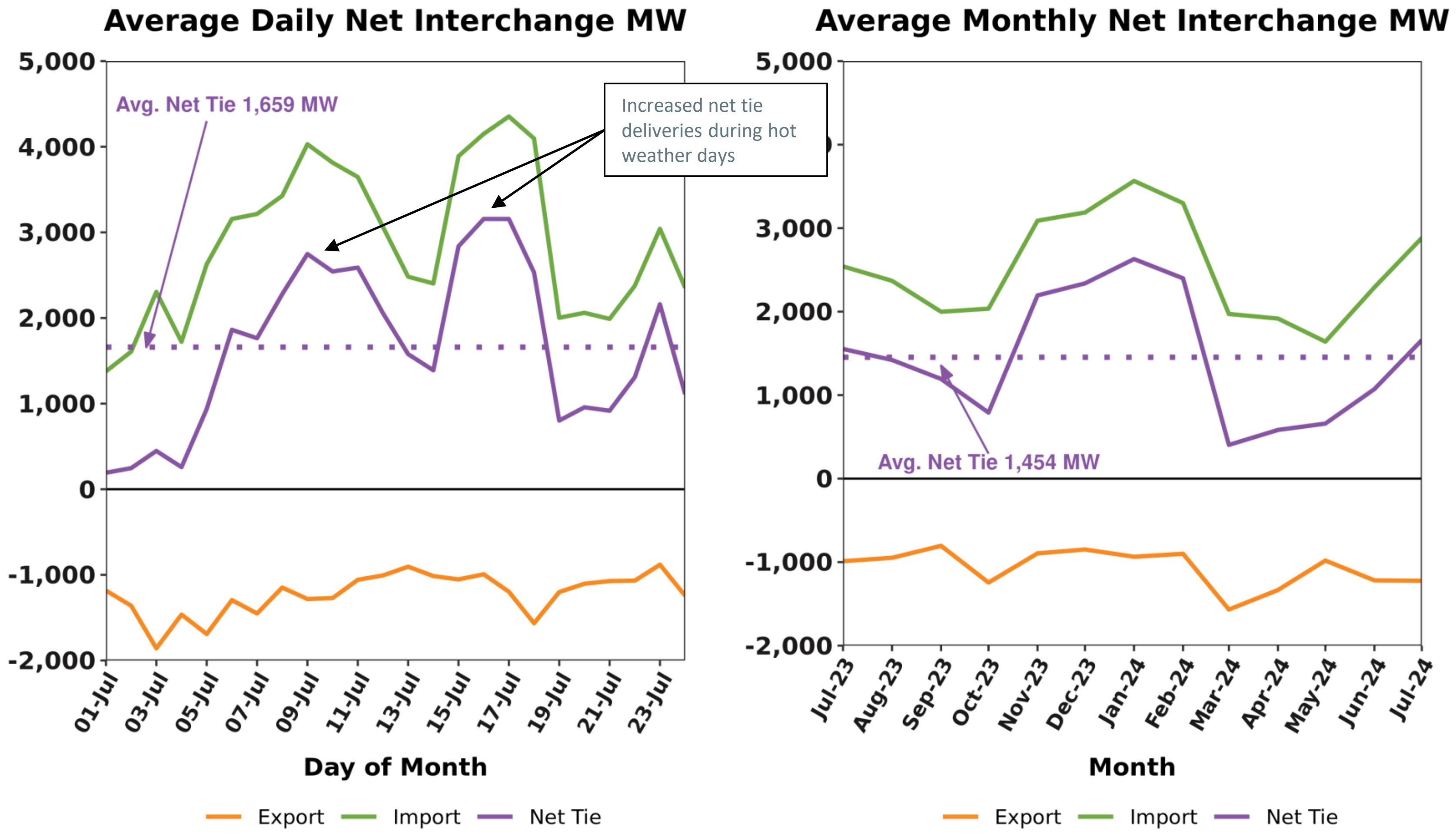


Renewable Generation by Fuel Type



CSF = Continuous Storage Facilities (a.k.a. Batteries)

RT Net Interchange



Average Daily Net Interchange MW

Average Monthly Net Interchange MW

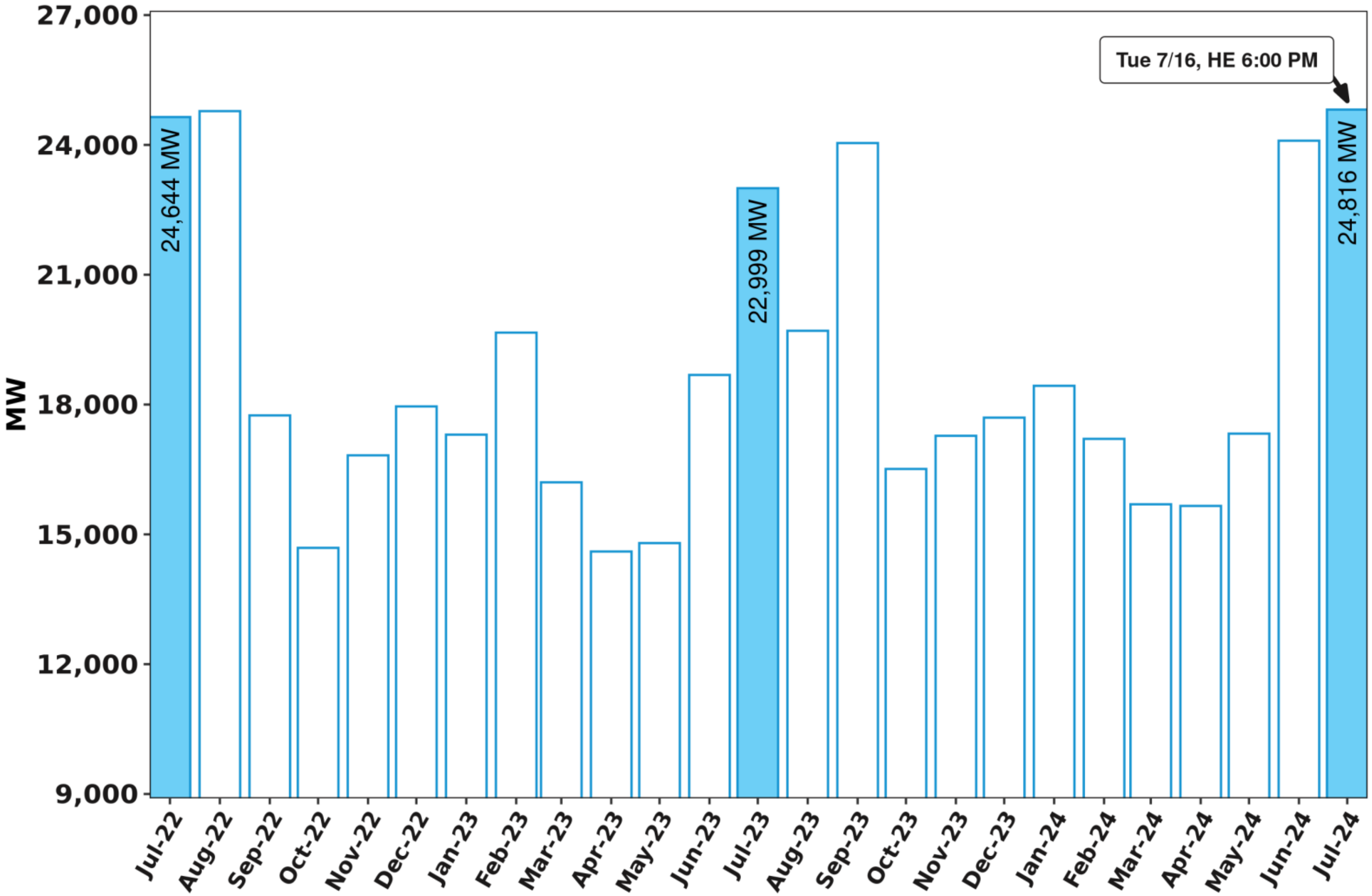
Avg. Net Tie 1,659 MW

Increased net tie deliveries during hot weather days

Avg. Net Tie 1,454 MW

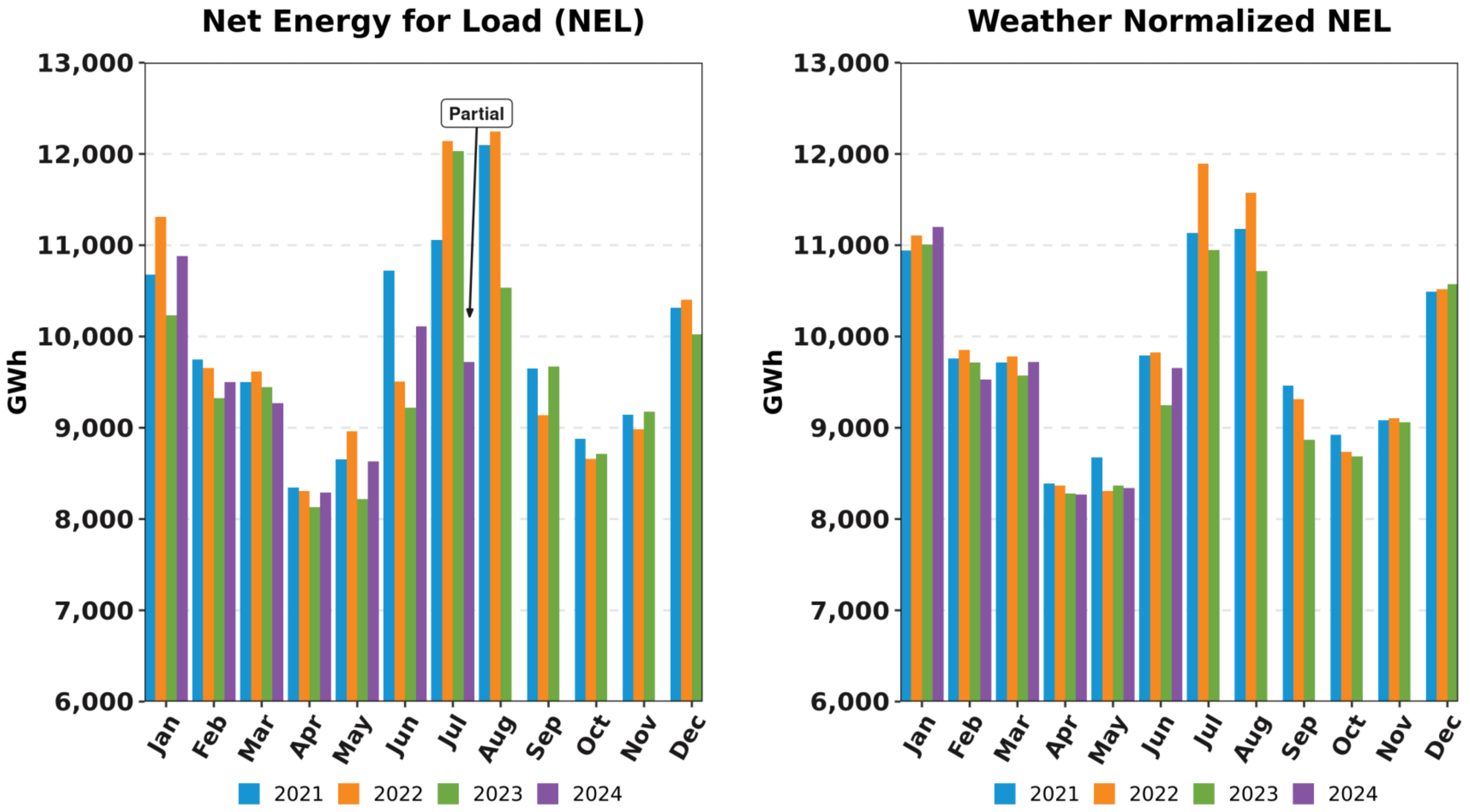
Net Interchange is the participant sum of daily imports minus the sum of daily exports; positive values are net imports

RQM System Peak Load MW by Month



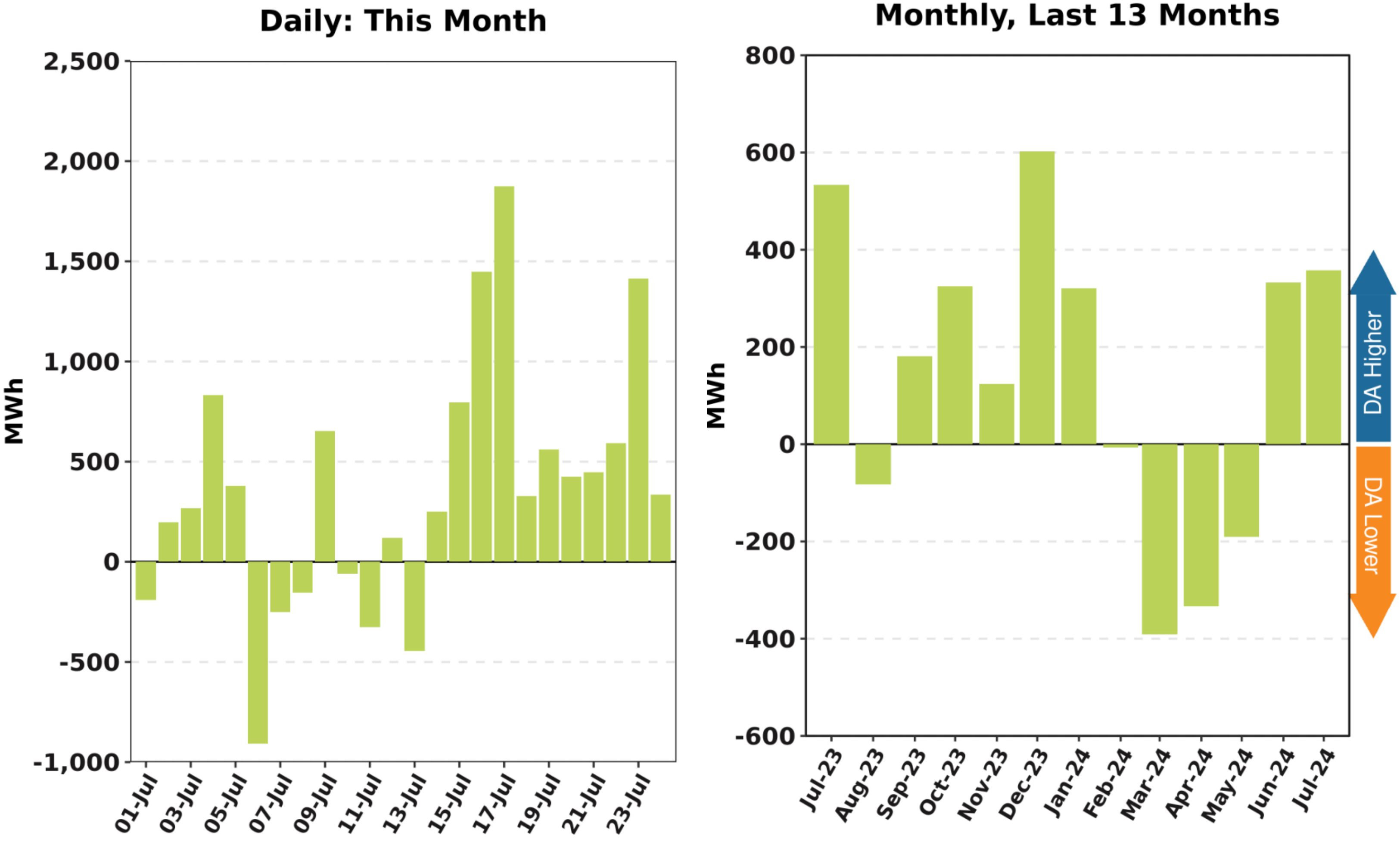
Shaded columns reflect current month and the same month the last 2 years

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



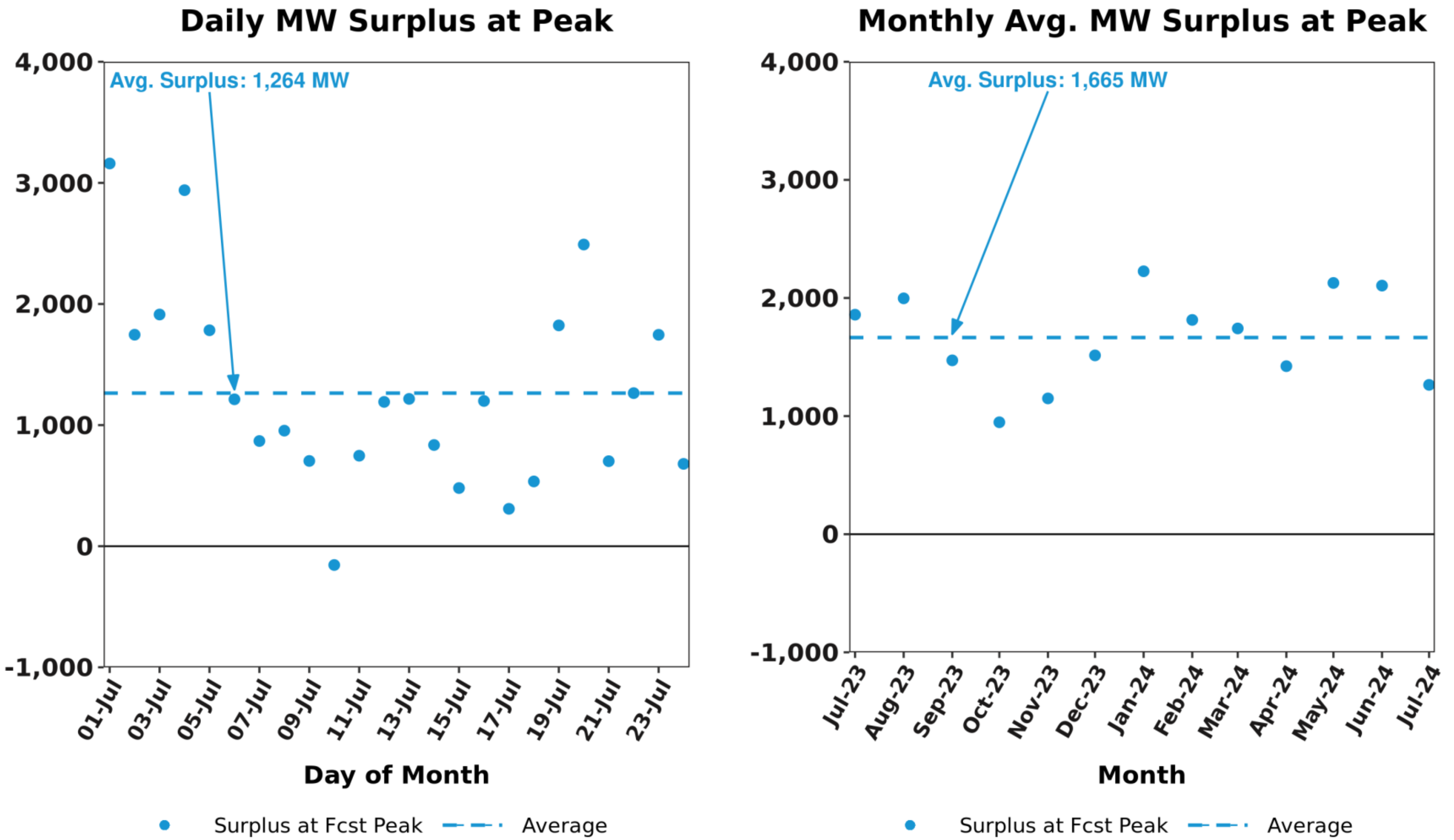
NEPOOL NEL is the total net revenue quality metered energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation + Demand Response Resource output - pumping load + net interchange where imports are positively signed. Current month's data may be preliminary. Weather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

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



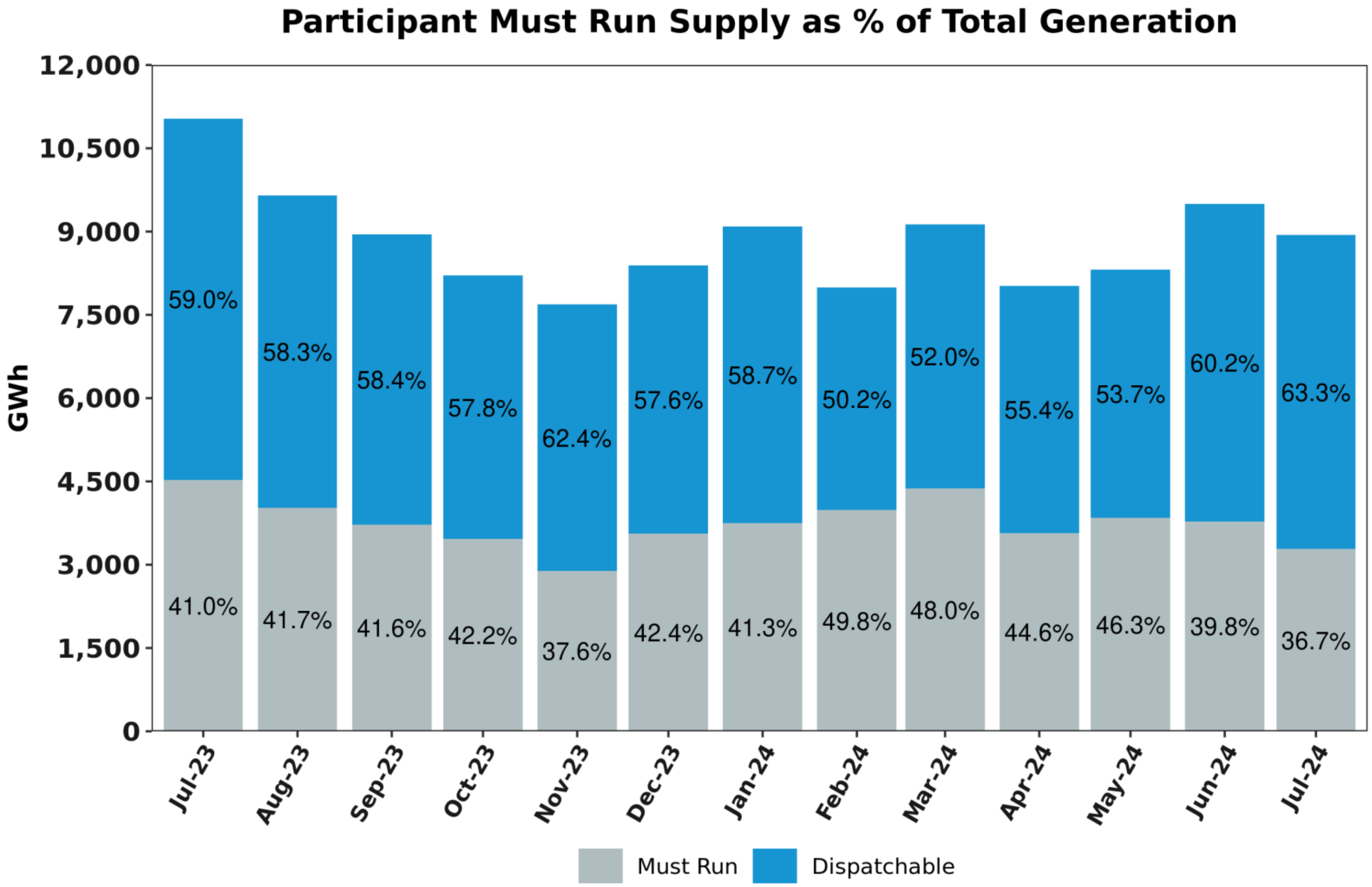
Negative values indicate DA Cleared Physical Energy value below its RT counterpart.

Capacity Surplus* Cleared in the DA Market Relative to Forecasted Peak-Hour Requirements



*DA capacity surplus includes DA offered ECO max above cleared amounts for cleared resources + offered reserves from available non-cleared resources + DA scheduled net interchange, reflected for the peak hour

RT Generation Output Offered as Must Run vs Dispatchable



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

MARKET PRICING

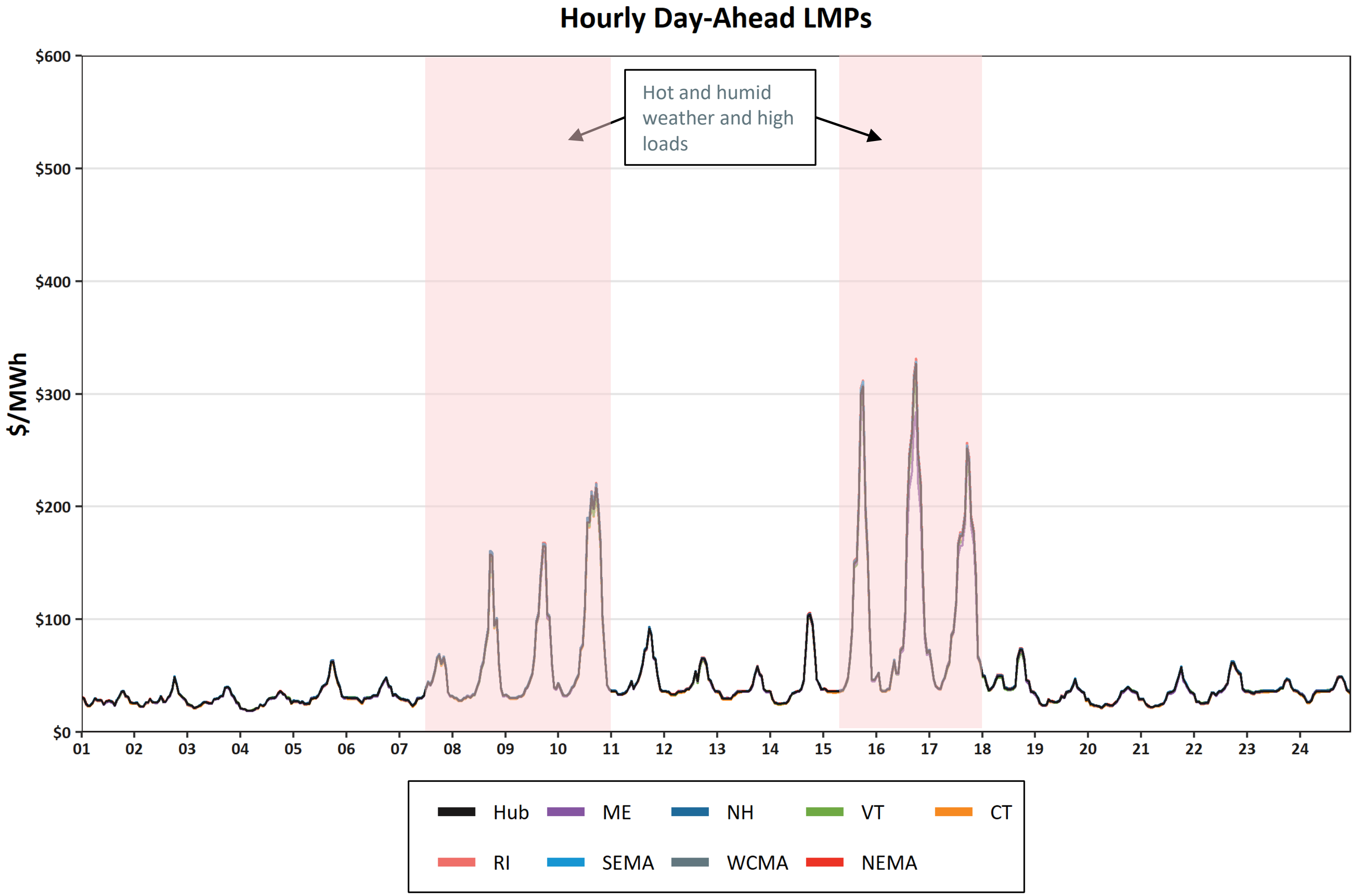
DA vs. RT LMPs ($/MWh)

Arithmetic Average

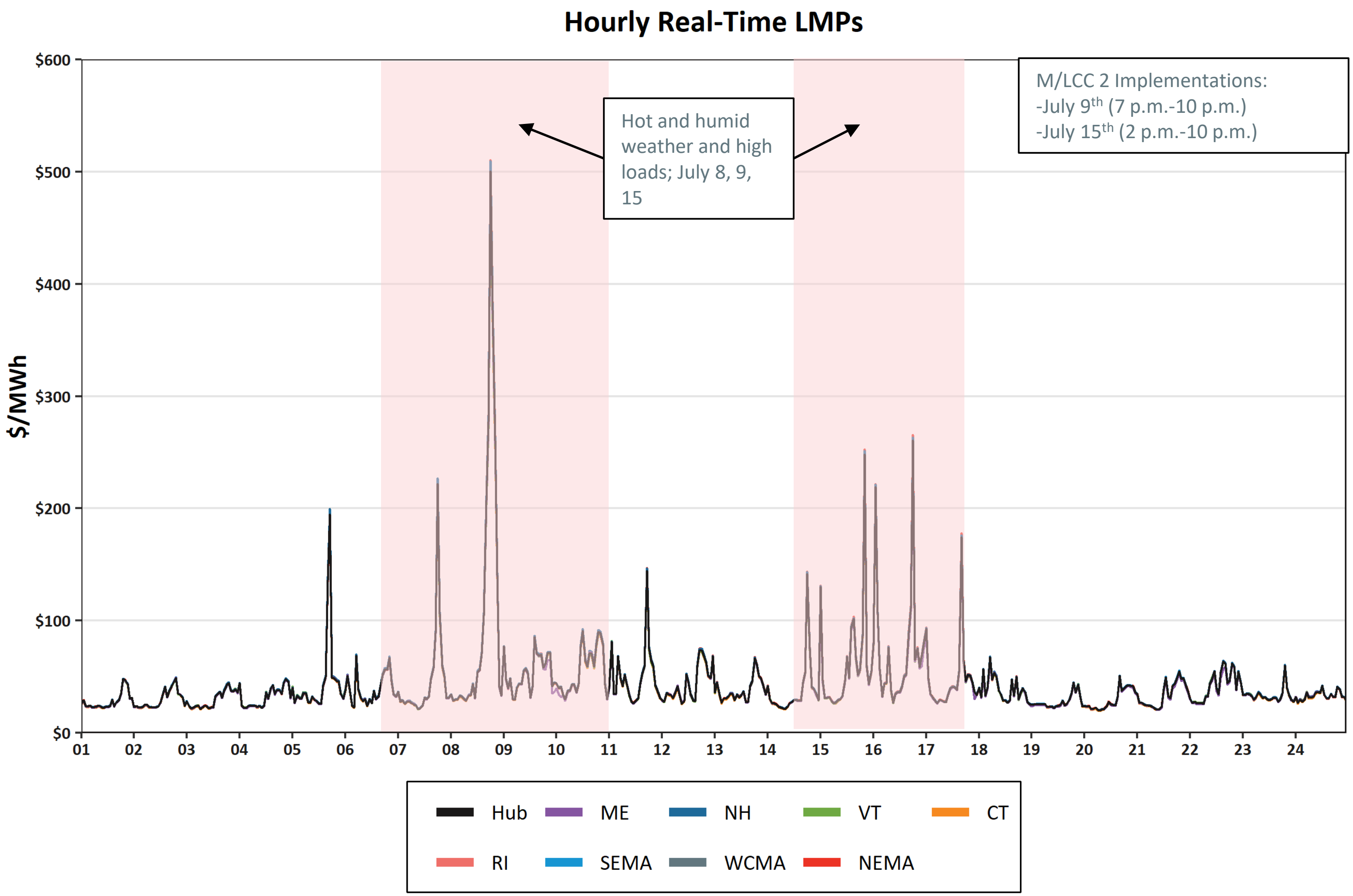
Year 2023	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$85.59	$84.20	$85.77	$84.48	$84.07	$85.39	$86.05	$85.69	$86.12
Real-Time	$84.89	$83.06	$85.05	$83.64	$83.80	$84.69	$85.35	$84.97	$85.40
RT Delta %	-0.82%	-1.35%	-0.84%	-0.99%	-0.32%	-0.82%	-0.81%	-0.84%	-0.84%
Year 2022	**Hub**	**ME**	**NH**	**VT**	**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 %	-0.82%	-1.35%	-0.84%	-0.99%	-0.32%	-0.82%	-0.81%	-0.84%	-0.84%

July-23	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$42.34	$41.47	$42.44	$41.96	$41.52	$42.04	$42.64	$42.36	$42.74
Real-Time	$39.05	$38.23	$39.10	$38.70	$38.53	$38.83	$39.38	$39.08	$39.44
RT Delta %	-7.77%	-7.81%	-7.87%	-7.77%	-7.20%	-7.64%	-7.65%	-7.74%	-7.72%
July-24	**Hub**	**ME**	**NH**	**VT**	**CT**	**RI**	**SEMA**	**WCMA**	**NEMA**
Day-Ahead	$49.33	$48.34	$49.93	$48.85	$48.22	$48.86	$49.67	$49.44	$50.12
Real-Time	$43.73	$43.09	$44.35	$43.55	$43.07	$43.35	$43.98	$43.86	$44.40
RT Delta %	-11.35%	-10.86%	-11.18%	-10.85%	-10.68%	-11.28%	-11.46%	-11.29%	-11.41%
Annual Diff.	**Hub**	**ME**	**NH**	**VT**	**CT**	**RI**	**SEMA**	**WCMA**	**NEMA**
Yr over Yr DA	16.51%	16.57%	17.65%	16.42%	16.14%	16.22%	16.49%	16.71%	17.27%
Yr over Yr RT	11.98%	12.71%	13.43%	12.53%	11.78%	11.64%	11.68%	12.23%	12.58%

Hourly DA LMPs, July 1-24, 2024



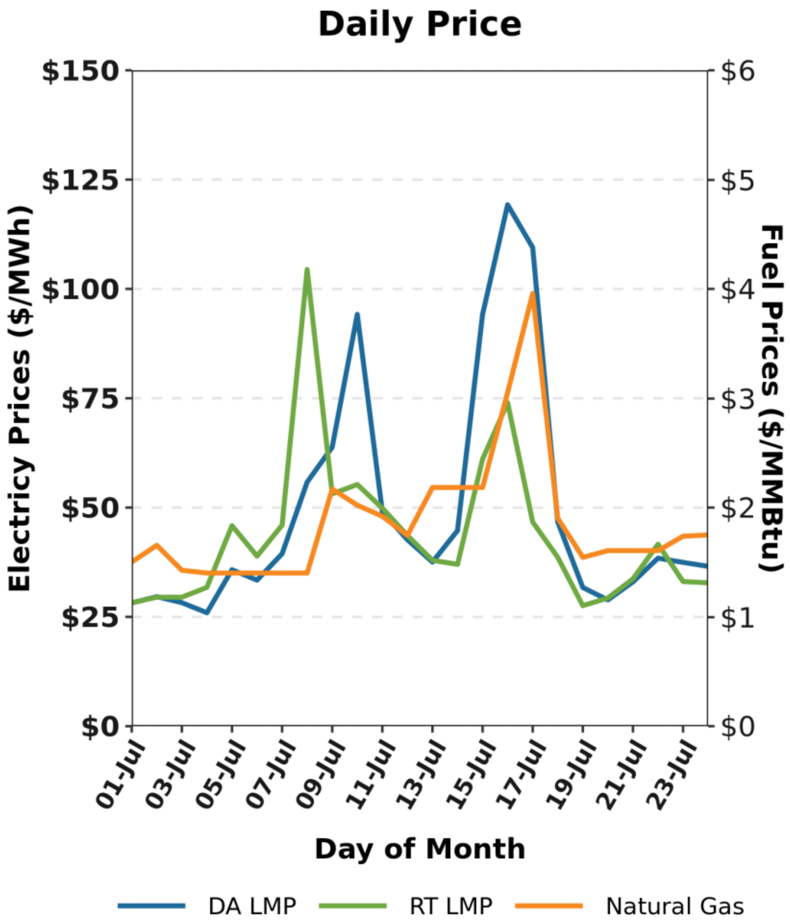
Hourly RT LMPs, July 1-24, 2024

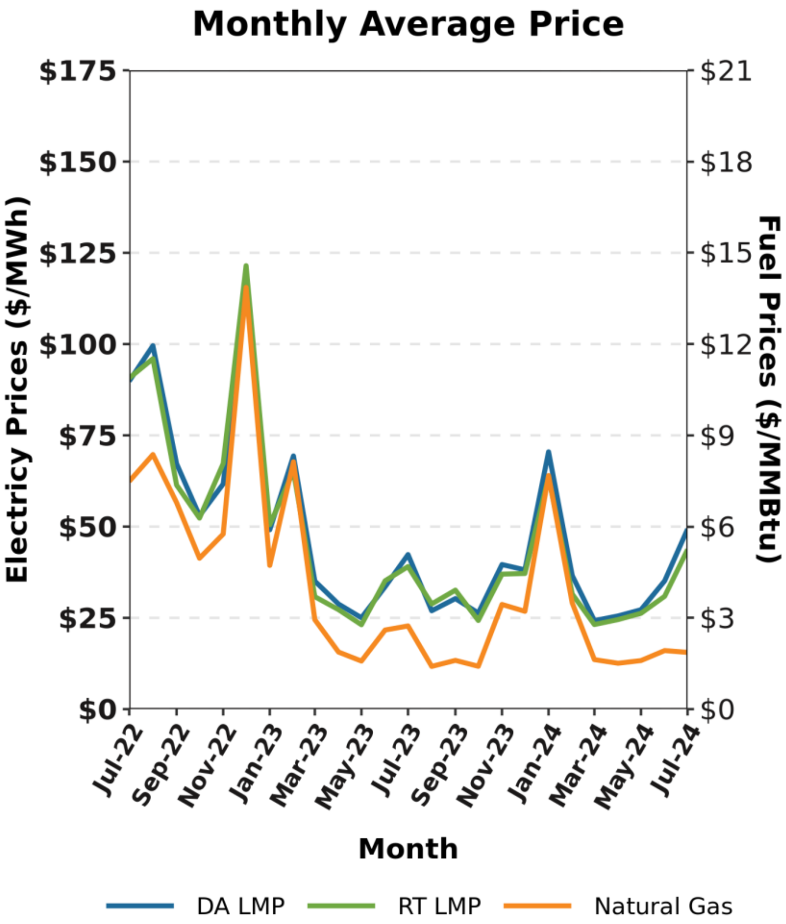


Hot and humid weather and high loads; July 8, 9, 15

M/LCC 2 Implementations:
-July 9th (7 p.m.-10 p.m.)
-July 15th (2 p.m.-10 p.m.)

