NEPOOL
NEW ENGLAND POWER POOL
Sebastian Lombardi
Secretary

October 3, 2024

VIA E-MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of October 10, 2024 Participants Committee Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the October 2024 meeting of the Participants Committee will be held at the **Renaissance Boston Waterfront Hotel, 606 Congress Street, Boston, Massachussetts on Thursday, October 10, 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/. For those who are unable to attend in person but who are otherwise authorized to attend NEPOOL meetings as Participant representatives or as approved guests, the dial-in number will be **866-803-2146; Passcode: 7169224.** To join Webex, click this link and enter the event password **nepool**.

In addition, please note two items requiring your attention at this time:

- **Thursday, November 7 Sector Meetings with ISO Board and State Official Panels** – The next Sector meetings with the ISO Board and State Officials are scheduled to be held in person on Thursday, November 7 at the Seaport Hotel, Boston, MA (prior to the start of the Participants Committee meeting and beginning for most Sectors at 9:00 am). ***Please work directly with your Sector's Vice-Chair to help prepare and finalize proposed agendas and any supporting material for those meetings***.

- **2025 NEPOOL Officers** – Each Sector needs to identify for us no later than ***Wednesday, October 30*** the voting member chosen by that Sector to serve as its 2025 Participants Committee Officer. The Participants Committee will then select its 2025 Chair from among those Sector-selected Officers, using the required voting process for that selection. We have included with this notice a memorandum that provides more information about the selection process.

Respectfully yours,

/s/
Sebastian Lombardi, Secretary

FINAL AGENDA

1. To approve the draft minutes of the September 5, 2024 Participants Committee meeting. A copy of the draft minutes, which were circulated under separate cover, are included with this supplemental notice. Please provide us with any final comments on those draft minutes no later than noon, **Tuesday, October 8, 2024**.

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

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

4. To receive a report from the ISO Chief Operating Officer on the following:

   a. Operations Report Highlights (September data); and

   b. 2025 Annual Work Plan.

   The October COO Report will be circulated and posted in advance of the meeting. The Annual Work Plan materials are included and posted with this supplemental notice.

5. To consider, and take action, as appropriate, on the following proposed budgets:

   a. 2025 ISO-NE Operating and Capital Budgets; and

   b. 2025 NESCOE Budget.

   Background materials and draft resolutions are included and posted with this supplemental notice.

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

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

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

8. Administrative matters.

9. 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.

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Pat Gerity, NEPOOL Counsel

DATE: September 26, 2024

RE: 2025 Participants Committee Officer Elections

In order to ensure that the selection process requirements in the Participants Committee Bylaws for 2025's Participants Committee officers can be timely completed, each Sector needs to identify, no later than **Wednesday, October 30, 2024,** who the Sector has selected to serve as the Sector's Participants Committee officer for 2025. A description of the qualifications, responsibilities, and expectations of the Sector officers selected has been included with this memorandum.

By way of reminder, the Bylaws require that one voting member from each Sector be selected by a majority of all the voting members in its Sector (i) to serve as a nominee for Chair of the Participants Committee and (ii) if not elected Chair, to serve as a Participants Committee Vice-Chair. A confidential, written balloting process will then be conducted to elect the 2025 Chair from among the Participants Committee officers selected by each of the Sectors. To allow time for that balloting process ahead of the December 5 Annual Meeting, as required by the Bylaws, we need the Sectors' officers to be identified by October 30, 2024.

If any Sector needs assistance in conducting the vote for its Sector officer, please let us know (preferably no later than October 16). We would be pleased to help however we can. Also, if you have any questions, please contact me at pmgerity@daypitney.com or (860) 275-0533.

Participants Committee Sector Officer
Qualifications, Responsibilities and Expectations

Qualifications: A Participants Committee Chair or Vice-Chair must be a voting member of the Participants Committee. Per the Participants Committee Bylaws, one voting member from each active Sector of the Participants Committee is to be selected to serve as the Vice-Chair of the Sector "by a majority of all the voting members in its Sector." The Chair is selected from among the nominated Vice-Chairs using the balloting procedures in the Bylaws.

Responsibilities and Expectations of Participants Committee Sector Vice-Chairs:

1. Help to build and maintain a collegial and productive working relationship with other Committee officers and members, ISO management, and state officials participating in Committee activities.

2. Communicate routinely and effectively with other members of the Sector:

    a. To help ensure that members have the information needed to support informed and active Committee participation;

    b. To ensure that the officer has sufficient information to provide to the other officers, ISO management and staff, and state and federal officials a fair and objective report of Sector members' positions and sensitivities on regional matters; and

    c. To report objectively to Sector members information, questions, positions, perspectives, and sensitivities of or from the other Sectors, the ISO, and state officials that are provided to the Officer to be shared with the Sector.

3. Attend and lead or support planning for and participation in Participants Committee meetings, including (a) participation in planning conference calls and in-person meetings to identify and confirm Committee meeting agenda topics and materials, meeting logistics and orderly flow of business at Committee meetings, and (b) serving as Chair if and as needed for a meeting or portions of a meeting at which the Chair is not able to preside.

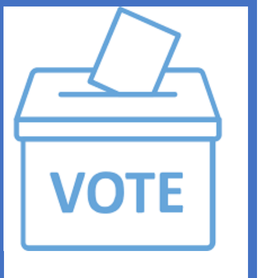
4. Coordinate and organize Sector members when appropriate, including for meaningful participation by the Sector members in the semi-annual meetings with the ISO Board of Directors, state officials and FERC representatives.

5. Ensure that the Sector is fairly and objectively represented at other committee and working group meetings and meetings among Officers, ISO management and state officials, and that the Officer or representative is reasonably informed as to the perspectives and sensitivities of the Sector members.

6. With the other NPC Officers, review and comment on NEPOOL filings or pleadings, raising awareness of any Sector-specific sensitivities.

7. Serve, or designate an appropriate Sector member to serve, on the Joint Nominating Committee that recommends to the Participants Committee for endorsement a slate of candidates for membership on the ISO Board of Directors.

1 September 5, 2024 Minutes



66.67%

RESOLVED, that the Participants Committee approves the preliminary minutes of the September 5, 2024 meeting, as circulated in advance of this meeting[, together with any changes agreed to by the Participants Committee at this meeting,] as the final minutes of the September 5, 2024 meeting.

PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held beginning at 10:00 a.m. on Thursday, September 5, 2024, at the Westin Portland Harborview Hotel, Portland, Maine. A quorum, determined in accordance with the Second Restated NEPOOL Agreement, was present and acting throughout the meeting. Attachment 1 identifies the members, alternates, and temporary alternates who participated in the meeting.

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

APPROVAL OF AUGUST 1, 2024 MEETING MINUTES

Ms. Bresolin referred the Committee to the preliminary minutes of the August 1, 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. Before asking for a motion, Ms. Bresolin asked Mr. Al McBride, ISO-NE Vice President, System Planning, to address the status and implementation of the revisions to Planning Procedure No. 5-6 (PP 5-6) (Orders 2023/2023-A-Related Revisions), the third of the three Consent Agenda Items. Mr. McBride explained that, because the FERC had not yet issued an order on the region's Order 2023 compliance filing, the ISO would put on hold its transition to the proposed new rules and continue its processing of existing interconnection requests under currently-effective Tariff provisions. While the ISO continued to seek support for the PP 5-6 changes, Mr. McBride said that the changes would not be made effective until the FERC issued an order on the Order 2023 compliance filing and the ISO had an opportunity to confirm that the PP 5-6 Revisions are consistent with that order. Any further revisions required by the FERC's order would be discussed and reviewed with the Reliability Committee (RC). Mr. McBride stated that a memo providing more formal notice of, and further guidance and details related to, the suspension of ongoing Order 2023 compliance proposal implementation activities would be circulated to Participants and posted later that day.

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

In response to questions, Mr. McBride assured members that the ISO memo to be released later in the day would provide further guidance and clarity on the impact to the October 11, 2024 deadline under the compliance proposal for interconnection customers to submit an executed Transitional Cluster Study Agreement. Members thanked the ISO for their efforts to incorporate stakeholder feedback into the PP 5-6 Revisions, as well as for their guidance on the path forward in the absence of a FERC order and looked forward to future efforts to advance the coordination and efficiency of the interconnection queue process.

ISO CEO REPORT

In the absence of Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), Ms. Maria Gulluni, ISO General Counsel, invited any questions on the September CEO Report, which had been circulated and posted with the materials for the meeting. There were no questions or comments on the CEO Report.

ISO COO REPORT

Operations Report

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), began by referring the Committee to his September operations report, which had been circulated and posted in advance of the meeting. Dr. Chadalavada noted that the data in the report was through August 27, 2024, unless otherwise noted. The September report highlighted: (i) that the Peak Hour for August, with 23,758 MW of Revenue Quality Metered (RQM) Data (including settlement-only generation), occurred on August 1, 2024 during the hour ending at 6:00 pm; (ii) August averages for Day-Ahead Hub LMP ($36.11/MWh), Real-Time Hub LMP ($39.06/MWh), and natural gas prices ($1.63/MMBtu); (iii) Energy Market value for August 2024 was $403 million, up from $310 million in August 2023 and down from the updated July 2024 Energy Market value of $674 million; (iv) Ancillary Markets value ($14.3 million) was down from August 2023 ($21.5 million); (v) average Day-Ahead cleared physical energy during the peak hours as percent of forecasted load was 102.5% during August (up from 101.4% reported for July 2024); (vi) Daily Net Commitment Period Compensation (NCPC) payments for August totaled $3 million, comprised of (a) $2.5 million in first contingency payments, including $439,000 in Dispatch Lost Opportunity Costs, $356,000 in Rapid Response Pricing Opportunity Costs, $327,000 paid to resources at external locations, (b) $66,000 in second contingency payments (protection for South Boston/SEMA due to transmission work), and (c) $412,000 in Distribution payments; and (vii) Forward Capacity Market (FCM) value was $120 million.

Dr. Chadalavada highlighted the heightened impacts that inaccurate weather forecasts could have on days when load levels are high (in the 22,000 - 24,500 MW range), noting by way of example four days in August (August 4, 16, 18, and 28) when there was a substantial deviation from the forecast load during periods of high demand. He explained that fleet performance and load forecasting accuracy each play a significant role in system operation, as would be further demonstrated during his review of the events on August 1.

Turning to transmission outages, Dr. Chadalavada noted three: the first, an outage at Sandy Pond Phase II, which would run from September 23, 2024 to October 14, 2024 and would limit transfer capacity across the Phase II interface to zero in both directions; the second, involving numerous outages on the New York to New England interface starting mid-September and running through the end of October (including ongoing maintenance and construction-driven outages on Lines 352 and 329 (Long Mountain - Frost Bridge and Frost Bridge – Southington) (September 30 to October 21) and on Line 398 (Long Mountain – Cricket Valley) (September 16 to September 29), which would limit transfer capacity in both directions; and third, the continuation of a large generator outage in New Brunswick, which had been further extended to November 15, 2024, and would continue to impact flows in both directions, as discussed at previous Participants Committee meetings. He encouraged members if interested to visit the ISO's portal to understand the specific limitations during these periods of time.

In response to questions and a request, Dr. Chadalavada provided an update on efforts to implement the Day-Ahead Ancillary Services Initiative (DASI) on March 1, 2025, which he said were going well and were on schedule. He reported that the ISO had received the final software from General Electric and was in the process of its comprehensive testing process and adjustments. He highlighted that a DASI testing environment (sandbox) would come online in October to facilitate Participants' training and preparation to use the DASI interface. Dr. Chadalavada committed the ISO to circulate information with project updates and highlighting some of the key dates/milestones that would precede the expected March 1, 2025 implementation date.

August 1, 2024 OP-4 Event and Capacity Scarcity Condition

Referring to the separate materials circulated and posted in advance of the meeting, Dr. Chadalavada provided a more detailed description and summary of the August 1 Capacity Scarcity Condition and implementation of Operating Procedure No. 4 (Action During a Capacity Deficiency) (OP-4). He explained that, while the ISO began the day with a thin capacity surplus (approximately 320 MW, including 160 MW of supplemental reserves), approximately 750 MW of generator outages and reductions (from the time the ~~m~~Morning ~~r~~Report was issued to the time that the Scarcity Event played out), together with higher-than-forecasted temperatures and loads during peak hours (temperatures 1-2°F higher; loads 1-2% above forecast), eventually triggered 10-minute Reserve Constraint Penalty Factor (RCPF) and 30-minute RCPF violations for several five-minute intervals between 16:55 and 19:20, and resulted in a Master/Local Control Center Procedure No. 2 (Abnormal Conditions Alert) (M/LCC 2) declaration and implementation of OP-4.

Dr. Chadalavada reported that the average Balancing Ratio ((Load + reserve requirement) / Capacity Supply Obligation (CSO) (excluding Energy Efficiency resources)) during the August 1 event was 89.6%. Pay-for-Performance (PFP) charges to underperforming FCM resources totaled approximately $49.9 Million, with the Balancing Fund (the surplus collection or the difference between payments and charges, allocated to CSOs) at $1.7 million. He added that approximately 34% of the resources performed greater than or equal to their expected requirements (their Balancing Ratio exceeded their ~~-~~adjusted CSO); 66% underperformed. He compared those percentages to the June 18, 2024 Capacity Scarcity Condition, where 26% over-performed and 74% underperformed.

Dr. Chadalavada then reviewed information from the last few OP-4/Capacity Scarcity Conditions, which illustrated that those events closely follow resource outages occurring within two hours of a day's peak load. He hoped that the information would assist Market Participants in evaluating/hedging risk and to focus/inform~~honing in on~~ internal strategies related to resources in the Market. He also reviewed report and notification enhancements under consideration, including enhancements to the reporting mechanisms for Real-Time Only export curtailments, to the reporting of daily forecasted surplus values (to include all, rather than just the peak, hours of the day), and the earlier release of information otherwise included in the Morning Report, following the close of the Day-Ahead Market.

In response to questions, Dr. Chadalavada clarified how, over time, changes to the resource mix had impacted operational flexibility to meet loads during peak hours. He opined that proposed Day-Ahead reserve products would have helped, but a 90-minute reserve product would have avoided all together the August 1 Capacity Scarcity Condition. He emphasized the transitory nature of the peak hour August 1 event, which in no way suggested that the system was in, or had approached, an energy deficiency. He explained further how equipment outages on August 1, which had begun prior to and thus were expected on August 1, but otherwise would not be expected during hot summer months, had further reduced operational flexibility that day. With respect to impacts on August's first contingency costs, Dr. Chadalavada estimated that roughly $600,000 to $800,000 of ~~the~~ total first contingency costs were incurred on August 1.

Dr. Chadalavada also noted the contribution of utility demand response that provided load relief of approximately 300 MW, which for 45 minutes brought the system up to a modest surplus until the loss of the additional 400 MW during the hour ending 19:00. He noted that the ISO's load forecasting algorithm was learning from these calls made by the utilities, forecasts were improved by predictable calls, though subject to mismatch if unpredictable. He confirmed that load was consistently buying up to the forecasted amount on an hourly basis, with Day-Ahead cleared physical energy during the peak hours as percent of forecasted load often in the high 90s, if not more -- ~~,~~a big improvement over past experience. In response to a member's request, Dr. Chadalavada agreed to consider adding the amount of capacity shortfall to the summary of Capacity Scarcity Condition intervals.

A member provided feedback that, because small temperature fluctuations could also have a fairly significant impact on certain generators operating at or near their thermal limitations, any improvements or expansion of the sharing/reporting of updated temperature forecasts, or improvements to the processes impacted by such temperature changes, would be beneficial to the region generally and to impacted generators specifically. In response to another question related to temperature impacts on ambient ratings and performance, Dr. Chadalavada agreed that the supply fleet would be impacted during times when temperatures are in the 90s, with high dew points, potentially resulting in unplanned forced outages in the 1-1.5 GWh range as seen during the August 1 Capacity Scarcity Event. He suggested that experience would likely be repeated, so that when forecasts call for tight conditions (load in the 21-24 GWh range), he recommended that Market Participants not only pay close attention to the surplus and planned outages identified in the ~~m~~Morning ~~r~~Report, and how loaded the ties might be for that day, but to also make allowances for unplanned forced outages of this magnitude when making operational plans for their resources. A member also requested that, as the ISO considers accelerating the release of certain information included in the ~~m~~Morning ~~r~~Report, it effort to also include in the

21-day and 7-day forecasts information on uncommitted available generation that is more consistent with how that availability information is accounted for and included in the ~~m~~Morning ~~r~~Report.

In response to a question related to potential differences in how Market Participants were compensated for violations of the System 30-Minute Operating Reserve constraint or the System 10-Minute Operating Reserve constraint during the identified five-minute intervals on August 1, Dr. Chadalavada committed the ISO to provide clarification on the compensation mechanics as soon as practicable. In response to a final set of questions, he estimated that, of the generators shown as available for August 1, approximately 3-4 GW were not able to be dispatched during the needed peak hours due to startup and/or notification limitations.

2025 ISO AND NESCOE BUDGETS

Mr. Tom Kaslow, Budget & Finance Subcommittee (B&F) Chair, referred the Committee to the materials circulated and posted in advance of the meeting related to the proposed 2025 ISO and NESCOE Budgets. He reported that the 2025 ISO Capital and Operating Budgets (ISO Budgets) had been reviewed and considered at B&F's August 9, 2024 meeting. He reported that no objections or concerns had been raised with respect to either those Budgets or to NESCOE's 2025 Budget, which had also been presented at that meeting. He said that the Budgets were scheduled for consideration and action at the October Participants Committee meeting.

Addressing the status of the 2025 ISO Budgets process, Mr. Bob Ludlow, ISO Chief Financial and Compliance Officer, referred members to the summary included with the meeting materials, which was largely consistent with what was shared with the Participants Committee at the June Summer Meeting. He said that the key changes to the ISO's Operating Budget since June related to refinements to professional fees, licensing (largely cyber security licensing) and employee full-time equivalent (FTE) estimates. Mr. Ludlow also remarked that, to address certain challenges associated with onboarding new employees, and given funds available resulting from an under-spend in 2024, the ISO had accelerated some of its planned hiring into 2024, allowing the ISO to benefit from a fuller FTE complement heading into 2025. The Capital Budget, he explained, reflected a $42.5 million program (up from the $40 million presented in June), reflecting improvements needed to address the ~~building~~ workspace issues previously discussed, including improvements related to moving planning functions to the Windsor (backup control center) Campus, which would be more efficiently financed as part of the capital program.

Mr. Ludlow reported that, as part of its budget process, the ISO had also met with New England State Officials. He referred the Committee to the Questions and Answers that had emerged from that discussion and that had been included with the meeting materials. Next steps in the budget process would include: (i) receipt of State comments, which would be shared with the ISO Board at its next Board meeting~~,~~; (ii) distribution to Participants of the projected 2025 revenue requirement and the resulting increases to Schedules 1-3 to Section IV of the ISO's Tariff (its Administrative Costs tariff)~~,~~; (iii) a Participants Committee vote at its October 10 meeting~~,~~; (iv) final action by the Board promptly thereafter~~,~~; and (v) a mid-October FERC filing.

There were no questions or comments on the ISO's or NESCOE's 2025 Budgets.

ISO FAP REVISIONS TO MITIGATE RISK OF PFP PENALTY PAYMENT DEFAULTS

Mr. Kaslow then summarized the B&F process preceding the ISO's proposed revisions to the Financial Assurance Policy (FAP) that would modify the PFP financial assurance provisions (FCM Delivery FA) by introducing a corporate liquidity assessment to evaluate PFP penalty default risk that could result in additional financial assurance requirements for higher-risk

Market Participants (Corporate Liquidity Revisions) and modify the intra-month collateral (IMC) variable in the FCM Delivery FA formula to prevent unnecessary collateral spikes (IMC Revisions) (together, the ISO FAP Revisions).

At the March B&F meeting, the ISO presented specific proposed modifications to the FAP, to become effective June 1, 2025, that would modify FA requirements for capacity sellers that are not determined to have adequate corporate liquidity relative to their potential PFP obligations. In discussion at the B&F's April and May meetings, some Participants expressed concern with the ISO's initial proposal, which included a magnitude of liquidity or required collateral that they believed would exceed reasonable expectations of default risk, could unfairly add new obligations to new capacity sales transactions, or might have been a more expensive option than permitting faster transfer of CSOs to reduce default risk. NEPGA subsequently proposed a number of amendments to the ISO proposal, including proposed modifications to (i) change the proposed effective date to coincide with start of the Capacity Commitment Period (CCP) for FCA19, (ii) permit shorted lead time transfers of CSOs to reduce future period PFP exposure and default risk; and (iii) extend the period over which large magnitude PFP charges could be paid by capacity sellers (subsequently dropped and not being offered for consideration at this meeting). At the July B&F meeting, the ISO presented a revised proposal that took into account the PFP default risk-decreasing effects of portfolio diversity and was the starting point for Committee considerationed~~ed~~ at this meeting. While some supported this revised proposal, the ISO FAP Revisions, a majority of those who spoke at the B&F meeting articulated a preference for the alternative timing for implementation proposed by NEPGA.

Because one of the NEPGA amendments to be considered at thise meeting involved Markets Committee (MC) review, Ms. Emily Laine, MC Chair, provided a summary of the MC's consideration of that separate proposal (the NEPGA CSO Bilateral Amendment). She further reported that, a~~A~~t its August 6 meeting, the MC considered, but did not recommend Participants Committee support for, the ISO FAP Revisions.

Summarizing for the ISO, Mr. Ludlow highlighted the effects that the ISO expected to see as a result of the ISO FAP Revisions, which were focused on adequate liquidity in Participants with CSOs. He suggested that roughly 20% of CSO holdings would not be impacted, 70% would have parent entities that would have an opportunity to provide parent guarantees to cover the risk of the CSOs, leaving 10% with no other opportunity than to seek an increase in liquidity or fund increased collateral requirements.

In response to clarifying questions, Mr. Chris Nolan, ISO Director, Market and Credit Risk, confirmed that the 70% figure represented the percentage of Participants that could receive a parent guarantee, but not necessarily the percentage that would actually receive a parent guarantee. Thus, the percentage of Participants that would have to ensure increased liquidity or fund increased collateral requirements would be higher than the 10% initially identified.

The following motion was then duly made and seconded:

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

NEPGA Effective Date Amendment

With the main motion before the Committee, the Chair invited a NEPGA representative to introduce the first of its amendments, as described in the materials circulated in advance of the meeting, to make the FAP Revisions effective as of June 1, 2028 (coinciding with the FCA19 Capacity Commitment Period (CCP)), rather than June 1, 2025 (the NEPGA Effective Date

Amendment). That member explained NEPGA's view that imposing an incremental FA requirement on CSO holders was likely in violation of the FERC's filed rate doctrine and unlikely to pass FERC scrutiny.

In response to a member's questions, Mr. Lombardi clarified the thresholds required for Committee ~~approval of~~support for the NEPGA Effective Date Amendment (66.67%) as well as on the expected second motion to amend Market Rule 1 (60%) and on the overall ISO FAP Revisions if and as amended (66.67%). A motion to approve the NEPGA Effective Date Amendment was then duly made and seconded.

Members then discussed the NEPGA Effective Date Amendment. Those supporting the NEPGA Effective Date Amendment argued that the Amendment recognized the commercial reality that the ISO's proposed changes add additional costs that could not have been, and were not, priced into auctions that had already been conducted; putting the fundamental commerical doctrine underlying the filed rate doctrine squarely in play. Others suggested that the ISO was underplaying the magnitude of the proposed changes and increase in FA requirements, with the inability to recover the costs of the proposal and the uncertainty of requirements associated with CSOs likely to undermine confidence in the markets.

Many also opposed the NEPGA Effective Date Amendment. While they expressed sympathy for the logic behind NEPGA's Amendment, some found that addressing the clearinghouse-type risk currently being assumed by Market Participants outweighed the concerns expressed, and they were generally unwilling to take on the significant Payment Default risk that would accompany any such delay. The ISO explained its opposition, particularly in light of increasing PFP penalty rates, to a delay in addressing the risks identified.

The NEPGA Effective Date Amendment was then voted and did not pass with a 48.02%[1] Vote in favor (Generation Sector – 16.67%; Transmission Sector – 0%; Supplier Sector – 11.11%; AR Sector – 16.67%; Publicly Owned Entity Sector – 0%; End User Sector – 3.57%;[1] and Provisional Members – 0.00%). (*see* Vote 1 on Attachment 2).

NEPGA CSO Bilateral Amendment

The Committee considered a second motion by NEPGA to amend the main motion so as to allow a Market Participant to submit a CSO Bilateral up to five business days before the Obligation Month and require the ISO to complete its Tariff-mandated review within five Business Days of receiving the CSO Bilateral in order to shorten the lead time for CSO transfers (NEPGA CSO Bilateral Amendment).

The NEPGA representative explained that the NEPGA CSO Bilateral Amendment would faciliate more nimble trading of those positions and would allow Market Participants subject to incemental FA requirements to better manage their monthly and FA positions. The NEPGA CSO Bilateral Amendment was then duly moved and seconded.

An AR Sector member commended NEPGA for proposing to address what was not, in his view, addressed by the ISO's collateralization proposal design, namely managing risk through markets. Others, echoing those sentiments, supported the NEPGA CSO Bilateral Amendment because it would allow Paricipants to manage additional financial requirements through liquidity in the markets, would in their view mitigate risk, significantly improve and complement the ISO's proposal, and was thus worthy of the efforts required to implement the Amendments.

[1] The Vote percentage increased slightly from the percentage announced during the meeting, reflecting three fewer votes in opposition cast by proxy (incorrectly registered during the meeting) in the End User Sector; the Vote outcome was not impacted.

Though generally supportive of the overall substance or goals of the NEPGA CSO Bilateral Amendment, other members pointed to the tight work plan and significant efforts ahead of the region, including the implementation of Capacity Auction Reforms (CAR), which could be adversely impacted by the efforts required to implement the NEPGA CSO Bilateral Amendment, as influencing their decision not to support the Amendment at that time. Some suggested that the NEPGA CSO Bilateral Amendment could and should be addressed as part of the larger CAR project.

On behalf of the ISO, Mr. Nolan explained the challenges presented by adopting the NEPGA CSO Bilateral Amendment, which included a not insignificant effort to understand the impacts on ISO systems and processes. The ISO believed that the NEPGA CSO Bilateral Amendment could be considered as part of the broader efforts toward a prompt and seasonal market design, but opposed pursuing the CSO Bilateral Amendment at this time.

The CSO Bilateral Amendment was then voted and did not pass with a 53.~~4~~87%[1] Vote in favor (Generation Sector – 16.67%; Transmission Sector – 0%; Supplier Sector – 14.58%; AR Sector – 16.67%; Publicly Owned Entity Sector – 0%; End User Sector – 5.~~5~~95%;[1] and Provisional Members – 0.00%). (*see* Vote 2 on Attachment 2).

Unamended Main Motion (ISO~~'s~~ FAP Proposal)

Members offered final thoughts on the unamended ISO FAP Proposal. Certain members thanked the ISO for their time and effort explaining and refining the ISO FAP Proposal, including reflecting Participant feeback received along the way. Others reiterated their concerns with the ISO's proposed effective date, the inability of some Participants to lean on affiliate relationships for credit support, and the failure of the ISO FAP Proposal to incorporate additional market mechanisms to mitigate the penalty payment default risk. A Supplier Sector member suggested that the impacts from an increasing PFP penalty rate and overall market design choices could have been addressed differently, particularly as to how the penalty payment default risk would be spread or allocated, and could have been limited to those participating in the capacity market.

There being no further discussion, the ~~ISO's~~ unamended ISO FAP Proposal was voted and failed to pass with a 62.50% Vote in favor (Generation Sector – 0%; Transmission Sector – 16.67%; Supplier Sector – 12.50%; AR Sector – 0%; Publicly Owned Entity Sector – 16.67%; End User Sector – 16.67%; and Provisional Members – 0.00%). (*see* Vote 3 on Attachment 2).

The Committee then broke for a brief lunch recess and subsequently reconvened to address the following:

NEPOOL GIS HOURLY CERTIFICATES RULE CHANGES

Ms. Samantha Regan, NEPOOL Counsel, referred the Committee to, and summarized the materials circulated and posted in advance of the meeting related to, Constellation's request for Committee approval of changes to the Generation Information System (GIS) and the GIS Operating Rules to accommodate the tracking of certificates on an hourly basis through a separate register maintained by APX, Inc. (GIS Administrator). She explained that, under the proposed GIS rule changes, only generators opting in to the tracking would be subject to hourly tracking and generators could later opt out of hourly tracking. She further stated that the GIS Administrator estimated that the hourly certificates rule changes would take 1,245 development hours to implement, and would be covered in part by the remaining annual allotted development hours for 2024 and 2025, leaving a remaining estimated cost of roughly $75,000.

Ms. Laine noted that the GIS hourly tracking proposal was first referred by the MC to the GIS Operating Rules Working Group in August 2022. Following refinements, she reported that the MC considered, but did not recommend, Participants Committee approval of the rule changes at its July 2024 summer meeting by a vote just short of the requisite two-thirds threshold.

Members asked clarifying questions related to the creation of the hourly certificates and what kinds of resources would be able to opt in/be available for supply. In response, Ms. Regan clarified that rounding of hourly certificates wou~~i~~ld occur so that only whole MWh certificates would~~ill~~ be retired. She further noted that only Market Settlement System (MSS) Generators would be permitted to~~may~~ opt in to hourly tracking. The Constellation representative added that a NEPOOL Generator that is a zero emissions generator may opt to have their hourly generation tracked, but the hourly tracking would~~ill~~ not be tied to an RPS program and therefore an hourly generator that is not enrolled in an RPS program would~~may~~ still be able to opt in to hourly tracking.

Ms. Bresolin invited the proposal sponsor to provide any additional remarks. The Constellation representative emphasized her view that the voluntary, more granular tracking of energy production and consumption would lead to more informed decisions regarding clean energy investment, procurement and deployment. She also noted that the ecosystem for hourly accounting was growing nationally, and approving and implementing the hourly tracking of Certificates regionally would be a natural next step and would ensure that the region would continue to be a leader in generation resource tracking.

The following motion was then duly made and seconded:

> RESOLVED, that the Participants Committee approves the changes to the NEPOOL Generation Information System (GIS) and the NEPOOL GIS Operating Rules proposed and discussed at this meeting related to transferring Certificates on an hourly basis, with such non-material changes thereto as the Chair of the Participants Committee may approve.

In discussion, members expressed both willingness and reluctance to support the GIS rule changes. Those supporting the hourly tracking proposal suggested that it could drive investment for resources in the region, provide resources with an additional value stream, and would advance the region into the future of certificate trading as other RTOs had already implemented hourly tracking. Explaining that the hourly tracking changes would facilitate voluntary transactions between willing buyers and willing sellers for a legitimate product, one member stressed that the proposal~~,~~ was consistent with the foundational purpose of the~~our~~ region's~~al~~ arrangements. Those inclined not to support the proposal focused on potential upward price pressure on GIS certificates in the market, the potential for the hourly tracking to become mandatory instead of voluntary, and concerns with hourly certificates not rounding or "banking" until reaching 1 MWh for retirement. Some members suggested that a working group effort could be established to subsequently address the rounding-related concerns raised.

Without further discussion, the motion was then voted and was approved, with a 70.47% Vote in favor (Generation Sector – 15.00%; Transmission Sector – 16.67%; Supplier Sector – 15.00%; AR Sector – 13.80%; Publicly Owned Entity Sector – 1.67%;[2] End User Sector – 8.77%;[2] and Provisional Members – 0.00%). (*See* Vote 4 on Attachment 2.)

GOVERNANCE ONLY END USER MEMBERSHIP APPLICATION

Mr. Brad Swalwell, Membership Subcommittee Chair, referred the Committee to the materials circulated in advance of the meeting related to approval of the application for Governance Only End User membership (Application) by Alan Sliski (Applicant). He also

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[2] The Vote percentage in favor on the NEPOOL GIS Hourly Certificate Rule Changes reflected herein also increased slightly from the percentage announced during the meeting, reflecting, in addition to the three fewer votes in the End User Sector as noted in fn. 1, an abstention (instead of an erroneously marked opposition) by one Publicly Owned Entity Sector Participant; the Vote outcome was not impacted.

referred to material from certain End User Sector representatives whose opposition to Subcommittee approval of the Application pursuant to the Subcommittee's delegated authority prompted Participants Committee consideration of the Application. Mr. Swalwell explained that Applicant was a Massachusetts residential customer of Eversource who has solar panels on the roof of his home (Rooftop System). Applicant had applied to become a Governance Only End User Participant, and his Application, together with data on his consumption in relation to the production of his Rooftop System, had been considered over the course of two Subcommittee meetings. The Application was before the Participants Committee in light of some concern and disagreement amongst Subcommittee members as to whether Applicant met the definition of End User Participant and was or should be eligible for membership in the End User Sector.

The following motion was duly made and seconded:

> RESOLVED, that the Participants Committee approves the application of Alan Sliski (Applicant) to be a Governance Only End User (Application) subject to the following conditions: (1) that NEPOOL Counsel and the ISO find the Application complete; (2) that the Applicant sign and return the Standard Membership Conditions, Waivers and Reminders letter; and (3) that Applicant execute an Indemnification Agreement to permit an expedited membership effective date.

Those with concerns and/or opposed to approving the Application for End User Sector membership identified characteristics of the Application that, for them, called into question whether End User Sector membership was appropriate, either definitionally or as a policy matter. Those that supported approving the Application found that the Application satisfied the eligibility requirements to be an End User Participant and believed that, in this case, Applicant's choice of End User Sector membership was appropriate for the Applicant. While certain members acknowledged that Sector eligibility requirements could reasonably be revisited in the future, they cautioned that revising eligibility requirements might not ensure more accurate

Participant groupings (pointing, by way of example, to the variety of interests that already participate in each of the Sectors) and found, at least in the circumstances presented, that such efforts were not warranted.

Without further discussion, the Application was approved by a show of hands, with oppositions registered by Maine Power, Harvard Dedicated Energy Limited, and the following additional Market Participant End Users: Bath Iron Works, Elektrisola, Garland Manufacturing, Hammond Lumber, The Moore Company, St. Anselm College, and Shipyard Brewing. An abstention by Mr. Lamson was also recorded.