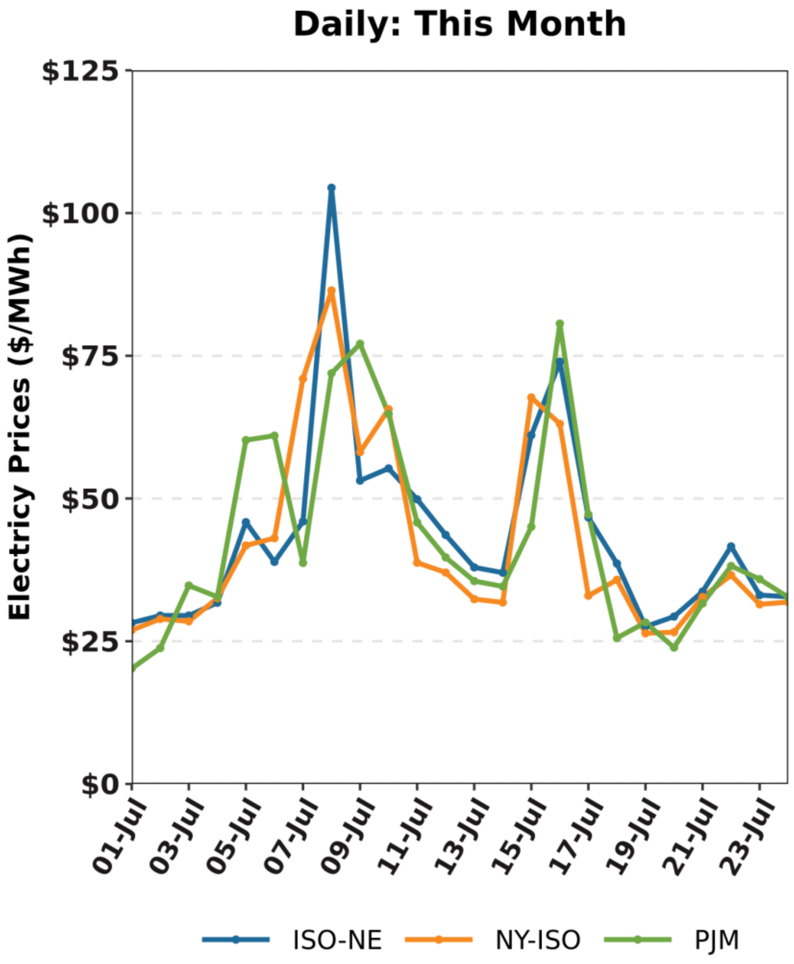
Wholesale Electricity vs Natural Gas Prices by Month

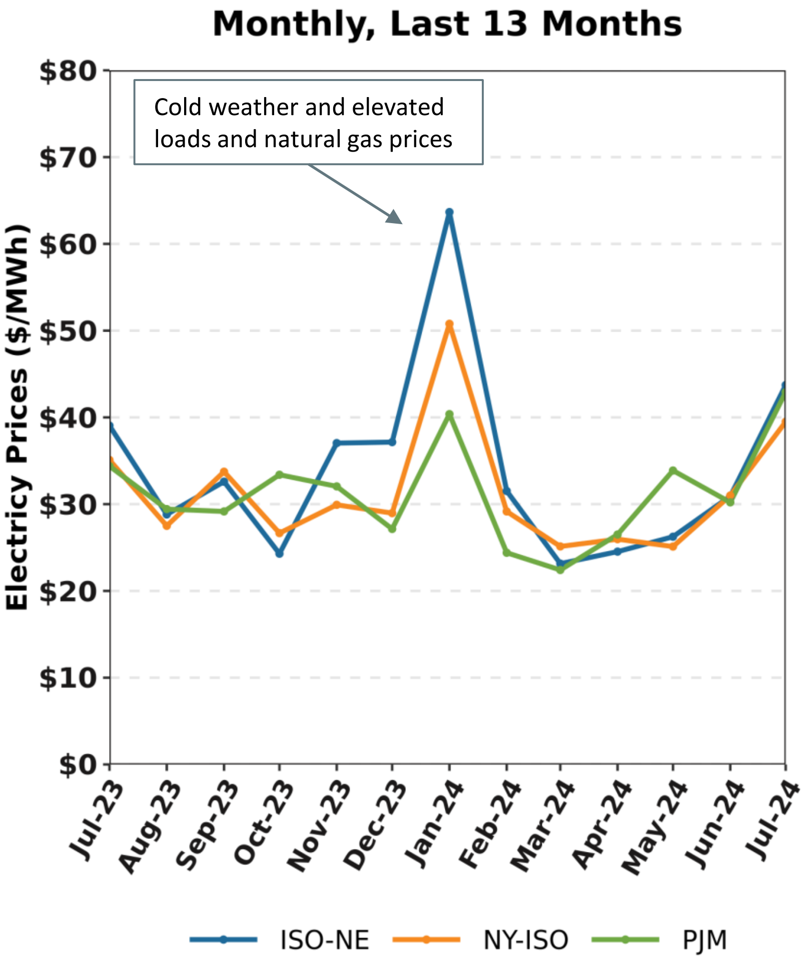




Gas price is average of Massachusetts delivery points

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

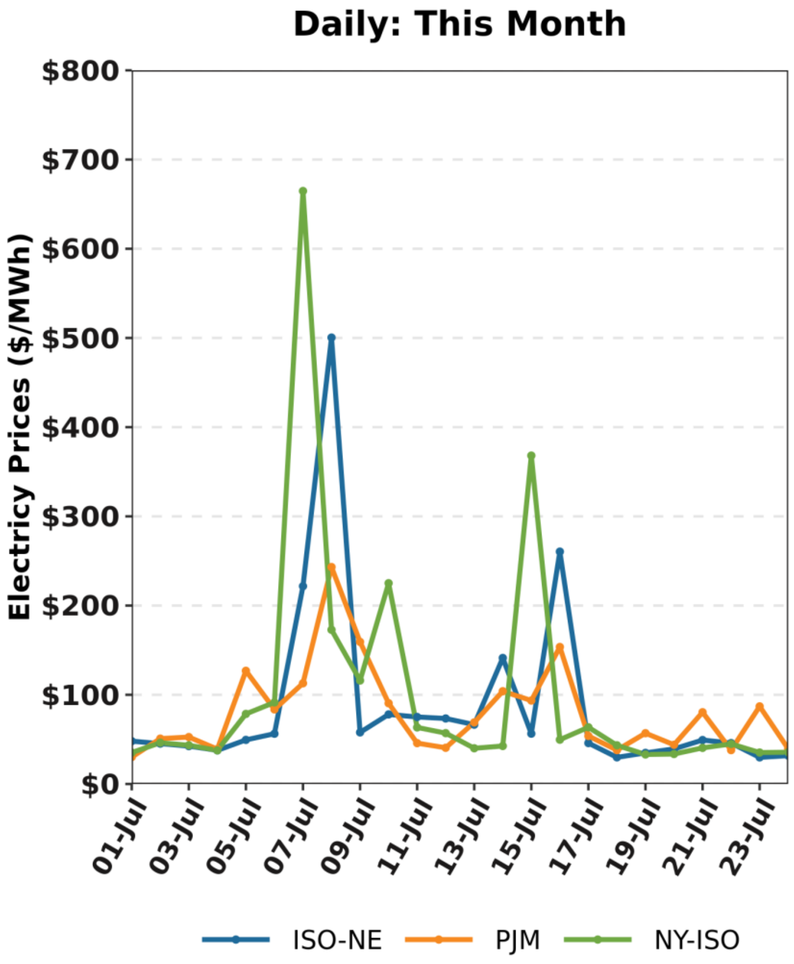


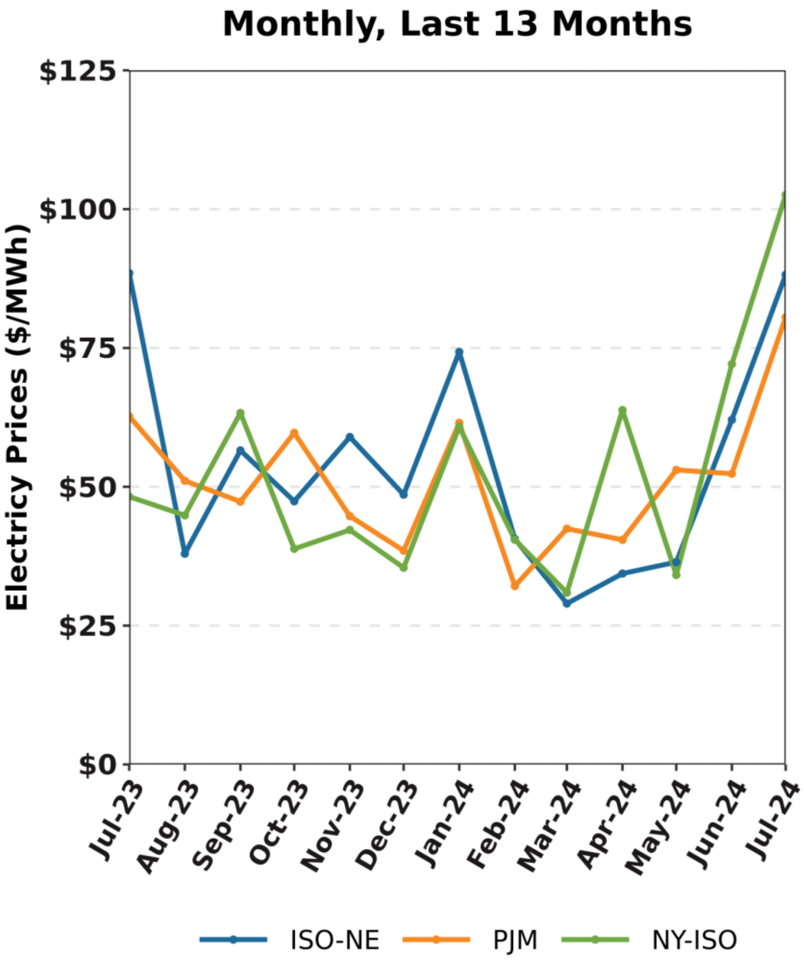


Cold weather and elevated loads and natural gas prices

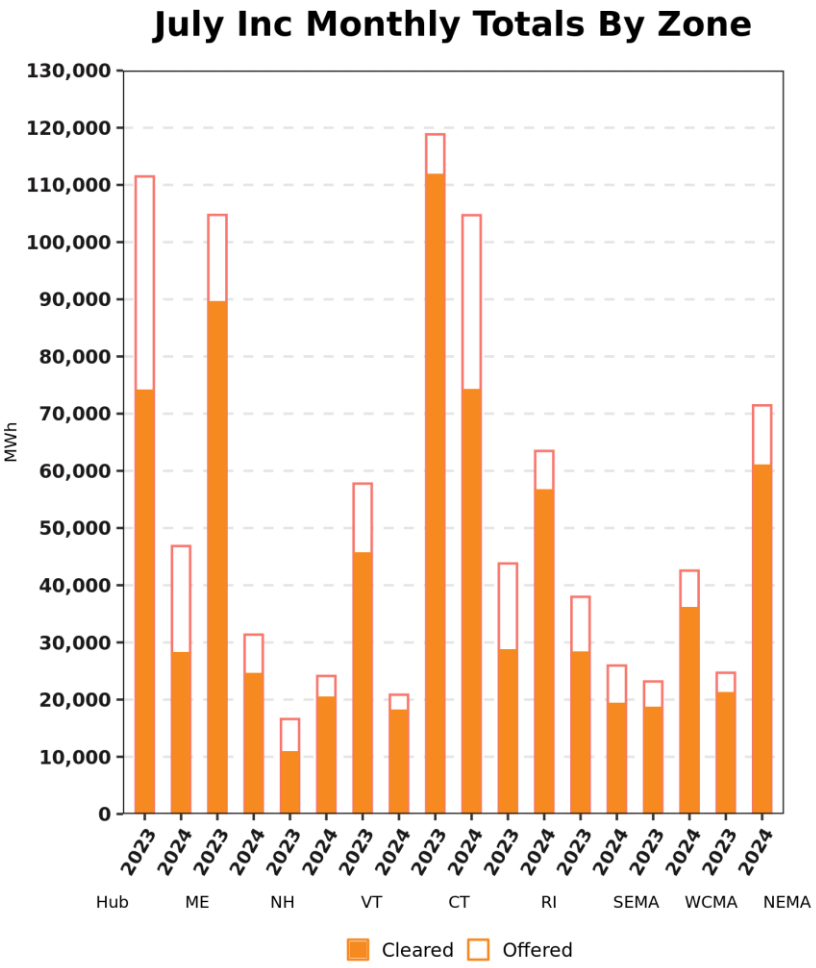
Hourly average prices are shown

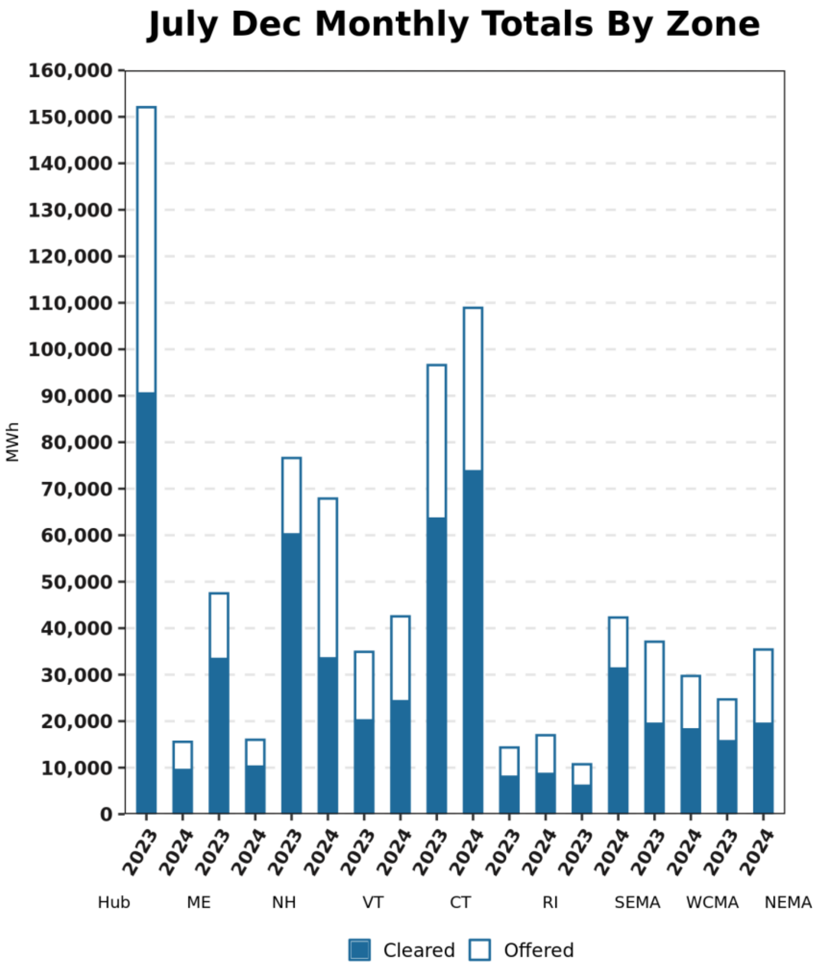
New England, NY, and PJM Average Forecasted Peak Hour RT Prices





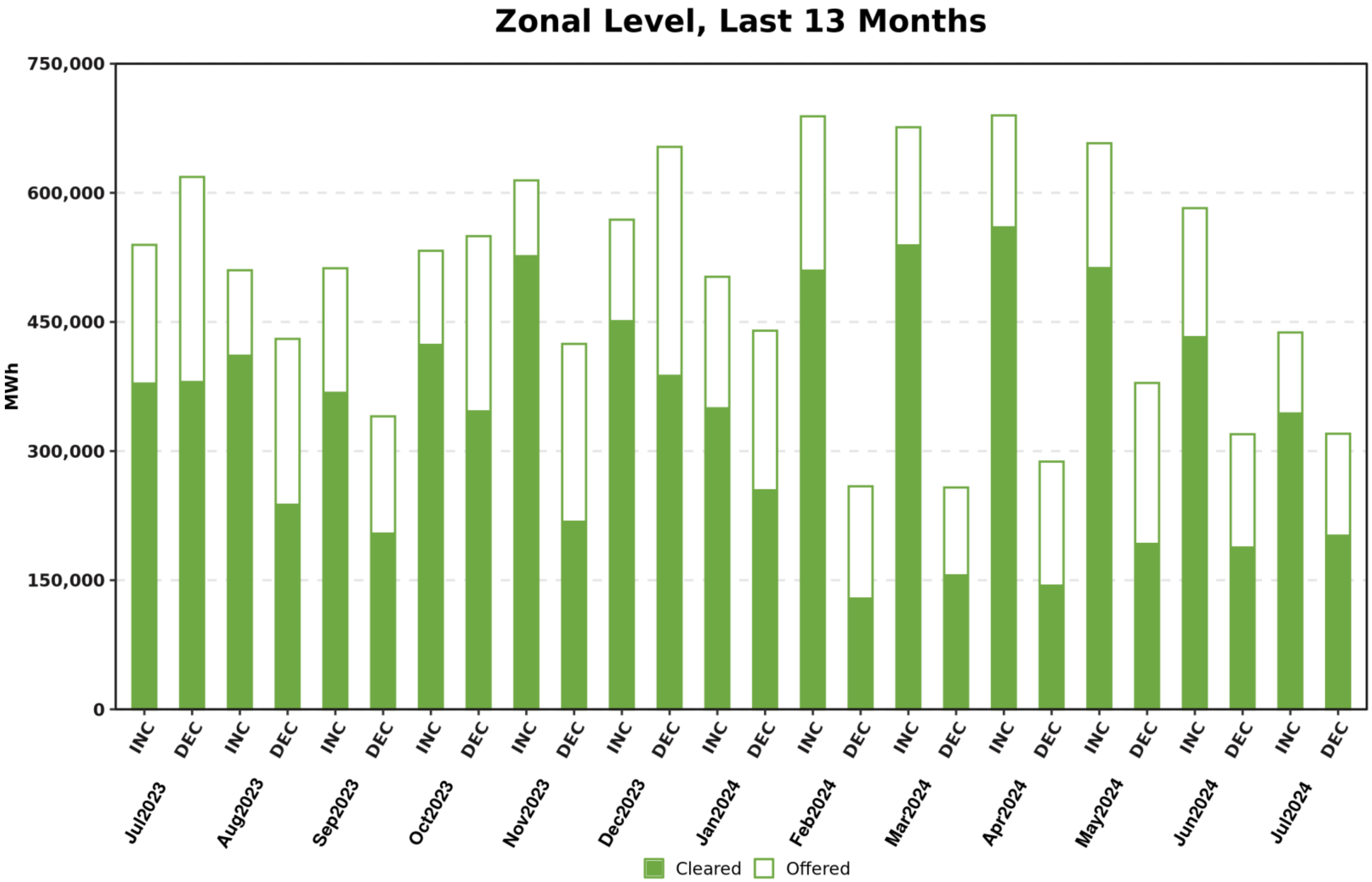
Zonal Increment Offers and Decrement Bid Amounts





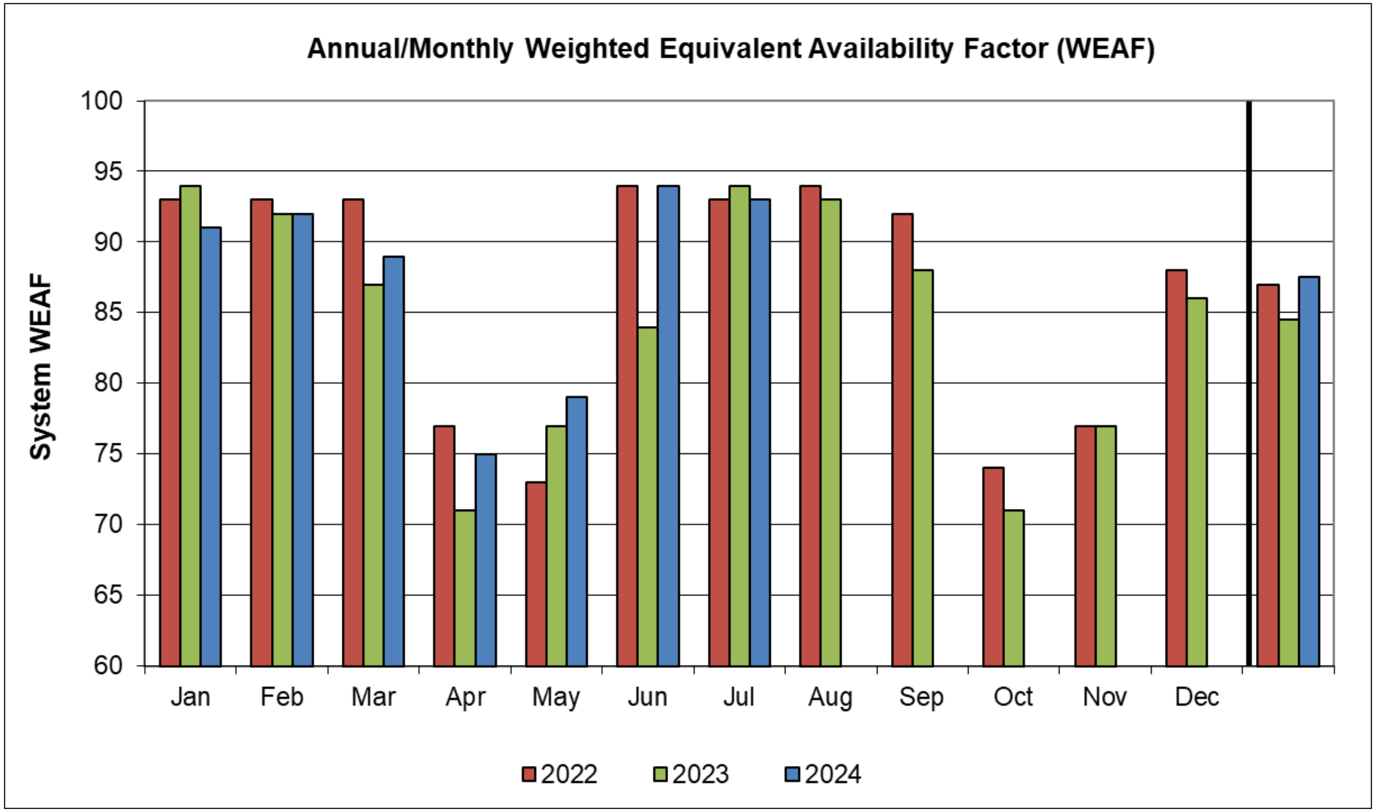
Includes nodal activity within the zone; excludes external nodes

Total Increment Offers and Decrement Bids



Includes nodal activity within the zone; excludes external nodes

System Unit Availability



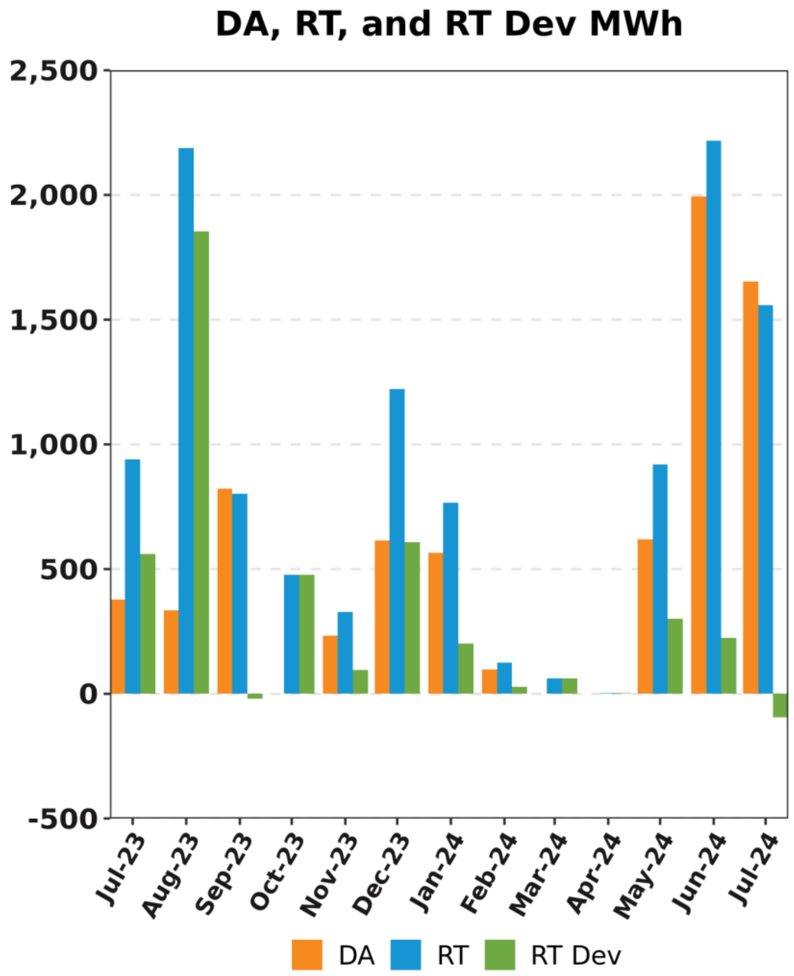
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2024	91	92	89	75	79	94	93						88
2023	94	92	87	71	77	84	94	93	88	71	77	86	85
2022	93	93	93	77	73	94	93	94	92	74	77	88	87

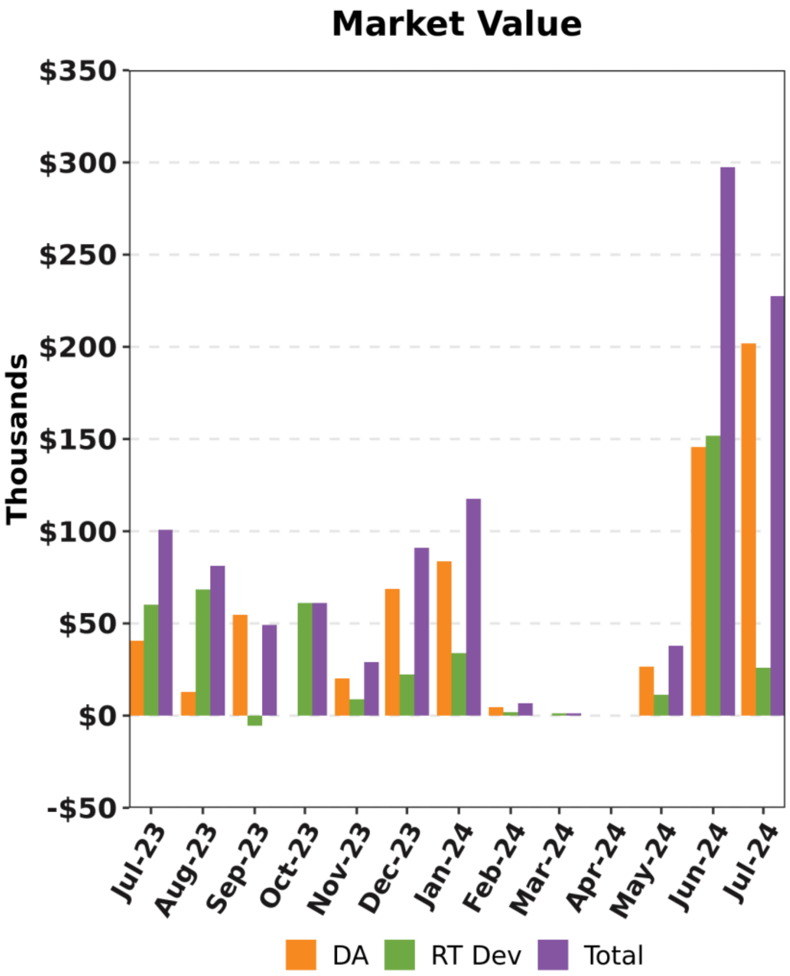
Data as of 7/23/24

BACK-UP DETAIL

DEMAND RESPONSE

Price Responsive Demand (PRD) Energy Market Activity by Month





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

NEW GENERATION

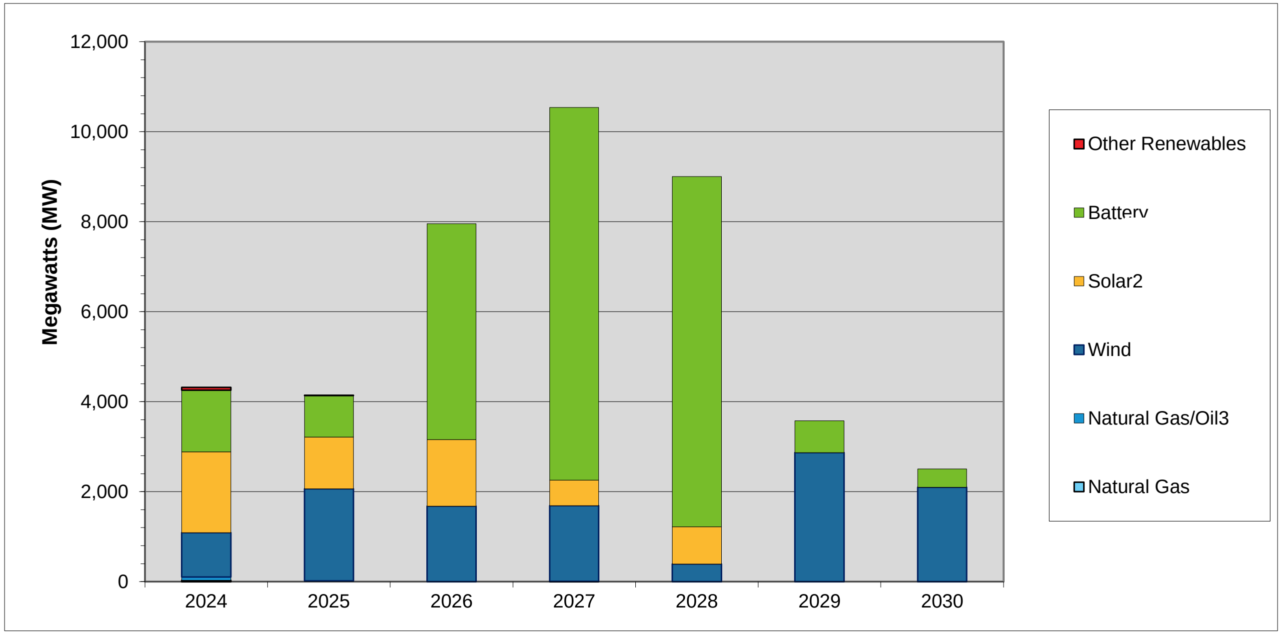
New Generation Update

Based on Queue as of 07/29/24

- 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
- In total, 446 generation projects are currently being tracked by the ISO, totaling approximately 50,498 MW

Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



	2024	2025	2026	2027	2028	2029	2030	Total MW	% of Total[1]
Other Renewables	58	2	0	0	0	0	0	60	0.1
Battery	1,376	925	4,798	8,282	7,784	704	404	24,273	57.8
Solar[2]	1,792	1,146	1,477	565	823	0	0	5,803	13.8
Wind	989	2,049	1,679	1,687	394	2,870	2,100	11,768	28.0
Natural Gas/Oil[3]	73	16	0	0	0	0	0	89	0.2
Natural Gas	26	0	0	4	0	0	0	30	0.1
Totals	4,314	4,138	7,954	10,538	9,001	3,574	2,504	42,023	100.0

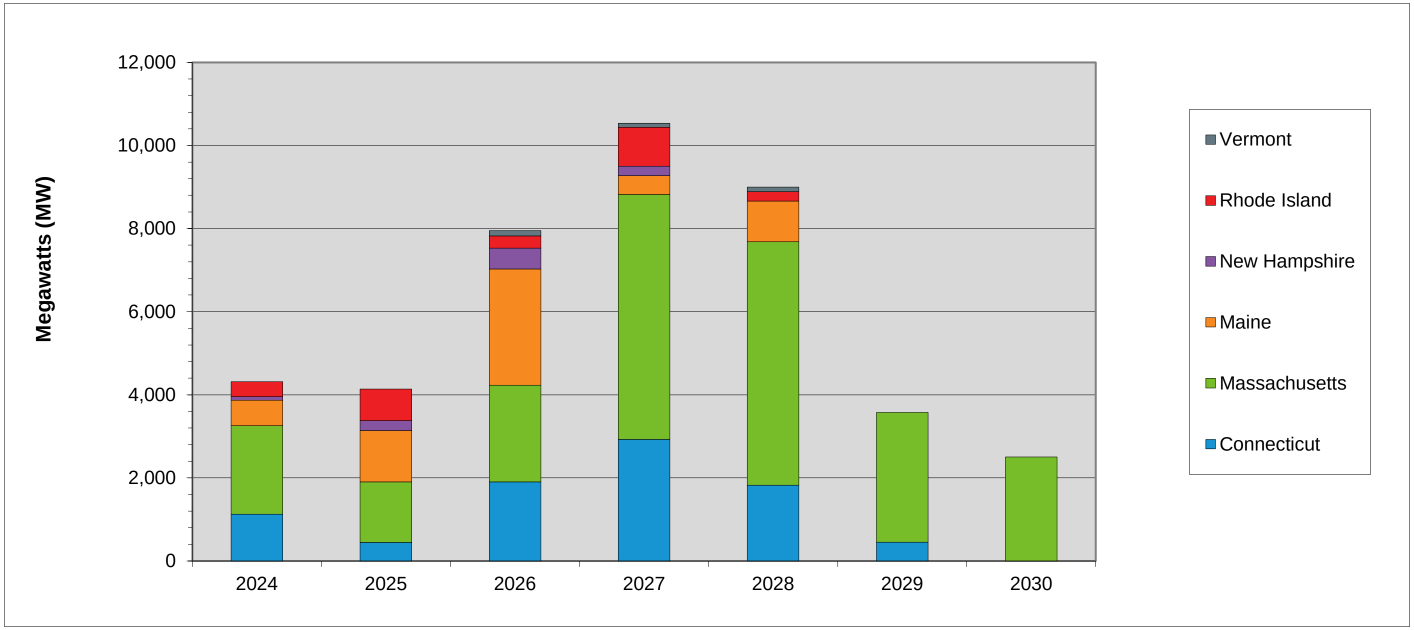
[1] Sum may not equal 100% due to rounding

[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

Projected Annual Generator Capacity Additions

By State



	2024	2025	2026	2027	2028	2029	2030	Total MW	% of Total[1]
Vermont	0	0	128	101	115	0	0	344	0.8
Rhode Island	360	758	295	938	221	0	0	2,572	6.1
New Hampshire	88	239	504	226	0	0	0	1,057	2.5
Maine	607	1,236	2,799	453	984	0	0	6,079	14.5
Massachusetts	2,134	1,461	2,323	5,893	5,860	3,120	2,504	23,295	55.4
Connecticut	1,125	444	1,905	2,927	1,821	454	0	8,676	20.6
Totals	**4,314**	**4,138**	**7,954**	**10,538**	**9,001**	**3,574**	**2,504**	**42,023**	**100.0**

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

New Generation Projection

By Fuel Type

	Total		Green		Yellow	
Unit Type	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**
Biomass/Wood Waste	0	0	0	0	0	0
Battery Storage	156	24,273	2	325	154	23,948
Fuel Cell	3	32	1	20	2	12
Hydro	1	28	1	28	0	0
Natural Gas	4	30	0	0	4	30
Natural Gas/Oil	2	89	0	0	2	89
Nuclear	0	0	0	0	0	0
Solar	250	5,803	14	310	236	5,493
Wind	30	20,243	3	985	27	19,258
Total	446	50,498	21	1,668	425	48,830

- Projects in the Natural Gas/Oil category may have either gas or oil as the primary fuel
- Green denotes projects with a high probability of going into service within the next 12 months
- Yellow denotes projects with a lower probability of going into service or new applications

New Generation Projection

By Operating Type

	Total		Green		Yellow	
Operating Type	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	6	73	2	48	4	25
Intermediate	2	89	0	0	2	89
Peaker	408	30,093	16	635	392	29,458
Wind Turbine	30	20,243	3	985	27	19,258
Total	446	50,498	21	1,668	425	48,830

- 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

	Total		Baseload		Intermediate		Peaker		Wind Turbine	
Unit Type	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**
Biomass/Wood Waste	0	0	0	0	0	0	0	0	0	0
Battery Storage	156	24,273	0	0	0	0	156	24,273	0	0
Fuel Cell	3	32	3	32	0	0	0	0	0	0
Hydro	1	28	1	28	0	0	0	0	0	0
Natural Gas	4	30	2	13	0	0	2	17	0	0
Natural Gas/Oil	2	89	0	0	2	89	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0
Solar	250	5,803	0	0	0	0	250	5,803	0	0
Wind	30	20,243	0	0	0	0	0	0	30	20,243
Total	446	50,498	6	73	2	89	408	30,093	30	20,243

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 14

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	592.043	688.07	96.027	659.671	-28.399	564.371	-95.3
	Passive Demand	3,327.071	3,327.932	0.861	3,315.207	-12.725	3,253.179	-62.028
Demand Total		**3,919.114**	**4,016.002**	**96.888**	**3,974.878**	**-41.124**	**3,817.550**	**-157.328**
Generator	*Non-Intermittent*	27,816.902	28,275.143	458.241	27,697.714	-577.429	27,684.252	-13.462
	Intermittent	1,160.916	1,128.446	-32.47	925.942	-202.504	893.444	-32.498
Generator Total		**28,977.818**	**29,403.589**	**425.771**	**28,623.656**	**-779.933**	**28,577.696**	**-45.96**
Import Total		**1,058.72**	**1,058.72**	**0**	**1,029.800**	**-28.92**	**958.380**	**-71.42**
Grand Total*		**33,955.652**	**34,478.311**	**522.661**	**33,628.334**	**-849.977**	**33,353.626**	**-274.708**
Net ICR (NICR)		**32,490**	**32,980**	**490**	**31,480**	**-1,500**	**31,690**	**210**

* 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 2023-2027 CCP Month Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 15

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	677.673	673.401	-4.272	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 2023-2027 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				
	Passive Demand	2,557.256	2,579.120	21.864				
Demand Total		**3,322.606**	**3,169.002**	**-153.604**				
Generator	*Non-Intermittent*	26,805.003	26,643.379	-161.624				
	Intermittent	1,178.933	1,146.783	-32.15				
Generator Total		**27,983.936**	**27,790.162**	**-193.774**				
Import Total		**1,503.842**	**1,247.601**	**-256.241**				
Grand Total*		**32,810.384**	**32,206.765**	**-603.619**				
Net ICR (NICR)		**31,645**	**30,585**	**-1,060**				

* 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 2023-2027 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				
	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				
	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 2023-2027 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						
	Passive Demand	2,070.498						
Demand Total		**2,614.078**						
Generator	*Non-Intermittent*	27,026.635						
	Intermittent	1,450.872						
Generator Total		**28,477.507**						
Import Total		**464.835**						
Grand Total*		**31,556.420**						
Net ICR (NICR)		**30,550**						

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

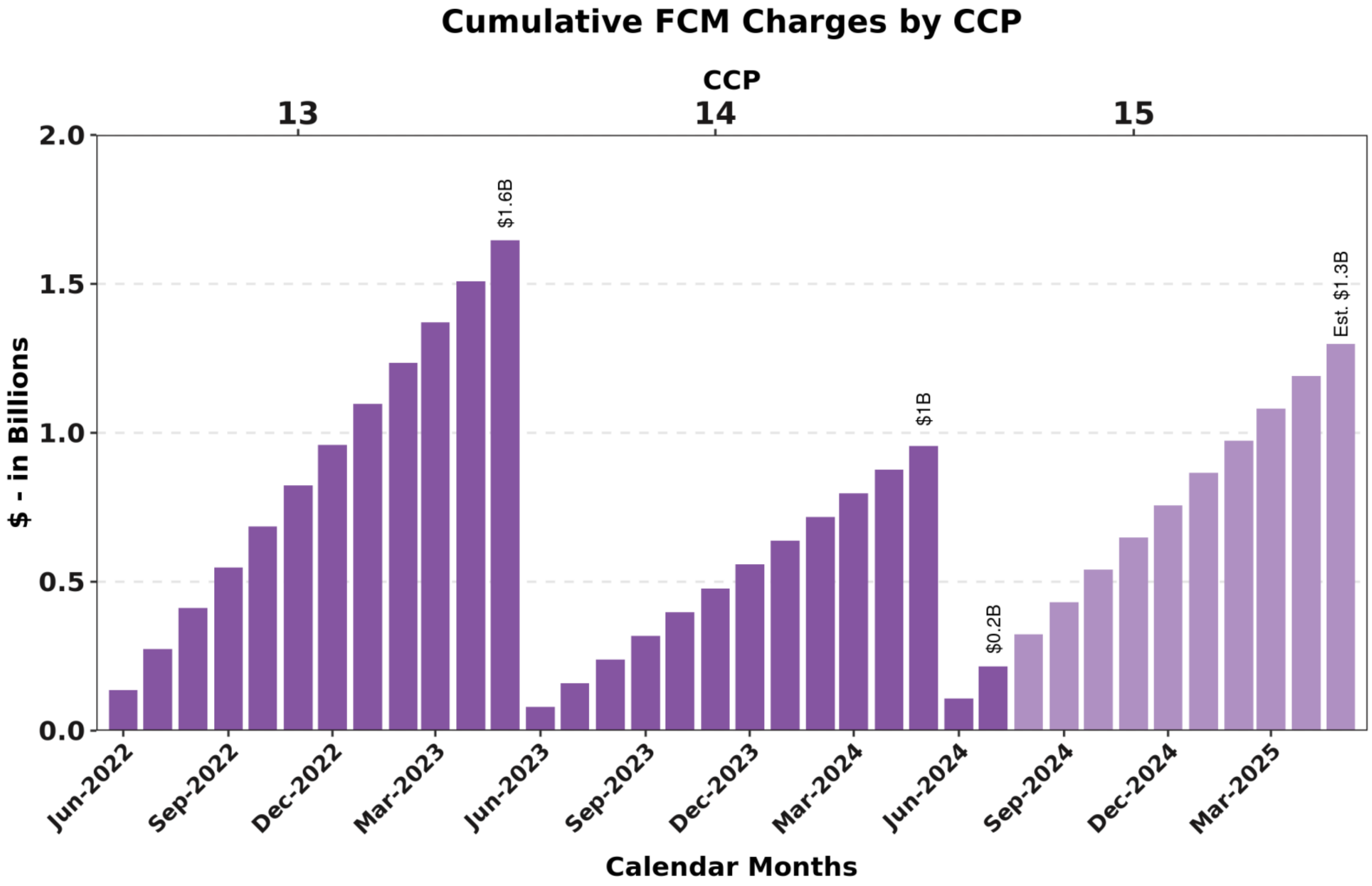
Note: A resource’s CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2023-2027 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**

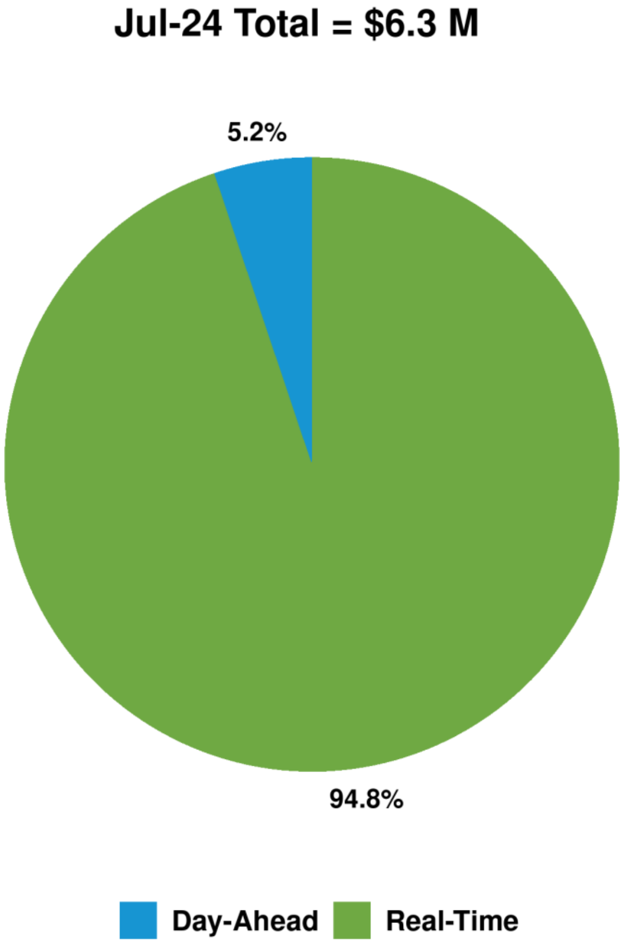
Forward Capacity Market Auctions

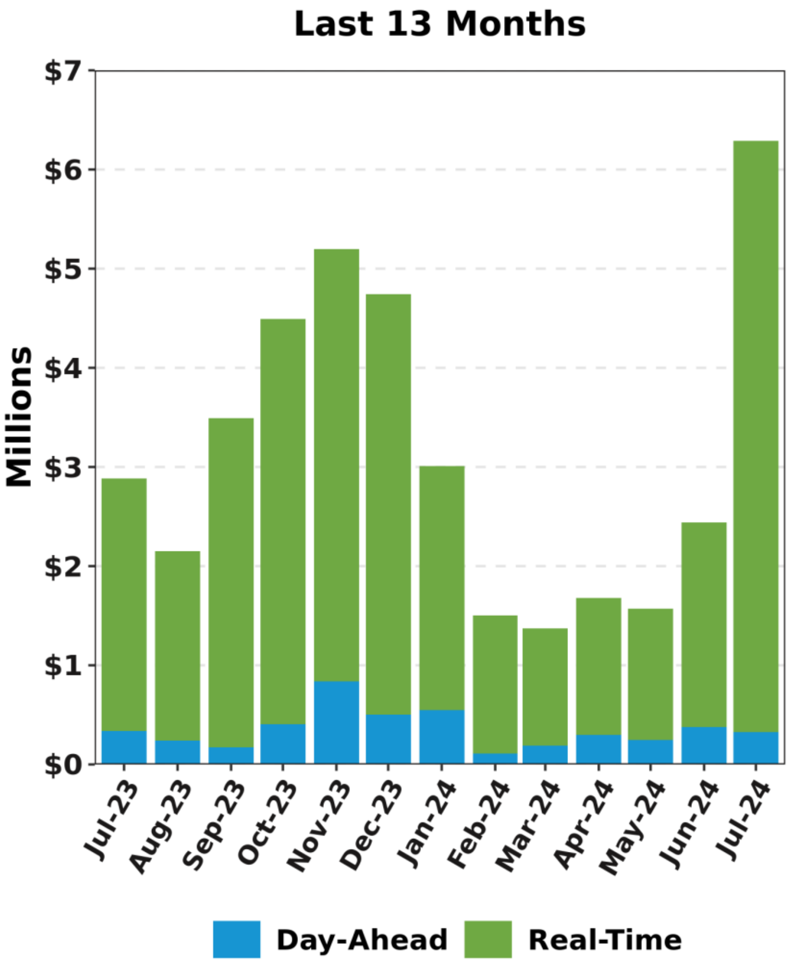


The items in the graph shaded in a lighter color represent the forecast for future months in the Capacity Commitment Period (CCP)

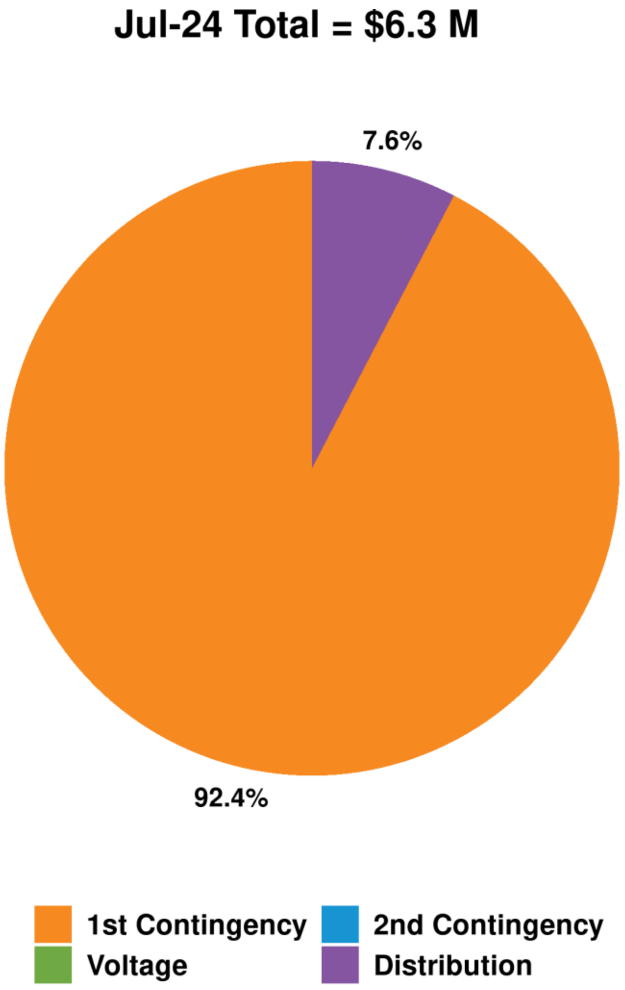
NET COMMITMENT PERIOD COMPENSATION

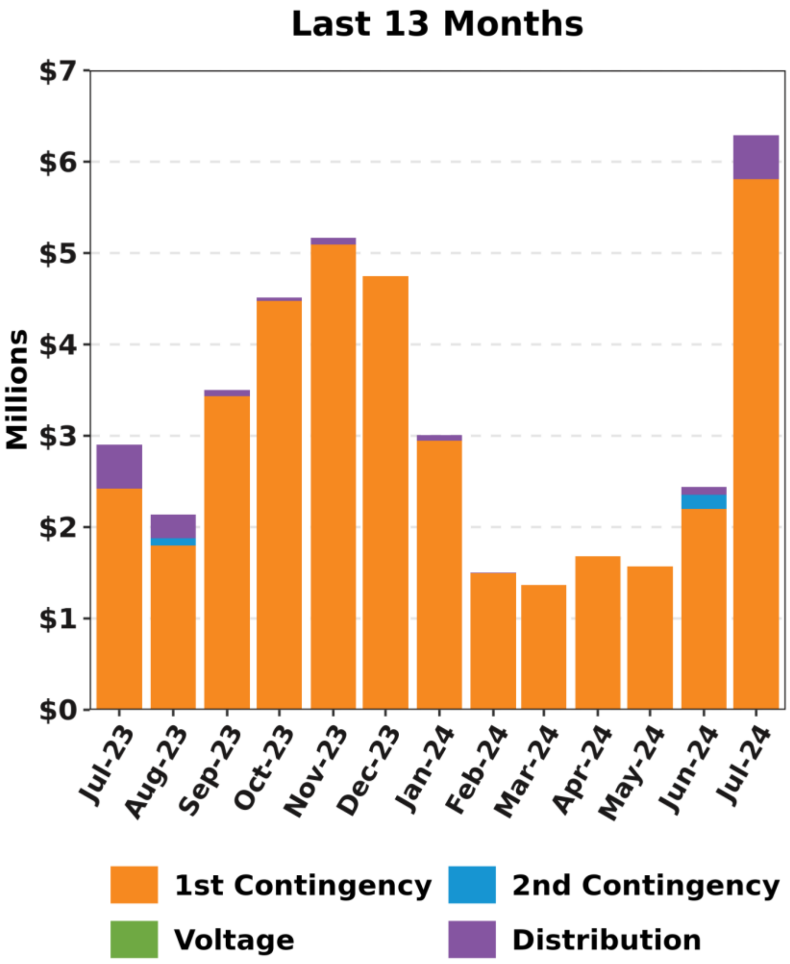
DA and RT NCPC Charges



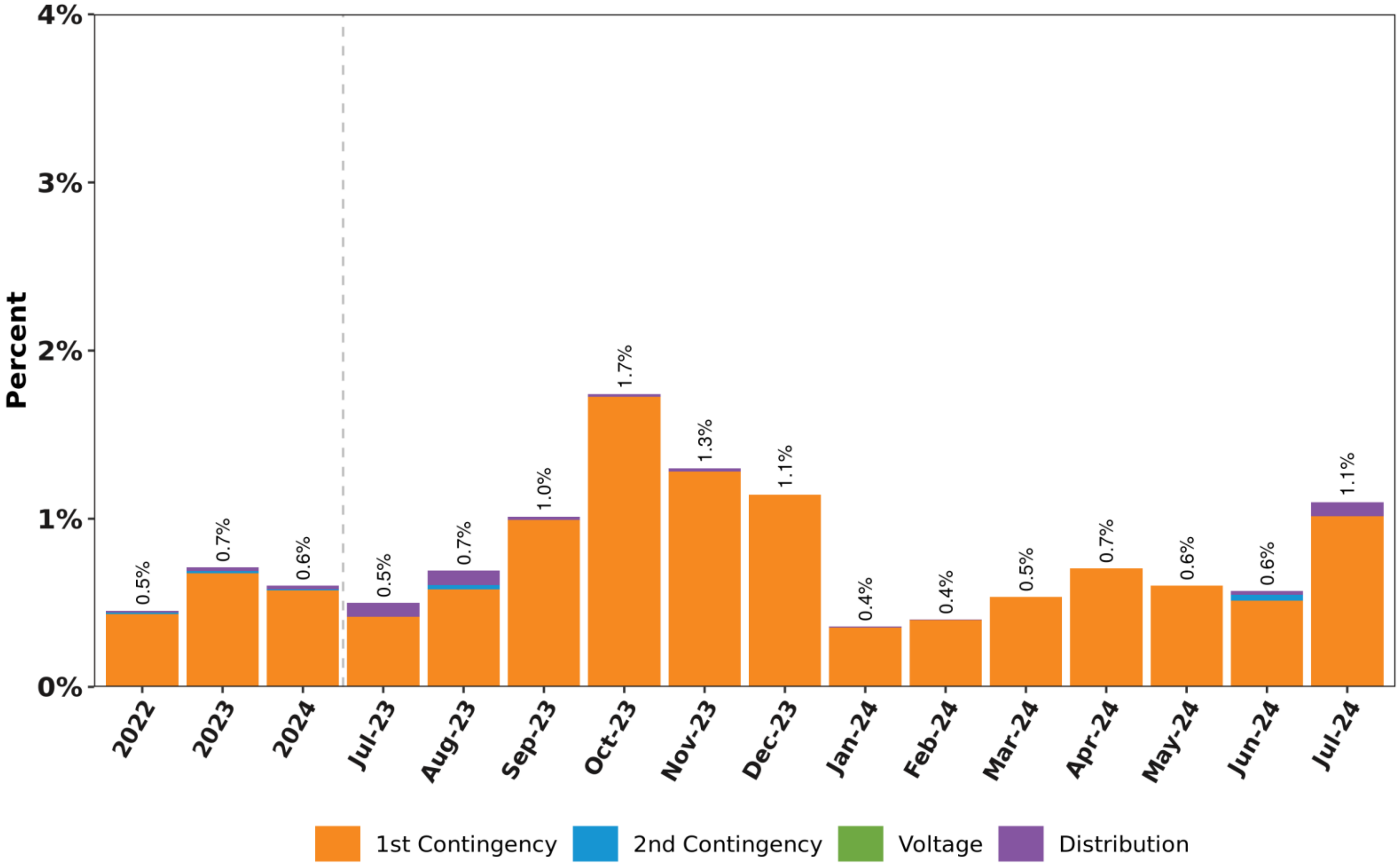


NCPC Charges by Type

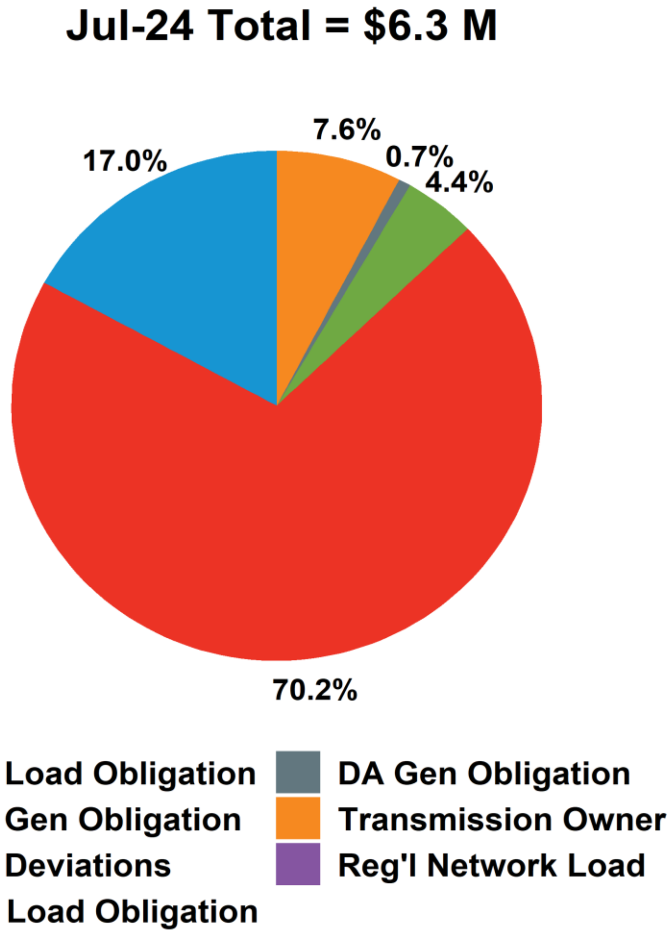


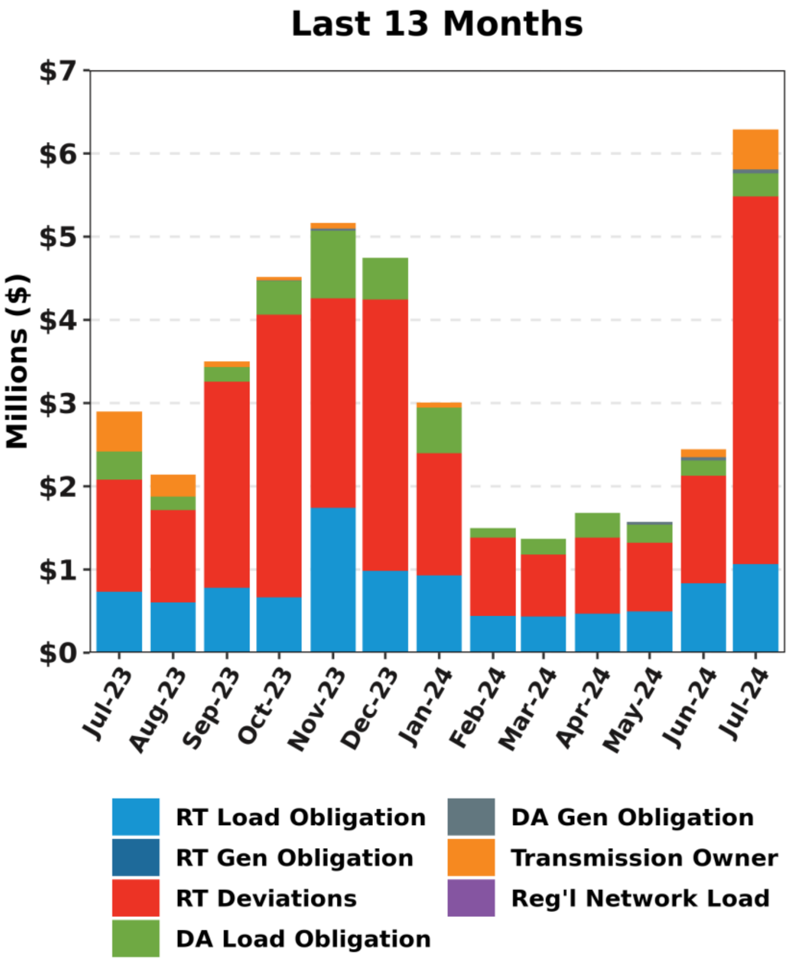


NCPC Charges by Type as Percent of Energy Market Value

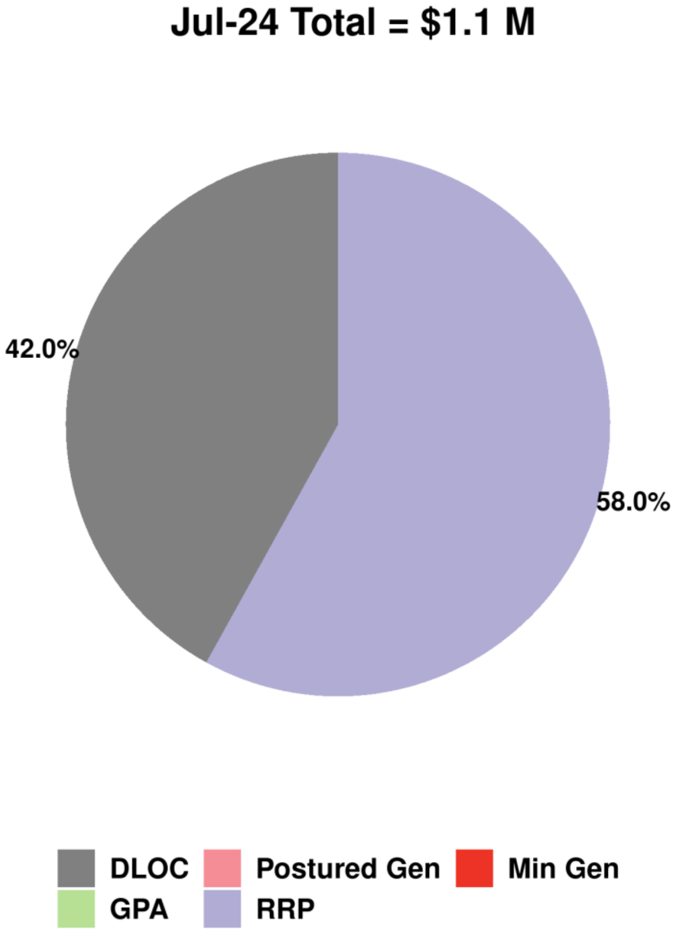


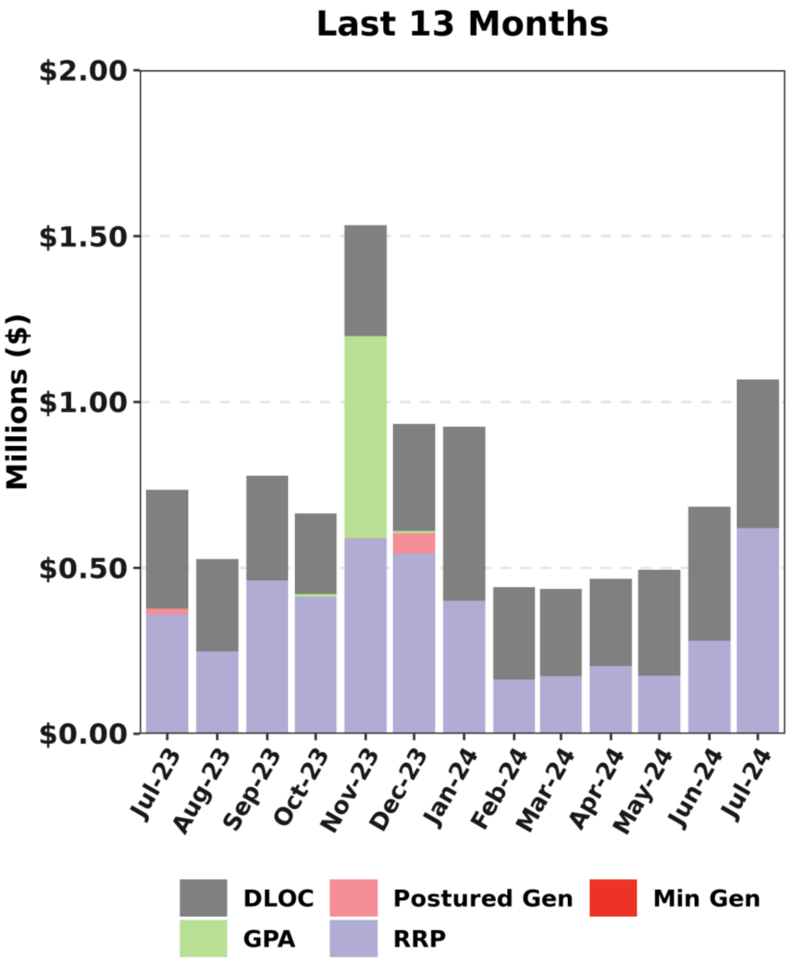
NCPC Charge Allocations





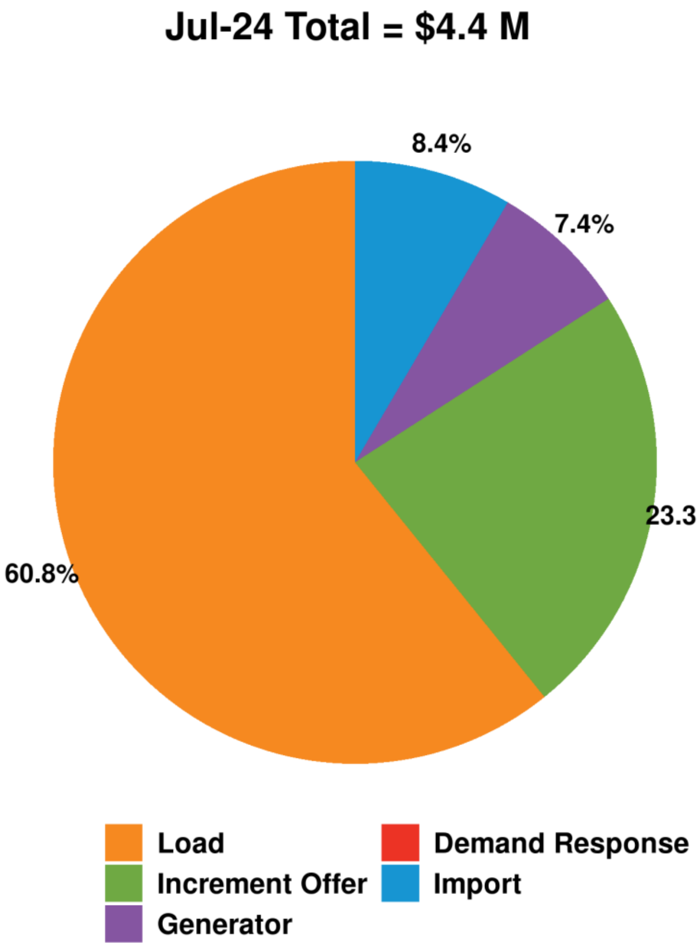
RT First Contingency NCPC Paid to Units and Allocated to RTLO and/or RTGO

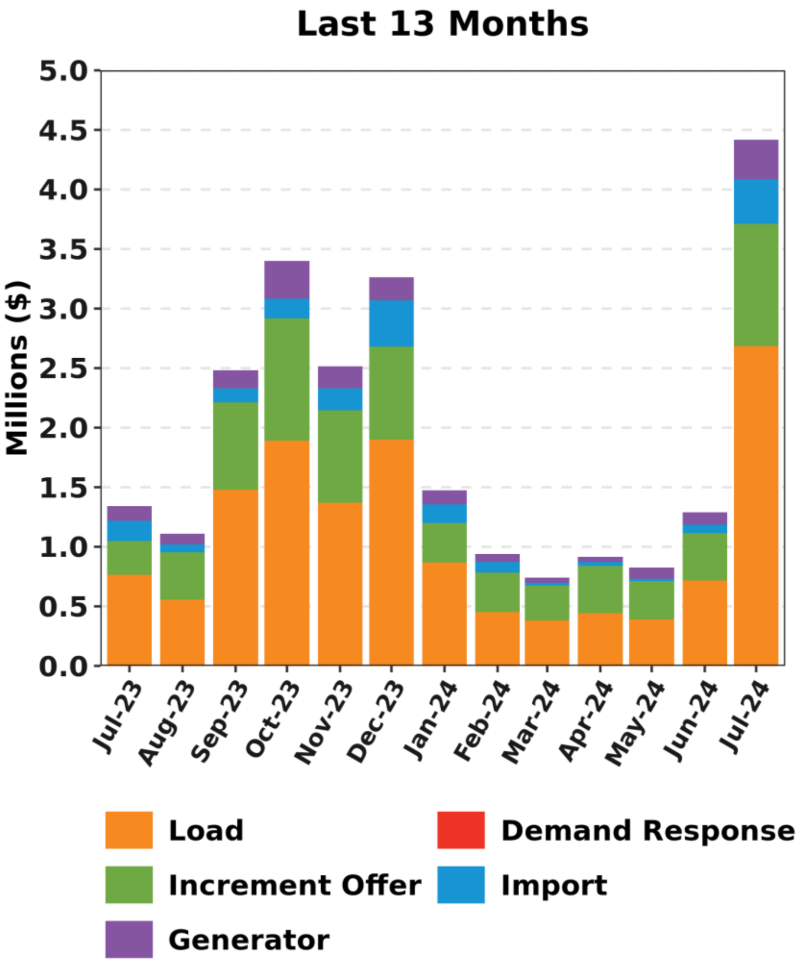




The categories shown above are a subset of those reflected in First Contingency NCPC throughout this report. The above categories are allocated to RTLO, except for Min Gen Emergency credits, which are allocated to RTGO.