LITIGATION REPORT

Mr. Lombardi referred the Committee to the September 3, 2024 Litigation Report that had been circulated and posted before the meeting. He highlighted the following three developments: (i) Committee-supported DASI Conforming Changes had been filed jointly by the ISO and NEPOOL (ER24-2883), with any comments due on or before September 17, 2024; (ii) the FERC had set for settlement judge procedures the pending waiver request filed by Canal Marketing to enable it to withdraw Canal 3 from the Winter 2023-24 Inventoried Energy Program (IEP) and return the net revenues it had received for that participation; and (iii) numerous Petitions for Review of FERC *Order 1920* (Transmission Planning Reforms), filed in nearly all of the US District Courts of Appeal, had been consolidated and assigned to the Fourth Circuit Court of Appeals by the Federal Courts' Judicial Panel on Multidistrict Litigation. Mr. Lombardi encouraged anyone with questions on any matter in the Litigation Report to reach out to NEPOOL Counsel.

COMMITTEE REPORTS

Markets Committee ~~(MC)~~. Mr. Bill Fowler, MC Vice-Chair, reported that the next MC meeting would be on September 10, 2024 at the DoubleTree Hotel in Westborough. He indicated that key topics would include discussion on the work scope of the Capacity Auction Reforms (CAR) project, introduction to DASI-conforming changes to the manuals, and a presentation by the Internal Market Monitor on its Spring 2024 Quarterly Markets Report.

Reliability Committee ~~(RC)~~. Mr. Bob Stein, RC Vice-Chair, reported that the RC would next meet on September 17, 2024, also at the Westborough DoubleTree. In addition to the RC's regular business items to review proposed plan and transmission cost allocation applications, the RC would review revisions to the Coordination Agreement with New Brunswick, and changes to certain operating and planning procedures.

Transmission Committee (TC). Mr. Dave Burnham, TC Vice-Chair, reported that the TC would next meet on September 25, 2024 by Webex/teleconference, with key topics for discussion to include Order 881-conforming Tariff changes and compliance with Order 1920.

Budget & Finance Subcommittee. Mr. Kaslow reported that the B&F had no scheduled meetings in September. The next scheduled meeting was October 11, 2024.

Membership Subcommittee. Mr. Brad Swalwell, Membership Subcommittee Chair, reported that the next Membership Subcommittee meeting would be by Zoom on September 16, 2024.

ACKNOWLEDGEMENT – PAUL ROBERTI

Ms. Bresolin announced that Mr. Paul Roberti, End User Vice-Chair, would be leaving the Rhode Island Division of Public Utilities Carriers for the private sector, which would take him away, at least for the foreseeable future, from the NEPOOL table. She thanked Mr. Roberti for his service over the past two years as a NEPOOL officer, noted that he would be missed, and invited him to attend a future Participants Committee meeting, particularly one convening in his home state of Rhode Island. The Committee congratulated and thanked Mr. Roberti with a round of applause.

ADMINISTRATIVE MATTERS

Mr. Lombardi advised members that the remaining Participants Committee meetings for 2024 would all be held in Boston, with the October 10 meeting at the Renaissance Boston Waterfront, the November 7 meeting at the Seaport Hotel (preceded the day before by the ISO's Annual Public Board meeting, and the morning of by the Sector meetings with the ISO Board and State Officials) and the December Annual Meeting at the Colonnade Hotel.

There being no other business, the meeting adjourned at 2:18 p.m.

Respectfully submitted,

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Sebastian Lombardi, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN SEPTEMBER 5, 2024 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Acadia Center	End User	Joe LaRusso (tel)		Claire Lang-Ree (tel)
Advanced Energy United	Associate Non-Voting		Alex Lawton (tel)	
AR Renewable Generation (RG) Large Group Seat	AR-RG		Aidan Foley (tel)	
Ashburnham Municipal Light Plant	Publicly Owned Entity		Matt Ide (tel)	Dan Murphy (tel)
AVANGRID: CMP/UI	Transmission	Alan Trotta	Jason Rauch	
Bath Iron Works	End User			Gus Fromuth
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
Boylston Municipal Light Department	Publicly Owned Entity	Matt Ide (tel)		Dan Murphy (tel)
BP Energy Company	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
Brookfield Energy Trading and Marketing LLC	Supplier	Aleks Mitreski		
Castleton Commodities Merchant Trading	Supplier			Bob Stein
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Matt Ide (tel)	Dan Murphy (tel)
CLEAResult Consulting, Inc.	AR-DG	Tamera Oldfield (tel)		
Clearway Power Marketing LLC	Supplier			Pete Fuller
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw (tel)		
Connecticut Office of Consumer Counsel	End User		Jamie Talbert-Slagle	
Conservation Law Foundation (CLF)	End User	Phelps Turner		
Constellation Energy Generation (Constellation)	Supplier	Gretchen Fuhr	Bill Fowler	
CPV Towantic, LLC	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
DTE Energy Trading, Inc.	Supplier			José Rotger
Dynegy Marketing and Trade, Inc.	Supplier	Ryan McCarthy		Bill Fowler
Earthjustice	End User		Ada Statler (tel)	
ECP Companies Calpine Energy Services, LP New Leaf Energy	Generation	Andy Gillespie	Alex Chaplin (tel)	Bill Fowler
Elektrisola, Inc.	End User		Gus Fromuth	
Emera Energy Services	Supplier			Bill Fowler
Engie Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Environmental Defense Fund	End User	Jolette Westbrook (tel)		
Eversource Energy	Transmission		Dave Burnham (tel)	
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	José Rotger	Jeff Iafrati (tel)	Steve Conant (tel)
Garland Manufacturing Company	End User	Gus Fromuth		
Generation Bridge Companies	Generation		Bill Fowler	
Generation Group Member	Generation		Abby Krich (tel)	Casey Roberts (tel)
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Groton Electric Light Department	Publicly Owned Entity		Matt Ide (tel)	Dan Murphy (tel)
Granite Shore Companies	Generation			Bob Stein
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQUS)	AR-RG	Louis Guilbault (tel)	Bob Stein	
Hammond Lumber Company	End User	Gus Fromuth		
Harvard Dedicated Energy Limited	End User			Stefan Koester
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity		Matt Ide (tel)	Dan Murphy (tel)
Holyoke Gas & Electric Department	Publicly Owned Entity		Matt Ide (tel)	Dan Murphy (tel)

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN SEPTEMBER 5, 2024 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Hull Municipal Lighting Plant	Publicly Owned Entity		Matt Ide (tel)	Dan Murphy (tel)
Icetec Energy Services, Inc.	AR-LR	Doug Hurley		
Industrial Energy Consumer Group	End User		Todd Griset	
Ipswich Municipal Light Department	Publicly Owned Entity		Matt Ide (tel)	Dan Murphy (tel)
Jericho Power LLC (Jericho)	AR-RG	Ben Griffiths		
Lamson, Jon	End User	Jon Lamson (tel)		
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	
Long Island Power Authority (LIPA)	Supplier	Bill Kilgoar (tel)		
Maine Power LLC	Supplier	Jeff Jones		
Maine Public Advocate’s Office	End User	Drew Landry		Stefan Koester
Maine Skiing	End User		Todd Griset	
Mansfield Municipal Electric Department	Publicly Owned Entity		Matt Ide (tel)	Dan Murphy (tel)
Marble River	Supplier		John Brodbeck (tel)	
Marblehead Municipal Light Department	Publicly Owned Entity		Matt Ide (tel)	Dan Murphy (tel)
Mass. Attorney General’s Office (MA AG)	End User	Jacquelyn Bihrle		Jamie Donovan (tel)
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Climate Action Network (MCAN)	End User			Casey Roberts (tel)
Mass. Dept. Capital Asset Management	End User		Paul Lopes (tel)	
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Matt Ide (tel)	Dan Murphy (tel)	
Mercuria Energy America, LLC	Supplier			José Rotger
Merrimac Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Moore Company	End User			Gus Fromuth
Narragansett Electric Co. (d/b/a RI Energy)	Transmission	Brian Thomson	Robin Lafayette (tel)	
Natural Resources Defense Council	End User	Claire Lang-Ree (tel)		
Nautilus Power, LLC	Generation		Bill Fowler	
New England Power (d/b/a National Grid)	Transmission	Tim Brennan (tel)	Tim Martin	
New England Power Generators Assoc. (NEPGA)	Associate Non-Voting	Bruce Anderson	Dan Dolan	
New Hampshire Electric Cooperative	Publicly Owned Entity			Brian Forshaw (tel)
New Hampshire Office of Consumer Advocate	End User	Matthew Fossum		Stefan Koester
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 Power Marketing LLC	Supplier		Pete Fuller	
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Pawtucket Power Holding Company	Generation	Dan Allegretti		
Paxton Municipal Light Department	Publicly Owned Entity		Matt Ide (tel)	Dan Murphy (tel)
Peabody Municipal Light Department	Publicly Owned Entity		Matt Ide (tel)	Dan Murphy (tel)
PowerOptions	End User			Stefan Koester
Princeton Municipal Light Department	Publicly Owned Entity		Matt Ide (tel)	Dan Murphy (tel)
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
RI Division of Public Utilities Carriers	End User	Paul Roberti		
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity		Matt Ide (tel)	Dan Murphy (tel)
Saint Anselm College	End User	Gus Fromuth		
Shell Energy North America (US) LP	Supplier	Jeff Dannels (tel)		
Shipyard Brewing LLC	End User	Gus Fromuth		
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Matt Ide (tel)	Dan Murphy (tel)
Sierra Club	End User	Casey Roberts (tel)		

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN SEPTEMBER 5, 2024 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
South Hadley Electric Light Department	Publicly Owned Entity		Matt Ide (tel)	Dan Murphy (tel)
Sterling Municipal Electric Light Department	Publicly Owned Entity		Matt Ide (tel)	Dan Murphy (tel)
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Sunrun Inc.	AR-DG			Pete Fuller
Tangent Energy	AR-LR	Brad Swalwell (tel)		
Taunton Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity		Matt Ide (tel)	Dan Murphy (tel)
Union of Concerned Scientists	End User			Francis Pullaro (tel)
Vermont Electric Power Company (VELCO)	Transmission	Frank Ettori (tel)		
Vermont Energy Investment Corporation	AR-LR		Stefan Koester	
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw (tel)
Versant Power	Transmission	Dave Norman		
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity	Dave Cavanaugh		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Matt Ide (tel)	Dan Murphy (tel)
Walden Renewables Development LLC	Generation			Abby Krich (tel)
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned Entity		Matt Ide (tel)	Dan Murphy (tel)
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler	
ZTECH, LLC	End User		Gus Fromuth	

ATTACHMENT 2

VOTES TAKEN AT
SEPTEMBER 5, 2024 PARTICIPANTS COMMITTEE MEETING

TOTAL

Sector/Group	Vote 1	Vote 2	Vote 3	Vote 4
GENERATION	16.67	16.67	0.00	15.00
TRANSMISSION	0.00	0.00	16.67	16.67
SUPPLIER	11.11	14.58	12.50	15.00
ALTERNATIVE RESOURCES	16.67	16.67	0.00	13.80
PUBLICLY OWNED ENTITY	0.00	0.000	16.67	1.67
END USER	3.57	5.95	16.67	8.77
% IN FAVOR	**48.02**	**53.87**	**62.50**	**70.91**

GENERATION SECTOR

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4
CPV Towantic, LLC	F	F	O	F
ECP Companies	S	S	S	S
Calpine	F	F	O	O
New Leaf Energy	F	F	O	F
FirstLight Power Management, LLC	F	F	A	F
Generation Bridge Companies	F	F	O	F
Generation Group Member	F	--	--	F
Granite Shore Power Companies	F	F	A	F
Nautilus Power, LLC	F	F	O	F
NextEra Energy Resources, LLC	A	F	A	F
Pawtucket Power Holding Co.	F	F	O	F
Walden Renewables Development	A	--	--	--
IN FAVOR (F)	~~8~~9	~~8~~9	0	9~~8.10~~
OPPOSED (O)	0	0	~~5~~6	1~~0.90~~
TOTAL VOTES	~~8~~9	~~8~~9	~~5~~6	9~~.00~~
ABSTENTIONS (A)	2	0	3	0

ALTERNATIVE RESOURCES SECTOR

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4
Renewable Generation Sub-Sector				
ENGIE Energy Marketing NA, Inc.	F	F	A	F
H.Q. Energy Services (U.S.) Inc.	F	A	A	F
Jericho Power LLC	F	F	O	O
Wheelabrator/Macquarie	F	F	O	F
Large RG Group Member	F	F	O	F
Distributed Gen. Sub-Sector				
CLEAResult Consulting, Inc.	A	A	A	A
Sunrun Inc.	A	A	A	A
Load Response Sub-Sector				
Icetec Energy Services, Inc.	F	F	O	A
Tangent Energy Solutions, Inc.	F	F	O	F
Vermont Energy Investment Corp.	A	A	A	A
IN FAVOR (F)	7	6	0	5
OPPOSED (O)	0	0	5	1
TOTAL VOTES	7	6	5	6
ABSTENTIONS (A)	3	4	5	4

TRANSMISSION SECTOR

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4
Avangrid (CMP/UI)	O	A	F	F
Eversource Energy	O	O	F	F
Rhode Island Energy	O	A	F	F
National Grid	O	A	F	F
VELCO	O	A	F	A
Versant Power	O	A	F	A
IN FAVOR (F)	0	0	6	5
OPPOSED (O)	6	1	0	0
TOTAL VOTES	6	1	6	5
ABSTENTIONS (A)	0	5	0	1

SUPPLIER SECTOR

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4
BP Energy Company	A	A	A	F
Brookfield Renewable Trading & Mktg	F	F	A	F
Castleton Comm. Merchant Trading	F	F	A	F
Clearway Power Marketing LLC	A	F	A	A
Constellation Energy Generation	A	A	A	F
Cross-Sound Cable Company	A	A	A	A
DTE Energy Trading, Inc.	A	A	A	F
Dynegy Marketing and Trade, LLC	F	F	F	A
Emera Energy Companies	A	F	A	F
Galt Power, Inc.	A	A	O	F
LIPA	A	A	A	A
Maine Power, LLC	O	O	F	O
Marble River, LLC	A	--	--	--
Mercuria Energy America, Inc	A	A	A	F
NRG Business Marketing, LLC	O	F	F	A
Shell Energy North America (US) LP	F	F	A	F
IN FAVOR (F)	4	7	3	9
OPPOSED (O)	2	1	1	1
TOTAL VOTES	6	8	4	10
ABSTENTIONS (A)	10	7	11	5

ATTACHMENT 2

VOTES TAKEN AT
SEPTEMBER 5, 2024 PARTICIPANTS COMMITTEE MEETING

END USER SECTOR

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4
Acadia Center	F	F	F	F
Bath Iron Works	O	O	F	O
Conn. Office of Consumer Counsel	A	A	A	F
Conservation Law Foundation	A	A	A	F
Earthjustice	A	--	A	F
Elektrisola, Inc.	O	O	F	O
Environmental Defense Fund	A	A	A	--
Garland Manufacturing Co.	O	O	F	O
Hammond Lumber Co.	O	O	F	O
Harvard Dedicated Energy Limited	A	F	A	O
Lamson, Jon	A	A	A	A
Maine Public Advocate Office	A	F	A	F
Mass. Attorney General's Office	O	A	F	F
Mass. Climate Action Network	--	--	--	F
Mass. Dept. of Capital Asset Management	F	F	A	--
Moore Company	O	O	F	O
Natural Resources Defense Council	A	A	A	F
NH Office of Consumer Advocate	O	A	F	A
PowerOptions, Inc.	F	F	A	F
RI Division of Public Utilities Carriers	O	O	F	A
St. Anslem	O	O	F	O
Shipyard Brewing Co.	O	O	F	O
Sierra Club	A	A	A	F
The Energy Consortium	--	A	A	A
Z-TECH, LLC	O	O	F	O
IN FAVOR (F)	3	5	12	10
OPPOSED (O)	11	9	0	9
TOTAL VOTES	14	14	12	19
ABSTENTIONS (A)	9	9	12	4

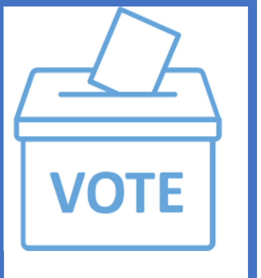
PUBLICLY OWNED ENTITY SECTOR

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4
Ashburnham Municipal Light Plant	O	O	F	O
Belmont Municipal Light Dept.	O	O	F	F
Block Island Utility District	O	O	F	A
Boylston Municipal Light Dept.	O	O	F	O
Braintree Electric Light Dept.	O	O	F	A
Chester Municipal Light Dept.	O	O	F	A
Chicopee Municipal Lighting Plant	O	O	F	A
Concord Municipal Light Plant	O	O	F	F
Conn. Municipal Electric Energy Coop.	O	O	F	A
Danvers Electric Division	O	O	F	A
Georgetown Municipal Light Dept.	O	O	F	A
Groton Electric Light Dept.	O	O	F	A
Groveland Electric Light Dept.	O	O	F	A

PUBLICLY OWNED ENTITY SECTOR (cont.)