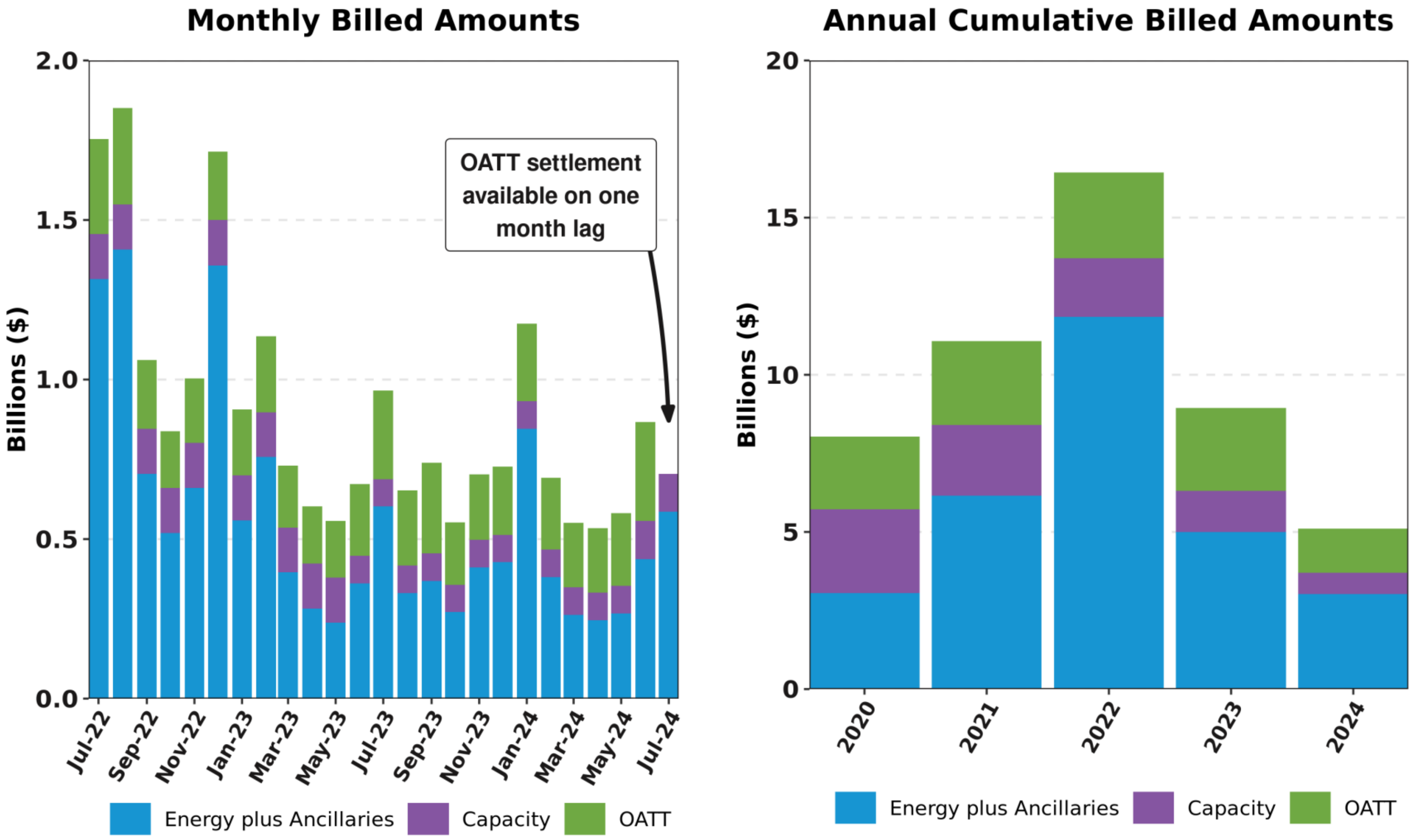
RT First Contingency Charges by Deviation Type





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)

- August 21 PAC Meeting Agenda Topics*
  - Asset Condition Projects
    - Railroad Corridor Transmission Line Asset Condition Assessment Update (Avangrid)
    - 313/343 Asset Condition Refurbishment Project (National Grid)
    - Brayton Point Substation Asset Replacements (National Grid)
  - NETO Presentations
    - NETO Responses to Stakeholder Feedback on Asset Condition Process Guide
    - RNS Rate and Asset Condition Projects Update
  - EPCET Draft Report Issuance, Final Slides, and Public Case
  - 2024 Economic Study: Benchmark Scenario & Policy Scenario Assumptions
  - 2050 Transmission Study: Results from Additional Analysis on Offshore Wind POI Screening

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

2050 Transmission Study

- Final version of the study, technical appendix, responses to stakeholder feedback, and study fact sheet were published on 2/14/24
- Additional analysis to address stakeholder comments on offshore wind points of interconnection was presented to PAC on 3/20/24, and will continue through Q2 and Q3 2024
- Results of additional analysis on offshore wind relocation were presented at the 4/18/24 PAC meeting
- The ISO expects to discuss the results of the offshore wind point of interconnection screening and constraint identification analysis at the 8/21/24 PAC meeting

Economic Studies: EPCET

- Economic Planning for the Clean Energy Transition (EPCET) Pilot Study
  - An effort to review all assumptions in economic planning and perform a test study consistent with the changes to the Tariff
  - PAC presentations for the study are complete except for a final presentation that will accompany the issuing of the draft report
  - The draft report will be issued in August 2024

Economic Studies: 2024 Study

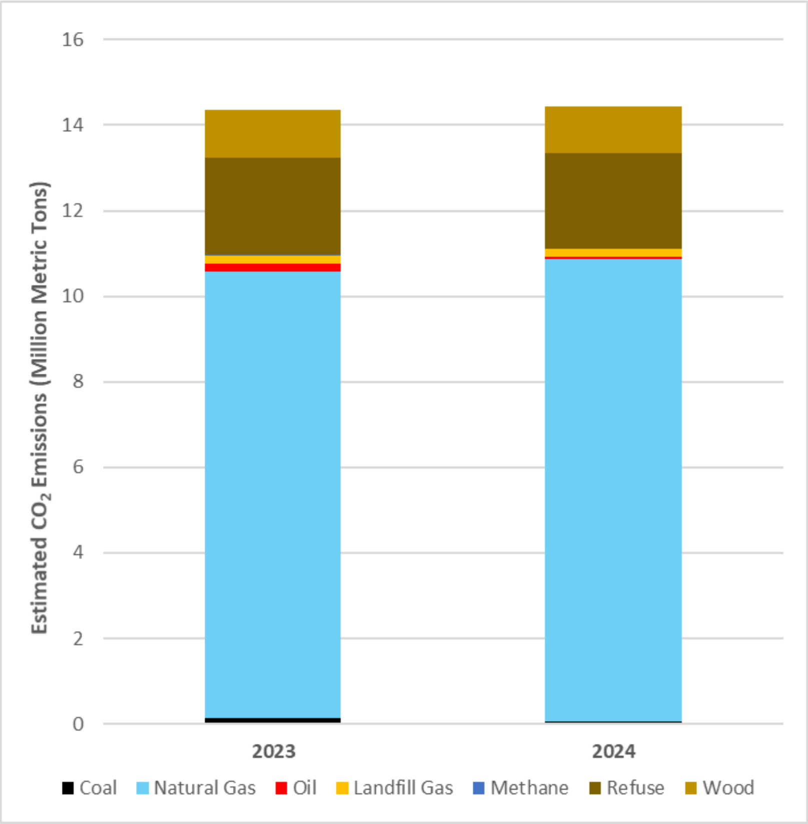
- The 2024 Economic Study
  - This study is the first use of new Economic Study Process Tariff language that was recently updated
    - The study was initiated at the January PAC meeting
  - The sequence is scenarios for the study begin with the Benchmark Scenario in Q1-Q3 2024, followed by the Policy Scenario and the Stakeholder-Requested Scenario in Q3 2024-Q1 2025
    - The stakeholder-Requested Scenario was discussed at the June PAC meeting. It focuses on the use of peaker plants in various future power system resource mixes
  - The Market Efficiency Needs Scenario will be studied in 2025

ISO-NE Tie Benefits Evaluation

- The ISO started the tie benefits evaluation at the October 19, 2023 PSPC meeting and held two additional PSPC meetings on January 25, 2024 and March 15, 2024 to review and discuss the evaluation
- The ISO issued a memo on June 26, 2024 to the RC and PSPC to summarize the evaluation and provide additional next steps
  - Continue to reach out to neighboring Balancing Areas to further modeling improvements
  - Continue efforts to adapt the current tie benefit framework into a combined accreditation design with a seasonal/prompt capacity market

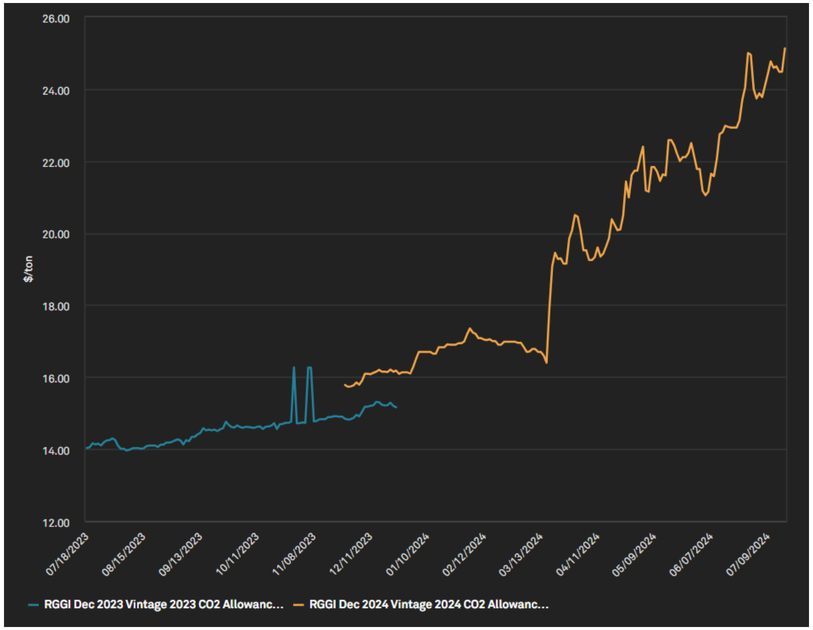
New England Power System Carbon Emissions

2023 vs. 2024 New England Power System Estimated Carbon Dioxide (CO_2) Emissions



Data as of 7/7/24

Regional Greenhouse Gas Initiative (RGGI) Allowance Prices



- 7/17/24: RGGI allowance spot price - $25.13
- The 65th RGGI auction will be on 9/4/24
    - Cost Containment Reserve (CCR) allowances were depleted in Auction 63 and will not be available in Auction 65
    - Initial Offering for Auction 65 includes 15,943,608 CO_2 allowances

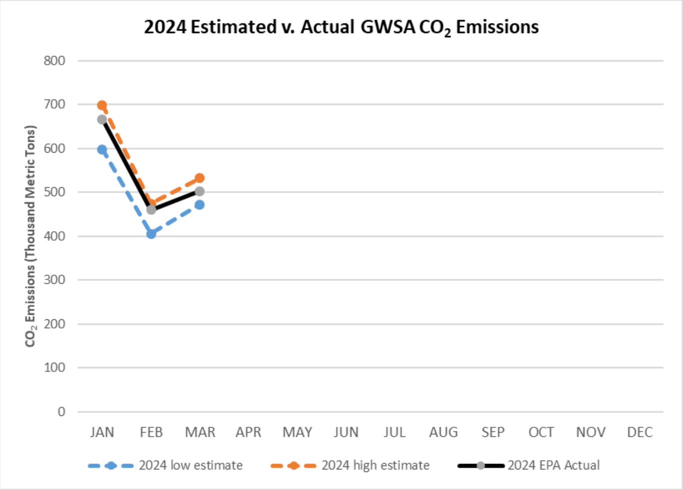
Massachusetts CO_2 Generator Emissions Cap

2024 Estimated Emissions Under CO_2 Cap

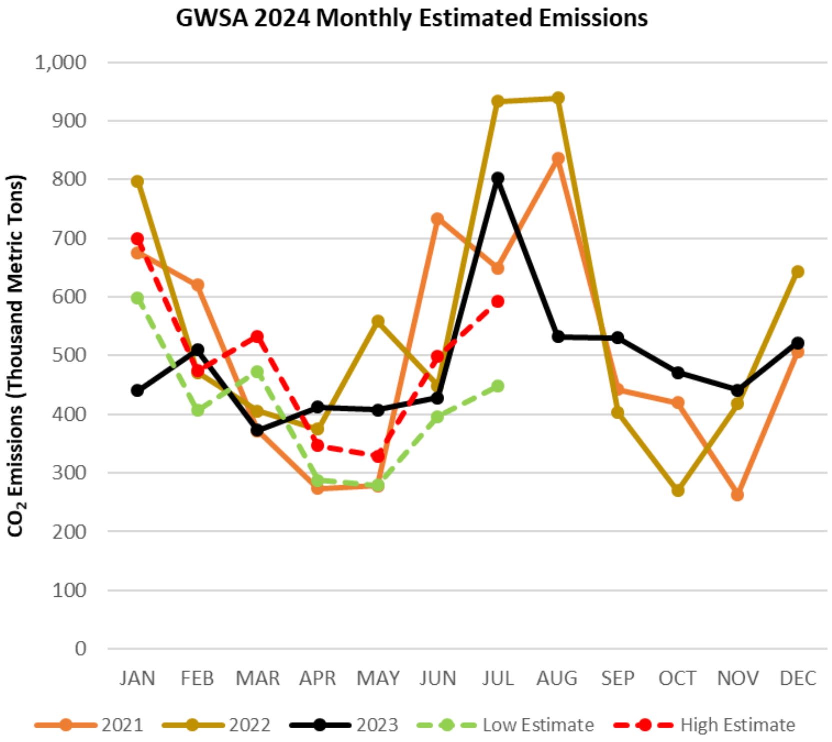
- As of 7/17/24, July estimated GWSA CO_2 emissions range between **447,595** and **591,903** metric tons
    - Year-to-date 2024 estimated emissions range between **37.9%** and **45.6%** of the 2024 cap of 7.61 MMT

2024 Q1 Actual Emissions Under CO_2 Cap

- According to the EPA CAMPD, the 1st Quarter (January-March) 2024 GWSA CO_2 emissions were **1.63 MMT**, or **21.4%** of the 2024 cap of 7.61 MMT



2021-2024 Estimated Monthly Emissions (Thousand Metric Tons)



GWSA – Global Warming Solutions Act
MMT – Million Metric Tons

Source: ISO-NE (estimated emissions)

RSP Project Stage Descriptions

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

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

Greater Boston Projects

Status as of 7/23/2024

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 7/23/2024

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1330	Separate X-24 and E-157W DCT	Dec-18	4
1363	Separate Q-169 and F-158N DCT	Dec-15	4
1637, 1640	Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap	May-17	4
1516	Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook	Sep-20	4
965	Install third 115 kV line from West Walpole to Holbrook	Sep-20	4
1558	Install new 345 kV breaker in series with the 104 breaker at Stoughton	May-16	4
1199	Install new 230/115 kV autotransformer at Sudbury and loop the 282-602 230 kV line in and out of the new 230 kV switchyard at Sudbury	Dec-17	4
1335	Install a new 115 kV line from Sudbury to Hudson	Mar-25	3

Greater Boston Projects, cont.

Status as of 7/23/2024

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 7/23/2024

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 7/23/2024

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 7/23/2024

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 7/23/2024

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-25	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 7/23/2024

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-25	2

SEMA/RI Reliability Projects, cont.

Status as of 7/23/2024

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 7/23/2024

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

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

Eastern CT Reliability Projects

Status as of 7/23/2024

Project Benefit: Addresses system needs in the Eastern Connecticut area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1815	Reconductor the L190-4 and L190-5 line sections	Dec-24	3
1850	Install a second 345/115 kV autotransformer (4X) and one 345 kV breaker at Card substation	Dec-22	4
1851	Upgrade Card 115 kV to BPS standards	Dec-22	4
1852	Install one 115 kV circuit breaker in series with Card substation 4T	Feb-23	4
1853	Convert Gales Ferry substation from 69 kV to 115 kV	Nov-23	4
1854	Rebuild the 100 Line from Montville to Gales Ferry to allow operation at 115 kV	Jun-23	4

Eastern CT Reliability Projects, cont.

Status as of 7/23/2024

Project Benefit: Addresses system needs in the Eastern Connecticut area

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

Eastern CT Reliability Projects, cont.

Status as of 7/23/2024

Project Benefit: Addresses system needs in the Eastern Connecticut area

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

New Hampshire Solution Projects

Status as of 7/23/2024

Project Benefit: Addresses system needs in the New Hampshire area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1878	Install a +55/-32.2 MVAR synchronous condenser at N. Keene 115 kV Substation with a 115 kV breaker	Jun-25	3
1879	Install a +55/-32.2 MVAR synchronous condenser at Huckins Hill 115 kV Substation with a 115 kV breaker	Dec-24	3
1880	Install a +127/-50 MVAR synchronous condenser at Amherst 345 kV Substation with two 345 kV breakers	Sep-24	3
1881	Install two 50 MVAR capacitors on Line 363 near Seabrook Station with three 345 kV breakers	Oct-23	4

Upper Maine Solution Projects

Status as of 7/23/2024

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	3
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-24	3

Upper Maine Solution Projects, cont.

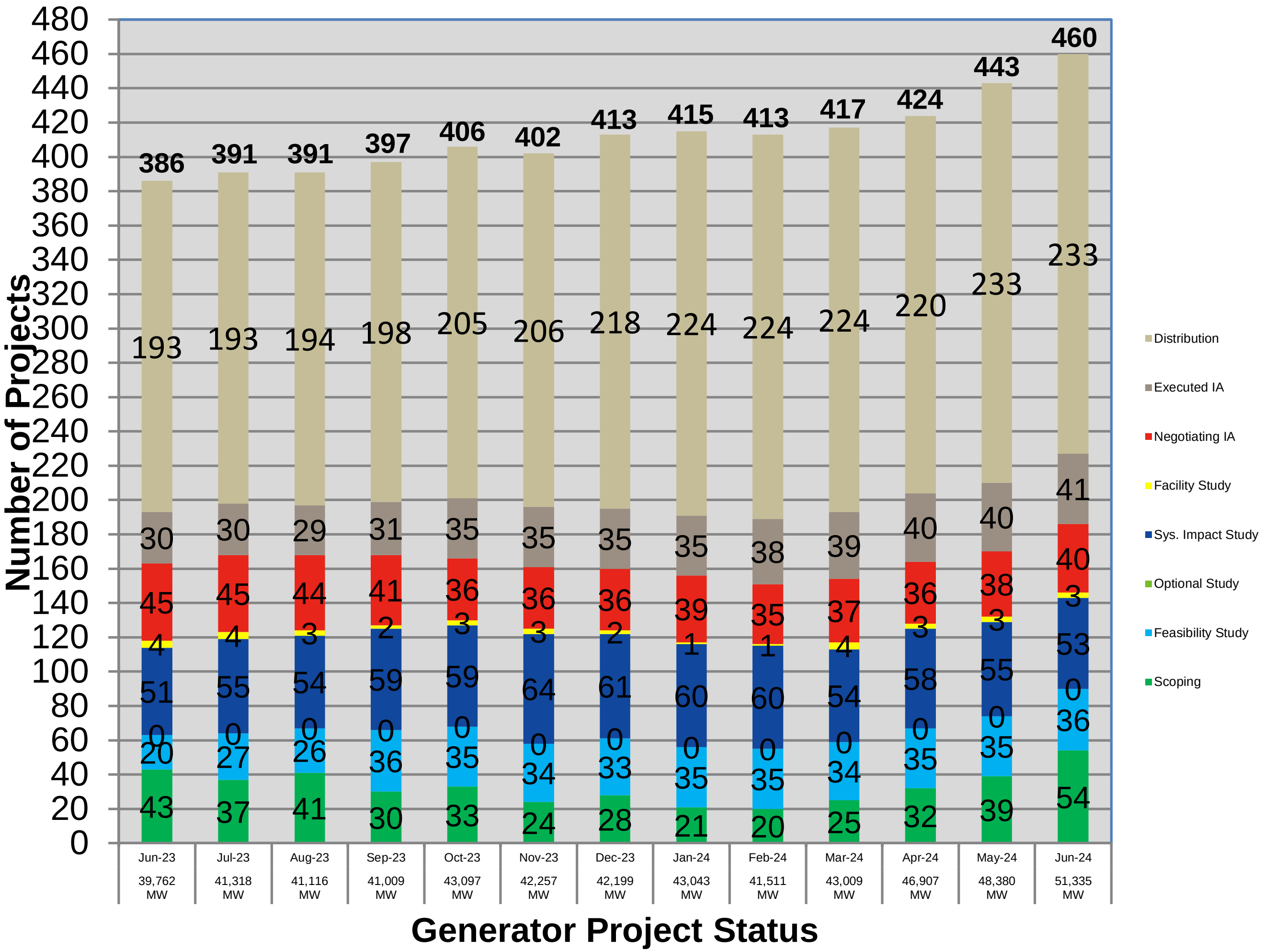
Status as of 7/23/2024

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	Aug-24	3
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	Dec-25	2

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

Status of Tariff Studies as of July 1, 2024



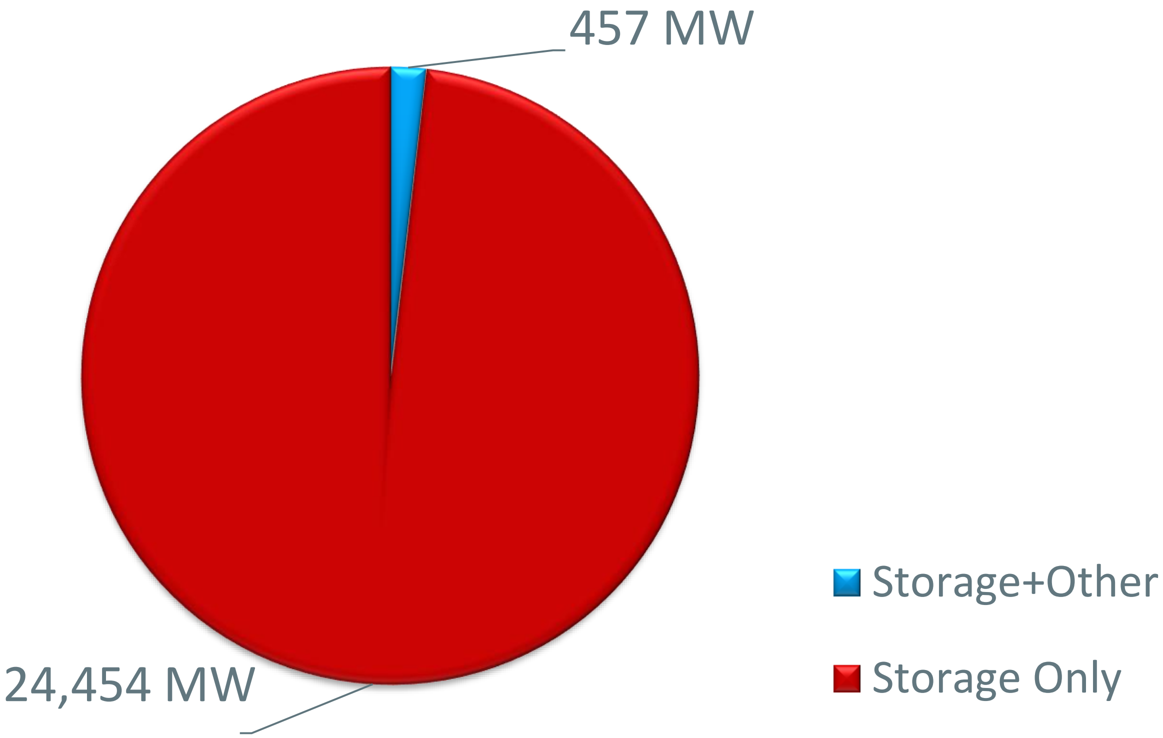
8 ETUs in Scoping, 3 in FS, 3 in SIS, 0 in OIS, 0 in FAC, 1 Negotiating IA, and 4 with Executed IA

Transmission Service Requests needing study: 0

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

What is in the Queue (as of July 1, 2024)

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



OPERABLE CAPACITY ANALYSIS

Summer 2024 Analysis

Summer 2024 Operable Capacity Analysis

50/50 **Load Forecast** (Reference)	**Sept - 2024[2] CSO (MW)**	**Sept - 2024[2] SCC (MW)**
Operable Capacity MW [1]	27,361	27,309
Active Demand Capacity Resource (+) [5]	426	388
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,194	1,194
Non Commercial Capacity (+)	247	247
Non Gas-fired Planned Outage MW (-)	829	837
Gas Generator Outages MW (-)	198	198
Allowance for Unplanned Outages (-) [4]	2,100	2,100
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	26,101	26,003
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	24,553	24,553
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	26,678	26,678
Operable Capacity Margin	-577	-675

[1] Operable Capacity is based on data as of **July 23, 2024** 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 **July 23, 2024.**

[2] Load forecast that is based on the 2024 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **Sept 14, 2024.**

[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.

Summer 2024 Operable Capacity Analysis

90/10 Load Forecast	**Sept - 2024[2] CSO (MW)**	**Sept - 2024[2] SCC (MW)**
Operable Capacity MW [1]	27,361	27,309
Active Demand Capacity Resource (+) [5]	426	388
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,194	1,194
Non Commercial Capacity (+)	247	247
Non Gas-fired Planned Outage MW (-)	829	837
Gas Generator Outages MW (-)	198	198
Allowance for Unplanned Outages (-) [4]	2,100	2,100
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	26,101	26,003
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	26,383	26,383
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	28,508	28,508
Operable Capacity Margin	-2,407	-2,505

[1] Operable Capacity is based on data as of **July 23, 2024** 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 **July 23, 2024.**

[2] Load forecast that is based on the 2024 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **Sept 14, 2024.**

[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.

Summer 2024 Operable Capacity Analysis
50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

July 23, 2024 - 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 June through mid September.

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
8/10/2024	27252	386	1274	99	556	100	2100	0	26255	24553	2125	26678	-423	N	Summer 2024
8/17/2024	27252	386	1274	99	587	42	2100	0	26282	24553	2125	26678	-396	N	Summer 2024
8/24/2024	27252	386	1274	99	321	42	2100	0	26548	24553	2125	26678	-130	N	Summer 2024
8/31/2024	27361	426	1194	247	314	77	2100	0	26737	24553	2125	26678	59	N	Summer 2024
9/7/2024	27361	426	1194	247	352	87	2100	0	26689	24553	2125	26678	11	N	Summer 2024
9/14/2024	**27361**	**426**	**1194**	**247**	**829**	**198**	**2100**	**0**	**26101**	**24553**	**2125**	**26678**	**-577**	**Y**	**Summer 2024**

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 2024 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.

Summer 2024 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

July 23, 2024 - 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 June through mid September.

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
8/10/2024	27252	386	1274	99	556	100	2100	0	26255	26383	2125	28508	-2253	N	Summer 2024
8/17/2024	27252	386	1274	99	587	42	2100	0	26282	26383	2125	28508	-2226	N	Summer 2024
8/24/2024	27252	386	1274	99	321	42	2100	0	26548	26383	2125	28508	-1960	N	Summer 2024
8/31/2024	27361	426	1194	247	314	77	2100	0	26737	26383	2125	28508	-1771	N	Summer 2024
9/7/2024	27361	426	1194	247	352	87	2100	0	26689	26383	2125	28508	-1819	N	Summer 2024
9/14/2024	**27361**	**426**	**1194**	**247**	**829**	**198**	**2100**	**0**	**26101**	**26383**	**2125**	**28508**	**-2407**	**Y**	**Summer 2024**

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 2024 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 Fall 2024 Analysis

Preliminary Fall 2024 Operable Capacity Analysis

50/50 Load Forecast (Reference)	**Oct - 2024[2] CSO (MW)**	**Oct - 2024[2] SCC (MW)**
Operable Capacity MW [1]	27,711	30,012
Active Demand Capacity Resource (+) [5]	426	346
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,161	1,161
Non Commercial Capacity (+)	293	293
Non Gas-fired Planned Outage MW (-)	5575	5711
Gas Generator Outages MW (-)	2395	3000
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	18,821	20,301
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	16,821	16,821
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	18,946	18,946
Operable Capacity Margin	-125	1,355

[1] Operable Capacity is based on data as of **July 23, 2024** 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 **July 23, 2024.**

[2] Load forecast that is based on the 2024 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **Oct 19, 2024.**

[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 Fall 2024 Operable Capacity Analysis

90/10 Load Forecast	**Oct - 2024[2] CSO (MW)**	**Oct - 2024[2] SCC (MW)**
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Gas Generator Outages MW (-)	2395	3000
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	18,821	20,301
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	17,482	17,482
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	19,607	19,607
Operable Capacity Margin	-786	694

[1] Operable Capacity is based on data as of **July 23, 2024** 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 **July 23, 2024.**

[2] Load forecast that is based on the 2024 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **Oct 19, 2024.**

[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.

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Preliminary Fall 2024 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

July 23, 2024 - 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.

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
9/21/2024	27361	426	677	247	1762	1798	2100	0	23051	20532	2125	22657	394	N	Fall 2024
9/28/2024	27711	426	677	293	2586	2386	2800	0	21335	15511	2125	17636	3699	N	Fall 2024
10/5/2024	27711	426	617	293	4503	3887	2800	0	17857	15546	2125	17671	186	N	Fall 2024
10/12/2024	27711	426	1101	293	5072	2725	2800	0	18934	16461	2125	18586	348	N	Fall 2024
10/19/2024	**27711**	**426**	**1161**	**293**	**5575**	**2395**	**2800**	**0**	**18821**	**16821**	**2125**	**18946**	**-125**	**Y**	**Fall 2024**
10/26/2024	27711	426	1161	293	4262	1813	3600	0	19916	17026	2125	19151	765	N	Fall 2024
11/2/2024	27711	426	1161	293	3013	2223	3600	0	20755	17140	2125	19265	1490	N	Fall 2024
11/9/2024	27711	426	1161	293	1495	2072	3600	0	22424	17481	2125	19606	2818	N	Fall 2024
11/16/2024	27711	426	1161	293	1492	1540	3600	0	22959	18211	2125	20336	2623	N	Fall 2024
11/23/2024	27711	426	1161	293	793	191	3600	1471	23536	18923	2125	21048	2488	N	Fall 2024

Column Definitions

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These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.

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

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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 2024 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.

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90/10 Forecast

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	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
9/21/2024	27361	426	677	247	1762	1798	2100	0	23051	22094	2125	24219	-1168	Y	Fall 2024
9/28/2024	27711	426	677	293	2586	2386	2800	0	21335	16125	2125	18250	3085	N	Fall 2024
10/5/2024	27711	426	617	293	4503	3887	2800	0	17857	16162	2125	18287	-430	N	Fall 2024
10/12/2024	27711	426	1101	293	5072	2725	2800	0	18934	17109	2125	19234	-300	N	Fall 2024
10/19/2024	**27711**	**426**	**1161**	**293**	**5575**	**2395**	**2800**	**0**	**18821**	**17482**	**2125**	**19607**	**-786**	**N**	**Fall 2024**
10/26/2024	27711	426	1161	293	4262	1813	3600	0	19916	17694	2125	19819	97	N	Fall 2024
11/2/2024	27711	426	1161	293	3013	2223	3600	0	20755	17812	2125	19937	818	N	Fall 2024
11/9/2024	27711	426	1161	293	1495	2072	3600	0	22424	18165	2125	20290	2134	N	Fall 2024
11/16/2024	27711	426	1161	293	1492	1540	3600	0	22959	18921	2125	21046	1913	N	Fall 2024
11/23/2024	27711	426	1161	293	793	191	3600	2385	22622	19658	2125	21783	839	N	Fall 2024

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***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 units <5 MW will be available and respond.
2. The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
3. The MW values are based on a 25,000 MW system load and verified by the most recent voltage reduction test.
4. EEA Levels are described in Attachment 1 to NERC Reliability Standard EOP-011 - Emergency Operations

Possible Relief Under OP4: Appendix A

OP 4 Action Number	Page 2 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
7	Request generating resources not subject to a Capacity Supply Obligation to voluntary provide energy for reliability purposes	0
8	5% Voltage Reduction requiring 10 minutes or less	250 [3]
9	Transmission Customer Generation Not Contractually Available to Market Participants during a Capacity Deficiency. Voluntary Load Curtailment by Large Industrial and Commercial Customers.	5 200 [2]
10	Radio and TV Appeals for Voluntary Load Curtailment Implement Power Warning	200 [2]
11	Request State Governors to Reinforce Power Warning Appeals.	100 [2]
Total		**2,520**

NOTES:
1. Based on Summer Ratings. Assumes 25% of total MW Settlement Only units <5 MW will be available and respond.
2. The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
3. The MW values are based on a 25,000 MW system load and verified by the most recent voltage reduction test.
4. EEA Levels are described in Attachment 1 to NERC Reliability Standard EOP-011 - Emergency Operations

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of July 31, 2024

The following activity, as more fully described in the attached Litigation Report, has occurred since the report dated June 24, 2024 ("last Report") was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

FERC Administrative Developments

		FERC Commissioners	Jun 28	Commissioner See sworn in
			Jul 15	Commissioner Chang sworn in

I. Complaints/Section 206 Proceedings

	1	206 Proceeding: *TO Initial Funding Show Cause Order* (EL24-83)	Jun 24-Jul 12	NEPOOL, AEU, Avangrid, CMEEC (out-of-time), EDP Renewables, Eversource, Invenergy, MA AG, NESCOE, NextEra, PPL, LA PSC, MPUC, ACRE, EEI, EPSA, RENEW, ATC, MISO TOs, NY TOs, NIPSCO, PJM ICC, Cordelio Services, Public Citizen intervene
			Jul 15	Indicated Utilities request reh'g, if and as appropriate, and request that the FERC rescind its *TO Initial Funding Show Cause Order*
	3	RENEW Network Upgrades O&M Cost Allocation Complaint (EL23-16)	Jul 16	RENEW submits supplemental affidavits as further evidence to support its Dec 13, 2022 Complaint; requests expedited FERC order
			Jul 31	PTOs protest RENEW's July 16 supplemental submissions

II. Rate, ICR, FCA, Cost Recovery Filings

*	6	Bear Swamp Power Co. CIP IROL (Schedule 17) Cost Recovery Schedule Filing (ER24-2260)	Jul 1	National Grid intervenes
	6	CSC CIP-IROL (Schedule 17) Section 205 Cost Recovery Filing (ER24-2159)	Jul 24	FERC accepts revisions to CSC's CIP-IROL Rate Schedule that will allow CSC to recover ***$478,182*** of incremental medium impact CIP-IROL Costs incurred between Jan 1, 2023 and Dec 31, 2023; eff. *Jul 31, 2024*
	6	MOPA Formal Challenge to TO's Annual (2023-24) Transmission Rate Update/Info Filing (ER20-2054-000)	Jul 26	FERC directs Indicated TOs to submit in this docket all responses to MOPA Formal Challenge (both public and confidential) on or before ***Aug 26, 2024***
	7	**Mystic 8/9 COSA (ER18-1639)**		
	9	(-027) Second CapEx Info Filing Settlement Proceedings	Jul 8	Deputy Chief ALJ adopts Protective Order to cover certain information to be provided during settlement negotiations
			Jul 19	Mystic hosts a technical conference
			Jul 30	Judge French schedules a 7th formal settlement conference for ***Aug 29, 2024***
*	10	Mystic COSA Protocols Waiver Request (ER24-2528)	Jul 12	Mystic requests waiver of the deadlines in Sections II.6.A and II.4.F of the Protocols; comment deadline ***Aug 2, 2024***
	11	ISO-NE Securities: Authorization for Issuance of Securities (ES24-41)	Jul 1	National Grid intervenes
			Jul 19	FERC authorizes ISO-NE issuance of up to $75 million in senior unsecured notes *through Jul 31, 2026*

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

*	12	MW-Dependent Fuel Price Adjustments (ER24-2584)	Jul 24	ISO-NE and NEPOOL jointly file changes; comment deadline ***Aug 14, 2024***
			Jul 30-31	Public Citizen, Calpine intervene
	12	eTariff § I.2 Corrections (ER24-2270)	Jul 1, 3	National Grid, NEPOOL intervene
			Jul 26	ISO-NE supplements its filing to add a request for waiver of the FERC's 60-day notice requirement to permit the conforming Tariff changes to become eff. on *Apr 15, 2024*
	15	New England's *Order 2222* Compliance Filings: Metering Data Submission Revisions (ER22-983-008)	Jul 1	NEPOOL files comments supporting the Metering Data Submission Revisions
	15	New England's *Order 2222* Compliance Filings: ATTR Submetering Revisions (ER22-983-009)	Jul 22	ISO-NE files comments supporting the Metering Data Submission Revisions; comment deadline ***Aug 12, 2024***

IV. OATT Amendments / TOAs / Coordination Agreements

	15	*Order 2023* Compliance Changes (ER24-2009)	Jul 5	Glenvale and Longroad Energy answer ISO-NE's Jun 20 Answer
			Jul 19	ISO-NE answers Glenvale's and Longroad Energy's Jul 5 answers
	16	*Order 2023* Related Changes (ER24-2007)	Jul 5	Glenvale and Longroad Energy answer ISO-NE's Jun 20 Answer
			Jul 19	ISO-NE answers Glenvale's and Longroad Energy's Jul 5 answers
	16	LTTP Phase 2 Tariff Changes (ER24-1978)	Jul 8	FERC accepts Changes, eff. *Jul 9, 2024*
			Jul 27	ISO-NE submits compliance filing, backing out yet-to-be effective changes inadvertently included with the LTTP Phase 2 Changes; comment deadline ***Aug 16, 2024***

V. Financial Assurance/Billing Policy Amendments

No Activities to Report

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

VII. NEPOOL Agreement/Participants Agreement Amendments

*	18	135th Agreement; PA13 (Unused Provisional Member Voting Share Allocation Changes) (ER24-2636)	Jul 31	NEPOOL and ISO-NE file 2nd RNA and PA changes; comment deadline ***Aug 21, 2024***

VIII. Regional Reports

*	19	IMM Quarterly Markets Reports (ZZ24-4)	Jul 22	IMM files Spring 2024 Report
	19	LFTR Implementation Quarterly Status Report (ER07-476)	Jul 15	ISO-NE files its 63rd quarterly report
	19	Reserve Market Compliance (36th) Semi-Annual Report (ER06-613)	Jul 8	FERC terminates ISO-NE's semi-annual reporting obligation

IX. Membership Filings

*	19	Aug 2024 Membership Filing (ER24-2623)	Jul 30	***New Member:*** Twig Redwood Inc.; and ***Termination of Participant status:*** MFT Energy US 1 LLC comment deadline ***Aug 20, 2024***
*	20	July 2024 Membership Filing (ER24-2430)	Jun 28	***New Members:*** Aurora Energy Research, Enverus; and ***Termination of Participant status:*** KCE CT 10, LLC
	20	June 2024 Membership Filing (ER24-2169)	Jul 30	FERC accepts (i) as new members: ATNV Energy; Delorean Power d/b/a Lightshift Energy; Fanfare Energy; ProGrid Ventures; and ZGE Massachusetts; (ii) the termination of the Participant status of Agile Energy Trading; Energy Harbor; Hydroland; and the CT Materials Innovations and Recycling Authority; and (iii) the name change of Reworld REC, LLC

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

	20	Revised Reliability Standard: EOP-012-2 (RD24-5)	Jun 27	FERC approves, subject to further modification, Reliability Standard EOP-012-2; directs NERC to submit revised EOP-012-2 by ***Mar 17, 2025***
*	21	Revised Reliability Standards: CIP-002-7 through CIP-013-3 (Virtualization) (RM24-8)	Jul 10	NERC submits for approval 11 CIP Standards and 18 new or revised definitions for inclusion in NERC's Glossary

XI. Misc. - of Regional Interest

*	22	203 Application: Berkshire Power/ Gate City Power (EC24-104)	Jul 19	Berkshire Power requests authorization for Gate City Power's acquisition of 100% of the interests in Berkshire's parent; comment deadline ***Aug 9, 2024***
			Jul 25	Public Citizen intervenes
	22	203 Application: Trailstone/ Engelhart (EC24-87)	Jul 25	FERC authorizes Engelhart's acquisition of 100% of the interests in the Trailstone companies from Riverstone V Trailstone Holdings
	22	203 Application: GIP/BlackRock (EC24-58)	Jul 9	Public Citizen and Private Equity Stakeholder Project file 3rd joint protest, this time in response to Applicants' Jun 20, 2024 deficiency letter response
			Jul 15	Applicants request prompt action on their Mar 12, 2024 application
	23	203 Application: Three Corners Solar/Three Corners Prime Tenant (EC23-90)	Jul 8	Transaction consummated
			Jul 10	Applicants file notice of consummation
*	23	E&P Agreement, 3d Amendment: Seabrook / NECEC Transmission (ER24-2588)	Jul 25	Seabrook files a third amendment to the E&P Agreement with NECEC Transmission; comment deadline ***Aug 15, 2024***
			Jul 29	Avangrid intervenes
*	24	D&E Agreement: CL&P / Vineyard Northeast (ER24-2523)	Jul 15	CL&P files D&E Agreement with Vineyard Northeast related to Vineyard Northeast's 1,200 MW Large Generating Facility; comment deadline ***Aug 5, 2024***
*	24	Interconnection Study Agreement: PSNH / Wok, LLC (ER24-2522)	Jul 15	PSNH files Interconnection Study Agreement with Wok, LLC; comment deadline ***Aug 5, 2024***
*	24	Versant *Order 1920* MPD Waiver Request (ER24-2462)	Jul 2	Versant Power requests for the MPD a waiver of *Order 1920*'s requirements related to regional transmission planning, interregional transmission coordination, and cost allocation methods

*	24	LCCSA: RIE/BIPCO/Pascoag (ER24-2390)	Jun 27	RI Energy submits a Local Control Center Services Agreement with BIPCO and Pascoag
			Jul 15	National Grid intervenes
*	24	D&E Agreement Cancellation: NSTAR/Medway Grid (ER24-2356)	Jun 25	NSTAR files notice of termination of D&E Agreement with Medway Grid
	25	TSA Amendment: NSTAR/Park City Wind (ER24-2104)	Jul 9	FERC accepts TSA Amendment, eff. *Jul 28, 2024*
	25	CSA: NextEra Seabrook/NECEC (ER24-2097)	Jul 17	FERC accepts CSA, eff. *May 24, 2024*
	25	SGIA: PSNH White Pine Hydro (ER24-2092)	Jul 17	FERC accepts SGIA, eff. *May 24, 2024*
	25	RFA Termination: PSNH/NECEC (ER24-2087)	Jul 17	FERC accepts FRA termination, *eff. May 23, 2024*
	26	IA 2nd Amendment: CMP/White Pine Hydro (ER24-1966)	Jun 25	CMP supplements May 8 filing
			Jun 28	FERC accepts Amended IA, eff. *Jul 8, 2024*
	26	CMP ESF Service Rate (ER24-1177)	Jul 17	2nd settlement conference held Judge Hessler schedules 3rd settlement conference for ***Sep 19, 2024***
*	27	RI Energy BITS Surcharge True-Up Adjustment (ER23-1003; -1000)	Jun 27	RI Energy submits True-Up Adjustment of its BITS Surcharge

XII. Misc. - Administrative & Rulemaking Proceedings

	27	Joint Federal-State Current Issues Collaborative (AD24-7)	Jul 19	NARUC submits nominees for the Collaborative, including, from NECPUC, MPUC Chairman Phil Bartlett and NHPUC Commissioner Pradip Chattopadhyay
*	28	ANOPR*:* Implementation of Dynamic Line Ratings (RM24-6)	Jun 27	FERC issues ANOPR presenting potential reforms to implement dynamic line ratings and, thereby, improve the accuracy of transmission line ratings; initial comments due on or before ***Oct 15, 2024***; reply comments, ***Nov 12, 2024***
			Jul 26	Electric Grid Monitoring submits comments in support of FERC moving forward with a NOPR and Final Rule
	31	*Order 1977*: Transmission Siting Changes (RM22-7)	Jul 15	FERC issues "Allegheny Notice", noting that requests for reh'g may be deemed to have been denied by operation of law, but that the requests will be addressed in a future order
	31	NOPR: Compensation for Reactive Power Within the Standard Power Factor Range (RM22-2)	Jun 25	NEPOOL replies to ISO-NE initial comments
			Jun 26	Reply comments also filed by: NEPGA, NESCOE, Elevate Renewables F7, EPSA, IPPNY, MISO TOs, Old Dominion Electric Coop, PJM IMM, and Dr. C. Gaunt
			Jul 23	Onward Energy files supplemental comments
	32	*Order 1920*: Transmission Planning Reforms (RM21-17)	Jul 15	FERC issues "Allegheny Notice", noting that requests for reh'g may be deemed to have been denied by operation of law, but that the requests will be addressed in a future order

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

*	33	SunSea Energy Stipulation and Consent (IN24-8)	Jun 27	FERC approves Stipulation and Consent Agreement that resolves OE's investigation into whether SunSea violated the NYISO Tariff and the FERC's Market Behavior Rules by failing to timely inform NYISO of the existence of ongoing investigations by the NYPSC that could have a material impact on its financial condition; SunSea agrees to pay a ***$5,000 civil penalty***
*	34	Josco Energy Stipulation and Consent Agreement (IN24-7)	Jun 28	FERC approves Stipulation and Consent Agreement that resolves OE's investigation into whether Josco violated the NYISO Tariff and the FERC's Market Behavior Rules by failing to timely inform NYISO of the existence of ongoing investigations by the NYPSC that could have a material impact on its financial condition; Josco agrees to pay a ***$5,000 civil penalty***
*	35	Galt Power Stipulation and Consent Agreement (IN20-5)	Jun 28	FERC approves Stipulation and Consent Agreement that resolves OE's investigation into whether Galt Power, and as to certain obligations, Customized Energy Solutions, violated the FERC's Anti-Manipulation Rule and the Federal Power Act by repeatedly engaging in prohibited wash trades between the NYISO and ISO-NE markets between Jul 8, 2016 and Apr 23, 2019; Galt agreed to: (a) ***pay a civil penalty of $1.5 million***; (b) ***disgorge (with interest) $372,297.85*** to the Commonwealth of Massachusetts; and (c) submit two annual compliance monitoring reports, with a third annual compliance monitoring report at OE's discretion
*	35	Ketchup Caddy and Philip Mango (IN23-14)	Jul 26	FERC amends answer deadline in the Order to Show Cause to require Respondents to respond to the Order to Show Cause by no later than 30 days after the date on which the Office of the Secretary serves the Order to Show Cause on Respondents

XIV. Natural Gas Proceedings

No Activity to Report

XV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XVI. Federal Courts

*	39	*Order 1920*: Transmission Planning Reforms (24-1254 et al.) (consolidated)	Jul 18 Jul 22	AUE/ACPA/SEIA, file Petitions for Review Clerk issues orders directing filing of initial submissions and consolidating appeals
	39	Mystic Second CapEx Info Filing (24-1077)	Jul 16 Jul 24	Mystic files an unopposed motion asking the Court to continue to hold this case in abeyance for an additional 120 days Mystic amends its Petition for Review to add the FERC’s May 23, 2024 *Second CapEx Info Filing Order Allegheny Order*
	40	*Orders 2023 and 2023-A* (23-1282 et al.) (consolidated)	Jul 2	Following an extension granted by the Court, the parties filed an unopposed motion to establish briefing procedures and a schedule
	40	*Order 2222* Compliance Orders (23-1167, 23-1168, 23-1169, 23-1170, 23-1335)(consolidated)	Jul 30	FERC asks for additional period of abeyance
	41	Mystic II (ROE & True-Up)	Jul 30	Court orders cases remain in abeyance and parties to submit motions to govern future proceedings by ***Nov 27, 2024***
	42	*Opinion 531-A* Compliance Filing Undo (20-1329)	Jul 23	FERC files status report, abeyance continues
*	43	*Chevron Doctrine* (US Supreme Ct 20-1329)	Jun 28	Supreme Court overturns the *Chevron* deference doctrine, which required courts to defer to a federal agency’s reasonable interpretation of ambiguity in a statute. A more fulsome summary of the Court’s decision is included as Appendix A

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Pat Gerity and Teresa Chen, NEPOOL Counsel

DATE: July 31, 2024

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 July 31, 2024. If you have questions, please contact us.

I. Complaints/Section 206 Proceedings

- **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).[2] 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.[3] 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.[4] 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.[5] The refund effective date for this proceeding will be June 24, 2024.[6] A more detailed summary of the *TO Initial Funding Show Cause Order* was circulated to, and was reviewed with, the Transmission Committee.

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

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

[3] *Id.* at P 1.

[4] *Id.*

[5] *Id.* at P 2.

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

Interventions were due on or before July 5, 2024 and were filed by the following New England-related parties:[7] NEPOOL, 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. On July 15, 2024, Indicated Utilities[8] requested rehearing, if and as appropriate, and requested that the FERC rescind its *TO Initial Funding Show Cause Order*.

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).

- **206 Proceeding: ISO Market Power Mitigation Rules (EL23-62)**

This Section 206 proceeding is being held in abeyance. As previously reported, this proceeding was instituted by the FERC on May 5, 2023, pursuant to its finding that the existing ISO-NE Tariff provisions related to the mechanics of its market power mitigation and the consideration of any proposed fuel price adjustment, may be unjust and unreasonable.[9] Changes in response to some of the requirements of the *Dynegy Mitigation Order* ("Upward Mitigation Revisions") were supported by the Participants Committee, jointly filed with ISO-NE, accepted by the FERC,[10] and became effective as of *December 12, 2023*. On January 29, 2024, ISO-NE requested that this proceeding continue to be held in abeyance,[11] through August 30, 2024, "pending completion of the stakeholder process through which further revisions to [the Tariff] are being proposed and vetted.[12] The FERC granted ISO-NE's motion on February 7, 2024, stating that it would not take any action on this 206 proceeding before ***August 30, 2024***.

Further changes to address issues raised by the FERC in the *Dynegy Mitigation Order* were filed on July 24, 2024 (*see* Section III, MW-Dependent Fuel Price Adjustments (ER24-2584), below). Comments on that filing are due on or before ***August 21, 2024***. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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[7] 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).

[8] "Indicated Utilities" are: Ameren Srvcs. Co. ("Ameren"), on behalf of Ameren Illinois Co. ("Ameren Illinois"), Union Elec. Co. d/b/a Ameren Missouri, and Ameren Trans. Co. of Illinois ("ATXI")); American Trans. Co. LLC ("ATC"); Duke Energy Corp., on behalf of Duke Energy Business Services, LLC and its franchised public utility affiliates, Duke Energy Ohio, Inc. ("Duke Ohio"), Duke Energy Kentucky, Inc. ("Duke Kentucky"), Duke Energy Indiana, LLC ("Duke Indiana") (collectively "Duke Energy"); Exelon Corp. on behalf of its affiliates Atlantic City Elec. Co., Baltimore Gas and Elec. Co., Commonwealth Edison Co., Delmarva Power & Light Co., PECO Energy Company, and Potomac Elec. Power Co.; Northern Indiana Pub. Srvc. Co. LLC ("NIPSCO"); and Xcel Energy Services, Inc. ("XES"), on behalf of Northern States Power Co., a Minnesota Corp. ("NSPM"), Northern States Power Co., a Wisconsin Corp. ("NSPW"), and Southwestern Public Service Co. ("SPS").

[9] *Dynegy Marketing and Trade, LLC and ISO New England, Inc.*, 183 FERC ¶ 61,091 (May 5, 2023) ("*Dynegy Mitigation Order*"). In the Dynegy Mitigation Order, ISO-NE was directed 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. The refund effective date for this proceeding is May 12, 2023.

[10] *ISO New England Inc.*, Docket No. ER24-324-000 (Dec. 12, 2023) (unpublished letter order).

[11] On July 14, 2023, the FERC granted ISO-NE's June 28, 2023 motion, supported by NEPOOL on July 5, 2023, requesting that the FERC hold this proceeding in abeyance to allow potential ISO-NE Tariff design changes to be vetted through the Participant Processes. The FERC stated that it would not take any action on this 206 proceeding before Feb. 1, 2024.

[12] ISO-NE identified as additional topics not fully addressed by the Upward Mitigation Revisions the following: (1) whether the duration of general threshold energy mitigation is appropriate; and (2) whether a Resource should be permitted to submit multiple fuel price adjustments that reflect the cost of fuel for segments of its Supply Offer that exceed a Resource's Day-Ahead Energy Market awards.

- **RENEW Network Upgrades O&M Cost Allocation Complaint (EL23-16)**

The December 13, 2022 complaint by RENEW Northeast, Inc. ("RENEW") against ISO-NE and the Participating Transmission Owners ("PTOs"), which seeks changes to the ISO-NE Tariff (Schedules 11 and 21) that would eliminate the direct assignment of Network Upgrade Operations and Maintenance ("O&M") costs to Interconnection Customers,[13] remains pending before the FERC. As previously reported, the proposed revisions to Schedule 11 of the Tariff were voted by the Transmission Committee at its October 26, 2021 meeting, and were discussed at the Participants Committee's November 3, 2021 meeting. RENEW asked the FERC to issue an order granting the Complaint by April 14, 2023 (approximately 60 days prior to the June 15, 2023 deadline for the NE PTOs to publish a draft of the Annual Update to the data used in the transmission formula rate). Both of those dates have long since passed.

Responses, comments and protests were filed in late January 2023 by ISO-NE (which alternatively moved to dismiss itself as a party ("ISO-NE Jan 19 Motion")), the PTO AC, NEPOOL, AEU/Clean Energy Council, CPV Towantic, Glenvale, MA AG, NECOS, NEPGA, and NESCOE. Doc-less interventions only were filed by Calpine, CMEEC, EMI, Eversource, Narragansett ("RI Energy"), National Grid, New Leaf Energy, NextEra, NRG, Versant, CT DEEP, MA DPU, the American Clean Power Association ("ACPA"), Solar Energy Industries Association ("SEIA"), and Public Citizen. In additional rounds of briefing, RENEW answered ISO-NE's Jan 19 Motion; RENEW, the PTO AC, and National Grid filed answers to the January 23 protests/comments; ISO-NE answered RENEW's February 7 answer; and CPV Towantic, Glenvale, and the MA AG filed answers to the February 7 answers. Since the last Report, RENEW submitted on July 16 supplemental affidavits as further evidence in support of its Complaint and requested that the FERC issue an order on an expedited basis. On July 31, 2024, the PTO AC protested RENEW's July 16 supplemental submission. This matter remains pending before the FERC. 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 pending before the FERC in which consumer representatives seek to reduce the TOs' return on equity ("Base ROE") for regional transmission service.

  - ***Base ROE Complaint I (EL11-66)***. In the first Base ROE Complaint proceeding, the FERC concluded that the TOs' ROE had become unjust and unreasonable,[14] 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*).[15] However, the FERC's orders were challenged, and in *Emera Maine,*[16] the U.S. Court of Appeals for the D.C. Circuit ("DC Circuit") vacated the FERC's prior orders, and remanded the case for further proceedings consistent with its order. The FERC's determinations in *Opinion 531* are

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[13] RENEW also requested (i) that it be considered an Interested Party or afforded adequate opportunity to participate and access transmission rate information under the PTOs' Formula Rate Protocols and (ii) the PTOs be directed to provide greater transparency regarding O&M costs in the interconnection process.

[14] 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*")).

[15] *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*").

[16] *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).

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)[17] and third (EL14-86)[18] 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.[19] 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[20] also went to hearing before an Administrative Law Judge ("ALJ"), Judge Glazer, who issued his initial decision on March 27, 2017.[21] 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.[22] 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.[23] 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*[24] (EL14-12; EL15-45) in

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[17] 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%.

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

[19] *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*").

[20] 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.

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

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

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

[24] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569-A, 171 FERC ¶ 61,154 (2020) ("*Opinion 569-A*"). The refinements to the FERC's ROE methodology included: (i) the use of the Risk Premium model instead of only relying on the DCF model and CAPM under both prongs of FPA Section 206; (ii) adjusting the relative weighting of long- and short-term growth rates, increasing the weight for the short-term growth rate to 80% and reducing to 20% the weight given to the long-term growth rate in the two-step DCF model; (iii) modifying the high-end outlier test to treat any proxy company as high-end outlier if its cost of equity

Section XI below). The FERC established a paper hearing on how its proposed methodology should apply to the four pending ROE proceedings.[25]

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%.[26] 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[27] for an extension of time to submit briefs, the latest date for filing initial and reply briefs was extended to January 11 and March 8, 2019, respectively. On January 11, initial briefs were filed by EMCOS, Complainant-Aligned Parties, TOs, Edison Electric Institute (“EEI”), Louisiana PSC, Southern California Edison, and AEP. As part of their initial briefs, each of the Louisiana PSC, SEC and AEP also moved to intervene out-of-time. Those interventions were opposed by the TOs on January 24, 2019. The Louisiana PSC answered the TOs’ January 24 motion on February 12. Reply briefs were due March 8, 2019 and were submitted by the TOs, Complainant-Aligned Parties, EMCOS, and FERC Trial Staff.

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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*.

[25] *Id.* at P 19.

[26] *Id.* at P 59.

[27] For purposes of the motion seeking clarification, “Customers” are CT PURA, MA AG and EMCOS.

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*[28] and requested that the FERC re-open the record to permit that additional testimony on the impacts of the *MISO ROE Order*'s changes. On January 21, 2020, EMCOS and CAPs opposed the TOs' request and brief.

These matters remain pending before the FERC. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Joe Fagan (202-218-3901; jfagan@daypitney.com).

II. Rate, ICR, FCA, Cost Recovery Filings

- **Bear Swamp Power Co. CIP-IROL (Schedule 17) Cost Recovery Schedule Filing (ER24-2260)**

On June 12, 2024, Bear Swamp Power Company ("Bear Swamp") requested FERC acceptance of a proposed rate schedule to allow Bear Swamp to begin the recovery period for certain Interconnection Reliability Operating Limits Critical Infrastructure Protection costs ("CIP-IROL Costs") under Schedule 17 of the ISO-NE Tariff. Bear Swamp stated that the rate schedule will provide interested parties notice of Bear Swamp's intent to recover CIP-IROL Costs for each affiliated facility designated as an IROL-Critical Facility, and an order accepting the rate schedule will provide an effective date after which associated costs incurred can be recovered following completion of the process contemplated by Schedule 17 and a subsequent Section 205 filing identifying the specific costs to be recovered. A June 13, 2024 effective date was requested. Comments on this filing were due on or before July 3, 2024; none were filed. National Grid filed a doc-less intervention. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **CSC CIP-IROL (Schedule 17) Section 205 Cost Recovery Filing (ER24-2159)**

On July 24, 2024, the FERC accepted revisions to Cross-Sound Cable's ("CSC") CIP-IROL Rate Schedule[29] that will allow CSC to recover **$478,182** of incremental medium impact CIP-IROL Costs incurred between January 1, 2023 and December 31, 2023.[30] The tariff changes were accepted effective *July 31, 2024*, as requested. Unless the *CSC 2023 CIP-IROL Cost Recovery Order* is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **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.[31] MOPA asserted that, (i) with respect to the cost of asset condition projects placed into service in

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[28] *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).

[29] CSC's CIP-IROL Rate Schedule allows CSC to recover eligible medium-impact Interconnection Reliability Operating Limits ("IROL") critical infrastructure protection ("CIP") costs ("CIP-IROL Costs") under Schedule 17 of the ISO-NE Tariff.

[30] Cross-Sound Cable Co., LLC, Docket No. ER24-2159-000 (July 24, 2024) (unpublished letter order) ("*CSC 2023 CIP-IROL Cost Recovery Order*").

[31] 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.

2022, Identified TOs[32] 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[33] (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).

Since the last Report, 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 are due on or before ***August 26, 2024***. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

Mystic I Remand. As previously reported, the DC Circuit issued a decision on August 23, 2022[34] that, among other things: (i) granted State Petitioners' petitions for review on the cost allocation issue; (ii) vacated the clawback portions excluding Everett costs and the challenged delay provision of the orders under review; and (iii) remanded the cases to the FERC to address NESCOE's request for clarification about revenue credits and for clarification of the apparent contradictions in the FERC's *December 2020 Rehearing Order*.

(-000) Third CapEx Info Filing. On September 15, 2023, Mystic submitted, as required by orders in this proceeding and Sections I.B.1.i. and II.6.of Schedule 3A of the COS Agreement ("Protocols") its "Third CapEx Info Filing" to provide support for the capital expenditures and related costs that Mystic projects will be collected as an expense between January 1, 2024 to May 31, 2024 ("2024 CapEx Projects"). This filing was not noticed for public comment by the FERC.

(-018) Second CapEx Info Filing. On December 5, 2023, the FERC issued an order[35] on the formal challenges to Mystic's September 15, 2022 "Second CapEx Info Filing".[36] As previously reported, formal challenges to the Second CapEx Info Filing were submitted by NESCOE and ENECOS[37] (with ENECOS challenges supported

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[32] "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").

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

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

[35] *Constellation Mystic Power, LLC*, 185 FERC ¶ 61,170 (Dec. 5, 2023) ("*Second CapEx Info Filing Order*").

[36] The "Second CapEx Info Filing" provides support for the capital expenditures and related costs that Mystic projects will be collected as an expense between January 1, 2023 to December 31, 2023 ("2023 CapEx Projects").

[37] ENECOS Formal Challenges included failures by Mystic: (1) to adequately support its July 1, 2004 – Dec. 31, 2017 Rate Base on Attachment B to Mystic 8&9 Schedule D (with the majority of the cost appearing to O&M expenses that should have been expensed prior to the term); (2) to adequately support its Jan. 1, 2018 – May 31, 2022 Rate Base in line with the requirements of Schedule 3A and the Methodology of the Mystic COSA; (3-5) to prove that certain costs under Mystic's 2022 CapEx Projects - specifically, its Campus Segregation Project and comprehensive rotor inspections - are necessary to meet the reliability need of the Mystic COSA and the least-cost commercially reasonable option consistent with Good Utility Practice; (6) to sufficiently support Everett's Nov. 1, 2018 – May 31, 2022 Rate Base in Attachment B; (7) to properly classify certain of Everett's 2022 and 2023 CapEx Projects costs (some of which should have been characterized as maintenance expenses charged before the term of the Mystic COSA); and (8) to include costs of firm interstate and intrastate pipeline transportation reservations in Everett Schedule B of the populated template.

separately by MMWEC/NHEC). Several rounds of answers, described in previous reports, followed. In February 2023, Mystic asked that the Formal Challenges to the Second CapEx Info Filing be held in abeyance pending submission of a settlement agreement to resolve challenges to the First CapEx Info Filing. ENECOS protested that request, identifying issues in their challenges to the Second CapEx Info Filing that would not be resolved by a First CapEx Settlement Agreement. The First CapEx Settlement Agreement was filed and approved, leaving for resolution certain of ENECOS' challenges.

In the *Second CapEx Info Filing Order*, the FERC granted in part, subject to hearing and settlement judge procedures, and dismissed in part, ENECOS' Formal Challenges. Specifically, the FERC found that, issues of material fact, that could not be resolved on the record before it, continued with respect to a number of ENECOS' Formal Challenges. Accordingly, the FERC set for hearing and settlement judge procedures issues raised, in whole or in part, in ENECOS Formal Challenges 1, 2, 6, and 7. The FERC summarily dismissed ENECOS' Formal Challenges 3-5 and 8 (as outside the scope of the proceeding).

(-026) Allegheny Order Addressing ENECOS' Request for Rehearing of Order on Remand Modification Order. On November 6, 2023, ENECOS requested rehearing of the *Mystic I Order on Remand Modification Order*.[38] Specifically, ENECOS requested that the FERC both (i) reinstate its conclusions as to the scope of customer scrutiny of formula rate inputs under the COSA set forth in its March 28, 2023 *Mystic I Order on Remand*[39] and (ii) grant Public Systems' motion for additional disclosure to facilitate customer review of the extraordinary costs incurred during the first 18 months of the COSA's operation. On December 7, 2023, the FERC issued an "Allegheny Notice", noting that ENECOS request for rehearing may be deemed to have been denied by operation of law, but noting that ENECOS' request will be addressed in a future order.[40] On February 15, 2024, the FERC issued that order, modifying the discussion in the *Mystic I Order on Remand Modification Order* but reaching the same result.[41] On February 29, 2024, ENECOS amended their petition for review before the DC Circuit (Case No. 24-1018) to include the *Mystic I Order on Remand Modification Order Allegheny Order* (*see* Section XVI below),

Recall that, as previously reported with respect to this aspect of the Mystic proceeding, Mystic requested rehearing and/or clarification of the March 28, 2023 *Mystic I Order on Remand (*-024*)*. Mystic asserted that (a) the FERC should have considered and rejected NESCOE's arguments about "truing up" and challenging the Revenue Credit; (b) the Tank Congestion Charge and the calculation of the Forward Sales Margin credited to Mystic and its ratepayers should not be included in the true-up process; and (c) if the FERC does not grant rehearing on (a) or (b), in the alternative, it should clarify that the scope of review during the true-up for Revenue Credits and the

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[38] *Constellation Mystic Power, LLC*, 185 FERC ¶ 61,016 (Oct. 6, 2023) ("*Mystic I Order on Remand Modification Order*"). The *Mystic I Order on Remand Modification Order* set aside the FERC determinations in the *Mystic I Order on Remand* that: (i) interested parties may review and challenge revenues and Revenue Credits during the true-up process; (ii) interested parties may review and challenge Tank Congestion Charges during the true-up process; and (iii) the revenues from the sliding scale revenue sharing mechanism for third-party vapor sales should be included within the true-up. As previously reported, the FERC concluded in the *Mystic I Order on Remand* that "the language of the true-up and Protocol provisions of the [COS] Agreement, Schedule 3A, does not include these three items within the scope of the true-up, nor is calculation of these items consistent with purpose for the true-up mechanism in the [COS] Agreement because none of them are projected in advance, but rather they are each settled and audited on a monthly basis. The FERC found that "existing cost review and audit processes, … facilitated by ISO-NE, its auditors, and the Internal Market Monitor, are sufficient to ensure that Mystic adheres to its filed rate with respect to these items and continues to appropriately balance customers' interest in transparency of the formula rate with Mystic's interests in protecting commercially-sensitive information, reducing security risks, and avoiding burdensome audit obligations".

[39] *Constellation Mystic Power, LLC*, 182 FERC ¶ 61,200 (Mar. 28, 2023) ("*Mystic I Order on Remand*"), *reh'g denied by operation of law,* 183 FERC ¶ 62,115 (May 30, 2023) ("*Mystic I Order on Remand Allegheny Notice*"); *Mystic I Order on Remand Modification Order* (addressing arguments raised on reh'g and setting aside the *Mystic I Order on Remand*, in part, granting Constellation motion to lodge and denying Public Systems' Request for Disclosure of Audit Information).

[40] *Constellation Mystic Power, LLC*, 185 FERC ¶ 62,120 (Dec. 7, 2023) ("*Mystic I Order on Remand Modification Order Allegheny Notice*").

[41] *Constellation Mystic Power, LLC*, 186 FERC ¶ 61,103 (Feb. 15, 2024) ("*Mystic I Order on Remand Modification Order Allegheny Order*").

Forward Sale Margin Shared with Mystic is not a prudence review and does not require disclosure of granular, unmasked transaction data. On May 30, 2023, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[42] The FERC then issued the *Mystic I Order on Remand Modification Order* which modified the discussion in the *Mystic I Order on Remand* and set aside that *Order* in part.[43] In addition, the *Order* also denied Public Systems[44] May 19, 2023 request that the FERC direct ISO-NE to release additional information concerning ISO-NE's audit of performance under Mystic COSA ("Audit Information Request").[45]

(-027) Second CapEx Info Filing Settlement Proceedings. While the FERC set several aspects of ENECOS Formal Challenges for a trial-type evidentiary hearing, the FERC encouraged the parties to make every effort to settle their disputes before hearing procedures are commenced, and to that end, is holding the hearing in abeyance pending the completion of settlement judge procedures. As directed, the Chief ALJ appointed a settlement judge, Judge Patricia M. French, to assist participants in settling the issues in this proceeding, and deemed the settlement proceedings continued without further action. Judge French has since convened six settlement conferences.[46] Judge French submitted her 3rd status report on June 10, 2024, recommending that the settlement process continue. Since the last Report, Deputy Chief ALJ Renee Terry adopted a protective order providing privileged treatment for certain information to be provided during settlement negotiations. Mystic hosted a technical conference on July 19, 2024. And Judge French scheduled a seventh formal settlement conference for ***August 29, 2024***.

(-028) Second CapEx Info Filing Order - Mystic's Request for Rehearing Deemed Denied by Operation of Law. On January 4, 2024, Mystic requested clarification, and in the alternative rehearing, of the *Second CapEx Info Filing Order*.[47] Specifically, Mystic requested clarification and/or rehearing of (i) the FERC's ruling on ENECOS's Formal Challenge No. 7 related to Everett's projected 2023 capital expenditures, (ii) that the FERC denied the accounting argument that ENECOS included in their Formal Challenge No. 1; and (iii) the FERC's rulings related to capital costs incurred prior to the start of the term of the COS Agreement (its grant in part of ENECOS's Formal Challenge No. 1 on the basis that Mystic did not adequately "support" Mystic 8&9 capital costs between July 2004 and December 31, 2017 ("Pre-2018 Rate Base"), and its grant of ENECOS's Formal Challenges Nos. 2 and 6). On January 19, 2024, ENECOS answered Mystic's request. On February 5, 2024, the FERC issued an "Allegheny Notice",[48] noting that ENECOS request for rehearing may be deemed to have been denied by operation of law, but

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[42] *Mystic I Order on Remand Allegheny Notice*.

[43] *Constellation Mystic Power, LLC*, 185 FERC ¶ 61,016 (Oct. 6, 2023) ("*Mystic I Order on Remand Modification Order*").

[44] "Public Systems" for these purposes are: MMWEC, CMEEC, NHEC, VPPSA, the Eastern New England Consumer-Owned Systems ("ENECOS"), and Energy New England, LLC ("ENE").

[45] In the *Mystic I Order on Remand Modification Order*, the FERC found that the additional audit information requested was "not supported by the Mystic [COSA] and unnecessary, given the attention that ISO-NE, its auditors, and the Market Monitor give these items on a regular basis". Nevertheless, the FERC accepted "ISO-NE's offer to provide additional transparency measures for the remainder of the Mystic Agreement as soon as practicable, starting no later than [Dec. 5, 2023]." (P 13).

[46] The first settlement conference was convened on Jan. 4, 2024; the second, Mar. 20, 2024; the third, Apr. 19, 2024; the fourth, May 17, 2024; the fifth, June 14, 2024; and the most recent and sixth settlement conference, June 18, 2024.

[47] *Constellation Mystic Power, LLC*, 185 FERC ¶ 61,170 (Dec. 5, 2023) ("*Second CapEx Info Filing Order*").

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

noting that ENECOS' request will be addressed in a future order.[49] On April 3, 2024, Mystic appealed to the DC Circuit the *Second CapEx Info Filing Order Allegheny Notice* (Case No. 24-1077) (*See* Section XVI below).

Second CapEx Info Filing Order Allegheny Order. On May 23, 2024, the FERC issued an order (i) modifying the discussion in the *Second CapEx Info Filing Order*; (ii) granting in part and denying in part, the clarifications requested by Mystic (granting Mystic's requested clarification of Formal Challenge Issue 7; denying Mystic's requested clarification regarding Formal Challenge Issue 1; confirming that Formal Challenge Issues 1, 2 and 6 were appropriately set for hearing and settlement judge procedures); and setting aside that order, in part (setting aside, in part, the determination regarding Challenge Issue 7)); and (iii) dismissing Mystic's alternative request for reh'g.[50] As noted immediately above, this matter has been appealed to, and is pending before, the DC Circuit.

(-014) Revised ROE (Sixth) Compliance Filing. Still pending is Mystic's December 20, 2021 filing in response to the requirements of the *Mystic ROE Allegheny Order*.[51] The sixth compliance filing revised (i) the Cost of Common Equity figures from 9.33% to 9.19%, for both Mystic 8&9 and Everett Marine Terminal ("Everett"), and (ii) the stated Annual Fixed Revenue Requirements for both the 2022/23 and 2023/24 Capacity Commitment Periods. Comments on the sixth compliance filing were due on or before January 10, 2022; none were filed. The Sixth Compliance Filing remains pending before the FERC.

30-Day Compliance Filing per Order on ENECOS Mystic COSA Complaint (ER23-1735). On April 27, 2023, Mystic filed, as directed by the FERC's March 28, 2023 *Order on ENECOS Mystic COSA Complaint*,[52] changes to the Mystic COSA to include pipeline-related crediting as an explicit provision in the COSA. Mystic also provided additional information/COSA changes to (i) describe the crediting process; (ii) differentiate, through both an explanation in its compliance filing and creation of two new line items in Schedule 3A, the credits and charges included as part of the Fixed Pipeline Costs; (iii) address how and whether the pipeline-related crediting procedure interacts or should interact with the true-up procedure already included in the COSA and revise the true-up as necessary; and (iv) differentiate in the COSA the Pipeline Transportation Costs as Fixed O&M/Return on Investment Costs from the Pipeline Transportation Agreement Costs. Comments on the 30-day compliance filing were due on or before May 18, 2023. ISO-NE and Monitoring Analytics, LLC filed doc-less motions to intervene.

On July 10, 2023, ENECOS submitted comments (out-of-time) asserting that Mystic's compliance filing did not provide information sufficient to show that Mystic's after-the-fact pipeline-related crediting ensures that Mystic customers do not pay for pipeline costs that do not benefit them ("Crediting Issue"), the Schedule 3A true-up process does not provide the opportunity for an adequate verification process, and ISO-NE's COSA-related filings to date have similarly not addressed the Crediting Issue. ENECOS requested that the FERC direct Mystic to provide a work paper to "verify its assertion that it has always applied a full credit for third-party pipeline transportation costs to Constellation LNG's billings to Mystic". On July 20, 2023, Mystic protested ENECOS' comments. This 30-day compliance filing remains pending before the FERC.

Mystic COSA Protocols Waiver Request (ER24-2528). On July 12, 2024, Mystic requested waiver of the deadlines in Sections II.6.A and II.4.F of the COSA Protocols so that the deadline to make the 2024 Informational

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[49] *Constellation Mystic Power, LLC*, 186 FERC ¶ 62,048 (Feb. 5, 2024) ("*Second CapEx Info Filing Order Allegheny Notice*").

[50] *Constellation Mystic Power, LLC*, 187 FERC ¶ 61,099 (May 23, 2024) ("*Second CapEx Info Filing Order Allegheny Order*").

[51] An "Allegheny Order" is a merits rehearing order issued on or after the 31st day after receipt of a rehearing request, reflecting the FERC's authority to "modify or set aside, in whole or in part," its order until it files the record on appeal with a reviewing federal court. An Allegheny Order will use "modifying the discussion" if the FERC is providing a further explanation, but is not changing the outcome, of the underlying order; or "set aside" if the FERC is changing the outcome of the underlying order. Aggrieved parties have 60 days after a deemed denial to file a review petition, even if FERC has announced its intention to issue a further merits order.

[52] *Belmont Municipal Light Dept., et al. v. Constellation Mystic Power, LLC and ISO New England, Inc.*, 182 FERC ¶ 61,199 (Mar. 28, 2023) ("*Order on ENECOS Mystic COSA Complaint*", which denied in part, and accepted in part, ENECOS' Complaint against Mystic and ISO-NE challenging the pass-through of firm pipeline transportation costs under the 2nd Amended and Restated Mystic COSA).

Filing (and subsequent related deadlines) can be delayed to allow Mystic and active intervenors in ER18-1639-027, who have agreed to a settlement in principle in that proceeding, to determine whether a settlement can be reached that may impact or obviate the need for the filing or challenges that might be filed subsequent thereto. Comments on Mystic's waiver request are due on or before ***August 2, 2024***.

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

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

RENEW Formal Challenge. RENEW's January 31, 2023 formal challenge ("Challenge") to the 2022/23 Update/Informational Filing[53] remains pending before the FERC. In the Challenge, RENEW asserted that (i) the TOs failed to provide adequate rate input information in the Annual Informational Filing and in the Information Exchange Period under the Interim Formula Rate Protocols regarding inclusion or exclusion of "O&M costs" on Network Upgrades that the TOs directly assign to Interconnection Customers (and thereby failing to demonstrate that such O&M costs are not being double counted in transmission rates); and (ii) the TO's Interpretation of "Interested Party" to exclude RENEW violated the Interim Formula Rate Protocols. RENEW thus asked that the FERC (a) require the TOs to show the calculation of the annual O&M charges with sources of data inputs and show how such O&M charges are not being double recovered in transmission rates, and (b) determine that an entity such as RENEW is an Interested Party under the Interim Formula Rate Protocols and that its Information Requests seeking rate inputs and support for the O&M charges on Network Upgrades are within the scope of the Interim Formula Rate Protocols process. Comments on RENEW's Challenge were due on or before March 16, 2023. Comments and protests were filed by: Avangrid, Eversource, National Grid, Public Systems, RI Energy, Unitil, Versant Power, VTransco/GMP. On March 31, 2023, RENEW answered the comments and protests to its Challenge. Subsequently, on April 14, 2023, Eversource answered RENEW's March 31 answer. There has been no activity in this proceeding since Eversource's answer. This matter remains pending before the FERC. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **ISO Securities: Authorization for Issuance of Debt Securities (ES24-41)**

On July 19, 2024, the FERC authorized[54] ISO-NE to issue up to $75 million in senior unsecured notes ("Notes") to (i) refinance its existing financings[55] and (ii) raise an additional $25 million of indebtedness to support additional capital expenditures to support ISO-NE's market design objectives of "moving toward clean energy, balancing resources, energy adequacy and robust transmission". ISO-NE proposes to issue the Notes within the two-year period in which this authorization will be effective and stated that the Notes will be long-term debt expected to mature in a minimum of 10 years and a maximum of 12 years from the date of issuance. Comments on this filing were due on or before July 8, 2024; none were filed. National Grid intervened doc-lessly. This matter

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[53] The 2022/23 annual filing reflected the charges to be assessed under annual transmission and settlement formula rates, reflecting actual 2021 cost data, plus forecasted revenue requirements associated with projected PTF, Local Service and Schedule 12C capital additions for 2022 and 2023, as well as the Annual True-up including associated interest. The formula rates in effect for 2023 included a billing true up of seven months of 2021 (June-Dec.). The Pool "postage stamp" RNS Rate, effective Jan. 1, 2023, was $140.94 /kW-year, a decrease of $1.84 /kW-year from the charges that went into effect the year prior. The updates to the revenue requirements for Scheduling, System Control and Dispatch Services (the Schedule 1 formula rate) resulted in a Schedule 1 charge of $1.75 kW-year (eff. June 1, 2022 through May 31, 2023), a $0.12/kW-year decrease from the Schedule 1 charge that last went into effect on June 1, 2022.