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4
Hingham Municipal Lighting Plant	O	O	F	A
Holden Municipal Light Dept.	O	O	F	O
Holyoke Gas & Electric Dept.	O	O	F	O
Hull Municipal Lighting Plant	O	O	F	O
Ipswich Municipal Light Dept.	O	O	F	A
Littleton (MA) Electric Light Dept.	O	O	F	O
Littleton (NH) Water & Light Dept.	O	A	F	A
Mansfield Municipal Electric Dept.	O	O	F	O
Marblehead Municipal Light Dept.	O	O	F	O
Mass. Municipal Wholesale Electric Co.	O	O	F	A
Mass. Bay Transportation Authority	O	O	F	A
Merrimac Municipal Light Dept.	O	O	F	A
Middleborough Gas and Elec. Dept.	O	O	F	A
Middleton Municipal Electric Dept.	O	O	F	O
New Hampshire Electric Cooperative	O	O	F	A
North Attleborough Electric Dept.	O	O	F	A
Norwood Municipal Light Dept.	O	O	F	A
Pascoag Utility District	O	O	F	A
Paxton Municipal Light Dept.	O	O	F	O
Peabody Municipal Light Plant	O	O	F	O
Princeton Municipal Light Dept.	O	O	F	O
Reading Municipal Light Dept.	O	O	F	O
Rowley Municipal Lighting Plant	O	O	F	A
Russell Municipal Light Dept.	O	O	F	O
Shrewsbury Electric & Cable Operations	O	O	F	A
South Hadley Electric Light Dept.	O	O	F	A
Sterling Municipal Electric Light Dept.	O	O	F	O
Stowe (VT) Electric Dept.	O	O	F	A
Taunton Municipal Lighting Plant	O	O	F	A
Templeton Municipal Lighting Plant	O	O	F	O
Vermont Electric Coop.	O	A	F	A
VT Public Power Supply Authority	O	O	F	A
Village of Hyde Park (VT) Electric Dept.	O	O	F	O
Wakefield Municipal Gas and Light Dept.	O	O	F	A
Wallingford (CT), Town of	O	O	F	A
Wellesley Municipal Light Plant	O	O	F	A
West Boylston Municipal Lighting Plant	O	O	F	O
Westfield Gas & Electric Light Dept.	O	O	F	A
IN FAVOR (F)	0	0	51	2
OPPOSED (O)	51	49	0	18
TOTAL VOTES	51	49	51	20
ABSTENTIONS (A)	0	2	0	31

2 Consent Agenda



66.67%

1. RC-Recommended Revisions to the NE/NB Coordination Agreement
2. MC-Recommended Revisions to the NE/NB Coordination Agreement
3. Revisions to OP-14 Appendix E and Form NX-12E (Additional Energy Storage Parameters)

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

CONSENT AGENDA

New Brunswick-New England Coordination Agreement

Reliability Committee (RC)

*From the previously-circulated notice of actions of the RC from its **September 17, 2024 meeting**, dated September 17, 2024.*[1]

1. **RC-Recommended Revisions to the NE/NB Coordination Agreement**

   Support the proposed revisions to the Coordination Agreement Between ISO New England and New Brunswick Power Corporation (NE/NB Coordination Agreement),[2] as recommended by the RC at its September 17, 2024 meeting, together with such non-material changes as may be approved by the RC Chair and Vice-Chair.

   The motion to recommend Participants Committee support was approved unanimously.

Markets Committee (MC)

*From the previously-circulated notice of actions of the MC's **September 10, 2024 meeting**, dated September 11, 2024.*[3]

2. **MC-Recommended Revisions to the NE/NB Coordination Agreement**

   Support the proposed revisions to the New Brunswick-New England Coordination Agreement Schedule C to update the Calculations for Security Energy, along with modifications to the structure of the document and updated entity names, as recommended by the MC at its September 10, 2024 meeting, together with such further non-substantive changes as may be approved by the MC Chair and Vice-Chair.

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

Additional RC Recommendation

*Also from the previously-circulated notice of actions of the RC's **September 17, 2024 meeting**.*

3. **Revisions to OP-14 Appendix E and Form NX-12E (Additional Energy Storage Parameters)**
   Support the proposed revisions to the ISO New England Operating Procedure No. 14 (OP-14) Appendix E (Explanation of Terms and Instructions for Data Preparation of Form NX-12E) and Form NX-12E (Asset Related Demand Data),[4] as recommended by the RC at its September 17, 2024 meeting, together with such non-material changes as may be approved by the RC Chair and Vice-Chair.

   The motion to recommend Participants Committee support was unanimously approved.

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

[2] The revisions to the NE/NB Coordination Agreement include: (i) revisions reflecting the change from the New Brunswick System Operator to the New Brunswick Power Corporation; (ii) alignment of the agreement with the structure used in the Coordination Agreement between ISO-NE and NYISO; (iii) conforming calculations to reflect sub-hourly settlement and the import price floor, (iv) incorporation of language for the Reserve Sharing Group, and (v) modifications to the calculation and allocation of Security Energy costs (which going forward will be split between the Control Areas instead of being covered solely by New England).

[3] 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

[4] The revisions to OP-14 Appendix E and Form NX12-E include the addition of the following additional energy storage parameters to allow better understanding of resource capabilities: Nominal DC Energy, Usable AC Energy, Summer Round-Trip Efficiency, Winter Round-Trip Efficiency, Maximum Charging Rate, and Minimum Time to Charge.

3 CEO Report

October 10, 2024
Meeting

NEPOOL
NEW ENGLAND POWER POOL
Participants Committee

Summary of ISO New England Board and Committee Meetings

October 10, 2024 Participants Committee Meeting

Since the last update, the Compensation and Human Resources Committee, Information Technology and Cyber Security Committee, Markets Committee, System Planning and Reliability Committee, and the Nominating and Governance Committee each met on September 18. The Board of Directors met on September 19. All of the meetings were held in Holyoke.

The Compensation and Human Resources Committee discussed the employee health and benefit plan renewals for 2025, and observed that the medical premiums had increased as a result of recent claims history and market trends, although at a lower rate given management's negotiations. The Committee also discussed benefit design issues related to bonus programs and the 401(k) plan, with a view to administrative ease and equity. In reviewing the 2025 compensation budget, the Committee looked at comparative information, including national compensation surveys of projected 2025 merit and promotional increase budgets for utilities and all industries, and data from other system operators. The Committee approved as reasonable and competitive a 4.0% merit increase and a 2.0% promotional/equity increase for the 2025 operating budget, acknowledging the challenges in recent years related to retaining and attracting employees. The Committee then received an annual report on the workforce and Company culture. The Committee discussed demographic shifts in the workforce, talent market dynamics, and management's actions focused on leveraging employee strengths and the evolving Company culture. Next, as part of the Company's compliance-related governance processes, the Committee undertook its periodic review of the suite of human resources policies to confirm completeness. The review included an overview of the processes in place to ensure that the policies remain relevant and comply with state and federal mandates. The Committee concluded that the Company's policies provide comprehensive coverage. Finally, the Committee considered, and agreed to recommend, a proposal that the Board adopt changes to the Company's Code of Conduct to replace the current spousal employment prohibition with a delegation to management to resolve spousal employment situations that are not true conflicts, and to update Code sections to cover cohabiting partners.

The Information Technology and Cyber Security Committee convened with the full Board for the Committee's annual "deep dive" on cyber security issues, and welcomed a guest speaker who provided a briefing on artificial intelligence. The presentation covered machine learning and a generative artificial intelligence overview, including data strategies, governance, and the applicability in the power industry. The Committee also received a report on power system modeling, and reviewed models, their purposes, and the organizational implications and trends. The overview detailed how a wide variety of models support the Company's operational, market, and planning decisions and studies. Management noted that this is a central focus area for the Company to enable a reliable and cost-effective clean energy transition. Following the session with the full Board, the Committee conducted its regular business and received an update on information technology trends. The Committee also discussed the recent CrowdStrike global information technology outage, which was precipitated by a software update issued by CrowdStrike which affected computers running on Microsoft Windows. The Committee noted that the reliable operation of the New England power system was maintained during the event, and although some manual dispatch processes were required, the Company was able to operate normally and the majority of systems and applications were remediated within approximately 12 hours. The Committee also received an update on a ransomware practice exercise undertaken by senior management.

The Markets Committee met with the System Planning and Reliability Committee to receive a report on the Capacity Auction Reforms project. The Committees discussed the project design objectives, scope, schedule, and potential project risks along with mitigating strategies. The Board also agreed on a schedule for updating the full Board and the Board Markets Committee. Following the joint session, the Committee conducted its regular business and considered its annual review of the External Market Monitor's business continuity and succession plans. The Committee then reviewed a summary of management's responses to both the Internal and External Market Monitor's annual reports, and discussed market areas where further evaluation may be needed.

The Nominating and Governance Committee discussed the Joint Nominating Committee process for 2025, and reviewed the Company's board succession process. The Committee also discussed ongoing director education, and the possibility of initiating a program that consists of lunchtime presentations by internal speakers on topics of interest to the Board and relate to ongoing work that is relevant to the Company's strategic plan, mission and vision. Next, the Committee received an update on the political environment, including state and federal topics, and discussed significant energy legislation and policies considered by federal and state policymakers this year. The Committee also reflected on potential topics for discussion with the NEPOOL sectors and state representatives, and plans for the open Board meeting in November.

The System Planning and Reliability Committee met with the Markets Committee to receive a report on the Capacity Auction Reforms project, as discussed above. Following the joint session, the Committee conducted its regular business and received a report on the 2024 NERC Operations and Planning Audit results. The Committee discussed the positive observations and the fact that the audit teams have consistently highlighted the organization's compliance culture and commitment to internal controls. The Committee was then provided with a status update on Regional System Plan projects, and discussed various issues related to asset condition projects, including the respective roles set out in the Transmission Operating Agreement, growing costs, possibilities for oversight over asset condition projects that report either to the FERC or the New England states. Next, the Committee received an annual update on renewable resources development, and discussed the development of large renewable projects in the New England region, fully-developed interconnection plans that are in place for multiple large projects, and how permitting, inflation and supply-chain issues have affected progress. The Committee then discussed revisions to its charter, and agreed to recommend that the Board adopt a revised charter that outlines and clarifies the Committee's responsibilities in more detail and to specify that at least one committee member must have relevant expertise in transmission planning or operations.

The Board of Directors held its annual meeting and began with a report from the CEO, including an update on a draft agenda and plans for the 2025 IRC Board Conference to be hosted by ISO New England. The General Counsel also provided an update on recent Supreme Court developments and a ruling overturning the Chevron doctrine and its potential impact on the energy industry. Next, the Board discussed the proposed 2025 operating and capital budgets, including the states' comments on the budgets, the impact on retail ratepayers, and noted the remaining stakeholder process, following which the Board will vote on the budgets. The Board also reviewed plans for the upcoming open board meeting. The Board then received reports from the standing committees. Following the committee reports, the Board was provided with an in-depth review of the Company's compliance program. The Board reviewed the structure of the program, with a focus on the first line of control, related to the establishment of internal controls. The Board reviewed specific internal controls, including the establishment of a database of regulatory requirements, management of new tariff changes, and key policies related to information protection and document retention. Regarding annual meeting matters, the Board re-elected Ms. LaFleur as Chair of the Board of Directors, and adopted the committee assignments recommended by the Nominating and Governance Committee, all of which (other than the Joint Nominating Committee) remain the same as in 2023-24:

- Ms. Flax and Messrs. Corneli, Curran and Ivey shall serve on the **Audit and Finance Committee**, with Ms. Flax to serve as Chair;
- Mses. Anders and LaFleur and Messrs. Ivey and Williams shall serve on the **Compensation and Human Resources Committee**, with Mr. Williams to serve as Chair;
- Messrs. Colangelo, Corneli, Curran, and Vannoy shall serve on the **Information Technology and Cyber Security Committee**, with Mr. Vannoy to serve as Chair;
- Ms. Anders and Messrs. Colangelo, Corneli, Curran, Ivey, van Welie, and Vannoy shall serve on the **Joint Nominating Committee**, with Mr. Colangelo to serve as Chair;
- Ms. Flax and Messrs. Curran, Corneli and Vannoy shall serve on the **Markets Committee**, with Mr. Curran to serve as Chair;
- Mses. Anders and LaFleur and Messrs. Colangelo and Vannoy shall serve on the **Nominating and Governance Committee**, with Mr. Colangelo to serve as Chair;
- Ms. Anders and Messrs. Colangelo, Ivey and Williams shall serve on the **System Planning and Reliability Committee**, with Ms. Anders to serve as Chair.

The Board also elected the Company's officers for the upcoming year, and reviewed assignments of directors as liaisons to individual states. Finally, in executive session, the Board approved recommended revisions to the Compensation and Human Resources Committee charter, approved additional management delegations regarding the 401(k) plan, and received an update on the Company's succession management plan.

4a

COO Report – Operations Report Highlights

October 10, 2024
Meeting

NEPOOL
NEW ENGLAND POWER POOL
Participants Committee

NEPOOL Participants Committee Report

October 2024

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Regular Operations Report - Highlights

Highlights: September 2024

- **Peak Hour** on September 1
  - 16,930 MW system peak (Revenue Quality Metered/RQM); hour ending 7:00 P.M.
- **Average Pricing**
  - Day Ahead (DA) Hub Locational Marginal Price (LMP): $32.24/MWh
  - Real Time (RT) Hub LMP: $32.09/MWh
  - Natural Gas: $1.81/Mmbtu (MA Natural Gas Avg)
- **Energy Market** value $320M down from $346M in September 2023
  - Ancillary Markets* value $8.5M down from $23.1M in September 2023
  - Average DA cleared physical energy** during the peak hours as percent of forecasted load was 100.3% during September, down from 102.0% during August
  - Updated August Energy Market value: $453M
- **Net Commitment Period Compensation (NCPC)** total $2.4M
  - First Contingency $2.4M
    - Dispatch Lost Opportunity Cost (DLOC) - $307K; Rapid Response Pricing (RRP) Opportunity Cost - $173K; Posturing - $0; Generator Performance Auditing (GPA) - $57K
    - $716K paid to resources at external locations, up $309K from August
      - $541K charged to Day Ahead Load Obligation (DALO) at external locations, $175K to RT Deviations
  - Second Contingency $2K
  - Distribution $18.7K
  - Voltage was zero
- **Forward Capacity Market (FCM)** market value $119.6M
  - FCM peak for 2024 is currently 24,366 MWh

*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

Underlying natural gas data furnished by:

Year-to-Date Peak Load* Statistics

- Telemetered System Peak Load: **24,310 MW**
  - hour ending 7:00 P.M. on Tuesday, July 16
- RQM System Peak Load: **24,816 MW**
  - hour ending 6:00 P.M. on Tuesday, July 16
- FCM Peak Load: **24,366 MW**
  - hour ending 6:00 P.M. 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 as reported by the Control Room. RQM loads are of settlement quality and reflect the contribution of Settlement Only Generation (SOG). Due to the difference in calculation methodologies and the impact of SOGs, these values can occur on different days and/or hours. Both are 'net energy for load' concepts and include transmission losses. FCM load values reflect the sum of active, normal load assets that are non-dispatchable, are included in the FCM settlement and do not include transmission losses.

Highlights

- 2024/25 load forecasting cycle began at the September 27 Load Forecast Committee, and included discussions about the planned implementation of a new hourly forecast methodology
- 2050 Transmission Study draft report on additional analysis to address stakeholder comments is expected to be issued by the end of 2024
- 2024 Economic Study Benchmark Scenario has been completed and the Policy and Stakeholder-Requested Scenarios are being analyzed between now and Q1 2025

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 held the second annual reconfiguration auction (ARA2) over August 1-5 and posted the results on August 30
- 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
  - The ISO presented tie benefits values for the ARAs to be conducted in 2025 at the September 19 PSPC meeting
- 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
  - No ICR and related values will be calculated for CCP 19 until the CAR project is completed

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (0.2°F) Max: 83°F, Min: 53°F Precipitation: 1.33" – Below Normal Normal: 3.56"	Hartford	Temperature: Above Normal (2.1°F) Max: 89°F, Min: 49°F Precipitation: 0.65" - Below Normal Normal: 4.39"

Peak Load:	16,853 MW	September 1, 2024	19:00 (ending)

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

Procedure	Declared	Cancelled	Note
None			

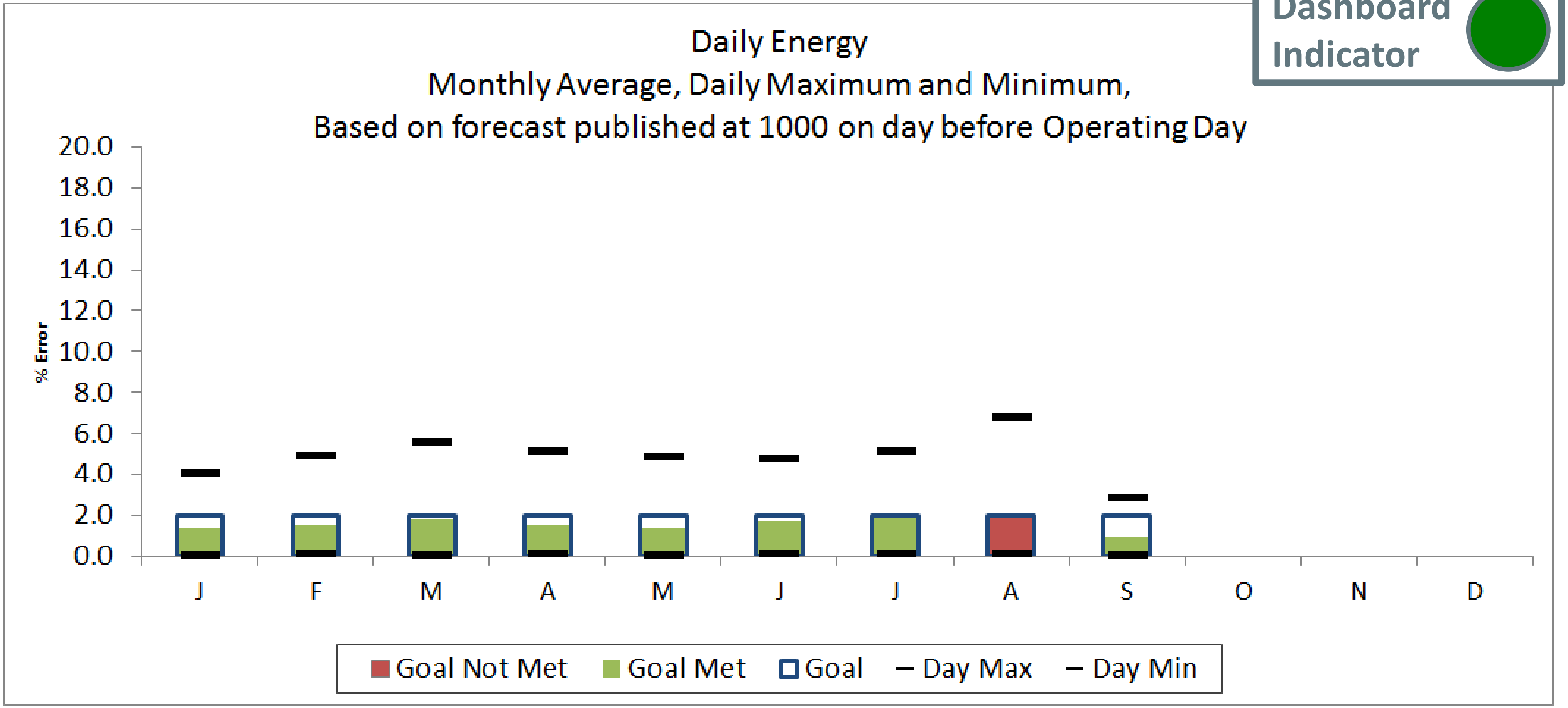
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
9/23/2024	NYISO	2056