[54] *ISO New England Inc.*, 188 FERC ¶ 62,038 (July 19, 2024).

[55] Prior to 2012, ISO-NE's existing capital projects had been financed through the proceeds of $39 million of private placement debt that was issued by ISO-NE in 2004 (the "2004 Capital Financing") (authorized by the FERC in 109 FERC ¶ 62,195 (2004)). In 2012, ISO-NE obtained FERC approval to raise an additional $11 million in indebtedness in order to support a higher sustained level of capital expenditures (the "2012 Capital Financing"). In 2013, the FERC authorized ISO-NE to issue notes in order to refinance the $39 million in aggregate principal amount of senior unsecured notes issued in the 2004 Capital Financing in order to reduce ISO-NE's interest costs (the "2013 Refinancing," and together with the 2004 Capital Financing and the 2012 Capital Financing, the "Existing Financings"). The notes issued in the Existing Financings mature on Nov. 8, 2024.

is now pending before the FERC. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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

- **MW-Dependent Fuel Price Adjustments (ER24-2584)**

On July 24, 2024, ISO-NE and NEPOOL jointly filed changes to allow Market Participants to submit up to two different MW-dependent fuel prices in their cost-based Reference Levels. In addition, ISO-NE provided its explanation for why the current market power mitigation provisions addressing the duration of mitigation are just and reasonable and not unduly discriminatory or preferential. Comments on this deadline are due on or before ***August 14, 2024***. Thus far, Calpine and Public Citizen have filed doc-less interventions. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **eTariff § I.2 Corrections (ER24-2270)**

On June 13, 2024, ISO-NE filed corrections to its eTariff to remove from Section I.2.2 changes (from the DASI (ER24-275) and SATOA (ER23-739) filings) that were inadvertently included in the FRM Offer Cap eTariff changes that became effective on April 15, 2024. Other than to pull out the yet-to-effective changes from the effective eTariff text, no other changes were made to the definitions. Comments on this filing were due on or before July 5, 2024; none were filed. NEPOOL, Calpine and National Grid intervened doc-lessly. On July 26, 2024, ISO-NE supplemented its filing to add a request for a waiver of the FERC's 60-day notice requirement to permit the conforming Tariff changes to become effective on April 15, 2024, the effective date of the FRM Offer Cap eTariff changes. 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).

- **Waiver Request: Withdrawal from IEP and Return of IEP Net Revenues Received (Canal Marketing/ Canal 3) (ER24-1407)**

As previously reported, on March 4, 2024 (as amended and supplemented on March 8 and March 22, 2024), Canal Marketing LLC (f/k/a Stonepeak Kestrel Energy Marketing LLC) ("CM") requested a one-time waiver of the provisions of Appendix K to Market Rule 1 (Inventoried Energy Program (the "IEP")) so as to permit CM to (i) withdraw CM's participation in the IEP on behalf of Canal 3 Generating LLC ("Canal 3")[56] for Winter 2023-24 and (ii) to return to ISO-NE the net revenues, with applicable interest, that CM received on behalf of Canal 3 for Canal 3's participation in the IEP for Winter 2023-2024 because Canal 3's return from a forced outage was delayed beyond the end of the IEP's Winter 2023-24 period.[57] CM explained that, when it elected to participate in the IEP on behalf of Canal 3 on September 21, 2023, CM anticipated that the Canal 3 Facility would be back in service by December 18, 2023, and would be available for the remainder of the IEP's Winter 2023-24 period. However, the actual return-to-service date for the Canal 3 Facility was delayed beyond the end of the IEP's Winter 2023-24 period and Canal 3 was not able to perform during the Winter 2023-24 period. CM seeks the requested waiver because no provision in Appendix K nor any other provision of the Tariff was identified as providing a mechanism for a Participant to withdraw from the IEP or to return IEP revenues to ISO-NE. Comments on the CM Waiver Request were due on or before March 25, 2024. The IMM submitted comments supporting the CM Waiver Request insofar as CM requests the prompt repayment of the revenues received on behalf of Canal 3 under the

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[56] Canal 3 is an approximately 333 MW (summer rating) gas- and oil-fired generation facility. Canal 3 has been on forced outage since Feb. 3, 2023, when a blade on the turbine wheel broke off and caused catastrophic damage to the gas turbine, which significantly impacted the compressor blades and bearings. As a result, the full train was disassembled and shipped to General Electric ("GE"), its manufacturer, for repair. GE initially provided a repair schedule that contemplated Canal 3's return to service by Dec. 15, 2023.

[57] At the time CM made its IEP election submission, CM anticipated that, based on information provided by GE, Canal 3 would be back on line by Dec. 18, 2023. CM informed ISO-NE in mid-December that forced outage of Canal 3 would continue until near the end of the IEP's Winter 2023-24 period, but no mechanism for a withdrawal from the IEP or the return of IEP payments received was identified.

IEP and, if determined to be warranted by the FERC, net of Program charges. NEPOOL (out-of-time) and National Grid intervened doc-lessly.

On May 24, 2024, CM requested that the FERC act on its waiver request and informed the FERC that ISO-NE supported CM's request to return to ISO-NE the net revenues, with applicable interest, that CM has received on behalf of Canal 3 for Canal 3's participation in the IEP. On June 7, 2024, CM answered the IMM's comments, highlighting that ISO-NE was apprised by mid-December 2023 of CM's intent to return all payments received on behalf of Canal 3 and to withdraw from the IEP, well before ISO-NE incurred any charges. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **ISO/RTO Credit-Related Information Sharing (ER24-138)**

On July 25, 2024, the FERC accepted changes to the Information Policy to (i) permit ISO-NE to share Market Participant, Transmission Customer and Applicant (collectively, "Participants") credit-related information with other ISO/RTOs; (ii) permit ISO-NE to use credit-related information received from other ISO/RTOs to the same extent and for the same purposes as ISO-NE is permitted under the Tariff with respect to its Participants; and (iii) require ISO-NE to keep such received credit-related information confidential in accordance with the Tariff, in each case for the purpose of credit risk management and mitigation (the "*Credit Info Sharing Changes*").[58] As previously reported, the Credit Info Sharing Changes were supported by the Participants Committee and jointly filed with ISO-NE in October of last year in response to the requirements of Order 895. *The Credit Info Sharing Changes* became effective *July 26, 2024*, as requested. Unless the *Credit Info Sharing Changes Order* is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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

In a lengthy compliance Order[59] issued March 1, 2023, the FERC approved in part, and rejected in part, the *Order 2222* compliance filing[60] ("*Order 2222 Compliance Order*") filed jointly by ISO-NE, NEPOOL and the PTO AC ("Filing Parties").[61] In the *Order 2222 Compliance Order*, the FERC directed a number of revisions and additional compliance and informational filings to be filed within 30, 60 or 180 days of the *Order 2222 Compliance Order.* As previously reported, the FERC accepted the 30-, 60- and 180-day compliance filings.[62] In the order conditionally

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[58] *ISO New England Inc.*, 188 FERC ¶ 61,065 (July 25, 2024) ("*Credit Info Sharing Changes Order*").

[59] Commissioners Danly and Clements each provided separate concurrences with, and Commissioner Christie provided a separate dissent from, the *Compliance Order*. Commissioners Danly and Christie, despite their opposing positions on the Compliance Order, both reiterated their reasons for dissenting from *Order 2222* and concern for FERC overreach and difficulty with complying with *Order 2222*. In her separate concurrence, Commissioner Clements urged the ISO on compliance to "modify its proposal to address undue barriers and make participation more workable" and "to pursue steps that genuinely open [the New England Markets] to DERs like behind-the-meter resources."

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

[61] *ISO New England Inc. and New England Power Pool Participants Comm.*, 182 FERC ¶ 61,137 (Mar. 1, 2023) ("*First Order 2222 Compliance Order*").

[62] *ISO New England Inc.*, Docket Nos. ER22-983-003 and ER22-983-005 (Oct. 25, 2023) (unpublished letter order) ("*30/180-Day Order 2222 Compliance Order*"). The 30-Day compliance filings explained how current Tariff capacity market mitigation rules would apply to DECRs participating in FCA18 and provided an update on implementation timeline milestones associated with DECR participation in FCA18 and the other markets. The 180-Day compliance filing explained how the current Tariff capacity market mitigation rules would apply to DECRs participating in FCA19 and beyond and the Mar. 1, 2024 effective date for the rules allowing DECRs to participate in the FCM).

accepting the 60-day compliance filing,[63] the FERC directed ISO-NE to submit a further compliance filing, on or before January 31, 2024, to comply with the directives of the *First Compliance Order* regarding the submission of DERA meter data.[64] The FERC also granted in part ISO-NE's request for an extension of time to address directives in the *First Order 2222 Compliance Order*.[65] On December 4, 2023, AEU requested rehearing of the *Order 2222 60-Day Compliance Filing Order*, which was deemed to have been denied by operation of law.[66]

(-006) Order 2222 60-Day Compliance Filing Order Allegheny Order. On May 23, 2024, in response to AEU's December 4, 2023 request for rehearing of the *Order 2222 60-Day Compliance Filing Order*, the FERC issued an *Allegheny* order,[67] sustaining three of the four findings challenged by AEU. However, the FERC set aside, in part, its prior finding that ISO-NE partially complies with the requirement to revise its Tariff to establish market rules that address metering requirements necessary for distributed energy resource aggregations ("DERAs").[68] The FERC found that, under its rule of reason,[69] ISO-NE's basic description of its metering practices for DERAs was incomplete because the Tariff did not include submetering requirements for DERAs participating as submetered Alternative Technology Regulation Resources ("ATRRs").[70] Accordingly, the FERC directed ISO-NE to file, on or before ***July 22, 2024***, a further compliance filing to revise ISO-NE's Tariff to specify its submetering requirements for DER Aggregations' participation as submetered ATRRs.

(-007) Further Compliance Changes. On April 11, 2024, the FERC conditionally accepted ISO-NE's January 31 Further Compliance Filing, subject to a further 60-day compliance filing. [71] In the *Further Order 2222 Compliance Filing Order*, the FERC found that ISO-NE complied with *Order 2222 60-Day Compliance Filing Order*'s

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[63] *ISO New England Inc.*, 185 FERC ¶ 61,095 (Nov. 2, 2023) ("*Order 2222 60-Day Compliance Filing Order*").

[64] Specifically, the FERC directed ISO-NE to revise the Tariff to designate the DER Aggregator as the entity responsible for providing any required metering information to ISO-NE, and to require that each DER Aggregator maintain and submit aggregate settlement data for the DERA, so that ISO-NE can regularly settle with the DER Aggregator for its market participation. To the extent that ISO-NE proposes in that further compliance filing that metering data come from or flow through distribution utilities, the FERC directed ISO-NE to coordinate with distribution utilities and relevant electric retail regulatory authorities to establish protocols for sharing such metering data, and explain how such protocols minimize costs and other burdens and address concerns raised with respect to privacy and cybersecurity. *Id.* at P 34.

[65] The FERC ordered ISO-NE in its 60-day compliance filing to revise the Tariff to: (1) have RERRA make the determination of whether to allow customers of small utilities to participate in ISO-NE's markets through aggregation; (2) require that each DER Aggregator maintain and submit aggregate settlement data for the DERA; (3) designate the DER Aggregator as the entity responsible for providing any required metering information to ISO-NE, and if necessary, establish protocols for sharing meter data that minimize costs and other burdens and address concerns raised with respect to privacy and cybersecurity; (4) designate the DER Aggregator as the entity responsible for providing any required metering information to ISO-NE; and (5) add specificity regarding existing resource non-performance penalties that would apply to a DERA when a Host Utility overrides ISO-NE dispatch instructions. ISO-NE was also directed to: (1) identify the existing rules requiring a Market Participant that provides energy withdrawal service to be a load serving entity that is billed for energy withdrawal ("LSE Requirement") and explain whether the LSE Requirement is required of all resources seeking to provide wholesale energy withdrawal service in the energy market; (2) explain why its proposed metering and telemetry requirements were just and reasonable and did not pose an unnecessary and undue barrier to individual DERs joining a DERA; (3) establish protocols for sharing metering data that minimize costs and other burdens and address privacy and cybersecurity concerns; and (4) address how ISO-NE will resolve disputes that are within its authority and subject to its Tariff, regardless of whether there is an available dispute resolution process established by the RERRA.

[66] *ISO New England Inc.*, 186 FERC ¶ 62,002 (Jan. 4, 2023) ("*Order 2222 60-Day Compliance Filing Order Allegheny Notice*").

[67] *ISO New England Inc.*, 187 FERC ¶ 61,100 (May 23, 2024) ("*Order 2222 60-Day Compliance Filing Order Allegheny Order*").

[68] *See id.* P 78 ("we find that ISO-NE partially complies with the requirement to revise its Tariff to establish market rules that address metering requirements necessary for DERAs").

[69] "[d]ecisions as to whether an item should be placed in a tariff or in a business practice manual are guided by the [FERC]'s rule of reason policy, under which provisions that 'significantly affect rates, terms, and conditions' of service, are readily susceptible of specification, and are not generally understood in a contractual agreement must be included in the tariff, while items better classified as implementation details may be included only in the business practice manual." *Order 2222 60-Day Compliance Filing Order Allegheny Order* at P 36 citing *Order 2222*, 172 FERC ¶ 61,247 at P 271.

[70] *Order 2222 60-Day Compliance Filing Order Allegheny Order at P 6.*

[71] *ISO New England Inc*., 187 FERC ¶ 61,017 (Apr. 11, 2024) ("*Further Order 2222 Compliance Filing Order*").

directive to (i) designate the DER Aggregator as the entity responsible for providing any required metering information to ISO-NE; (ii) require that each DER Aggregator maintain and submit aggregate settlement data for DERAs; and (iii) establish protocols for sharing metering data. However, the FERC disagreed with ISO-NE's assertion that meter data submission responsibilities and deadlines at issue are technical and timing details to implement the Tariff's settlement requirements, and, therefore, properly included in ISO-NE's manuals rather than its Tariff. Rather, the FERC found that "the meter data submission deadline is a key component of metering practices for DER Aggregators that should be included in the basic description of metering practices in the Tariff".[72] Accordingly, the FERC directed ISO-NE, on or before June 10, 2024, "to submit … Tariff revisions that include the meter data submission deadline in its Tariff."[73]

***(-008) Metering Data Submission Revisions*.** The Metering Data Submission Revisions required by the April 11, 2024 *Further Order 2222 Compliance Filing Order* were recommended for Participants Committee support by the Markets Committee at its May 7-8, 2024 meeting and, because of the compliance deadline, filed by ISO-NE on June 10, 2024. The changes were supported by the Participants Committee at the June 25-26 Summer Meeting (Consent Agenda Item No. 6). Comments on ISO-NE's June 10 compliance filing were due on or before July 1, 2024; NEPOOL filed comments supporting the Revisions. The June 10, 2024 compliance filing is now pending before the FERC.

***(-009) ATTR Submetering Tariff Revisions*.** The ATTR Submetering Revisions required by the *Order 2222 60-Day Compliance Filing Order Allegheny Order*[74] were recommended for Participants Committee support by the Markets Committee at its July 9-10, 2024 Summer Meeting and, because of the compliance deadline, filed by ISO-NE on July 22, 2024. The Participants Committee will consider supporting the ATTR Submetering Revisions at its August 1, 2024 meeting (Consent Agenda Item No. 1). Comments on ISO-NE's July 22 compliance filing are due on or before **August 12, 2024**. NEPOOL will submit comments reporting on the Participants Committee's August 1 action.

***Federal Court (DC Circuit) Appeals*.** As previously reported, CMP and UI, National Grid, Eversource, and ISO-NE filed separate appeals of the *Order 2222 Compliance Order*. Those appeals have been consolidated (Case No. 23-1167) and are reported on in Section XVI below.

If you have any questions concerning these matters, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com); Eric Runge (617-345-4735; ekrunge@daypitney.com); or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

IV. OATT Amendments / TOAs / Coordination Agreements

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

On May 14, 2024 (as corrected May 31, 2024), ISO-NE, NEPOOL and the PTO AC filed proposed Tariff revisions tin response to the requirements of *Orders 2023* and *2023-A* ("*Order 2023* Revisions"). The Order 2023 Revisions adopt most of the required *pro forma* OATT changes, with some regional variations to recognize certain existing features of the ISO-NE interconnection process, including an existing cluster process to address cases where cluster enabling transmission is required, integration of the interconnection process with FCM participation, and a unified treatment of all ISO interconnection requests, including those for small generators and Elective Transmission Upgrades ("ETU") (such revisions were filed in a separate concurrent filing (ER24-2007)). Concurrently, the Filing Parties proposed changes to aspects of the Tariff impacted by the *Order 2023* Revisions, but that may be considered to be beyond the scope of the compliance obligations (see ER24-2007 immediately

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[72] *Id.* at P 13.

[73] *Id.*

[74] *See Order 2222 60-Day Compliance Filing Order Allegheny Order (-006) infra*.

below). The filing parties requested an effective date of August 12, 2024 for the *Order 2023* Revisions. Comments on this filing were due on or before June 4, 2024, and were filed by BlueWave, Glenvale, New Leaf, RENEW, Clean Energy Associations,[75] and Longroad Energy Holdings. Calpine, Clearway, Constellation, National Grid, NESCOE, RIE, Shell Energy/Savion, MA DPU, and Cordelio Services intervened doc-lessly. On June 20, 2024, ISO-NE answered the June 4 comments. On July 5, Glenvale and Longroad Energy answered ISO-NE's Jun 20 Answer. On July 19, ISO-NE answered Glenvale's and Longroad Energy's further answers. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617- 345-4735; ekrunge@daypitney.com).

- ***Order 2023* Related Changes (ER24-2007)**

Also on May 14, 2024, ISO-NE, NEPOOL and the PTO AC filed proposed Tariff revisions to harmonize the SGIP, ETU Interconnection Procedures ("ETUIP"), and Regional Transmission Service rules with the contemporaneously-filed Order 2023 Revisions ("*Order 2023* Related Changes"). The *Order 2023* Related Changes, which propose changes to aspects of the Tariff impacted by the *Order 2023* Revisions, but that may be considered to be beyond the scope of the *Order 2023* compliance requirements, include: (i) revisions to the *pro forma* SGIP beyond those explicitly required in *Order 2023/2023-A* to align the Small Generator Interconnection Procedures ("SGIP") with the Large Generator Interconnection Procedures ("LGIP") and include Small Generating Facilities in the new Cluster Study Process; (ii) revisions to the ETUIP to ensure it remains aligned with the LGIP and include ETUs in the Cluster Study Process; and (iii) revisions to Study Procedures for Regional Network Service Requests and Through or Out Service Requests to require that System Impact Studies related to Regional Transmission Service requests take place in the Cluster Study incorporated as part of the Cluster Study Process. An effective date of August 12, 2024 was requested. Comments on the *Order 2023* Related Changes were due on or before June 4, 2024, and were filed by Glenvale, Longroad, New Leaf Energy, RENEW and Clean Energy Associations. BlueWave, Calpine, Clearway (out-of-time), National Grid, NESCOE, RIE, Shell Energy/Savion, Cordelio Services, and the MA DPU intervened doc-lessly. On June 20, 2024, ISO-NE answered the June 4 comments. On July 5, Glenvale and Longroad Energy answered ISO-NE's June 20 Answer. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617- 345-4735; ekrunge@daypitney.com).

- **LTTP Phase 2 Tariff Changes (ER24-1978)**

On July 8, 2024, the FERC accepted proposed revisions to Section 16 of Attachment K of the OATT to establish, as part of the optional, longer-term transmission planning process, the mechanisms that enable the New England states to develop policy-based transmission facilities in connection with Longer-Term Transmission Studies ("LTTS"), and the associated cost allocation methods for these upgrades (the "LTTP Phase 2 Changes").[76] As previously reported, the LTTP Phase 2 Changes incorporate the following processes: (i) a comprehensive core process (which allows the New England states to advance the development of transmission when at least one Longer-Term Proposal submitted in response to a request for proposal meets the identified needs and has financial benefits that exceed the project's costs as calculated over the first 20 years of the project's life has a benefit-to-cost ratio ("BCR") that is greater than one) and (ii) an add-on supplemental process (which enables the New England states to agree to move forward with a transmission project where none of the proposals that meet the identified needs satisfy the greater-than-one BCR requirement). The FERC addressed, but ultimately found misplaced, arguments made regarding the right of first refusal, and found that even if aspects of the LTTP Phase 2 Changes "make it more difficult for nonincumbent transmission developers to submit comprehensive proposals than it would be for incumbent transmission owners, such potential difficulty does not render the proposed LTTP Phase 2 Changes unjust and

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[75] "Clean Energy Associations" are, collectively, Advanced Energy United ("AEU"), the American Clean Power Association ("ACPA"), Natural Resources Defense Council ("NRDC"), and the Solar Energy Industries Association ("SEIA").

[76] *ISO New England Inc. and New England Power Pool*, 188 FERC ¶ 61,010 (July 8, 2024) ("*LTTP Phase 2 Changes Order*").

unreasonable or unduly discriminatory or preferential."[77] The LTTP Phase 2 Changes were accepted effective *July 9, 2024*, as requested.

In addition, the FERC accepted ISO-NE's proposal to correct Tariff Section I.1.2, to remove the revisions to the definition of the term "Regulation Resources" and the addition of the terms "Storage as Transmission-Only Asset (SATOA)" and "Real-Time SATOA Obligation" that are not yet intended to be in effect and were included with the LTTP Phase 2 Changes in error. Those corrections were submitted on July 27, 2024. Comments on the compliance filing are due on or before ***August 16, 2024***. If you have any questions concerning this proceeding, please contact Eric Runge (617- 345-4735; ekrunge@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

No Activities to Report

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

- **Schedule 21-VP: Versant/Jonesboro LSA (ER24-24)**

As previously reported, the FERC accepted for filing a Local Service Agreement ("LSA") by and among Versant, ISO-NE, NE Renewable Power, and Jonesboro, LLC ("Jonesboro"), effective *December 4, 2023*, but denied waiver of the FERC's 60-day prior notice requirement for the filing.[78] The FERC found that the Filing Parties did not make the required showing of extraordinary circumstances to warrant waiver of the prior filing requirement. Accordingly, the FERC directed the Filing Parties (i) to refund the time value of revenues collected for the time period the rate was collected without FERC authorization, with refunds limited so as not to cause Filing Parties to operate at a loss ("Time Value Refunds"); and (ii) to file a refund report, including information supporting calculation of the Time Value Refunds.

Time Value Refunds Report. On December 18, 2023, Versant Power filed a refund report ("Report") detailing the Time Value Refunds it paid to NE Renewable Power and Jonesboro on December 15, 2023. Comments on the Report were due on or before January 8, 2024; none were filed. The Report remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-GMP: National Grid/Green Mountain Power LSA (ER23-2804)**

As previously reported, ISO-NE and New England Power ("National Grid", and together with ISO-NE, the "Filing Parties") filed on September 11, 2023, a 20-year LSA by and among National Grid, ISO-NE and Green Mountain Power ("GMP").[79] The Filing Parties stated that the LSA conformed to the *pro forma* LSA contained in the ISO-NE Tariff and superseded and replaced another conforming LSA among ISO-NE, National Grid, and GMP that listed an expiration date of September 30, 2022 (TSA-NEP-25). The Parties requested that the FERC grant waiver of its notice requirement[80] to the extent necessary to permit a requested October 21, 2022 effective date. The LSA was filed separately given that requested effective date.

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[77] *Id.* at P 40.

[78] *ISO New England Inc.*, Docket No. ER24-24-000 (Nov. 30, 2023) (unpublished letter order).

[79] The LSA was designated as Service Agreement No. TSA-NEP-114 under the ISO-NE OATT.

[80] 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.

LSA Accepted; Waiver of Prior Filing Requirement Denied; Time Value Refunds Ordered. Similar to the Versant/Jonesboro proceeding (*see* ER24-24 above), the FERC accepted the National Grid/GMP LSA for filing, effective *November 11, 2023*, but denied waiver of the FERC's 60-day prior notice requirement for the filing.[81] The FERC found that the Filing Parties did not make the required showing of extraordinary circumstances to warrant waiver of the prior filing requirement. Accordingly, the FERC directed the Filing Parties to make Time Value Refunds. On December 4, 2023, Filing Parties requested, and on December 6, 2023 the FERC granted, a 45-day extension of time (to January 22, 2024) to make the Time Value Refunds, with the corresponding refund report to be filed no later than February 21, 2024.

Time Value Refunds Report. On February 21, 2024, National Grid filed a refund report ("Report") detailing the Time Value Refunds National Grid paid to GMP on January 22, 2024. Comments on the Report were due on or before March 13, 2024; none were filed. The Report remains pending before the FERC. If you have any questions concerning these matters, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-VP: Versant/Black Bear LSAs (ER23-2035)**

On July 28, 2023, the FERC accepted seven fully executed, non-conforming LSAs by and among Versant Power, ISO-NE and Black Bear Hydro Partners, LLC or Black Bear SO, LLC (together with Black Bear Hydro Partners, "Black Bear").[82] The service agreements are based on the Form of Local Service Agreement contained in Schedule 21-Common under the ISO-NE OATT, but were filed because they are non-conforming insofar as they reflect different rates from those set forth in Schedule 21-VP. The LSAs were accepted for filing effective *August 1, 2023*, rather than January 1, 2021 as requested, triggering a Time Value Refund requirement.[83] On August 29, 2023, Versant Power submitted a Refund Report detailing the Time Value Refunds it paid to Black Bear Hydro Partners, LLC and Black Bear SO, LLC on August 18, 2023. Comments on the Refund Report were due on or before September 19, 2023; none were filed. The Refund Report remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On August 29, 2023, Versant submitted a 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. Comments on the Versant 2022 Annual Update Settlement Agreement were due on or before September 19, 2023; none were filed. MPUC intervened doc-lessly on September 15, 2023. This matter remains pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VII. NEPOOL Agreement/Participants Agreement Amendments

- **135th Agreement; PA13 (Unused Provisional Member Voting Share Allocation Changes) (ER24-2636)**

On July 31, 2024, NEPOOL and ISO-NE jointly filed the 135th Agreement Amending New England Power Pool Agreement ("135th Agreement") and Amendment No. 13 to the PA (together, the "Unused Provisional Member Voting Share Allocation Changes" or "Changes"). The Changes modify the allocation of

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[81] *ISO New England Inc.*, Docket No. ER23-2804-000 (Nov. 7, 2023) (unpublished letter order).

[82] *ISO New England Inc.*, Docket No. ER23-2035-000 (July 28, 2023) ("*Versant Black Bear LSAs Order*").

[83] The FERC denied the requested waiver of its 60-day prior notice requirement (18 C.F.R. § 35.11), finding that the Filing Parties did not make an adequate showing of extraordinary circumstances. Accordingly, Versant was required to refund the time value of revenues collected for the time period the rate was collected without FERC authorization (with refunds limited so as not to cause Versant to operate at a loss) and file a refund report with the FERC.

any unused Provisional Member Group Seat voting share to all six Sectors. As previously reported, the Changes were approved unanimously by the Participants Committee pursuant to balloting under Section 6.10 of the NEPOOL Agreement and Section 17.2.3 of the Participants Agreement in which the Minimum Response Requirement was satisfied. An August 1, 2024 effective date was requested. Comments on the Changes are due on or before ***August 21, 2024***. If you have any questions concerning the Changes, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VIII. Regional Reports[84]

- **IMM Quarterly Markets Reports: Spring 2024 (ZZ24-4)**

On July 22, 2024, the IMM filed with the FERC its Spring 2024 report of "market data regularly collected by [the IMM] in the course of carrying out its functions under … Appendix A and analysis of such market data," as required pursuant to Section 12.2.2 of Appendix A to Market Rule 1. These filings are not noticed for public comment by the FERC. The Spring Report will be discussed with the Markets Committee at the Markets Committee's August meeting.

- **LFTR Implementation Quarterly Status Report (ER07-476)**

On July 15, 2024, ISO-NE filed its 63rd quarterly status report regarding LFTR implementation. ISO-NE reported that it implemented monthly reconfiguration auctions (accepted in ER12-2122) beginning with the month of October 2019. ISO-NE further reported that, while it will continue to evaluate its as-filed LFTR design and financial assurance issues, including an ongoing evaluation of the FTR market and risk associated with FTRs and LFTRs, it is currently focused on higher priority market-design initiatives. ISO-NE concluded its report by describing the 18-month implementation that would be required once the LFTR financial assurance issues are resolved. These status reports are not noticed for public comment.

- **Reserve Market Compliance (36th) Semi-Annual Report (ER06-613)**

On July 8, 2024, after nearly 18 years of semi-annual reserve market compliance reports (as directed by the original ASM II Order,[85] as modified[86] (together, the "Orders")), and a finding that, in light of its order accepting the proposed forward market for TMSR, effective March 1, 2025,[87] the FERC terminated any further reporting obligation established by the Orders.[88] Unless the *Order Terminating Reporting Requirement* is challenged, this proceeding will be concluded. If you have any questions, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

IX. Membership Filings

- **August 2024 Membership Filing (ER24-2623)**

On July 30, 2024, NEPOOL requested that the FERC accept: (i) the following Applicant's membership in NEPOOL as of August 1, 2024: Twig Redwood Inc.; and (ii) the termination of the Participant status of MFT Energy US 1 LLC. Comments on this filing are due on or before August 20, 2024.

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[84] 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.

[85] *See NEPOOL and ISO New England Inc.*, 115 FERC ¶ 61,175 (2006) ("*ASM II Order*") (directing the ISO to provide updates on the implementation of a forward TMSR market), *reh'g denied* 117 FERC ¶ 61,106 (May 12, 2006).

[86] *See NEPOOL and ISO New England Inc.*, 123 FERC ¶ 61,298 (June 23, 2008) (continuing the semi-annual reporting requirement with respect to the consideration and implementation of a forward market for Ten-Minute Spinning Reserve ("TMSR")).

[87] *ISO New England Inc.*, 186 FERC ¶ 61,076 (Jan. 29, 2024) ("*DASI Order*").

[88] *ISO New England Inc.*, 188 FERC ¶ 61,014 (July 8, 2024) ("*Order Terminating Reporting Requirement*").

- **July 2024 Membership Filing (ER24-2430)**

On June 28, 2024, NEPOOL requested that the FERC accept: (i) the following Applicants' Data-Only Participant memberships in NEPOOL as of July 1, 2024: Aurora Energy Research LLC and Enverus, Inc.; and (ii) the termination of the Participant status of KCE CT 10, LLC. Comments on this filing were due on or before July 19, 2024; none were filed. This matter is pending before the FERC.

- **June 2024 Membership Filing (ER24-2169)**

On July 30, 2024, the FERC accepted: (i) the following Applicants' membership in NEPOOL: ATNV Energy LP (Supplier Sector); Delorean Power LLC d/b/a Lightshift Energy [Related Person to Howard Wind LLC, Hecate Energy Albany 2 LLC, RoxWind LLC, and Weaver Wind, LLC (Supplier Sector)]; Fanfare Energy, LLC [Related Person to Think Energy, LLC and to Brookfield Renewable Trading and Marketing LP (Supplier Sector)]; ProGrid Ventures, LLC (Supplier Sector); and ZGE Massachusetts LLC (Supplier Sector); (ii) the termination of the Participant status of: Agile Energy Trading LLC (Supplier Sector); Energy Harbor LLC [Related Person to Dynegy Marketing and Trade, LLC (Supplier Sector)]; Hydroland, Inc. (AR Sector); and Connecticut Materials Innovations and Recycling Authority (Publicly Owned Entity Sector); and (iii) the name change of Reworld REC, LLC (f/k/a Covanta Energy Marketing, LLC).[89] Unless the July 30 order is challenged, this proceeding will be concluded.

X. Misc. - ERO Rules, Filings; Reliability Standards[90]

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

- **Revised Reliability Standard: EOP-012-2 (RD24-5)**

On June 27, 2024, the FERC approved Reliability Standard EOP-012-2 (Extreme Cold Weather Preparedness and Operations) ("Freeze Protection Standards"),[91] subject to further modification.[92] As previously reported, EOP-012-2 clarifies the applicability of standard's requirements for generator cold weather preparedness, further defining the circumstances under which a Generator Owner may declare that constraints preclude them from implementing one or more corrective actions to address freezing issues. EOP-012-2 also reflects additional improvements that would address the recommendations of the FERC, NERC, and Regional

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[89] *New England Power Pool Participants Comm.*, Docket No. ER24-2169-000 (July 30, 2024) (unpublished letter order).

[90] Reporting on the following ERO Reliability Standards or related rule-making proceedings has been suspended since the last Report 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.*).

[91] *N. Am. Elec. Rel. Corp.*, 187 FERC ¶ 61,204 (June 27, 2024).

[92] On or before Mar. 25, 2025, NERC was directed to develop and submit modifications to EOP-012-2: (1) to address concerns related to the ambiguity of the newly defined term Generator Cold Weather Constraint to ensure that the Generator Cold Weather Constraint declaration criteria included within EOP-012-2 are objective and sufficiently detailed so that applicable entities understand what is required of them and to remove all references to "reasonable cost," "unreasonable cost," "cost," and "good business practices" and replace them with objective, unambiguous, and auditable terms; (2) to require NERC to receive, review, evaluate, and confirm the validity of each Generator Cold Weather Constraint invoked by a generator owner, in a timely fashion, to ensure that such declaration cannot be used to avoid mandatory compliance with EOP-012-2 or obligations in a corrective action plan; (3) to shorten and clarify the corrective action plan implementation timelines and deadlines in Requirement R7; (4) to ensure that any extension of a corrective action plan implementation deadline beyond the maximum implementation timeframe required by EOP-012-2 is pre-approved by NERC and to ensure that the generator owner informs relevant registered entities of operating limitations in extreme cold weather during the period of the extension; and (5) to implement more frequent reviews of Generator Cold Weather Constraint declarations to verify that the constraint declaration remains valid.

Entity Staff Joint Inquiry into the causes of the February 2021 cold weather event affecting Texas and the south-central United States. EOP-012-2 will become effective on *October 1, 2024*.[93]

- **Revised Reliability Standard: CIP-012-2 (RD24-3)**
  On May 23, 2024, the FERC approved Reliability Standard CIP-012-2 (Cyber Security – Communications between Control Centers), which improves upon and expands the protections required by Reliability Standard CIP-012-1 by requiring Responsible Entities to mitigate the risk posed by loss of availability of communication links and Real-time Assessment and Real-time monitoring data transmitted between Control Centers.[94] Reliability Standard CIP-012-2 modified CIP-012-1 by adding two new Parts to Requirement R1 to address availability: Part 1.2, which requires protections for the availability of data in transit; and Part 1.3, which requires protections to initiate recovery of lost (i.e., unavailable) communication links. Pursuant to the approved implementation plan, CIP-012-2 will become effective on *July 1, 2026*.

- **NERC Cold Weather Data Collection Plan (RD23-1-002)**
  On May 23, 2024, the FERC accepted NERC's compliance filing for cold weather data collection as directed by the *Cold Weather Standards Order*[95] ("Cold Weather Data Collection Plan").[96] The Cold Weather Data Collection Plan proposes to gather and analyze certain data related to generator owner declared constraints and the performance of freeze protection measures during future extreme cold weather events. NERC noted that it plans to issue a Section 1600 data request for its first October 1 informational filing, thereafter, it may use other data collection methods.

- **Revised Reliability Standards: CIP-002-7 through CIP-013-3 (Virtualization) (RM24-8)**
  On July 10, 2024, NERC filed for approval 11 revised Critical Infrastructure Protection ("CIP") Reliability Standards,[97] as well as 18 new or revised definitions for inclusion in NERC's Glossary,[98] 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 has not notice a proposed rulemaking proceeding or otherwise invited public comment.

- **Report of Comparisons of 2023 Budgeted to Actual Costs for NERC and the Regional Entities (RR24-3)**
  On May 30, 2024, NERC filed its annual comparisons of actual to budgeted costs for 2023 for NERC and the six Regional Entities operating in 2023,[99] including NPCC. The Report includes comparisons of actual funding

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[93] Nearly all of EOP-012-2 Requirements will also become enforceable on *October 1, 2024*, with the exception of Requirement R3 which will become mandatory and enforceable on *October 1, 2025*.

[94] *N. Am. Elec. Rel. Corp.*, 187 FERC ¶ 61,086 (May 23, 2024).

[95] *N. Am. Elec. Rel. Corp.*, 182 FERC ¶ 61,094 (Feb. 16, 2023) ("*Cold Weather Standards Order*"), *reh'g denied*, 183 FERC ¶ 62,034 (Apr. 20, 2023), *order addressing arguments raised on reh'g*, 183 FERC ¶ 61,222 (June 29, 2023).