2024 System Operations - Load Forecast Accuracy cont.

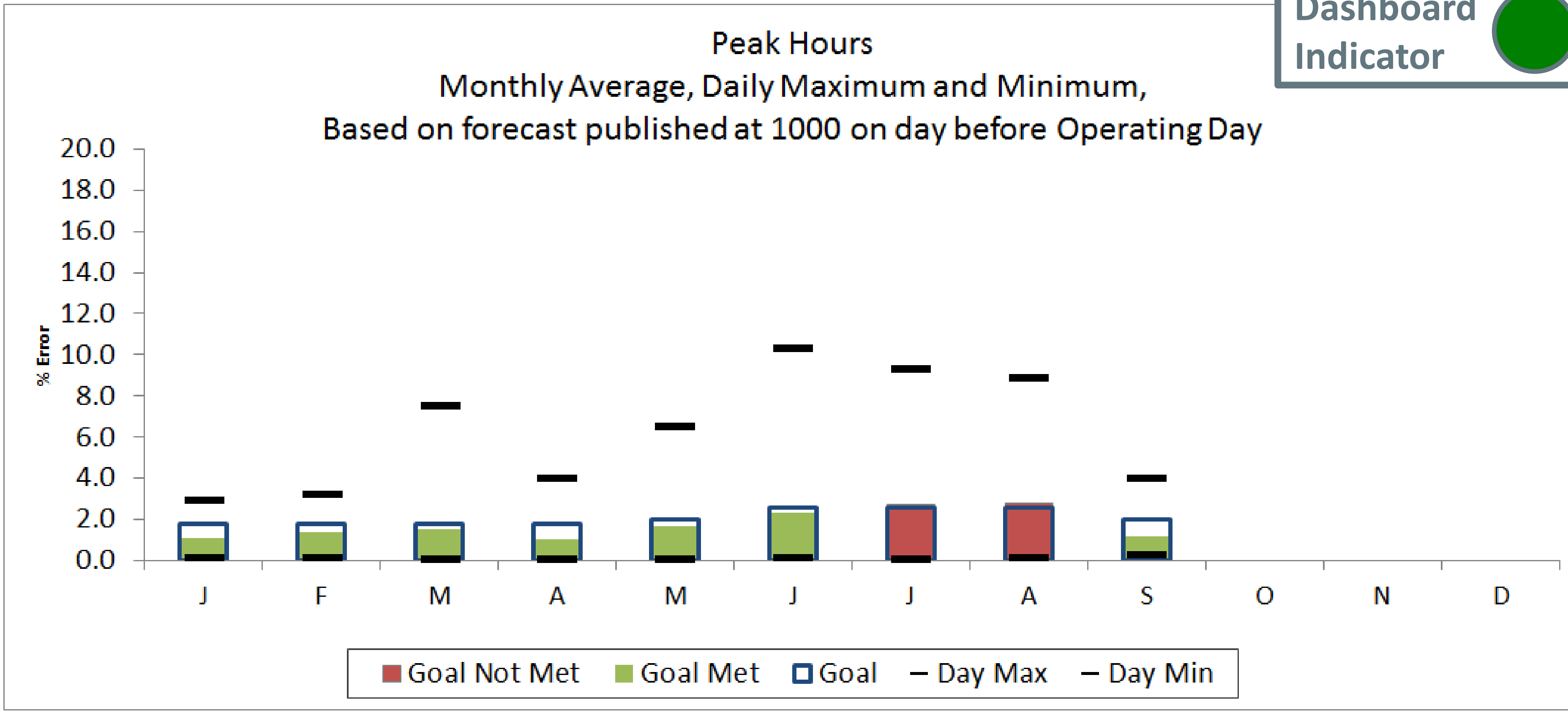
Dashboard Indicator



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	6.75	2.82				6.75
Day Min	0.00	0.12	0.02	0.09	0.07	0.11	0.10	0.12	0.03				0.00
MAPE	1.38	1.54	1.82	1.52	1.40	1.79	1.94	2.06	0.94				1.60
Goal	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00				

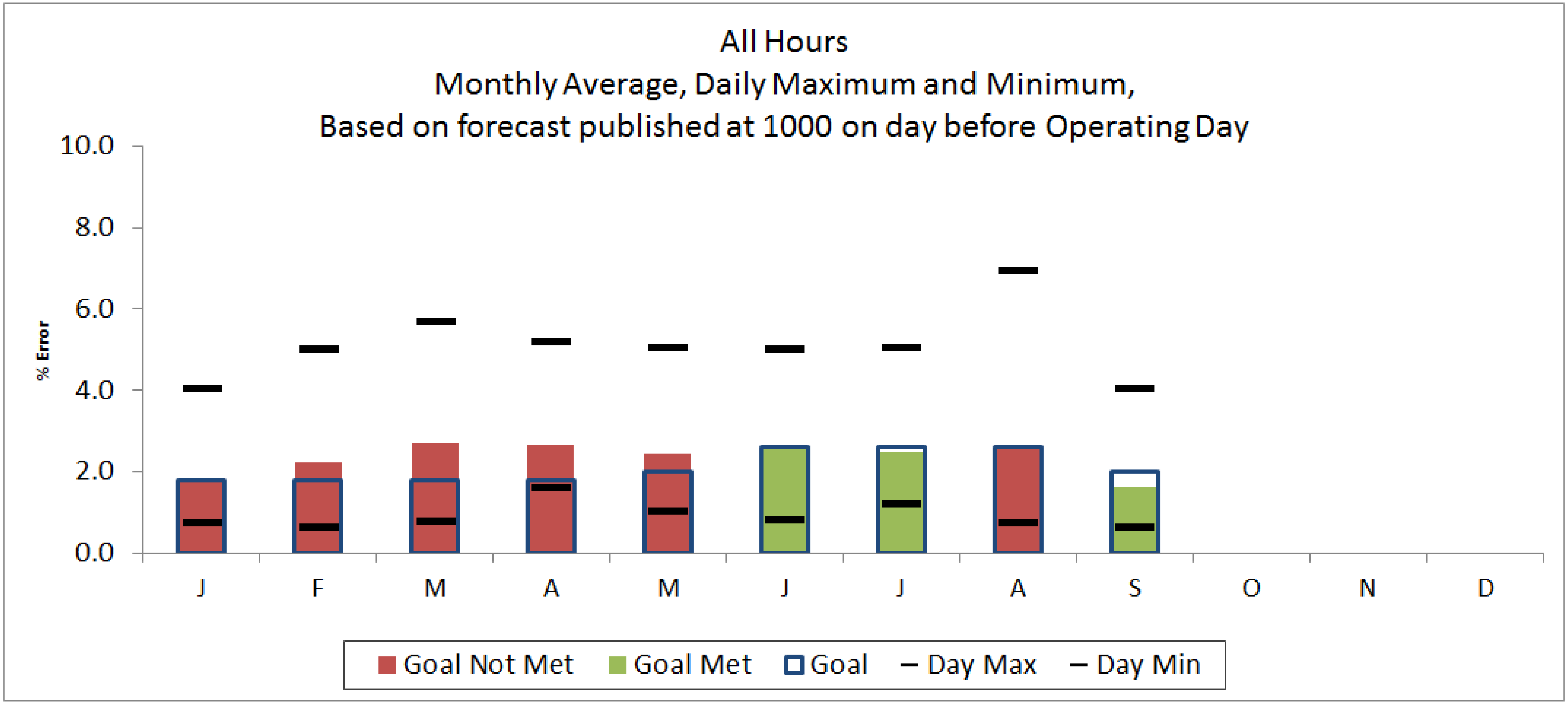
2024 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



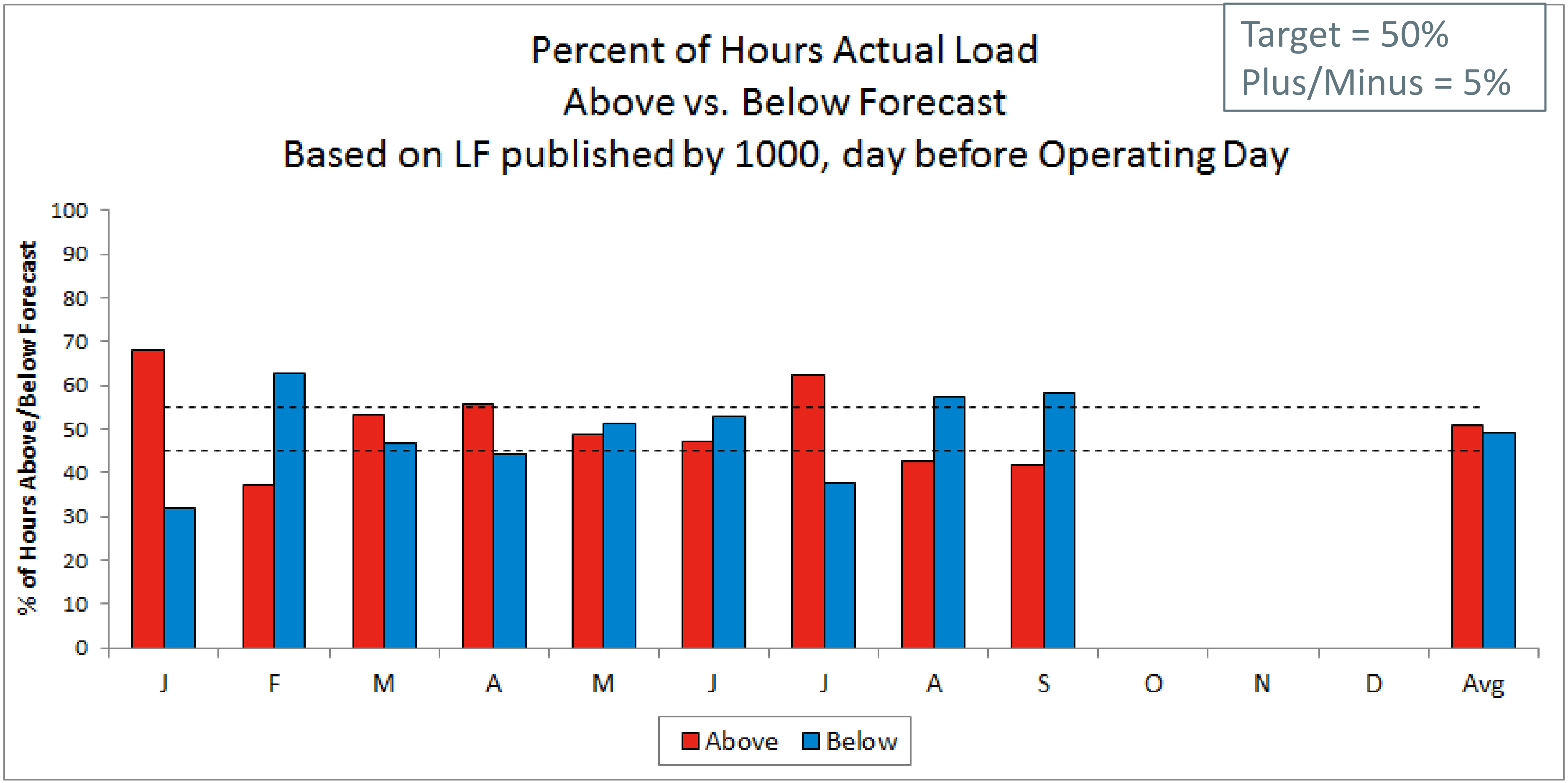
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	2.90	3.17	7.45	3.99	6.46	10.30	9.30	8.86	3.96				10.30
Day Min	0.08	0.10	0.02	0.03	0.01	0.14	0.00	0.08	0.28				0.00
MAPE	1.10	1.39	1.54	1.02	1.66	2.32	2.70	2.76	1.16				1.74
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00				

2024 System Operations - Load Forecast Accuracy



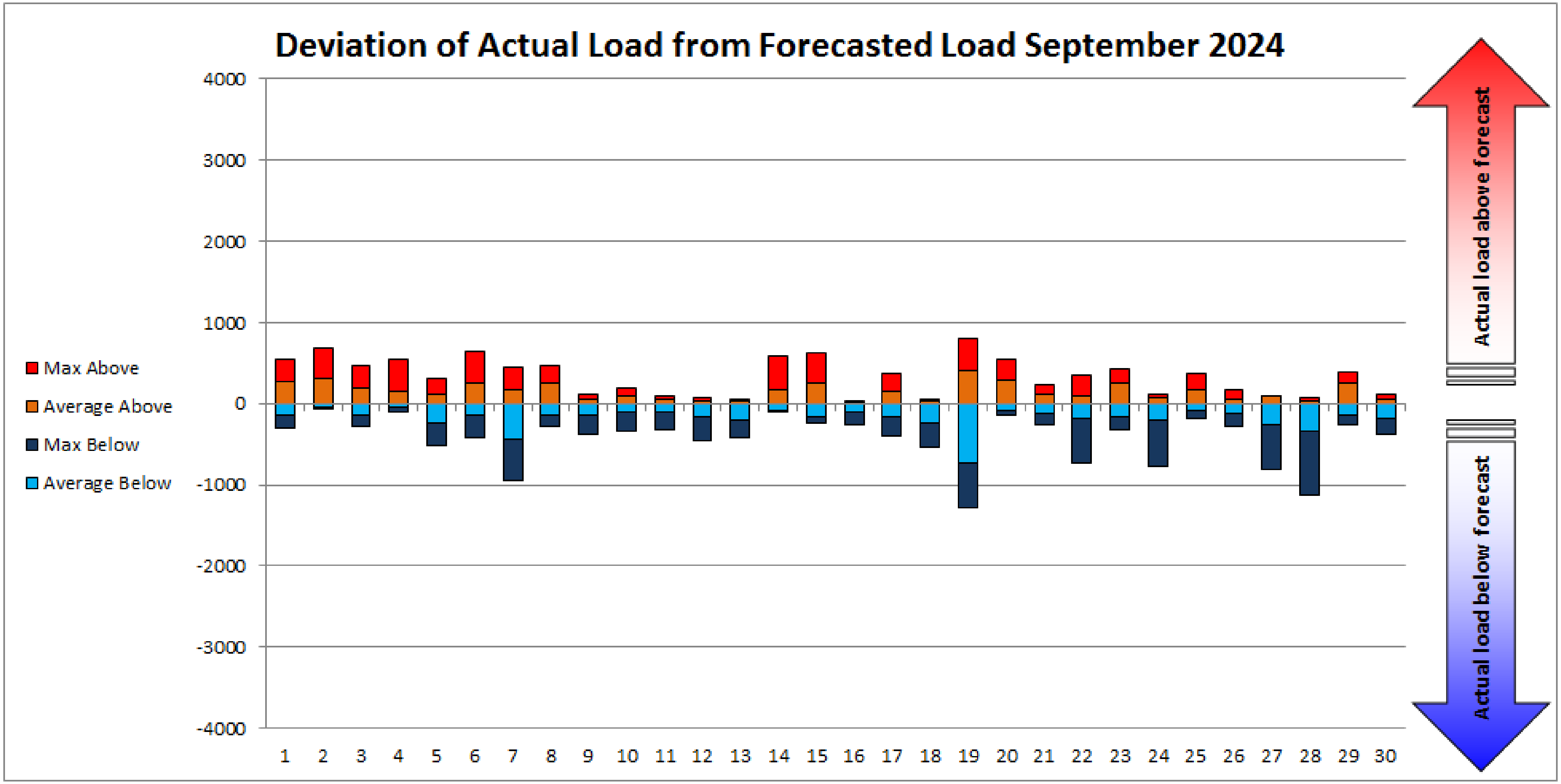
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.03	5.00	5.67	5.18	5.04	4.99	5.02	6.94	4.04				6.94
Day Min	0.73	0.64	0.76	1.59	1.00	0.81	1.20	0.74	0.62				0.62
MAPE	1.83	2.24	2.72	2.66	2.46	2.57	2.49	2.68	1.64				2.37
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00				