[96] *N. Am. Elec. Rel. Corp.*, 187 FERC ¶ 61,087 (May 23, 2024).

[97] 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).

[98] 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").

[99] Midwest Rel. Org. ("MRO"), Northeast Power Coordinating Council, Inc. ("NPCC"), ReliabilityFirst Corp. ("ReliabilityFirst"), SERC Rel. Corp. ("SERC"), Texas Rel. Entity, Inc. ("Texas RE"), and Western Elec. Coordinating Council ("WECC").

received and costs incurred, with explanations of significant actual cost-to-budget variances, audited financial statements, and tables showing metrics concerning NERC and Regional Entity administrative costs in their 2023 budgets and actual results. Comments on this filing were due on or before June 20, 2024; none were filed. This matter remains pending before the FERC.

XI. Misc. - of Regional Interest

- **203 Application: Berkshire Power/Gate City Power (EC24-104)**

On July 19, 2024, Berkshire Power Company, LLC ("Berkshire Power") requested authorization for a proposed transaction whereby Gate City Power – NE Generation LLC ("Gate City Power") will acquire all of the membership interests of Berkshire Power's parent, Tenaska Hampden Partners, LLC ("Tenaska Hampden"), from Tenaska Energy, Inc. ("Tenaska Energy") and Tenaska Energy Holdings, LLC ("Tenaska Holdings"). Following consummation of the proposed transaction, Berkshire Power will no longer be a Related Person to Tenaska Power Services *et al*. Comments on this application are due on or before ***August 9, 2024***. Thus far, Public Citizen has filed a doc-less intervention. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Trailstone/Engelhart US (EC24-87)**

On July 25, 2024, the FERC authorized the acquisition by Engelhart CTP (US) LLC ("Engelhart US") of 100% of the interests in the Trailstone Companies[100] from Riverstone V Trailstone Holdings (making the Trailstone Companies and Engelhart US Related Persons).[101] Pursuant to the *Trailstone Order*, Engelhart US and the Trailstone Companies 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: Eversource/GIP IV (EC24-59)**

On June 7, 2024, the FERC issued an order authorizing the proposed transaction pursuant to which GIP IV Whale Fund Holdings, L.P. ("GIP Whale") and/or one more of its affiliates will acquire Eversource Investment, LLC's interests in North East Offshore, LLC, Revolution Wind, LLC, South Fork Wind, LLC (together with North East Offshore, Revolution Wind and GIP Whale, the "Applicants").[102] Upon consummation, GIP Whale will hold: (i) Eversource Investment's 50 percent interest in North East Offshore and will thereby also indirectly hold a 50 percent interest in Revolution Wind; and (ii) Eversource Investment's 50 percent Class B interest in South Fork Class B and will thereby also indirectly hold an interest in South Fork Wind. The Applicants must file a notice within 10 days of consummation of the transaction, which as of the date of this Report has not happened. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: GIP/BlackRock (EC24-58)**

On March 12, 2024, Global Infrastructure Management, LLC ("GIM") d/b/a Global Infrastructure Partners, on behalf of investment funds sponsored by GIM that own public utility subsidiaries, and BlackRock, Inc. requested authorization for a transaction pursuant to which BlackRock Funding Inc. will acquire 100% of the LLC interests in GIM and thereby an indirect controlling interest in the GIM public utility subsidiaries, including, among others, Clearway Power Marketing and GenConn Energy. Following an errata notice, comments on this 203 application were due on or before May 13, 2024. As previously reported the FERC issued a deficiency letter, to which GIM

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[100] The "Trailstone Companies" are Trailstone Energy Marketing, LLC and Trailstone Renewables, LLC.

[101] *TrailStone Energy Marketing, LLC, Trailstone Renewables, LLC, and Engelhart CTP (US) LLC*, 188 FERC ¶ 62,046 (July 25, 2024) ("*Trailstone Order*").

[102] *North East Offshore, LLC, et al.*, 187 FERC ¶ 62,151 (June 7, 2024).

responded on June 18, 2024.[103] Public Citizen and Private Equity Stakeholder Project[104] have filed three joint protests (the first related to upstream ownership/affiliate issues; the second, addressing Applicants' proposed purchase of Allete; the third, with GIM's deficiency letter response, particularly the transaction would impact the blanket authorization granted to BlackRock and certain of its investment management subsidiaries); Sierra Club also filed a protest. On June 5, 2024, Applicants answered the Protests. On June 18, 2024, Applicants answered the FERC's deficiency letter. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Three Corners Solar/Three Corners Prime Tenant (EC23-90)**

On July 28, 2023, the FERC authorized[105] the disposition and consolidation of jurisdictional facilities and the lease of an existing generation facility that will result from the commencement of a master lease agreement ("Lease") between Three Corners Solar, LLC ("Lessor") and Three Corners Prime Tenant, LLC ("Lessee") pursuant to which Lessee will lease, operate, and control an approximately 112 MWac solar photovoltaic ("PV") electric generation facility owned by Lessor in Kennebec County, Maine (the "Transaction"). On July 10, 2024, Lessor and Lessee filed a notice that the transaction was consummated on *July 8, 2024*. Reporting on this matter is now concluded. If you have any questions regarding this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **PURPA Enforcement Petition – Allco Finance Ltd/CT DEEP (EL24-95)**

On May 23, 2024, the FERC issued a Notice of Intent Not to Act on the petition by Allco Finance Limited ("Allco").[106] As previously reported, Allco asked the FERC to initiate an enforcement action against the Connecticut Department of Energy and Environmental Protection ("CT DEEP") to remedy what it asserted was CT DEEP's improper implementation of section 210 of PURPA. Allco asked the FERC to (i) invalidate and permanently enjoin the Shared Clean Energy Facility program's 50 MW volumetric cap, (ii) invalidate and permanently enjoin the CT DEEP from implementing Conn. Gen. Stat. §§ 16a-3f, 16a-3g, 16a-3j, and 16a-3m, which compel CL&P and UI to procure energy from zero carbon resources that have a 5 MW or greater nameplate capacity rating and participate in the New England Markets, (iii) invalidate and permanently enjoin the CT DEEP from implementing solicitations for off-shore wind facilities and/or nuclear facilities, and (iv) to permanently enjoin the CT DEEP from regulating wholesale sales except as permitted by PURPA. In light of the *Allco CT DEEP Notice,* Allco may now initiate an action against CT DEEP in an appropriate court. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **E&P Agreement 3d Amendment: Seabrook/NECEC Transmission (ER24-2588)**

On July 25, 2024, NextEra Energy Seabrook, LLC ("Seabrook") filed a third amendment to the Engineering and Procurement ("E&P") Agreement between Seabrook and NECEC Transmission LLC ("NECEC") (the "A&R E&P Agreement"). The A&R E&P Agreement covers the final engineering drawings through the procurement and delivery of the 24.5 kV generator circuit breaker and ancillary equipment to Seabrook Station in advance of the Fall 2024 outage. The third amendment seeks approximately $3 million in additional funding to cover "higher costs driven by increased engineering scope, outage planning, and higher internal project support". Comments on this filing are due on or before ***August 15, 2024***. Thus far, Avangrid has filed a

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[103] The FERC issued a deficiency letter on June 5, 2024 directing Applicants to address issues related to the data and methods used for the submitted Delivered Price Test ("DPT") and how the Proposed Transaction is consistent with, or would have any impact on the terms of, the blanket authorization granted to BlackRock and certain of its investment management subsidiaries. GIM responded to the deficiency letter on June 18, 2024. Comments on the deficiency letter were due on or before July 9, 2024. As noted herein, Public Citizen and Private Equity Stakeholder Project protested a piece of the deficiency letter response.

[104] The Private Equity Stakeholder Project states that it supports stakeholders impacted by private equity firms and similar private asset managers. *See* https://pestakeholder.org/.

[105] *Three Corners Solar, LLC and Three Corners Prime Tenant, LLC*, 184 FERC ¶ 62,060 (Jul. 28, 2023).

[106] *Allco Finance Ltd. et al.*, 187 FERC ¶ 61,092 (May 23, 2024) ("*Allco CT DEEP Notice*").

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

- **D&E Agreement: CL&P / Vineyard Northeast (ER24-2523)**

On July 15, 2024, CL&P filed an Engineering Agreement with Vineyard Northeast to cover the costs to perform necessary engineering and design services related to Vineyard Northeast's 1,200 MW Large Generating Facility (Queue Position 1488). Comments on this filing are due on or before ***August 5, 2024***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Interconnection Study Agreement: PSNH / Wok, LLC (ER24-2522)**

Also on July 15, 2024, PSNH filed an Interconnection Study Agreement with Wok, LLC (which is proposing to potentially construct a facility and establish a load interconnection to PSNH's transmission system) to cover the costs of assessing the viability of a potential interconnection and providing high-level, non-binding cost estimates for the portion of such infrastructure that would be paid for by Wok. Comments on this filing are due on or before ***August 15, 2024***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Versant *Order 1920* MPD Waiver Request (ER24-2462)**

On July 2, 2024, Versant Power requested for the Maine Public District ("MPD") a waiver of *Order 1920*'s requirements related to regional transmission planning, interregional transmission coordination, and cost allocation methods. Comments on this filing were due on or before July 23, 2024; 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).

- **LCCSA: RIE/BIPCO/PUD (ER24-2390)**

On June 27, 2024, Rhode Island Energy ("RIE") filed a Local Control Center Services Agreement ("LCCSA") between Block Island Power Company ("BIPCO) and Pascoag Utility District that sets forth the terms of certain local control services provided at or through a dispatching center by RIE and operated under the direction or authorization of ISO-NE. An effective date of May 30, 2024 was requested. Comments on this filing were due on or before July 18, 2024; none were filed. National Grid intervened doc-lessly. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement Cancellation: NSTAR/Medway Grid (ER24-2356)**

On June 25, 2024, NSTAR filed to terminate the Engineering, Design and Procurement Agreement ("D&E Agreement") between NSTAR and Medway Grid, LLC. NSTAR stated that it has completed all work pursuant to the Agreement. An effective termination date of June 26, 2024 was requested. Comments on this filing were due on or before July 16, 2024; 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).

- **D&E Agreement: CL&P/BPUS (ER24-2233)**

On June 11, 2024, CL&P filed a Design & Engineering ("D&E") Agreement that sets forth the terms and conditions under which CL&P will perform necessary engineering, procurement and design services in connection with the interconnection of BPUS Generation Development LLC's 50 MW solar facility in Windham, Connecticut. Comments on this filing were due on or before July 2, 2024; 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).

- **TSA Amendment: NSTAR/Park City Wind (ER24-2104)**

On July 9, 2024, the FERC accepted an Amended and Restated Settlement Transmission Support Agreement ("TSA") memorializing NSTAR's commitment to construct certain transmission facilities required to interconnect Park City Wind LLC's ("PCW") proposed 800 MW offshore wind farm to the NSTAR transmission system and setting forth the parties' respective responsibilities to finance and pay for those facilities.[107] The initial Settlement TSA was approved on June 17, 2022. The amended TSA amends and restates the Settlement TSA with primary revisions to certain milestone dates associated with (i) PCW's provision of notices to NSTAR to proceed with work related to constructing transmission facilities required to interconnect PCW's offshore wind farm and (ii) NSTAR's completion of such facilities and costs of certain of the transmission facility upgrades that NSTAR will construct under the TSA. The Amended TSA was accepted effective as of July 28, 2024, as requested. Unless the July 9, 2024 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).

- **CSA: NextEra Seabrook/NECEC (ER24-2097)**

On July 17, 2024, the FERC accepted a Construction Services and Cost Reimbursement Agreement for Affected System Project ("Agreement") between NextEra Energy Seabrook, LLC ("Seabrook") and NECEC Transmission LLC ("NECEC").[108] As previously reported, the Agreement sets forth the terms of Seabrook's performance related to the construction, implementation, and testing of the Seabrook Station 24.5 kV generator circuit breaker and ancillary equipment, including pre-Fall 2024 Planned Outage work that will commence following the effective date of the Agreement. The Agreement was accepted effective as of May 25, 2024, as requested. Unless the July 17 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).

- **SGIA: PSNH/Brookfield White Pine Hydro (ER24-2092)**

On July 17, 2024, the FERC accepted a non-conforming SGIA between Public Service Company of New Hampshire ("PSNH") and Brookfield governing the continued interconnection to the PSNH system of Brookfield White Pine Hydro LLC's ("White Pine Hydro") 3.2 MW hydroelectric generation facility (located in Errol, New Hampshire).[109] As previously reported, the SGIA restates and updates the terms under which White Pine Hydro will continue to receive interconnection service and is non-conforming in that ISO-NE is not a party to the agreement. The SGIA was accepted effective as of *May 24, 2024*, as requested. Unless the July 17 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).

- **RFA Termination: PSNH/NECEC (ER24-2087)**

On July 17, 2024, the FERC accepted the termination of the Related Facilities Agreement ("RFA") between PSNH and NECEC.[110] As previously reported, PSNH stated that it had completed all work pursuant to the RFA. The RFA termination was accepted effective as of *May 23, 2024*, as requested. Unless the July 17 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 2023* Compliance Filing: Versant MPD OATT (ER24-2035)**

On May 16, 2024, Versant Power proposed revisions to its *pro forma* LGIP, Large Generator Interconnection Agreement ("LGIA"), SGIP and Small Generator Interconnection Agreement ("SGIA") in the MPD OATT in compliance with *Orders 2023* and *2023-A*. The revised LGIP contains two deviations from *Order 2023-A*, Versant proposes (i) to eliminate the reference to when the transition process will commence and, instead, only

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[107] *NSTAR Elec. Co.*, Docket No. ER24-2104-000 (July 9, 2024) (unpublished letter order).

[108] *NextEra Energy Seabrook, LLC*, Docket No. ER24-2097-000 (July 17, 2024) (unpublished letter order).

[109] *Public Service Co. of New Hampshire*, Docket No. ER24-2092-000 (July 17, 2024) (unpublished letter order).

[110] *Public Service Co. of New Hampshire*, Docket No. ER24-2087-000 (July 17, 2024) (unpublished letter order).

reference when it plans to hold its first Cluster Study process on January 1, 2025 langauge that was previously approved by the FERC in Versant Power's Order No. 845 compliance filing and (ii) to limit the use of surety bonds to those where the surety bond is "issued by an insurer reasonably acceptable to the Transmission Provider" and that "specify a reasonable expiration date." An effective date of January 1, 2025 was requested. Comments were due on or before June 6, 2024; 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).

- **IA 2nd Amendment – CMP/Brookfield White Pine Hydro (ER24-1966)**
  On June 28, 2024, the FERC accepted a second amendment to the Interconnection Agreement between CMP and Brookfield White Pine Hydro. As previously reported, the amendment removed references to the "Bonny Eagle" and "West Buxton Hydro" generating facilities (now subject to a new *pro forma* LGIA between CMP, Brookfield and ISO-NE). The amended IA does not implement any new rates or charges. The second amendment was accepted effective as of *July 8, 2024,* as requested. The June 28, 2024 order was not challenged and is final and unappealable; this proceeding is now concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **LGIA – ISO-NE/CMP/Andro Hydro (ER24-1477)**
  On March 13, 2024, ISO-NE and CMP filed a non-conforming LGIA to govern the interconnection of Andro Hydro, LLC's 27.57 MW hydro facility, which interconnects to the Jay Substation. The LGIA is non-conforming in that it contains limited deviations from the Schedule 22 *pro forma* LGIA that are necessary to reflect unique characteristics of Andro Hydro's proposed interconnection, including the interconnection of its facility through shared facilities co-owned, and used by, JGT2 Redevelopment LLC to serve its own load. A February 12, 2024 effective date was requested. Comments on the LGIA filing were due on or before April 3, 2024; none were filed. Andro Hydro intervened doc-lessly. On May 7, 2024, the Filing Parties filed a replacement LGIA to allow the FERC additional time to consider the filing, as well as a related filing made by Andro Hydro (ER24-1629), and further consultation among the Filing Parties. Comments on the May 7 filing were due on May 28, 2024; 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).

- **CMP ESF Rate (ER24-1177)**
  As previously reported, the FERC accepted, 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").[111] CMP filed the ESF Rate following re-consideration by the MPUC of the jurisdictional applicability of the ESF rate (which, while it recovers costs associated with the use of local the distribution network, the MPUC found upon re-consideration to include charges related to a FERC-jurisdictional wholesale transaction per *Order 841*). CMP sought in this proceeding to obtain FERC approval of a modified version of the MPUC Rate, with the primary difference between the MPUC Rate and the ESF Rate being the removal of state benefit charges. In the *CMP ESF Rate Order*, the FERC found that CMP's filing had not been shown to be just and reasonable, and raised issues of material fact that could not be resolved based on the record and would be more appropriately addressed in hearing and settlement judge procedures.[112] Accordingly, the FERC accepted the filing, subject to refund, and established hearing and settlement judge procedures. The FERC denied CMP's request for waiver of the FERC's 60-day prior notice requirement, and accepted the ESF Rate effective April 2, 2024, though, as noted, subject to refund and hearing and settlement judge procedures.[113] The FERC encouraged efforts to reach settlement before hearing procedures commence and will hold the hearing in abeyance pending the outcome of settlement judge procedures.

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[111] *Central Maine Power Co.,* 187 FERC ¶ 61,002 (Apr. 1, 2024) ("*CMP ESF Rate Order*").

[112] *Id.* at P 29.

[113] *Id*.

Settlement Judge Proceedings. As directed, the Chief ALJ appointed a settlement judge, Judge Jeremy Hessler, to assist participants in settling the issues in this proceeding, and deemed the settlement proceedings continued without further action.[114] There have been two settlement conferences (May 3 and July 17, 2024); a third settlement conference is scheduled for ***September 19, 2024.*** Settlement Judge proceedings are on-going. Judge Hessler's next status report addressing the parties' progress toward settlement is due on or before ***August 6, 2024***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **IA Cancellation Versant / PERC (ER24-965)**

At Versant's request, action on this matter has not yet been taken. As previously reported, on January 22, 2024, Versant filed a notice of cancellation of an Interconnection Agreement ("IA") between itself and Penobscot Energy Recovery Company ("PERC"). Versant reported that PERC discontinued operations of an approximately 25 MW solid waste-fired generating facility that interconnected to its Orrington Substation. The facility was later sold to C&M Faith Holdings LLC, and is no longer connected or operating. Comments on the notice of cancellation are due on or before February 12, 2024; none were filed. On February 12, PERC intervened doc-lessly. On February 29, 2024, Versant Power asked that the FERC take no action on the filed notice of cancellation prior to May 1, 2024, in order to allow Versant and the new owner of the PERC facility, which may wish to reenergize the facility and assume the IA, to agree to a course of action. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **RI Energy BITS Surcharge True-Up Adjustment (ER23-1003 and ER23-1000)**

On June 27, 2024, RI Energy submitted for informational purposes its true-up adjustments ("True-Up Adjustments") of its Block Island Transmission System ("BITS") Surcharge.[115] The True-Up Adjustments reconcile actual monthly billings under the provisions set forth in TSA-NECO-83 and TSA-NECO-86 to the same calculations based on actual data, including FERC Form No. 1 data. The difference, RI Energy stated, together with interest, was applied to RI Energy's monthly BITS Surcharge billings in July 2024. The FERC did not notice this filing for public comment, and no further FERC action is expected. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

XII. Misc. - Administrative & Rulemaking Proceedings[116]

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

On July 19, 2024, NARUC submitted the following nominees for the Federal and State Current Issues Collaborative ("Collaborative"), the successor to the Joint Federal-State Task Force on Electric Transmission:[117]

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[114] *Central Maine Power Co.*, Docket No. ER24-1177-000 (Apr. 5, 2024) (unpublished letter order).

[115] The BITS Surcharge became effective under TSA-NECO-83 and TSA-NECO-86 as of Jan 1, 2023, the date that RI Energy became an independent additional Participating Transmission Owner ("PTO") under the Transmission Operating Agreement ("TOA") between ISO-NE and the PTOs. *ISO New England Inc.*, Docket No. ER23-1003-000 at 1 (Dec. 13, 2023) (unpublished letter order); *ISO New England Inc.*, Docket No. ER23-1000 at 1 (Dec. 13, 2023) (unpublished letter order).

[116] Reporting on the following Administrative proceedings have been suspended since the last Report and will be continued if and when there is new activity to report: ACPA Petition for Capacity Accreditation Technical Conference (AD23-10); and Reliability Technical Conference (AD23-9).

[117] *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 FERC expects that the first public

From NECPUC: MPUC Chairman Phil Bartlett and NHPUC Commissioner Pradip Chattopadhyay; from MACRUC: PA PUC Vice Chair Kimberly M. Barrow and PH PUC Commissioner Dennis P. Deters; from the Mid-America Regulatory Conference ("MARC") IN Utility Regulatory Commission Chairman Jim Huston and MI PUC Commissioner Katherine Peretick; from SEARUC: NC Utilities Commissioner Kimberly W. Duffley and FL PSC Commissioner Art Graham; and from WESTERN: ID PUC Commissioner Eric Anderson and NM Public Regulation Commission Chair Patrick O'Connell.

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

On June 27, 2024, the FERC issued an advanced notice of proposed rulemaking ("ANOPR")[118] seeking comments on both the need for a dynamic line ratings ("DLRs")[119] 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. Comments in response to the ANOPR are due ***October 15, 2024***.[120] Reply comments are due ***November 12, 2024***. A more detailed summary of the ANOPR was provided to and reviewed with the Transmission Committee. Since the last Report, Electric Grid Monitoring submitted comments in support of FERC moving forward with a NOPR and Final Rule.

- **NOPR: EQR Filing Process and Data Collection (RM23-9)**

On October 19, 2023, the FERC issued a NOPR[121] proposing various changes to current Electric Quarterly Report ("EQR") filing requirements, including both the method of collection and the data being collected. The proposed changes are designed to update the data collection, improve data quality, increase market transparency, decrease costs, over time, of preparing the necessary data for submission, and streamline compliance with any future filing requirements. Among other things, the FERC proposes to implement a new collection method for EQR reporting based on the eXtensible Business Reporting Language ("XBRL")-Comma-Separated Values standard; amend its regulations to require ISO/RTOs to produce reports containing market participant transaction data; and modify or clarify EQR reporting requirements. Requests for additional time to comment on the *EQR NOPR* were filed by EEI/EPSA, the IRC and the Bonneville Power Administration ("BPA"). On December 7, 2023, the FERC extended the deadline for submitting comments to and including February 26, 2024. Comments on the NOPR were filed by ISO-NE, CAISO, MISO, NYISO, PJM, BPA, EEI, Energy Compliance Consulting, EPSA, Interstate Gas Supply, Macquarie, PG&E, Systrends, Tri-State, XBRL US. This matter remains pending before the FERC.

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meeting of the Collaborative will be held in the Fall of 2024. 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.

[118] *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.

[119] 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.

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

[121] *Revisions to the Filing Process and Data Collection for the Electric Quarterly Report*, 185 FERC ¶ 61,043 (Oct. 19, 2023) ("*EQR NOPR*").

- ***Orders 2023 and 2023-A*: Interconnection Reforms (RM22-14)**

Order 2023. On July 28, 2023, the FERC issued *Order 2023*,[122] its final rule on proposed reforms to the *pro forma* LGIP, *pro forma S*GIP, *pro forma* LGIA, and *pro forma* SGIA to address interconnection queue backlogs, improve certainty, and prevent undue discrimination for new technologies. *Order 2023* adopts reforms to: (i) implement a first-ready, first-served cluster study process;[123] (ii) increase the speed of interconnection queue processing;[124] and (iii) incorporate technological advancements into the interconnection process.[125] Many of the reforms adopted in *Order 2023* closely track the reforms set out in the FERC's Notice of Proposed Rulemaking.[126] However, the FERC did revise aspects of the reforms.[127] *Order 2023* became effective November 6, 2023[128] (60 days from its publication in the *Federal Register* ("Publication Date")).

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[122] *Improvements to Generator Interconnection Procedures and Agreements*, Order No. 2023, 184 FERC ¶ 61,054 (July 28, 2023) ("*Order 2023*").

[123] A first-ready, first-served cluster study process improves efficiency in the interconnection study process by including the following elements: increased access to information prior to entering the queue; a mechanism to study interconnection requests in groups where all interconnection requests in the group are equally queued and of equal study priority; and increased financial commitments and readiness requirements to enter and proceed through the queue. In contrast, the existing first-come, first-served serial study process in the *pro forma* LGIA and LGIP provides limited information to interconnection customers prior to entering the queue, assigns interconnection requests an individual queue position based solely on the date of entry into the queue, and contains limited financial and readiness requirements.

In order to implement a first-ready, first-served cluster study process, *Order 2023* requires: (1) transmission providers to publicly post available information pertaining to generator interconnection; (2) transmission providers to use cluster studies as the interconnection study method; (3) transmission providers to allocate cluster study costs on a pro rata and per capita basis; (4) transmission providers to allocate network upgrade costs based on a proportional impact method; (5) interconnection customers to pay study and commercial readiness deposits as part of the cluster study process; (6) interconnection customers to demonstrate site control at the time of submission of the interconnection request; and (7) transmission providers to impose withdrawal penalties on interconnection customers for withdrawing from the interconnection queue, with certain exceptions. We also require transmission providers to adopt a transition process to move from the existing serial interconnection process to the new cluster study process.

[124] In order to increase the speed of interconnection queue processing, *Order 2023*: (1) eliminates the reasonable efforts standard for conducting interconnection studies and imposes a financial penalty on transmission providers that fail to meet interconnection study deadlines; and (2) establishes an affected system study process and associated *pro forma* affected system agreements.

[125] In order to incorporate technological advancements into the interconnection process, *Order 2023* requires transmission providers to: (1) allow more than one generating facility to co-locate on a shared site behind a single point of interconnection and share a single interconnection request; (2) evaluate the proposed addition of a generating facility at the same point of interconnection prior to deeming such an addition a material modification if the addition does not change the originally requested interconnection service level; (3) allow interconnection customers to access the surplus interconnection service process once the original interconnection customer has an executed LGIA or requests the filing of an unexecuted LGIA; (4) use operating assumptions in interconnection studies that reflect the proposed charging behavior of an electric storage resource; and (5) evaluate the list of alternative transmission technologies enumerated in this final rule during the generator interconnection study process.

[126] *Order 2023* also requires: (i) interconnection customers requesting to interconnect a non-synchronous generating facility to: (a) provide the transmission provider with the models needed for accurate interconnection studies; and (b) have the ability to maintain power production at pre-disturbance levels and provide dynamic reactive power to maintain system voltage during transmission system disturbances and within physical limits; (ii) all newly interconnecting large generating facilities provide ride through capability consistent with any standards and guidelines that are applied to other generating facilities in the balancing authority area on a comparable basis; and (iii) with respect to the *pro forma* SGIP and *pro forma* SGIA, the incorporation of enumerated alternative transmission technologies into the interconnection process, and the provision of modeling and ride through requirements for non-synchronous generating facilities.

[127] Reforms revised in *Order 2023* pertain to the cluster study process, allocation of cluster study and network upgrade costs, increased financial commitments and readiness requirements, financial penalties for delayed interconnection studies, the affected system study process, pro forma affected system agreements, the material modification process, operating assumptions for interconnection studies, incorporating the enumerated alternative transmission technologies, and ride through requirements. In addition, the FERC declined to adopt the NOPR proposals pertaining to informational interconnection studies, shared network upgrades, the optional resource solicitation study, and the alternative transmission technologies annual report.

[128] *Order 2023* was published in the Fed. Reg. on Sep. 6, 2023 (Vol. 88, No. 171) pp. 61,041-61,349.

A more detailed summary of, and a presentation on, *Order 2023* was provided to, and discussed with, the Transmission Committee. Compliance will require changes to the Tariff's *pro forma* LGIA, LGIP, SGIA and SGIP.

Requests for Clarification and/or Rehearing. Requests for rehearing, clarification and/or an extension of time were filed by 35 parties. Those parties raised, among other issues, the following:

- The FERC erred in removing the Reasonable Efforts standard and imposing penalties for late studies;
- The FERC must clarify aspects of the transition process and use of Transitional Cluster Studies and Transitional Serial Studies;
- Transmission Providers need additional details on the FERC's requirement for Transmission Provider's to publish heatmaps;
- The FERC must provide insight on the process of performing cluster studies as well as the cost allocation methodology; and
- Transmission Providers require further clarity regarding the alternative transmission technologies that they are required to review.

Requests for Clarification and/or Rehearing Denied by Operation of Law. On September 28, 2023, the FERC issued a "Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration".[129] The *Order 2023 Allegheny Notice* confirmed that the 60-day period during which a petition for review of *Order 2023* can be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing and/or clarification of *Order 2023* within the required 30-day period. The Notice also indicated that the FERC would address, as is its right, the rehearing request in a future order, and may modify or set aside its order, in whole or in part, "in such manner as it shall deem proper." The FERC issued that order, *Order 2023-A*, on March 21, 2024 (*see* immediately below). Several parties submitted petitions in Federal Court challenging *Order 2023*. Developments in those federal court proceedings will be summarized in Section XVI below.

Order 2023-A. On March 21, 2024, the FERC issued *Order 2023-A*[130] addressing arguments raised on rehearing of *Order 2023*. *Order 2023-A* set aside, in part, and clarified *Order 2023*. Among other things, in *Order 2023-A* the FERC:

- upheld its prior determination that eliminating the Reasonable Efforts Standard with firm steady deadlines was "warranted as part of a package of comprehensive reforms to address interconnection queue delays and backlogs;"[131]
- denied several requests for rehearing or clarification regarding the transition process, including requests to revise the deposit amounts and withdrawal penalty amounts for the transitional process;[132]
- declined to revise the eligibility date for participation in a transitional cluster study or set a size threshold for the transitional cluster study;[133]
- declined to clarify whether transmission providers may use Energy Resource Interconnection Service ("ERIS") or Network Resource Interconnection Service ("NRIS") assumptions for public heatmaps, rather than just NRIS, but provided that a transmission provider may propose on

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[129] *Improvements to Generator Interconnection Procedures and Agreements*, 184 FERC ¶ 62,163 (Sep 28, 2023) ("*Order 2023 Allegheny Notice*").

[130] *Improvements to Generator Interconnection Procedures and Agreements*, 186 FERC ¶ 61,199 (Mar. 21, 2024) ("*Order 2023-A*").

[131] *Id.* at P 280.

[132] *Id.* at P 257.

[133] *Id.*

compliance an option for heatmap users to view results using ERIS assumptions in addition to NRIS assumptions;[134]

- declined requests to revisit the requirement that transmission providers evaluate the list of alternative transmission technologies and noted that as long as a transmission provider has evaluated the list, it has complied with *Order 2023* and affirmed its prior decision not to include dynamic line ratings or storage-as-a-transmission-asset on the list of alternative transmission technologies.[135]

Due to breadth of the issues addressed in *Order 2023-A*, the FERC extended the *Order 2023* compliance filing deadline to May 16, 2024.[136] A more fulsome summary from NEPOOL Counsel of the Order was distributed to, and was reviewed with, the Transmission Committee at the March 27, 2024 meeting. ISO-NE's *Order 2023* and *Order 2023-A* Revisions were unanimously supported at the March 7 and May 2 Participants Committee meetings, respectively, and were filed on May 14, 2024 (see ER24-2007 and ER24-2009 above). Several parties submitted petitions in Federal Court challenging *Order-A 2023*. Developments in those federal court proceedings will be summarized in Section XVI below.

If you have any questions concerning this matter, please contact Margaret Czepiel (202-218-3906; mczepiel@daypitney.com) or Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Order 1977*: Transmission Siting (RM22-7)**

On May 16, 2024, the FERC issued *Order 1977*[137] updating the regulations governing applications for permits to site electric transmission facilities under section 216 of the FPA, as amended by the Infrastructure and Jobs Act, and particularly to reflect FERC's jurisdiction over projects located in National Interest Electric Transmission Corridors that have been denied state siting authority. There is no compliance filing requirement associated with *Order 1977*, but applicants seeking to develop transmission under federal authority in a National Interest Corridor must comply with the revised and new regulations effective ***July 29, 2024***.[138] NEPOOL Counsel prepared a summary of *Order 1977* which was distributed to the Transmission Committee.

Requests for rehearing of *Order 1977* were filed by the LA PSC, NY PSC, PA PUC, and Public Interest Organizations.[139] On July 15, 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.[140] If you have any questions concerning *Order 1977*, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

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

On March 21, 2024, the FERC issued a NOPR[141] proposing revisions to 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

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[134] *Id*. at P 95.

[135] *Id*. at P 615.

[136] *Order 2023-A* was published in the *Fed. Reg.* on Apr. 16, 2024 (Vol. 89, No. 74) pp. 27,006-27,243.

[137] *Applications for Permits to Site Interstate Elec. Transmission Facilities*, 187 FERC ¶ 61,069 (May 13, 2024) ("*Order 1977*").

[138] *Order 1977* was published in the *Fed. Reg.* on May 29, 2024 (Vol. 89, No. 104) pp. 46,682-46,740.

[139] "Public Interest Organizations" are Earthjustice, Environmental Defense Fund, NRDC, Sierra Club, Sustainable FERC Project, UCS, WE ACT for Environmental Justice, and the Yurok Tribe.

[140] *Applications for Permits to Site Interstate Elec. Transmission Facilities*, 188 FERC ¶ 61,027 (July 15, 2024).

[141] *Compensation for Reactive Power Within the Standard Power Factor Range*, 186 FERC ¶ 61,203 (Mar. 21, 2024) ("*Reactive Power NOPR*").

the provision of reactive power within the standard power factor range or "deadband."[142] The proposed change may affect revenues received by reactive power resources in New England.[143] The NOPR seeks comments on, among other issues, the following:

(i) The reliability impact of prohibiting transmission providers from including in their transmission rates any charges associated with the supply of reactive power within the standard power factor range from a generating facility in regions where generating facilities currently receive such compensation;

(ii) Whether, and if so how, the elimination of separate reactive power payments will affect generating facilities' ability to recover their costs in the markets that currently provide reactive power compensation within the standard power factor range;

(iii) Whether, and if so how, eliminating separate reactive power compensation within the standard power factor range may affect investment decisions to build, or finish building, generation facilities, and whether, and if so how, the elimination could otherwise affect generators' business decisions in those markets; and

(iv) If the FERC allows existing generation resources that have previously received compensation for reactive power supply to continue to receive compensation for a limited period while prohibiting new generation resources from receiving reactive power compensation, how should it determine eligibility for continued compensation in a manner that is just and reasonable and not unduly discriminatory or preferential.[144]

Initial comments on the *Reactive Power NOPR* were due May 28, 2024; reply comments are due ***June 26, 2024***.[145] NEPOOL Counsel prepared a summary of the NOPR which was distributed to, and was reviewed with, the Transmission Committee at the March 27, 2024 TC Meeting.

Comments. Initial comments were filed on May 28, 2024 by over 30 parties, including by: ISO-NE, Calpine, CT OCC, EDP Renewables, Glenvale, National Grid, New England Consumer Advocates, ACPA/SEI, ACORE, EPSA, National Hydropower Assoc., NEI, and Reactive Service Providers. Reply comments were due by June 26, 2024 and filed by: NEPOOL in response to ISO-NE's initial comments, NEPGA, NESCOE, Elevate Renewables F7, EPSA, IPPNY, MISO TOs, Old Dominion Electric Coop, PJM IMM, and Dr. C. Gaunt. Onward Energy filed supplemental comments on July 23, 2024.

The Reactive Power NOPR is pending before the FERC.

- ***Order 1920*: Transmission Planning Reforms (RM21-17)**

On May 13, 2023, the FERC issued *Order 1920*,[146] its final rule on proposed reforms to existing the transmission planning and cost allocation requirements. In *Order 1920*, the FERC explained that under existing processes, transmission providers are not required to: (i) perform a sufficiently long-term assessment of transmission needs identifying Long-Term Transmission Needs; (ii) adequately account for known determinants of Long-Term Transmission Needs prospectively; and (iii) consider the broader benefits of regional transmission facilities planned to meet Long-Term Transmission Needs. The existing processes result in less efficient and cost-effective investment in transmission infrastructure and higher costs to customers and, therefore, unjust and unreasonable rates and need for reforms. *Order 1920* requires all transmission providers, *inter alia*, to

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[142] *Reactive Power NOPR* PP 51-53.

[143] Generating facilities in New England are compensated for reactive power under a flat, inflation-adjusted rate design.

[144] *Id.* at PP 47, 49, 56.

[145] The *Reactive Power NOPR* was published in the Fed. Reg. on Mar. 28, 2024 (Vol. 89, No. 61) pp. 21,454-21,468.

[146] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 187 FERC ¶ 61,068 (May 13, 2024) ("*Order 1920*").

(i) conduct Long-Term Regional Transmission Planning to identify, evaluate and select Long-Term Regional Transmission Facilities to address Long-Term Transmission Needs;

(ii) to evaluate for selection regional transmission facilities that will address identified interconnection-related transmission needs through the existing Order No. 1000 processes;

(iii) to include in their compliance filings one or more default ex ante Long Term-Regional Transmission Cost Allocation Methods to allocate costs for Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) that are selected for regional cost allocation; and

(iv) revise their existing interregional transmission coordination procedures to reflect the long-term regional transmission planning reforms adopted in *Order 1920*.