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	62.4	42.5	41.9				51
Below %	32.1	62.6	46.7	44.2	51.3	52.8	37.6	57.5	58.1				49
Avg Above	260.5	155.2	254.6	254.9	245.5	267.4	320.4	267.8	149.9				320
Avg Below	-155.5	-292.3	-253.5	-239.2	-223.2	-265.6	-270.5	-298.2	-181.5				-298
Avg All	132	-130	39	38	11	-16	82	-58	-30				9

2024 System Operations - Load Forecast Accuracy cont.



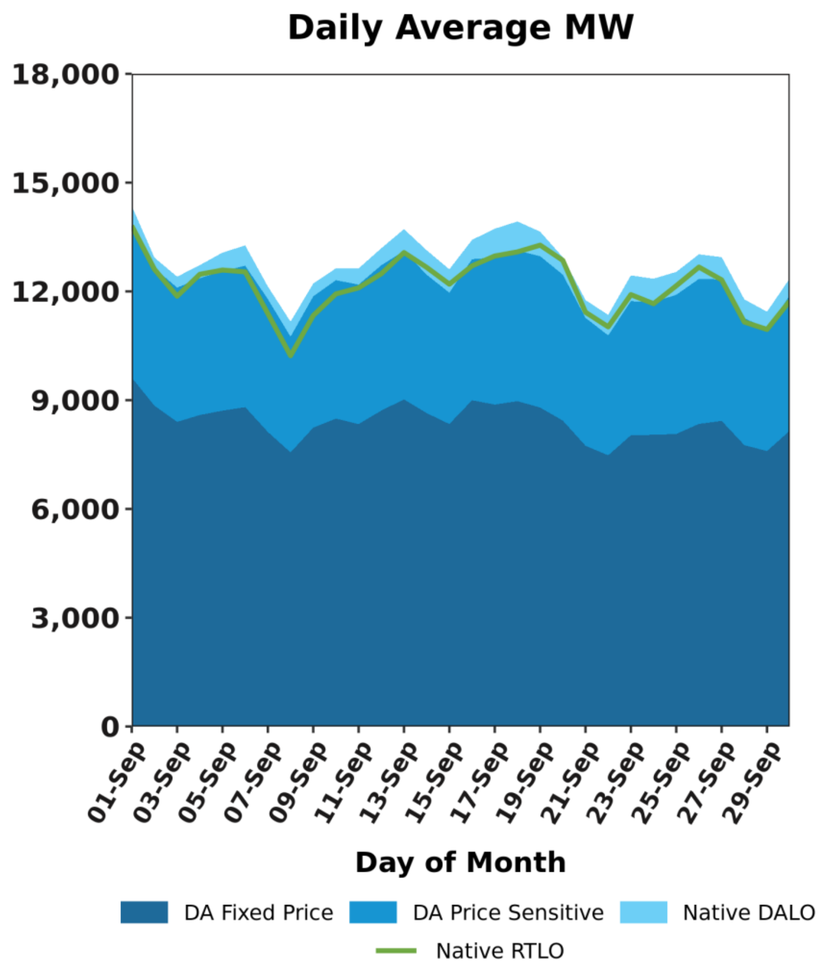
Note on Wind and Solar Forecast Error Statistics

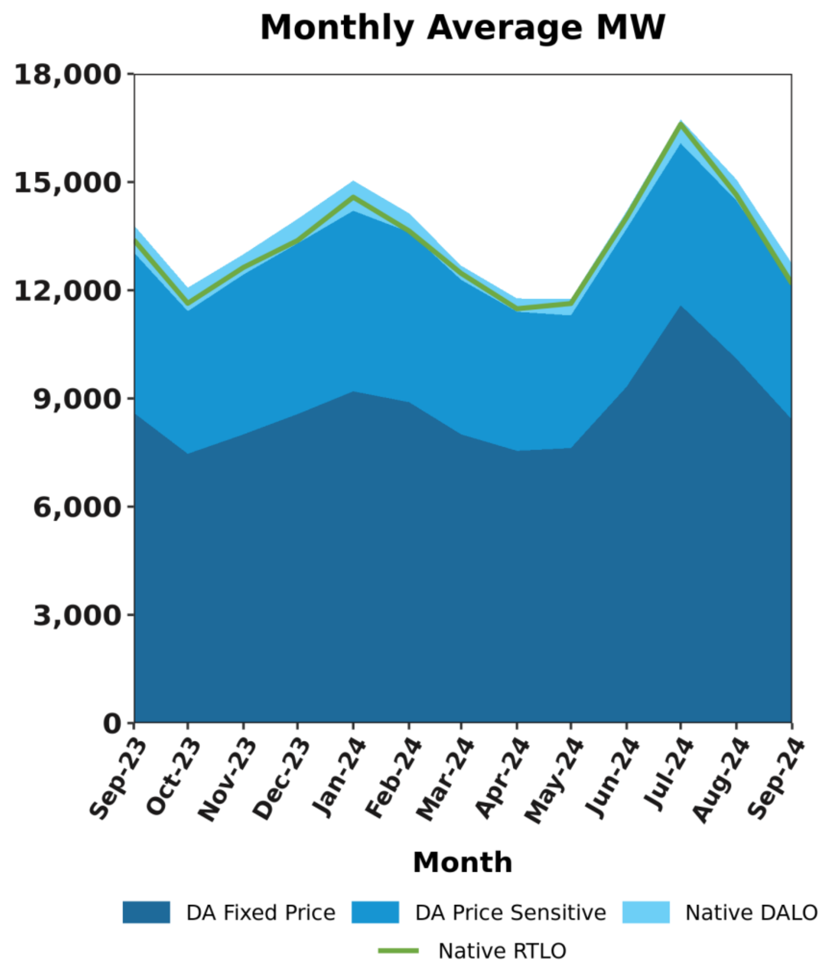
- With the launch of solar do-not-exceed dispatch in December 2023, the ISO is now able to provide the same forecast error statistics for do-not-exceed dispatchable generator (DDG) solar resources as it does for DDG wind resources
- For stakeholders' information, from now on, these monthly updates will 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)

MARKET OPERATIONS

SUPPLY AND DEMAND VOLUMES

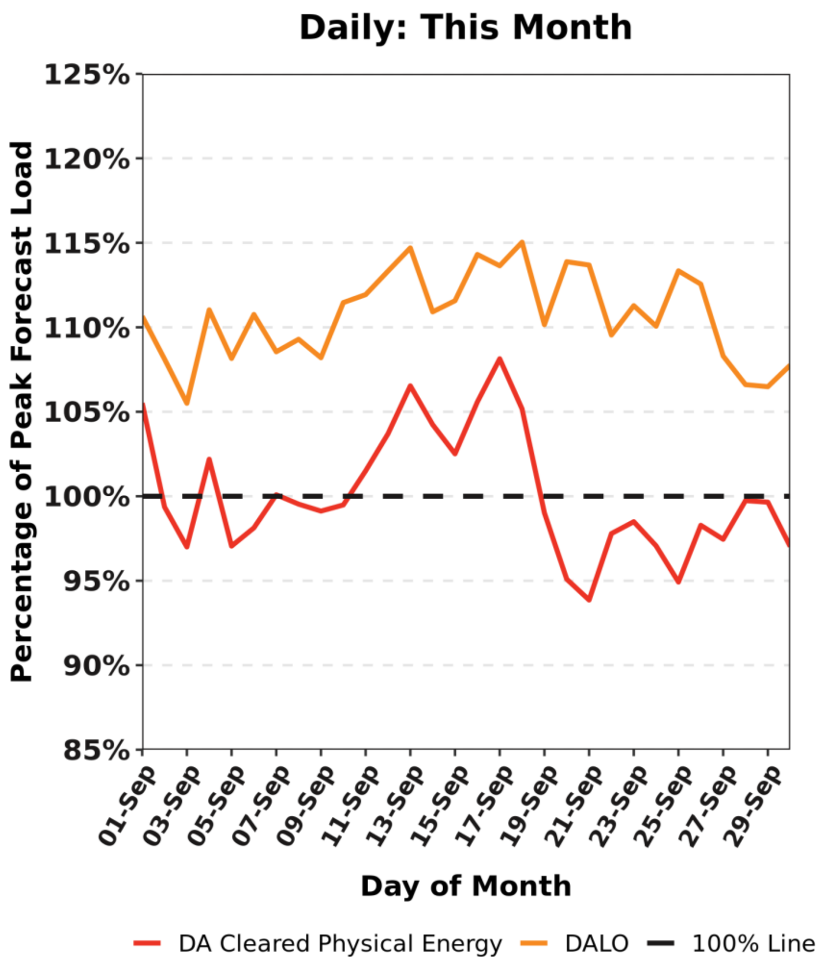
DA Cleared Native Load by Composition Compared to Native RT Load

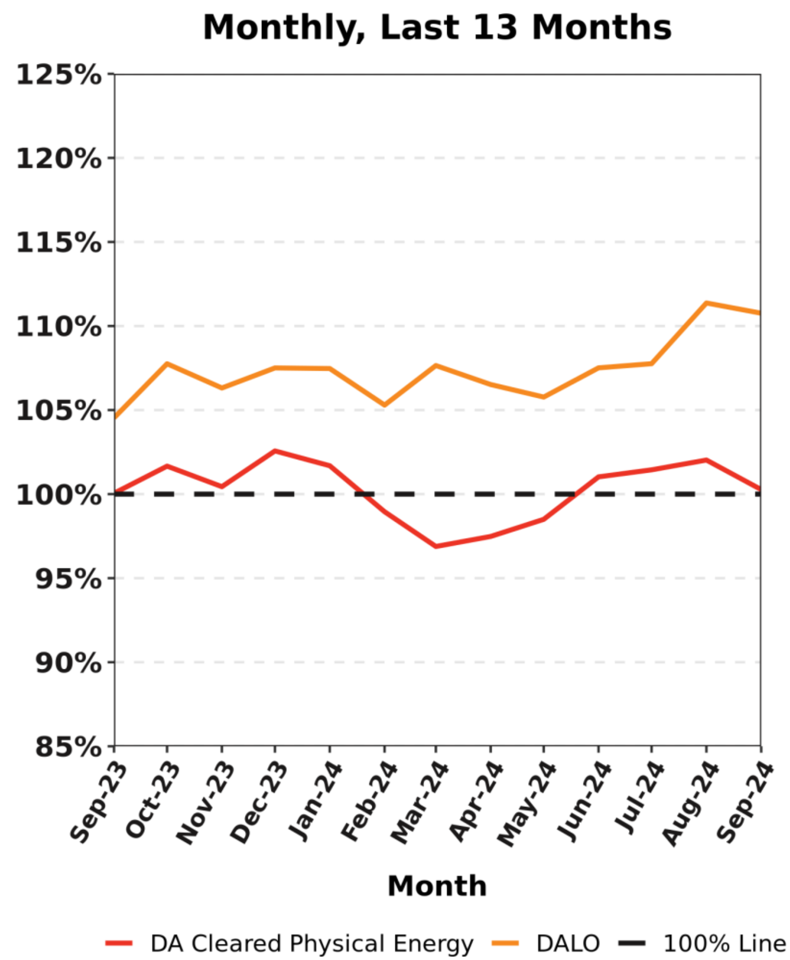




Native Day-Ahead Load Obligation (DALO) is the sum of all day-ahead cleared load, excluding modeled transmission losses and exports
Native Real-Time Load Obligation (RTLO) is the sum of all real-time load, excluding exports

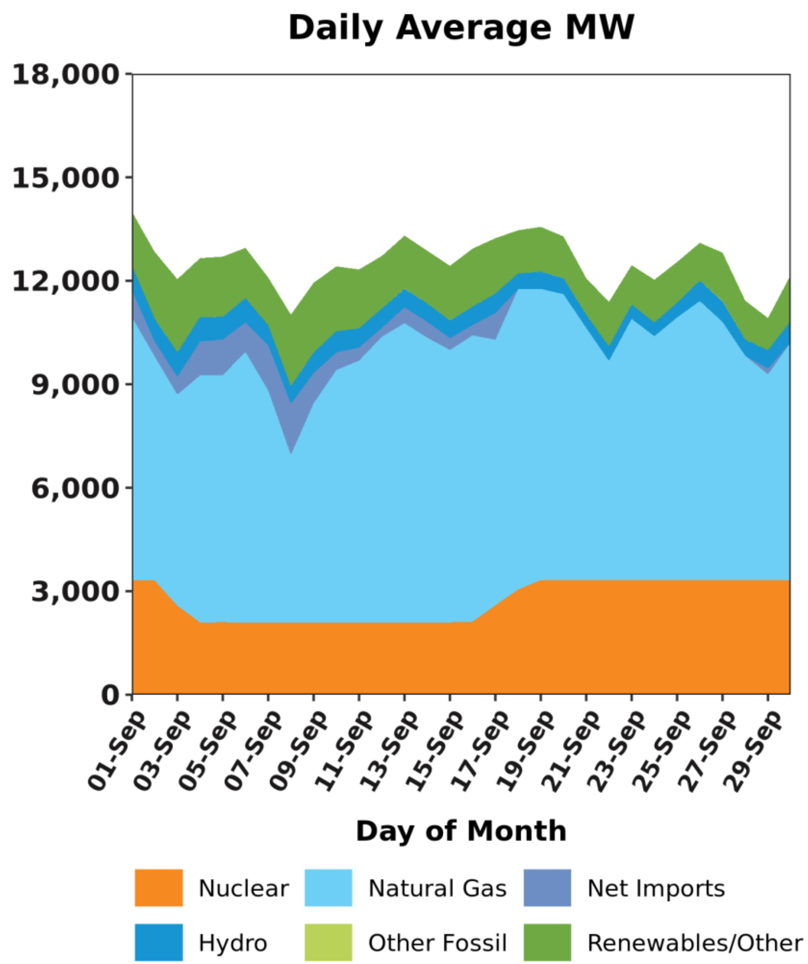
DA Volumes as % of Forecast in Peak Hour

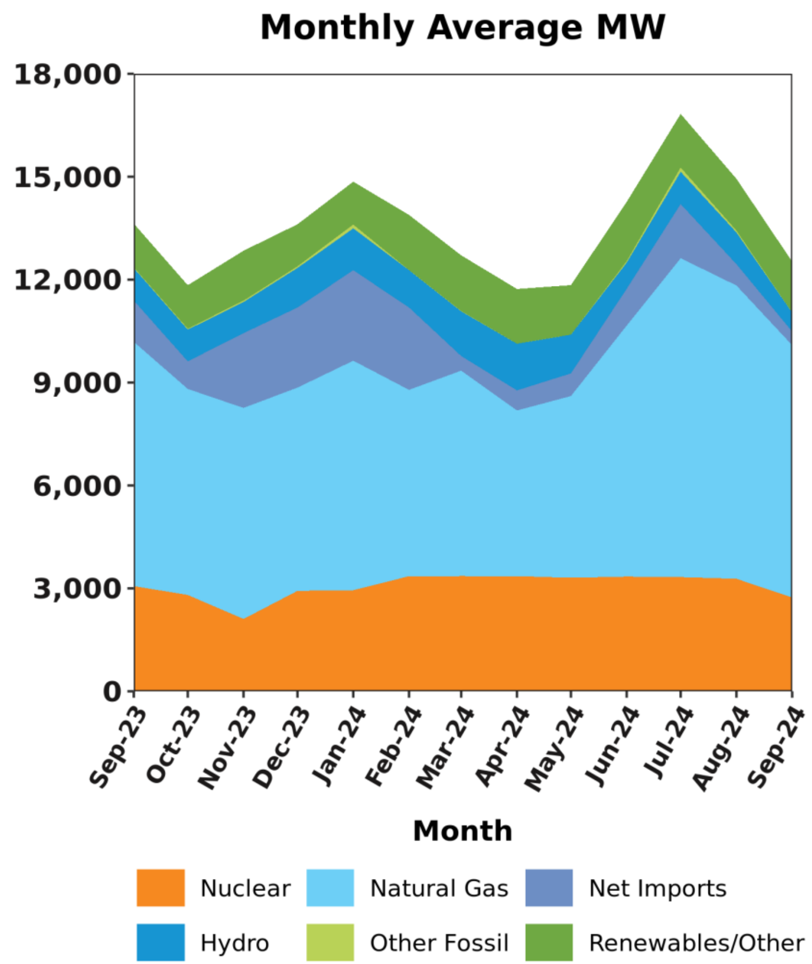




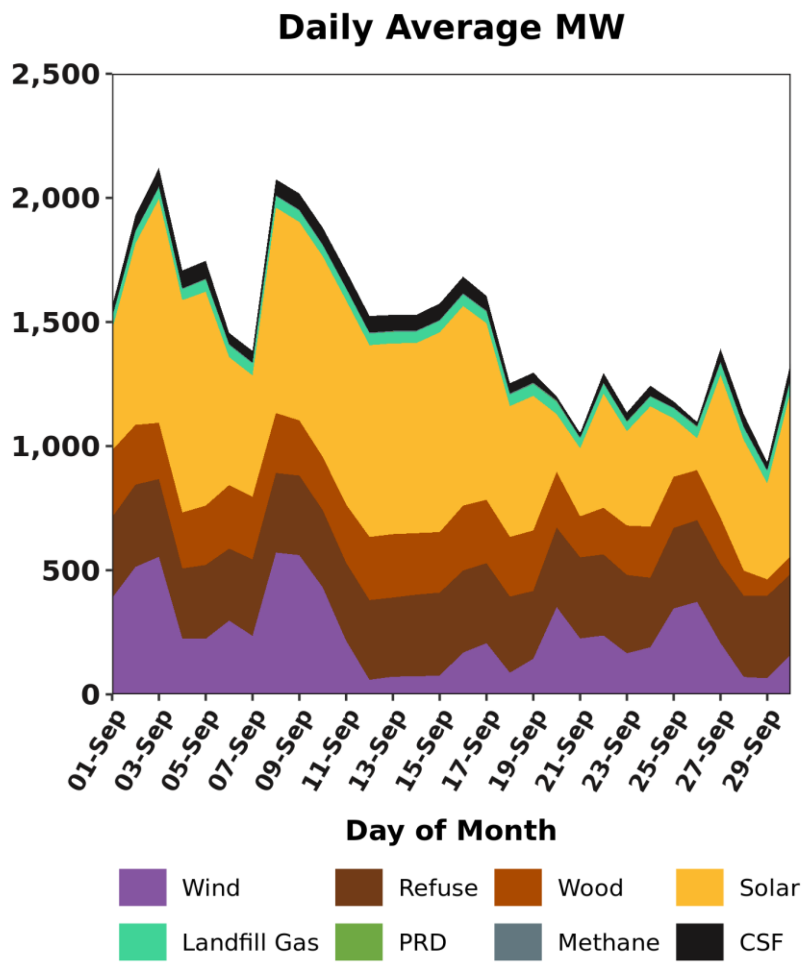
The number of system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) period during the month was: none