Order 1920 adopts a number of reforms from the *Transmission NOPR,*[147] but also declines to adopt several reforms, including the NOPR proposal to restrict the availability of the construction-work-in-progress ("CWIP") incentive for Long-Term Regional Transmission Facilities and to establish a federal rights of first refusal ("ROFR") for incumbent transmission providers, conditioned on the incumbent transmission provider establishing joint ownership of the transmission facilities. Although the FERC did not adopt a federal ROFR, it did adopt a limited ROFR applicable only to certain "right-sized" replacement transmission facilities. In addition, the FERC noted a willingness to consider the CWIP and ROFR issues in future proceedings.

Order 1920 takes effect on *August 12, 2024.*[148] Transmission providers must submit compliance filings by ***June 12, 2025*** with respect to most of the Order's requirements, while filings to comply with the interregional transmission coordination requirements are due by ***August 12, 2025***.

A detailed high-level summary of *Order 1920* was distributed to, and was reviewed with, the Transmission Committee. NEPOOL counsel will coordinate with ISO-NE counsel on stakeholder engagement to develop a compliance filing in response to *Order 1920*.

Requests for Clarification and/or Rehearing. Over 50 parties file requests for clarification and/or rehearing, including requests by: AEU, Dominion, Invenergy, NESCOE (with VT PUC supporting), Versant, APPA, EEI, Large Public Power Council, NARUC, NRECA, TAPS, WIRES, Consumer Advocates, and Harvard Electricity Institute. On July 15, 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.[149]

If you have any questions concerning *Order 1920*, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

- **SunSea Energy Stipulation and Consent Agreement (IN24-8)**

On June 28, 2024, the FERC approved a Stipulation and Consent Agreement with SunSea Energy, LLC ("SunSea") to resolve OE's investigation of whether SunSea violated Section 26.2.1.3 of the credit reporting provisions of the NYISO Tariff and the FERC's duty of candor rule by failing to timely inform NYISO of the existence

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

[148] *Order 1920* was published in the Fed. Reg. on Jun. 11, 2024 (Vol. 89, No. 113) pp. 49,280-49,586.

[149] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 188 FERC ¶ 62,025 (July 15, 2024).

of multiple ongoing investigations by the New York Public Service Commission ("NYPSC") between December 2020 and May 2021 (the "Relevant Period").[150] NYISO Tariff section 26.2.1.3 requires Customers to disclose ongoing investigations that could have a material impact on its financial condition. Enforcement determined that, during the Relevant Period, SunSea failed to disclose in its NYISO annual credit questionnaire form ("CQF") that it was under investigation by the NYPSC in multiple proceedings that could have a material impact on its financial condition. Enforcement further noted that NYPSC's issuance of orders (1) to show cause asking why it should not revoke SunSea's then-eligibility to operate as an Energy Services Company ("ESCO") in New York; (2) revoking SunSea's eligibility to serve customers in New York; and (3) to show cause requiring SunSea to show cause why its eligibility application to continue to enroll new customers and/or renew existing contracts should not be denied demonstrate that the financial impact of the proceedings could be material and therefore should have been disclosed in the CQF. In recommending the appropriate remedy, OE considered SunSea's cooperation during the investigation. Under the Stipulation and Consent Agreement, SunSea agreed to pay a ***civil penalty of $5,000*** to the United States Treasury. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Josco Energy Stipulation and Consent Agreement (IN24-7)**

On June 28, 2024, the FERC approved a Stipulation and Consent Agreement with Josco Energy Corp. ("Josco") to resolve OE's investigation of whether Josco violated Section 26.2.1.3 of the credit reporting provisions of the NYISO Tariff and the FERC's duty of candor rule by failing to timely inform NYISO of the existence of multiple ongoing investigations by NYPSC between October 2020 and May 2021 (the "Relevant Period").[151] NYISO Tariff section 26.2.1.3 requires Customers to disclose ongoing investigations that could have a material impact on its financial condition. Enforcement determined that, during the Relevant Period, Josco failed to disclose in its NYISO annual CQF that it was under investigation by the NYPSC in multiple proceedings that could have a material impact on its financial condition. Enforcement further noted that NYPSC's issuance of orders (1) to show cause asking why it should not revoke Josco's then-eligibility to operate as ESCO; (2) revoking Josco's eligibility to serve customers in New York; and (3) to show cause requiring Josco to show cause why its eligibility application to continue to enroll new customers and/or renew existing contracts should not be denied demonstrate that the financial impact of the proceedings could be material and therefore should have been disclosed in the CQF. In recommending the appropriate remedy, OE considered Josco's cooperation during the investigation. Under the Stipulation and Consent Agreement, Josco agreed to pay a ***civil penalty of $5,000*** to the United States Treasury. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Engie Stipulation and Consent Agreement (IN24-6)**

On May 20, 2024, the FERC approved a Stipulation and Consent Agreement with ENGIE Energy Marketing NA, Inc. ("Engie") to resolve OE's investigation of Engie's involvement as Lead Market Participant and energy manager for unaffiliated generator assets (the "FRM Assets") that participated in the ISO-NE Forward Reserve Market ("FRM") between July 2021 and September 2022 (the "Relevant Period").[152] Enforcement determined that during the Relevant Period, Engie routinely submitted attestations to the ISO-NE IMM that one or more FRM Assets satisfy all six conditions necessary to seek exemption from energy market mitigation under the ISO-NE Tariff when certain conditions were not met. Enforcement determined that there were no instances during the Relevant Period in which the FRM Assets would have been subject to energy market mitigation but for an exemption request submitted by Engie. Enforcement found no intent to defraud; instead, Engie failed to properly evaluate whether necessary conditions were met prior to the submission of an attestation to the IMM; and, relatedly, failed to evaluate how changes Engie made to the internal model it used to generate offers might impact the accuracy of its attestations. Under the Stipulation and Consent Agreement, Engie agreed to pay a ***civil***

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[150] *SunSea Energy, LLC,* 187 FERC ¶ 61,225 (Jun. 28, 2024).

[151] *Josco Energy Corp.,* 187 FERC ¶ 61,221 (Jun. 28, 2024).

[152] *ENGIE Energy Marketing NA, Inc.*, 187 FERC ¶ 61,084 (May 20, 2024).

penalty of $48,000 to the United States Treasury and file one annual compliance report with the requirement of a second annual filing at Enforcement's discretion. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Ketchup Caddy / Phillip Mango (MISO DR Program Violations) (IN23-14)**

On February 21, 2024, the FERC directed Ketchup Caddy, LLC ("Ketchup Caddy") and Phillip Mango, Ketchup Caddy's CEO and co-owner (together, "Respondents"), to show cause why they should not be found to have violated FPA section 222, along with section 1c.2 of the FERC's regulations, Sections 69A.3.5 and 69A.7.1 of the MISO Tariff by offering uncontracted resources into the annual Planning Resource Auctions ("PRAs") that MISO uses to procure capacity necessary to maintain the reliability of the MISO grid.[153] The FERC directed Ketchup Caddy and Mango to show cause why they should not be assessed ***civil penalties of $25 million*** and ***$1.5 million***, respectively, and why ***Mango*** should not ***disgorge $506,502, plus interest***, in unjust profits. Enforcement alleges that "Ketchup Caddy operated as a fraudulent enterprise with no legitimate market activity, registering and clearing demand response resources without their knowledge or consent and collecting capacity payments in turn, without making payments to the registered resources. Mango … made no attempt to contract with—or even to contact—legitimate customers, and the purported customers Ketchup Caddy registered with MISO would not have responded if dispatched. Collectively, Mango and his co-owner received $1,013,004 in capacity payments paid to Ketchup Caddy by MISO during the Relevant Period. Staff's recommended penalties are predicated on its finding that Respondents caused $17,639,142.07 in losses to other suppliers because Ketchup Caddy's fraudulent offers lowered capacity prices in the 2019/20, 2020/21, and 2021/22 MISO PRAs."[154]

Since the last Report, finding that the Order to Show Cause was not served on Respondents, as required by Rule 2010 of the FERC's Rules of Practice and Procedure, the FERC directed the FERC Secretary to serve the Order to Show Cause on Respondents and to issue a notice in this proceeding indicating the date on which service was made.[155] The FERC amended the answer deadline in the Order to Show Cause to require Respondents to respond to the Order to Show Cause by no later than 30 days after the date on which the Office of the Secretary serves the Order to Show Cause on Respondents. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Galt Power Stipulation and Consent Agreement (IN20-5)**

On June 28, 2024, the FERC approved a Stipulation and Consent Agreement with Galt Power, Inc. ("Galt") to resolve OE's investigation into whether Galt Power, and as to certain obligations, Customized Energy Solutions Ltd. ("Customized"), violated the FERC's Anti-Manipulation Rule and the Federal Power Act by repeatedly engaging in prohibited wash trades between the NYISO and ISO-NE markets between July 8, 2016 and April 23, 2019 (the "Relevant Period").[156] Enforcement determined that during the Relevant Period, Galt repeatedly executed offsetting import-export trades to send the same quantity of energy from NYISO to ISO-NE in order to obtain Massachusetts Class I RECs (necessary to obtain the Class I RECs), and back from ISO-NE to NYISO in the same hour in order to eliminate the price risk of the NYISO to ISO-NE transactions. These prearranged offsetting trades constitute prohibited wash trades under the Anti-Manipulation Rule. In addition, Galt also violated the Anti-Manipulation Rule by making untrue statements of material fact to APX during the Relevant Period in connection with the wash trades. Under the Stipulation and Consent Agreement, Galt agreed to pay a ***civil penalty of $1.5 million*** to the United States Treasury, ***disgorge (with interest) $372,297.85*** to the Commonwealth of Massachusetts, and submit two annual compliance monitoring reports, with a third annual compliance monitoring

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[153] *Ketchup Caddy, LLC and Philip Mango*, 186 FERC ¶ 61,132 (Feb. 21, 2024).

[154] *Id.* at P 3.

[155] *Ketchup Caddy, LLC and Philip Mango*, 188 FERC ¶ 61,081 (July 26, 2024) at P 4.

[156] *Galt Power Inc.,* 187 FERC ¶ 61,224 (Jun. 28, 2024).

report at Enforcement's discretion. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

Natural Gas-Related Enforcement Actions

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

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,[157] 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,[158] 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[159] 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,[160] 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;[161] (ii) failing to adequately monitor the right-of-way at the site of the Tuscarawas River HDD operation; and (iii) improperly disposing of inadvertently released drilling mud that was contaminated with diesel fuel and hydraulic oil. The FERC directed Respondents to show why they should not be assessed civil penalties in the amount of ***$40 million***.

On March 21, 2022, Respondents answered and denied the allegations in the *Rover/ETP CPCN Show Cause Order*. On April 20, 2022, OE Staff answered Respondents' March 21 answer. On May 13, Respondents submitted a surreply, reinforcing their position that "there is no factual or legal basis to hold either [Respondent] liable for

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[157] 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.

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

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

[160] *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*").

[161] 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.

the intentional wrongdoing of others that is alleged in the Staff Report." The FERC denied Respondents' request for rehearing of the FERC's January 21, 2022 designation notice.[162] This matter is pending before the FERC.

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

On April 28, 2016, the FERC issued a show cause order[163] in which it directed Total Gas & Power North America, Inc. ("TGPNA") and its West Desk traders and supervisors, Therese Tran f/k/a Nguyen ("Tran") and Aaron Hall (collectively, "Respondents") to show cause why Respondents should not be found to have violated NGA Section 4A and the FERC's Anti-Manipulation Rule through a scheme to manipulate the price of natural gas at four locations in the southwest United States between June 2009 and June 2012.[164]

The FERC also directed TGPNA to show cause why it should not be required to disgorge unjust profits of ***$9.18 million***, plus interest; TGPNA, Tran and Hall to show cause why they should not be assessed civil penalties (TGPNA - ***$213.6 million***; Hall - ***$1 million*** (jointly and severally with TGPNA); and Tran - ***$2 million*** (jointly and severally with TGPNA)). In addition, the FERC directed TGPNA's parent company, Total, S.A. ("Total"), and TGPNA's affiliate, Total Gas & Power, Ltd. ("TGPL"), to show cause why they should not be held liable for TGPNA's, Hall's, and Tran's conduct, and be held jointly and severally liable for their disgorgement and civil penalties based on Total's and TGPL's significant control and authority over TGPNA's daily operations. Respondents filed their answer on July 12, 2016. OE Staff replied to Respondents' answer on September 23, 2016. Respondents answered OE's September 23 answer on January 17, 2017, and OE Staff responded to that answer on January 27, 2017.

Hearing Procedures. On July 15, 2021, the FERC issued and order establishing hearing procedures to determine whether Respondents violated the FERC's Anti-Manipulation Rule, and to ascertain certain facts relevant for any application of the FERC's Penalty Guidelines.[165] On July 27, 2021, Chief Judge Cintron designated Judge Suzanne Krolikowski as the Presiding ALJ and established an extended Track III Schedule for the proceeding.

Discovery in this case closed on December 2, 2022. On December 16, 2022, Respondents filed for a preliminary injunction in the US District Court for the Southern District of Texas ("Southern District"). In order to allow for briefing and a decision on that motion, the FERC placed this proceeding in abeyance.[166]

On June 14, 2023, the FERC issued an Order on Presiding Officer Reassignment,[167] 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 *TGPNA Presiding Officer Reassignment Order* takes effect; (ii) held that the *TGPNA Presiding Officer Reassignment Order* will take effect once the Southern District clarifies or lifts its stay for the limited purpose of allowing the *TGPNA Presiding Officer Reassignment Order* to take effect or the stay is lifted or

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[162] *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.

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

[164] The allegations giving rise to the Total Show Cause Order were laid out in a September 21, 2015 FERC Staff Notice of Alleged Violations which summarized OE's case against the Respondents. Staff determined that the Respondents violated NGA section 4A and the Commission's Anti-Manipulation Rule by devising and executing a scheme to manipulate the price of natural gas in the southwest United States between June 2009 and June 2012. Specifically, Staff alleged that the scheme involved making largely uneconomic trades for physical natural gas during bid-week designed to move indexed market prices in a way that benefited the company's related positions. Staff alleged that the West Desk implemented the bid-week scheme on at least 38 occasions during the period of interest, and that Tran and Hall each implemented the scheme and supervised and directed other traders in implementing the scheme.

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

[166] *Total Gas & Power North America, Inc., Total, S.A., Total Gas & Power, Ltd., Aaron Hall, and Therese Tran f/k/a Nguyen*, 181 FERC ¶ 61,252 (Dec. 21, 2022).

[167] *Total Gas & Power North America, Inc., Total, S.A., Total Gas & Power, Ltd., Aaron Hall, and Therese Tran f/k/a Nguyen*, 183 FERC ¶ 61,189 (June 14, 2023) ("*TGPNA Presiding Officer Reassignment Order*").

dissolved such that hearing procedures may resume; (iii) stated that this proceeding otherwise remains suspended until the Southern District's stay is lifted or dissolved such that hearing procedures may resume; and (iv) provided procedural guidance to the new presiding officer. On July 18, Judge Patricia M. French was substituted as Presiding Judge (relieving Judge Krolikowski of all of her duties with respect to this proceeding).

XIV. Natural Gas Proceedings

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

New England Pipeline Proceedings

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

- **Iroquois ExC Project (CP20-48)**
    - 125,000 Dth/d of incremental firm transportation service to ConEd and KeySpan by building and operating new natural gas compression and cooling facilities at the sites of four existing Iroquois compressor stations in Connecticut (Brookfield and Milford) and New York (Athens and Dover).
    - Three-year construction project; service request by November 1, 2023.
    - On March 25, 2022, after procedural developments summarized in previous Reports, the FERC issued to Iroquois a certificate of public convenience and necessity, authorizing it to construct and operate the proposed facilities.[168] 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.
        - In its March 8, 2024 monthly status report, Iroquois indicated that it is still awaiting issuance of air permits from the New York State Department of Environmental Conservation ("NYDEC") and the CT DEEP. Iroquois noted that the public comment period on the NY DPS reliability and needs determination, noticed by NYDEC was open until March 29, 2024. Iroquois has still not yet requested or received authorization to commence construction; accordingly, no construction activities were undertaken in February 2024 and no construction was planned for March 2024.

XV. State Proceedings & Federal Legislative Proceedings

No activities to report.

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

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 1920: Transmission Planning Reforms (24-1254 et al.) (consolidated)**
  Underlying FERC Proceeding: RM21-17[169]
  Petitioners: AEU/ACPA/SEIA, Invenergy
  Status: Filing of Initial Submissions Underway

On July 18, 2024, AEU/ACPA/SEIA, Invenergy, and (collectively, "Petitioners") petitioned the DC Circuit Court of Appeals for review of the FERC's *Order 1920*.[170] The Court ordered Petitioners to file, by August 21, 2024, a Docketing Statement, a Statement of Intent to Utilize Deferred Joint Appendix, a Statement of Issues, and the Underlying Decision from which the appeal arose. Appearances and other procedural motions, if any, are also due on or before August 21. A Certified Index to the Record and Dispositive Motions, if any, are due on or before September 5, 2024.

- **Mystic Second CapEx Info Filing (24-1077)**
  Underlying FERC Proceeding: ER18-1639-028[171]
  Petitioner: Mystic
  Status: Being Held In Abeyance

On April 3, 2024, Constellation Mystic Power, LLC petitioned the DC Circuit Court of Appeals for review of the FERC's orders. Mystic filed, on May 6, 2024, a Certificate as to Parties, Rulings, and Related Cases, a Docketing Statement, a Statement of Intent to Utilize Deferred Joint Appendix, a Statement of Issues, and the Underlying Decision from which the appeal arose. Appearances and other procedural motions, if any, were also due on or before May 6. Interventions were filed by ISO-NE, NESCOE, and a collective of Massachusetts municipal utilities.[172]

In response to a motion by the FERC, the Court order that this case be held in abeyance pending further order of the court. The Court directed the parties to file motions to govern further proceedings in this case by July 16, 2024. On July 16, 2024, Mystic filed an unopposed motion asking the Court to continue to hold this case in abeyance for an additional 120 days to allow for continued settlement discussions that "appear likely to succeed". The July 16 motion is pending before the Court. Also since the last Report, Mystic amended its Petition for Review to add the FERC's May 23, 2024 *Second CapEx Info Filing Order Allegheny Order*.

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[169] *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*").

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

[171] *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*").

[172] Braintree Electric Light Department, Concord Municipal Light Plant, Georgetown Municipal Light Department, Hingham Municipal Lighting Plant, Littleton Electric Light & Water Department, Middleborough Gas & Electric Department, Middleton Electric Light Department, Norwood Light & Broadband Department, Pascoag Utility District, Reading Municipal Light Department, Taunton Municipal Lighting Plant, Wellesley Municipal Light Plant, and Westfield Gas & Electric Department (collectively, the "Eastern New England Consumer-Owned Systems").

- **Orders 2023 and 2023-A (23-1282 et al.) (consolidated)**
  Underlying FERC Proceeding: RM22-14[173]
  Petitioners: AEU et al.
  Status: Being Held In Abeyance; Unopposed Proposed Schedule to Govern Future Proceedings Pending

Several Petitioners have challenged *Orders 2023 and 2023-A*. Those challenges have now been consolidated, with the AEU docket (23-1282) as the lead docket. Since the last Report, the Court ordered that these consolidated cases remain in abeyance pending further order of the court. Following an extension granted by the Court, the parties filed on July 2, 2024 an unopposed motion to establish briefing procedures and a schedule. Deadlines would be keyed off the date that the Court accepts the proposed schedule (which as of the date of this Report has not yet happened). The first deadline would be for initial submissions, which would be due 2 weeks from the date of such an order.

- ***Order 2222*** **Compliance Orders (23-1167, 23-1168, 23-1169, 23-1170, 23-1335)(consolidated)**
  Underlying FERC Proceeding: ER22-983[174]
  Petitioners: Eversource, ISO-NE, National Grid, and CMP/UI
  Status: Being Held In Abeyance

On June 30, 2023, ISO-NE (23-1168), CMP/UI (23-1170), Eversource (23-1167), and National Grid (23-1169) petitioned the DC Circuit Court of Appeals for review of the FERC's orders related to the FERC's *Order 2222 Compliance Orders*.[175] On July 3, 2023, the Court consolidated the cases, with Case No. 23-1667 as the lead case. On July 24, 2023, the FERC moved to have the consolidated cases held in abeyance pending the issuance of the Commission's further order on rehearing. The Court granted that motion on July 27, 2023, with the case to be held in abeyance pending further order of the Court. On June 6, 2024, the FERC filed a status report reporting that, on May 23, 2024, the Commission issued its order on rehearing of its November 2023 order in the ER22-983 docket and that, under the Court's February 6 order, the parties therefore have until ***August 5, 2024***, to file motions to govern future proceedings in these consolidated appeals. However, since the last Report, the FERC asked that the Court continue to hold these consolidated petitions for review in abeyance until 90 days after the Commission's issuance of a final order in ER22-983, with parties to file motions to govern future proceedings at the end of the abeyance period. The FERC asked for the additional period of abeyance "because compliance filings in the ER22-983 proceeding remain pending before the Commission, and Commission action on those filings may ultimately result in further petitions for review of ER22-983 orders, or otherwise expand or reduce the issues presented for review". The FERC's motion is pending before the Court.

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[173] *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).

[174] *ISO New England Inc. and New England Power Pool Participants Comm.*, 182 FERC ¶ 61,137 (Mar. 1, 2023) ("*Order 2222 Compliance Order*"); *ISO New England Inc. and New England Power Pool Participants Comm.*, 183 FERC ¶ 62,050 (May 1, 2023) ("*Order 2222 Compliance Allegheny Notice*", and together with the *Order 2222 Compliance Order*, the "*Order 2222 Compliance Orders*").

[175] In response to the region's *Order 2222 Changes*, the FERC directed a number of revisions and additional compliance and informational filings to be filed within 30, 60 or 180 days of the *Order 2222 Compliance Order*, as described in previous Reports. When filed, the Filing Parties stated that the *Order 2222 Changes* create a pathway for Distributed Energy Resource Aggregations ("DERAs") to participate in the New England Markets by: creating new, and modifying existing, market participation models for DERA use; establishing eligibility requirements for DERA participation (including size, location, information and data requirements); setting bidding parameters for DERAs; requiring metering and telemetry arrangements for DERAs and individual Distributed Energy Resources ("DERs"); and providing for coordination with distribution utilities and relevant electric retail regulatory authorities ("RERRAs") for DERA/DER registration, operations, and dispute resolution purposes.

- **Seabrook Dispute Order (23-1094, 23-1215) (consolidated)**
  Underlying FERC Proceeding: EL21-6, EL 23-3[176]
  Petitioner: NextEra Energy Resources, LLC and NextEra Energy Seabrook, LLC
  Status: Oral Argument Held Feb 6, 2024; Case Pending Before the Court

On April 4, 2023, NextEra Energy Resources, LLC and NextEra Energy Seabrook, LLC (collectively, "NextEra") petitioned the DC Circuit Court of Appeals for review of the FERC's orders related to the Seabrook Dispute.[177] NextEra subsequently petitioned the Court for review of the June 15, 2023 *Seabrook Dispute Allegheny Order*, which was consolidated with Case No. 23-1094. Briefing is completed. Oral argument was heard on February 6, 2024 by Judges Millett, Katsas and Rao. This matter remains pending before the Court.

- **Mystic II (ROE & *True*-Up)**
  (21-1198; 21-1222, 21-1223, 21-1224, 22-1001, 22-1008, 22-1026) (consolidated)
  Underlying FERC Proceeding: ER18-1639-010, -011,[178] **-013**[179] **-017**[180]
  Petitioners: Mystic, CT Parties,[181] **MA AG, ENECOS**
  Status: Being Held in Abeyance; Motions to Govern Future Proceedings Due Nov 27, 2024

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

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[176] *NextEra Energy Seabrook, LLC and NECEC Transmission LLC and Avangrid, Inc. v. NextEra Energy Resources, LLC and NextEra Energy Seabrook, LLC*, 182 FERC ¶ 61,044 (Feb. 1, 2023) *("Seabrook Dispute Order")*, *reh'g denied by operation of law*, *NextEra Energy Seabrook, LLC et al.*, 183 FERC ¶ 62,001 (Apr. 3, 2023) ("*Seabrook Dispute Allegheny Notice*"); *NextEra Energy Seabrook, LLC et al.*, 183 FERC ¶ 61,196 (June 15, 2023) ("*Seabrook Dispute Allegheny Order*").

[177] In the Seabrook Dispute Order, the FERC (i) both denied and granted in part the Seabrook Complaint; (ii) dismissed the Seabrook Declaratory Order Petition; and (iii) directed Seabrook to replace the Seabrook Station breaker pursuant to its obligations under the Seabrook LGIA and Good Utility Practice. Specifically, the FERC denied the Seabrook Complaint in part because it found that Avangrid had "not shown that Seabrook is obligated to replace the breaker due to Seabrook failing to meet certain open access obligations or because Seabrook has failed to comply with Schedule 25 of the ISO-NE Tariff". However, the FERC found that, "under Seabrook's LGIA, Seabrook may not refuse to replace the breaker because it is needed for reliable operation of Seabrook Station and required by Good Utility Practice" and thus, given the specific facts and circumstances in the record, granted the Seabrook Complaint in part. With respect to cost issues, the FERC agreed with Avangrid that, in this case, Seabrook should not recover opportunity costs (e.g. lost profits, lost revenues, and foregone Pay for Performance ("PFP") bonuses) or legal costs. In dismissing the Declaratory Order Petition, the FERC noted that the issues raised in the Petition were addressed in the Seabrook Dispute Order, that additional findings were unnecessary, and thus exercised its discretion to not take action on, and to dismiss, the Petition. The breaker replacement is currently expected to take place during the Fall 2024 refueling outage and the commercial operation date for the NECEC Project is December 2024. Seabrook plans to file an agreement governing installation at the earlier of 30 days prior to delivery of the breaker or 120 days prior to the start of the Fall 2024 outage. The FERC noted its expectation that such an agreement would resolve whatever remaining issues exist between the parties to allow replacement of the breaker to move forward during the 2024 outage, or if not, an unexecuted agreement would be filed.

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

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

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

[181] In this appeal, "CT Parties" are the CT PURA CT PURA, CT DEEP, and the CT OCC.

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

Abeyance. As previously reported, these proceedings have been held in abeyance pending disposition of *MISO Transmission Owners v. FERC*, 16-1325 ("*MISO TOs*"), now on remand at the FERC. Most recently, on July 22, 2024, Constellation reported that all parties agree and asked the Court that this case should remain in abeyance for an additional 90 days pending FERC action on remand in the *MISO TOs* case. On July 30, 2024, the Court issued an order that these cases remain in abeyance and that the parties file motions to govern future proceedings by ***Nov 27, 2024***.

- ***CASPR* (20-1333, 21-1031) (consolidated)****
  Underlying FERC Proceeding: ER18-619[182]
  Petitioners: Sierra Club, NRDC, RENEW Northeast, and CLF
  Status: Being Held in Abeyance; Motions to Govern Future Proceedings Due Mar 2, 2026

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

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

- ***Opinion 531-A* Compliance Filing Undo (20-1329)**
  Underlying FERC Proceeding: ER15-414[183]
  Petitioners: TOs (CMP et al.)
  Status: Being Held in Abeyance

On August 28, 2020, the TOs[184] 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*[185] 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

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

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

[184] 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.

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

requested abeyance. On February 11, 2021, the Court issued an order that that this case remain in abeyance pending further order of the court. On April 21, 2021, the FERC filed an unopposed motion for continued abeyance of this case *because* the Commission intends to issue a future order on Petitioners' request for rehearing of the challenged *Order Rejecting Compliance Filing*, and because the remand proceeding in which the challenged order was issued remains ongoing.

On May 4, 2021, the Court ordered that this case remain in abeyance pending further order of the Court, directing the FERC to file a status report by September 1, 2021 and at 120-day intervals thereafter. The parties were directed to file motions to govern future proceedings in this case within 30 days of the completion of agency proceedings. The FERC's last status report, indicating that the proceedings before the FERC remain ongoing and that this appeal should continue to remain in abeyance, was filed on July 23, 2024.

- ***Chevron Doctrine* (US Supreme Ct 20-1329)**[186]
  Status: Overturned
  On June 28, 2024, the Supreme Court overturned the *Chevron* deference doctrine in its decisions in *Loper Bright v. Raimondo* and *Relentless, Inc. v. Dep't of Commerce*.[187] *Chevron*, a landmark and often-cited 1984 decision, required courts to defer to a federal agency's reasonable interpretation of ambiguity in a statute.[188] A more fulsome summary of the *Loper Bright* and *Relentless* Decisions and some of their projected impacts are included as Appendix A to this Report.

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[186] *Loper Bright Enterprises v. Raimondo*, No. 22-451 at 1–2 (U.S. June 28, 2024) (citing *Chevron U.S.A. Inc. v. Natural Resources Defense Council, Inc.*, 467 U. S. 837, 842 (1984)).

[187] *Loper Bright Enterprises v. Raimondo*, No. 22-451 at 1–2 (U.S. June 28, 2024) (citing *Chevron U.S.A. Inc. v. Natural Resources Defense Council, Inc.*, 467 U. S. 837, 842 (1984)).

[188] Chevron had established a two-step framework for courts to address ambiguity and gaps in statutes. In step one, a court was required to determine whether Congress had "directly spoken to the precise question at issue" using "traditional tools of statutory construction." If the courts could not determine a clear congressional intent, in step two, the court was required to assess whether the agency's interpretation was a "permissible construction of the statute."

INDEX
Status Report of Current Regulatory and Legal Proceedings
as of July 31, 2024

I. Complaints/Section 206 Proceedings

II. Rate, ICR, FCA, Cost Recovery Filings

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

IV. OATT Amendments/Coordination Agreements

V. Financial Assurance/Billing Policy Amendments

No activities to Report

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

VII. NEPOOL Agreement/Participants Agreement Amendments

VIII. Regional Reports

IX. Membership Filings

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

XI. Misc. Regional Interest

XII. Misc: Administrative & Rulemaking Proceedings

XIII. FERC Enforcement Proceedings

XIV. Natural Gas Proceedings

XV. State Proceedings & Federal Legislative Proceedings

No activities to Report

XVI. Federal Courts

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: NEPOOL Counsel

DATE: July 31, 2024

RE: Supreme Court overturns *Chevron* doctrine

Summary of Loper Bright and Relentless Decisions:

On June 28, 2024, the Supreme Court overturned the *Chevron* deference doctrine in its decisions in *Loper Bright v. Raimondo* and *Relentless, Inc. v. Dep't of Commerce*.[1] *Chevron* is a landmark 1984 decision requiring courts to defer to a federal agency's reasonable interpretation of ambiguity in a statute.[2]

In *Loper Bright* and *Relentless*, commercial herring fisherman challenged a National Marine Fisheries Service (NMFS) rule that required herring fishing operators to have a government-certified observer onboard their vessels to monitor data related to the conservation and management of herring fishing and also required that the fisherman pay for the observers. The Magnuson-Stevens Fishery Conservation and Management Act (MSA) grants the NMFS authority to implement a fishery management program with rules that are "necessary and appropriate" for the conservation and management of herring fisheries. Fishing operators argued that while the MSA provides that the NMFS may require herring fishing vessels to carry government-certified observers, the statute did not authorize the NMFS to establish a rule that the observers be paid for by the operators of those vessels. Relying on the *Chevron* doctrine, the district court granted summary judgement in both cases in favor of the government because the MSA did not mandate who is required to bear the cost of the observers and the NMFS's interpretation of its authority was reasonable given the MSA mandate to implement the observers. The appellate courts upheld the lower courts' decision under the *Chevron* doctrine. Afterward, the Supreme Court granted certiorari on the issue of whether *Chevron* should be overruled or clarified.

Writing for the majority, Chief Justice Roberts held that courts must exercise independent judgement in interpreting statutes and may not defer to an agency's interpretation of a statute simply because the statute is ambiguous. The Court stated that the *Chevron* doctrine is inconsistent with the court's role to "say what the law is,"[3] and conflicts with the Administrative Procedure Act (APA),

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[1] *Loper Bright Enterprises v. Raimondo*, No. 22-451 at 1–2 (U.S. June 28, 2024) (citing *Chevron U.S.A. Inc. v. Natural Resources Defense Council, Inc.*, 467 U. S. 837, 842 (1984)).

[2] Chevron had established a two-step framework for courts to address ambiguity and gaps in statutes. In step one, a court was required to determine whether Congress had "directly spoken to the precise question at issue" using "traditional tools of statutory construction." If the courts could not determine a clear congressional intent, in step two, the court was required to assess whether the agency's interpretation was a "permissible construction of the statute."

[3] *Id*. at 7 (quoting *Marbury v. Madison*, 1 Cranch 137, 177 (1803)).

which requires courts to review federal agencies' actions and invalidate agency action that is either "arbitrary or capricious" or beyond an agency's "statutory jurisdiction, authority or limitations."[4]

The Court found that the *Chevron* doctrine prevents judges from exercising their constitutional duty to adjudicate cases and controversies,[5] and it undermines the Judiciary's role as a constitutional check on the Executive Branch,[6] effectively allowing the views of the Executive Branch to supersede the Judiciary's judgement.[7] The Supreme Court determined that the *Chevron* doctrine was "unworkable" because the first step of the framework requires an analysis of whether the issue involves a statutory ambiguity, and "ambiguous" had never been meaningfully defined.[8] Arguments that federal agencies have subject matter expertise concerning the statutes they administer and, thus, agencies' interpretations should be given deference did not persuade the Court. Chief Justice Roberts explained that the "Framers anticipated that courts would often confront statutory ambiguities and expected that courts would resolve them by exercising independent legal judgement."[9] He further noted that Congress also expects courts to handle technical statutory questions with the aid of information from the parties and friends of the court, along with the agency's experience and informed judgment.[10]

Justice Kagan dissented and was joined by two other justices.[11] Her dissent defended the *Chevron* doctrine as a longstanding cornerstone of administrative law that allowed the agency with the relevant expertise to interpret the statute and make policy choices as Congress had intended.[12] She also warned that this decision gives the Judiciary power over every open issue, no matter how expertise-driven or policy-laden[13] and will cause a massive shock to the legal system.[14]

The Supreme Court vacated and remanded the judgments in the *Loper Bright* and *Relentless* proceedings.

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[4] Section 706 of the APA requires courts reviewing agency actions to "decide all relevant questions of law and interpret constitutional and statutory provisions." *Id*. at 14 (quoting 5 U.S. C. § 706).

[5] *Id*. at 7.

[6] "The Framers structured the Constitution to allow judges to exercise that judgement independent of influence from the political branches." *Id*.

[7] *Id*. at 9.

[8] *Id* at 30.

[9] *Id*. at 23.

[10] *Id*. at 24.

[11] Justice Sotomayor joined and Justice Jackson joined as it applied to No. 22-1219.

[12] *Id*. at 2 (Kagan, J., dissenting).

[13] *Id*. at 3 (Kagan, J. dissenting).

[14] *Id*. at 24 (Kagan, J., dissenting).

Impact of Loper Bright and Relentless Decisions:

The elimination of *Chevron* deference is expected to increase regulatory uncertainty across various regulated industries, including FERC-regulated industries. While prior *Chevron*-based precedents remain in place, [15] federal courts are no longer bound to defer to an agency's statutory interpretations. The shift is likely to level the playing field between a federal agency and a party challenging that agency's action, potentially leading to an uptick in regulatory litigation with parties more willing to challenge an agency decision or action. Consequently, energy project developments and investments may slow because energy project stakeholders and investors must now evaluate the increased risk of regulatory challenges to a rule or permit allowing a project to proceed and the time needed to navigate any such challenge.

Furthermore, the rise in regulatory uncertainty may impact the pace at which federal agencies promulgate rules. Variability in judicial interpretations across circuits could create a patchwork of regulatory standards, with states possibly stepping in to fill gaps or establish their own regulations. A fragmented approach could result in a lack of uniformity in the energy industry, making it more challenging for energy project stakeholders and investors to navigate the regulatory landscape.

For instance, the FERC's recent *Order 1920*, issued earlier this year,[16] which introduced new requirements for transmission planning funding and design, has already faced scrutiny in light of the *Loper Bright* decision. Commissioner Mark Christie voiced doubts about *Order 1920*'s viability post-*Chevron* deference, arguing that the FERC lacks congressional authority. He stated that *Order 1920* is almost certainly going to be struck down by courts now that the Supreme Court overturned *Chevron* because *Order 1920* relies on legal authority that Congress never granted — and thus, *Order 1920*'s "chances of surviving court challenges just shrank to slim to none."[17] Conversely, FERC Chairman Willie Phillips defended the FERC's authority, asserting that the *Loper Bright* decision and the overruling of the *Chevron* doctrine do not affect the FERC's authority to regulate regional transmission planning and cost allocation because those responsibilities fit squarely into the agency's authority under the Federal Power Act. Further, he noted that *Order 1000* is recognized as precedent through the *stare decisis* effect acknowledged in *Loper Bright*.

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[15] *Id*. at 34.

[16] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, Order No. 1920, 187 FERC ¶ 61,068 (May 13, 2024) ("*Order 1920*").

[17] Statement, Commissioner Mark Christie's Statement Concerning *Order 1920* and U.S. Supreme Court's Overruling of Chevron Deference (June 28, 2024), https://www.ferc.gov/news-events/news/commissioner-mark-christies-statement-concerning-order-no-1920-and-us-supreme.