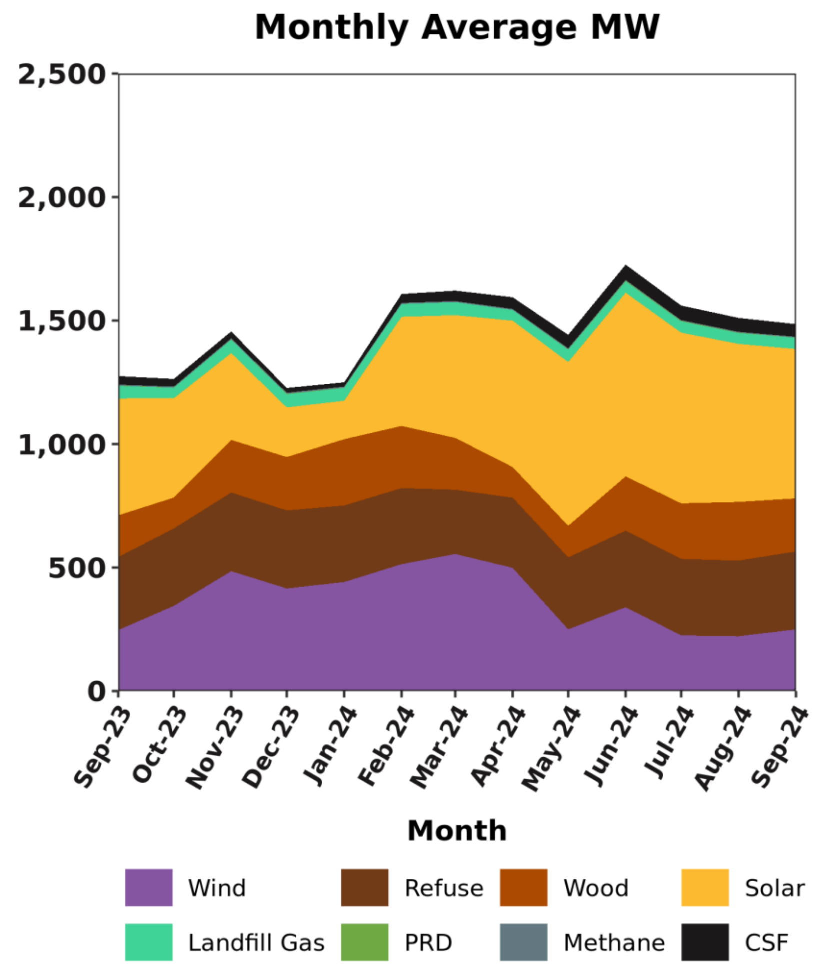
Resource Mix





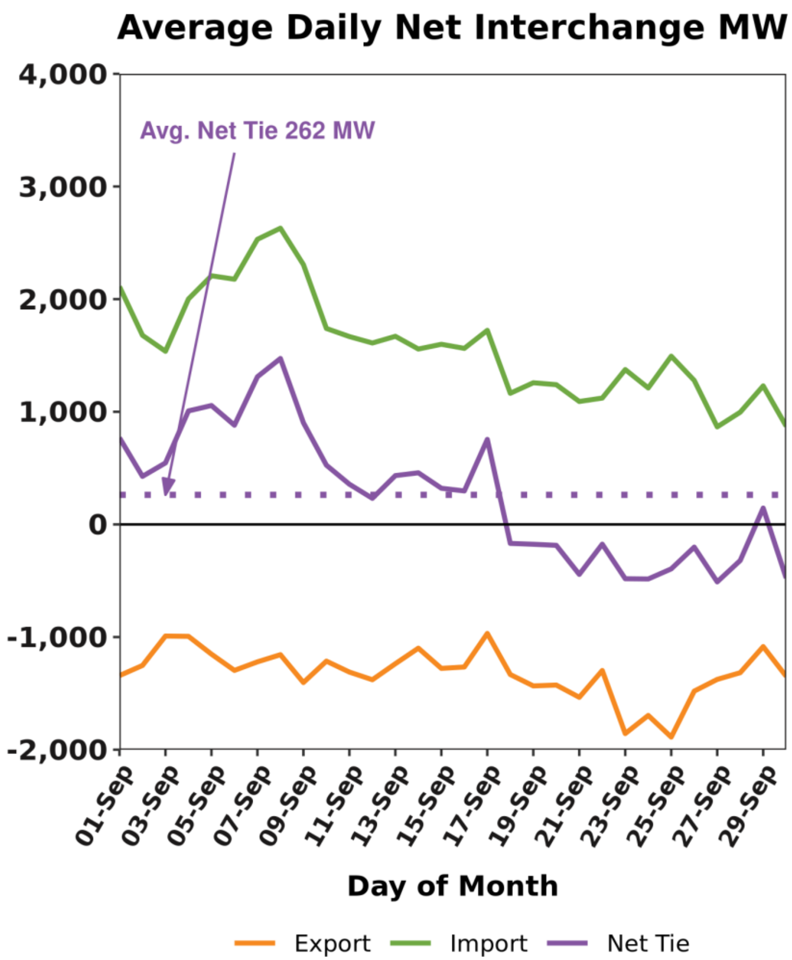
Renewable Generation by Fuel Type

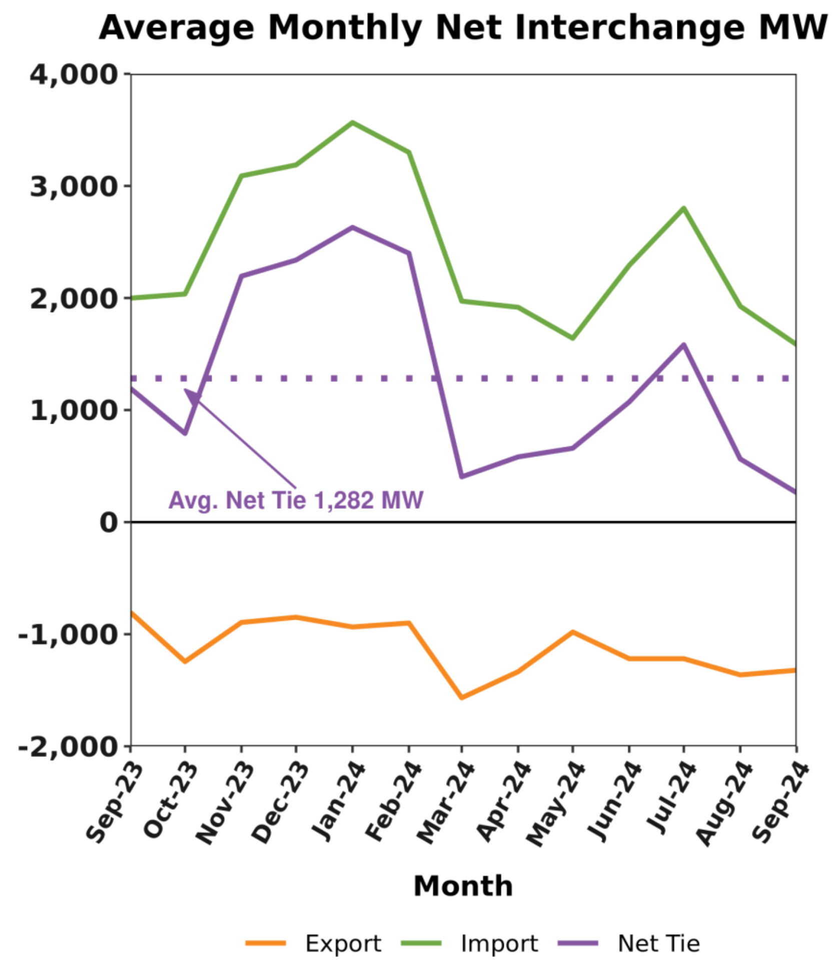




CSF = Continuous Storage Facilities (a.k.a. Batteries)

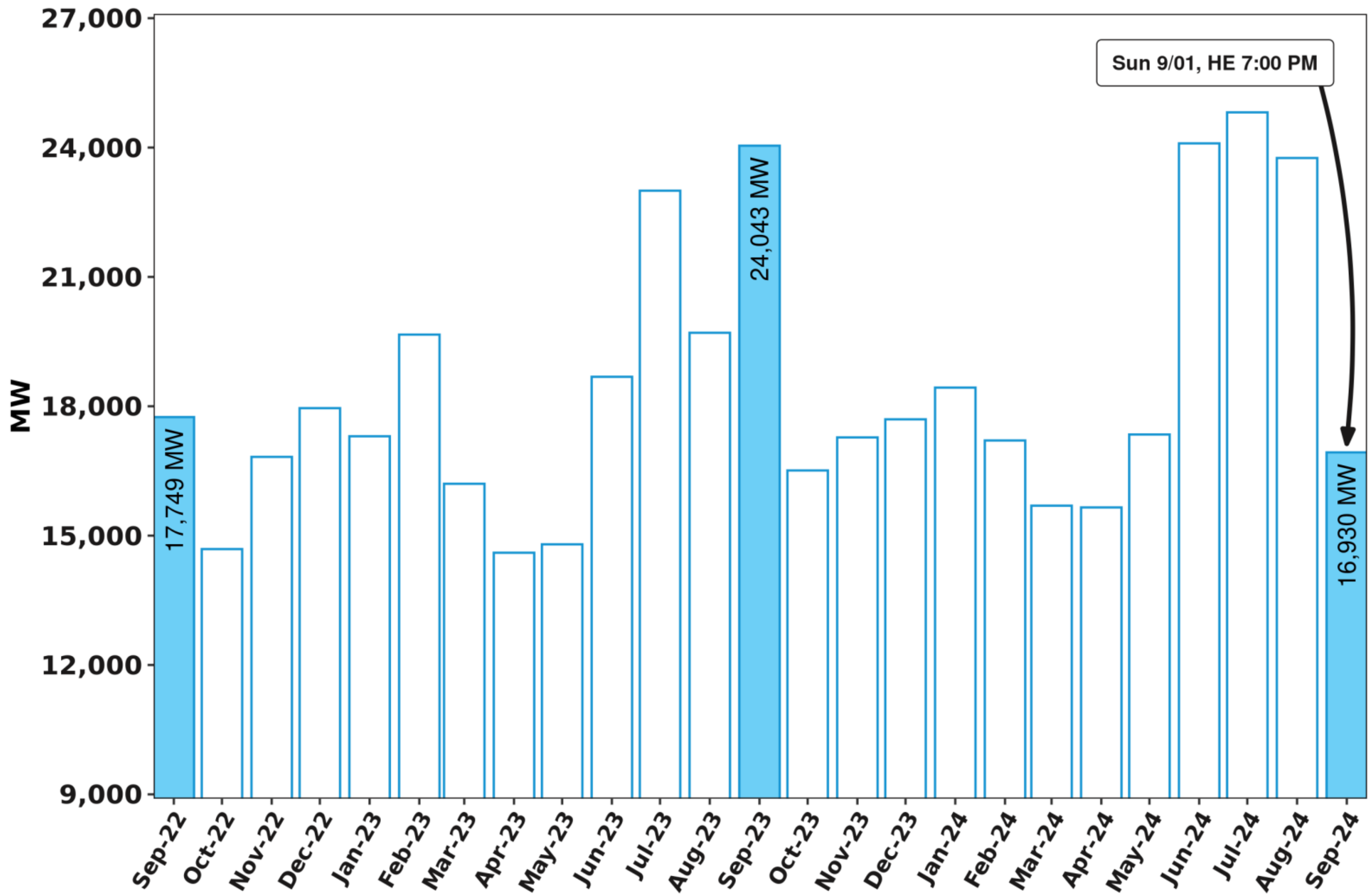
RT Net Interchange





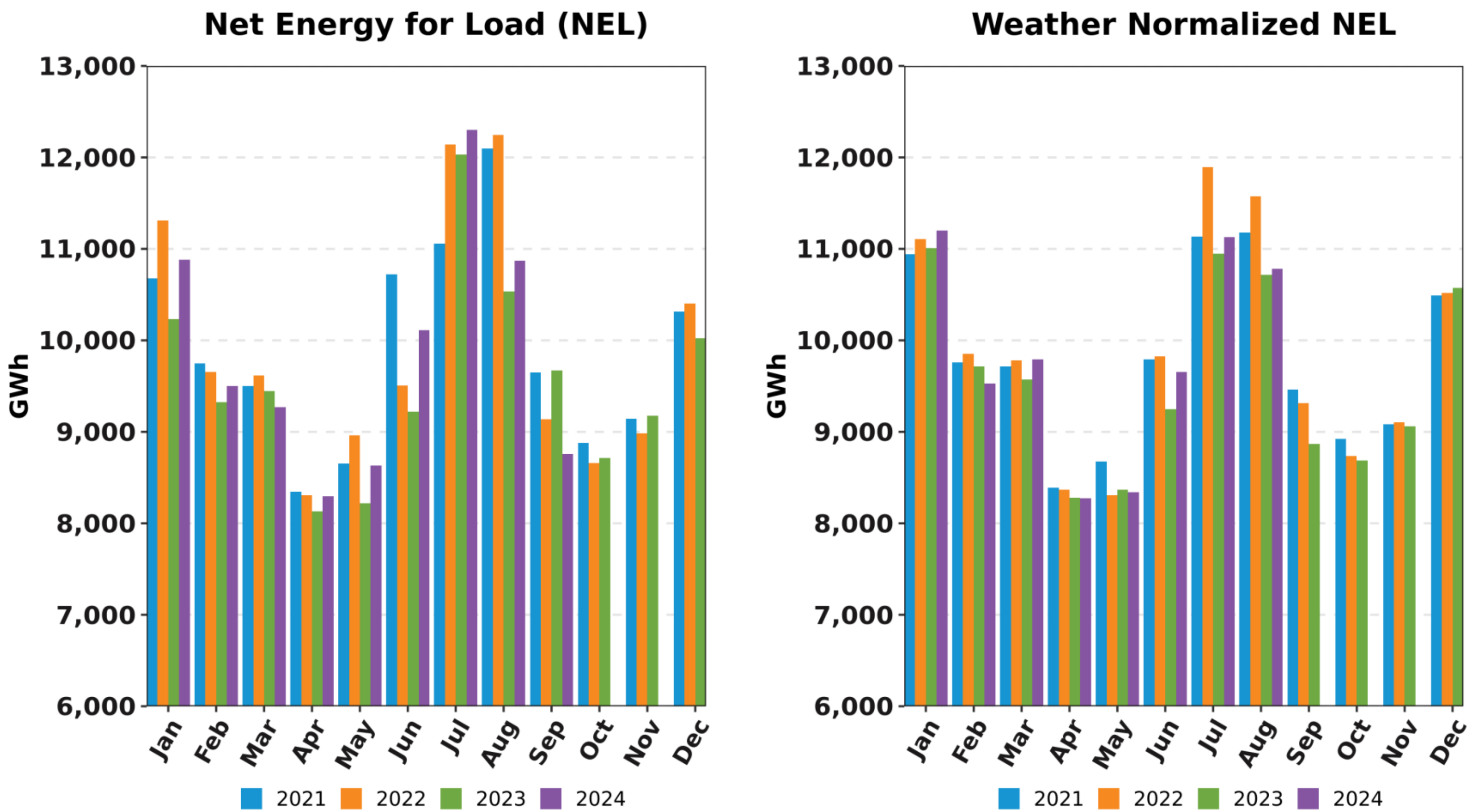
Net Interchange is the participant sum of daily imports minus the sum of daily exports; positive values are net imports

RQM System Peak Load MW by Month



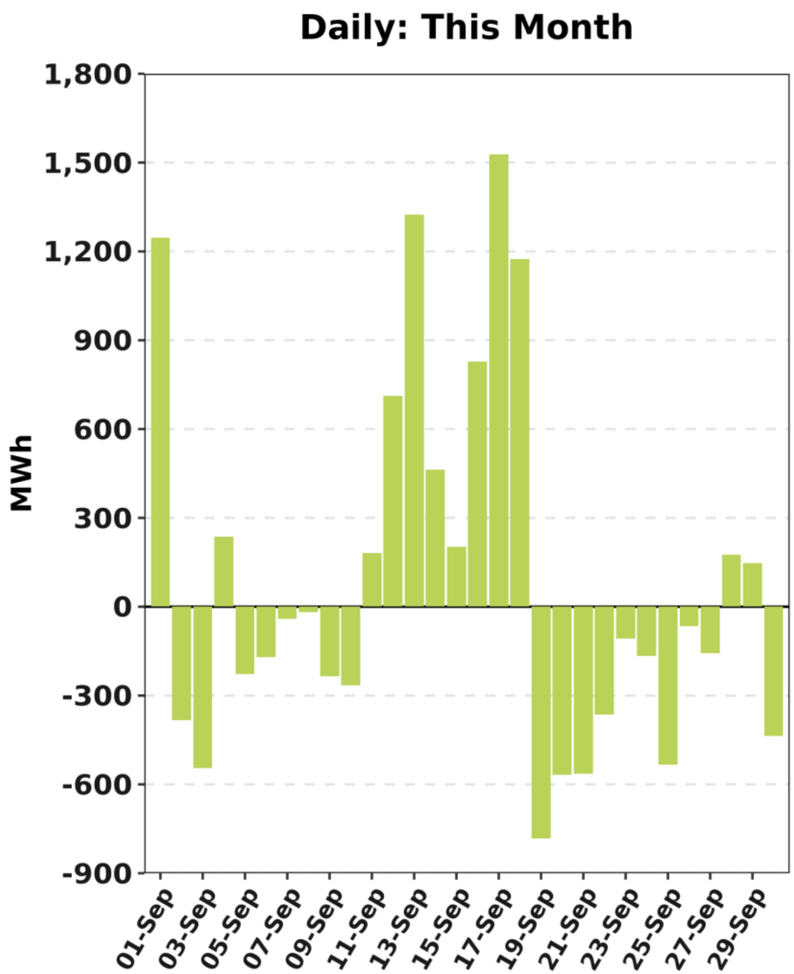
Shaded columns reflect current month and the same month the last 2 years

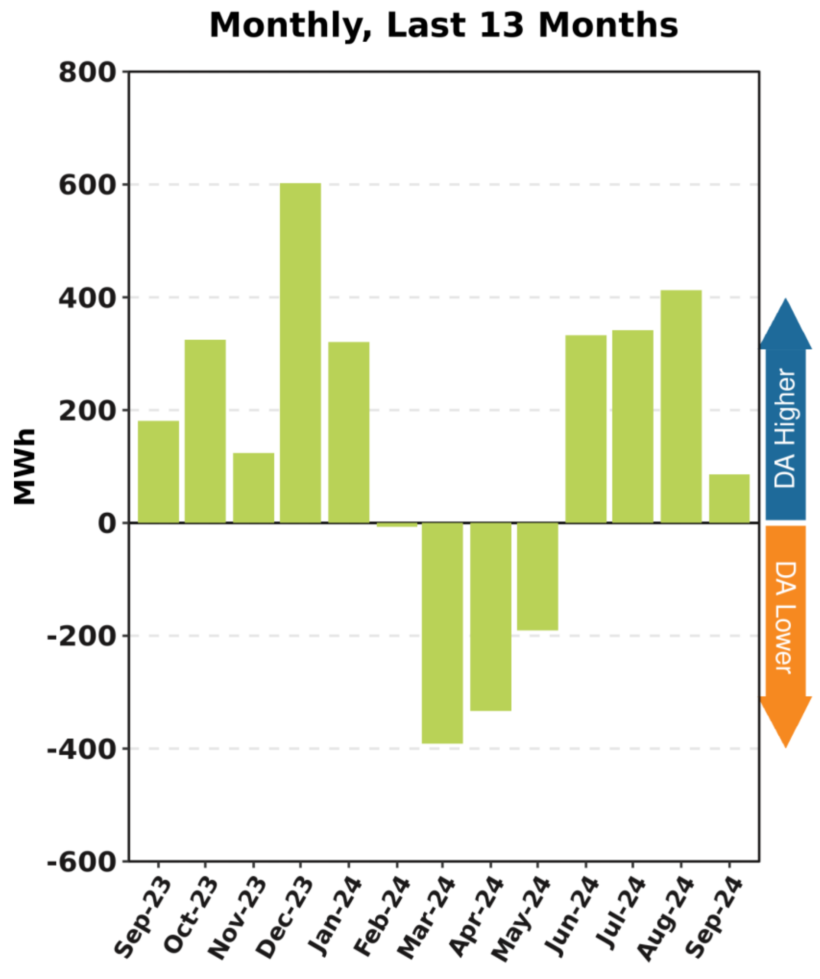
Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL



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.

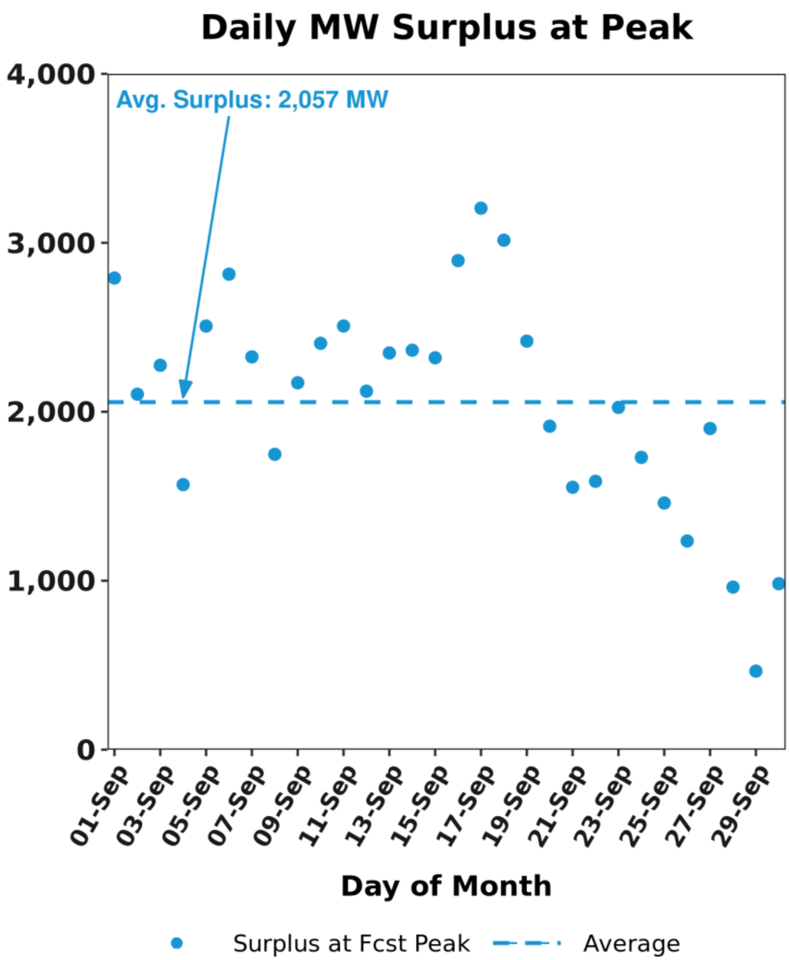
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour

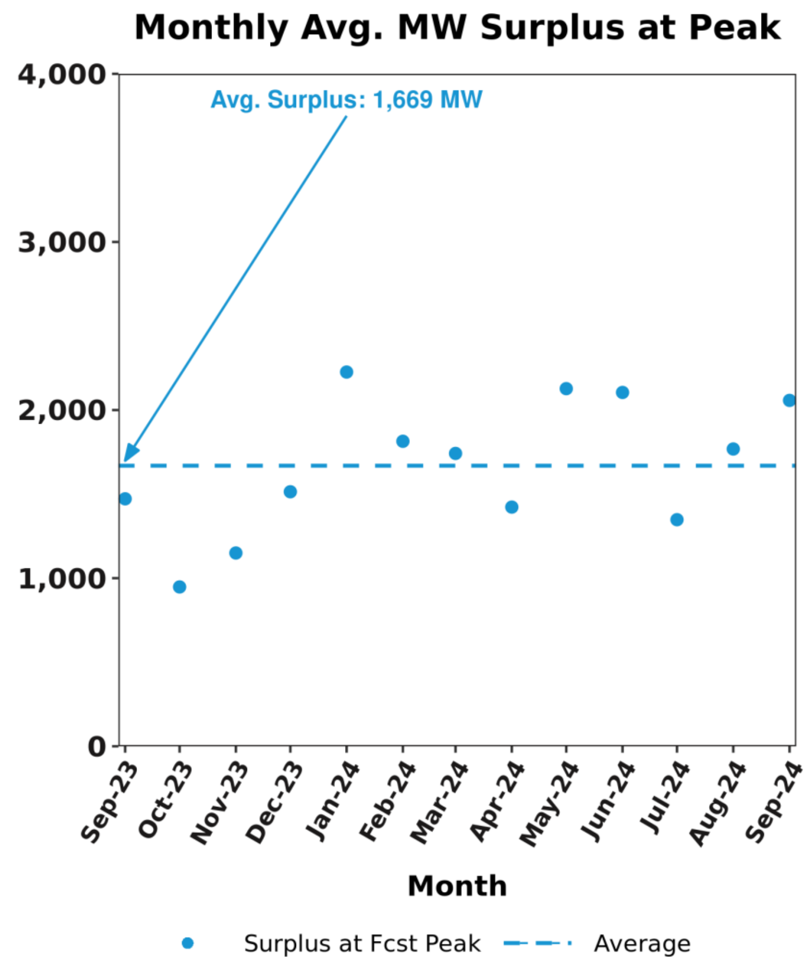




Negative values indicate DA Cleared Physical Energy value below its RT counterpart.

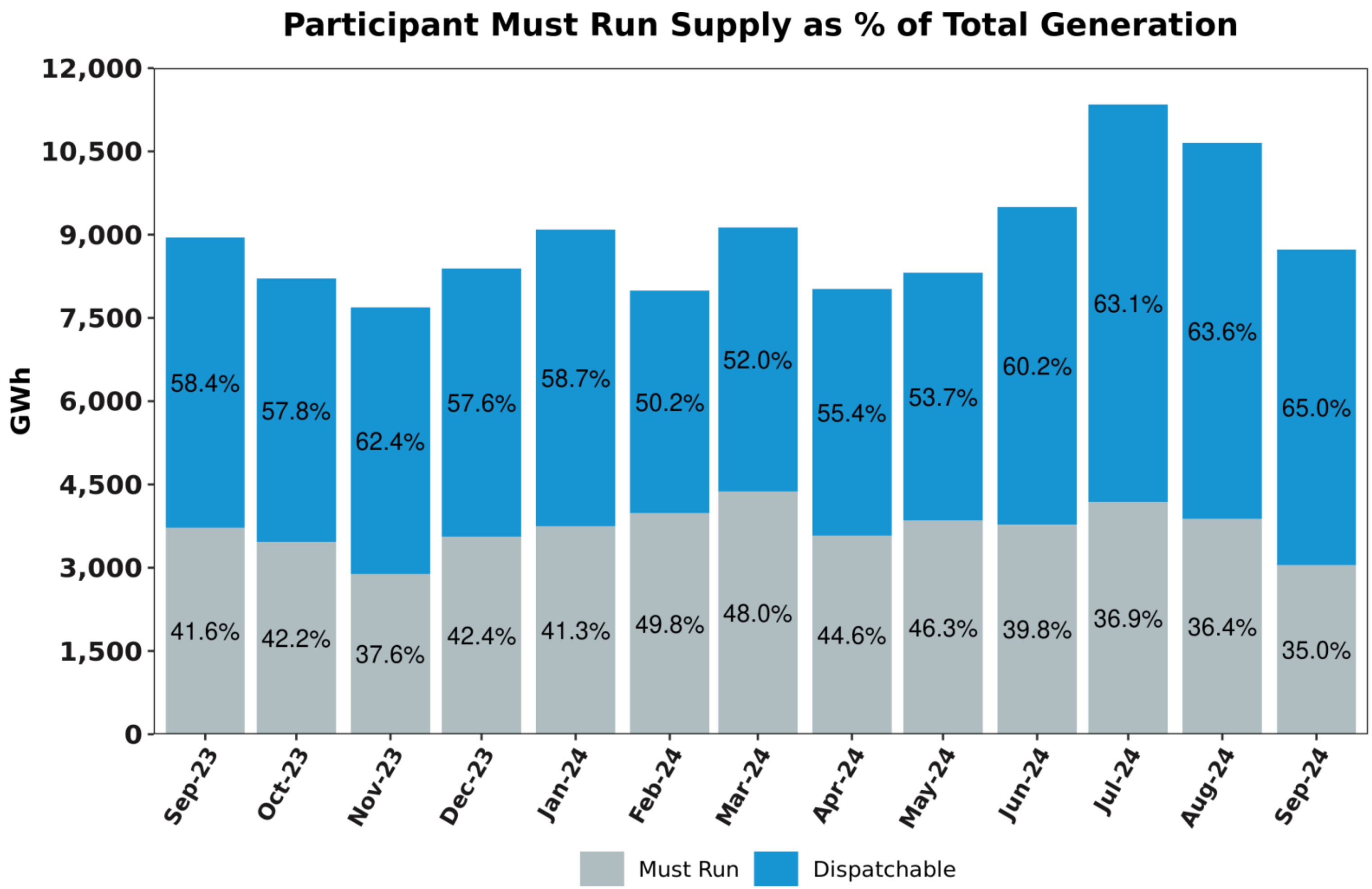
Capacity Surplus* Cleared in the DA Market Relative to Forecasted Peak-Hour Requirements





*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

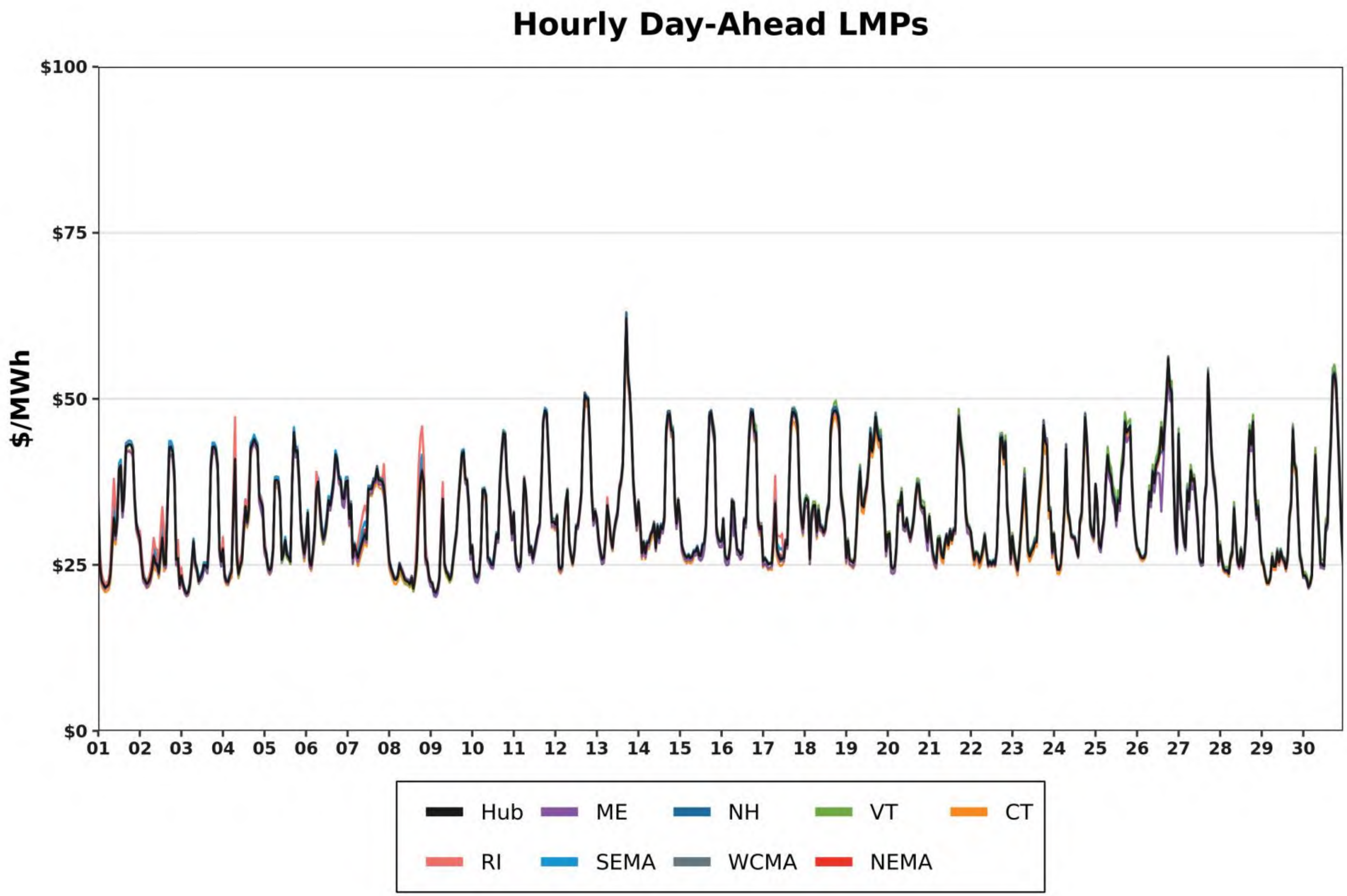
DA vs. RT LMPs ($/MWh)

Arithmetic Average

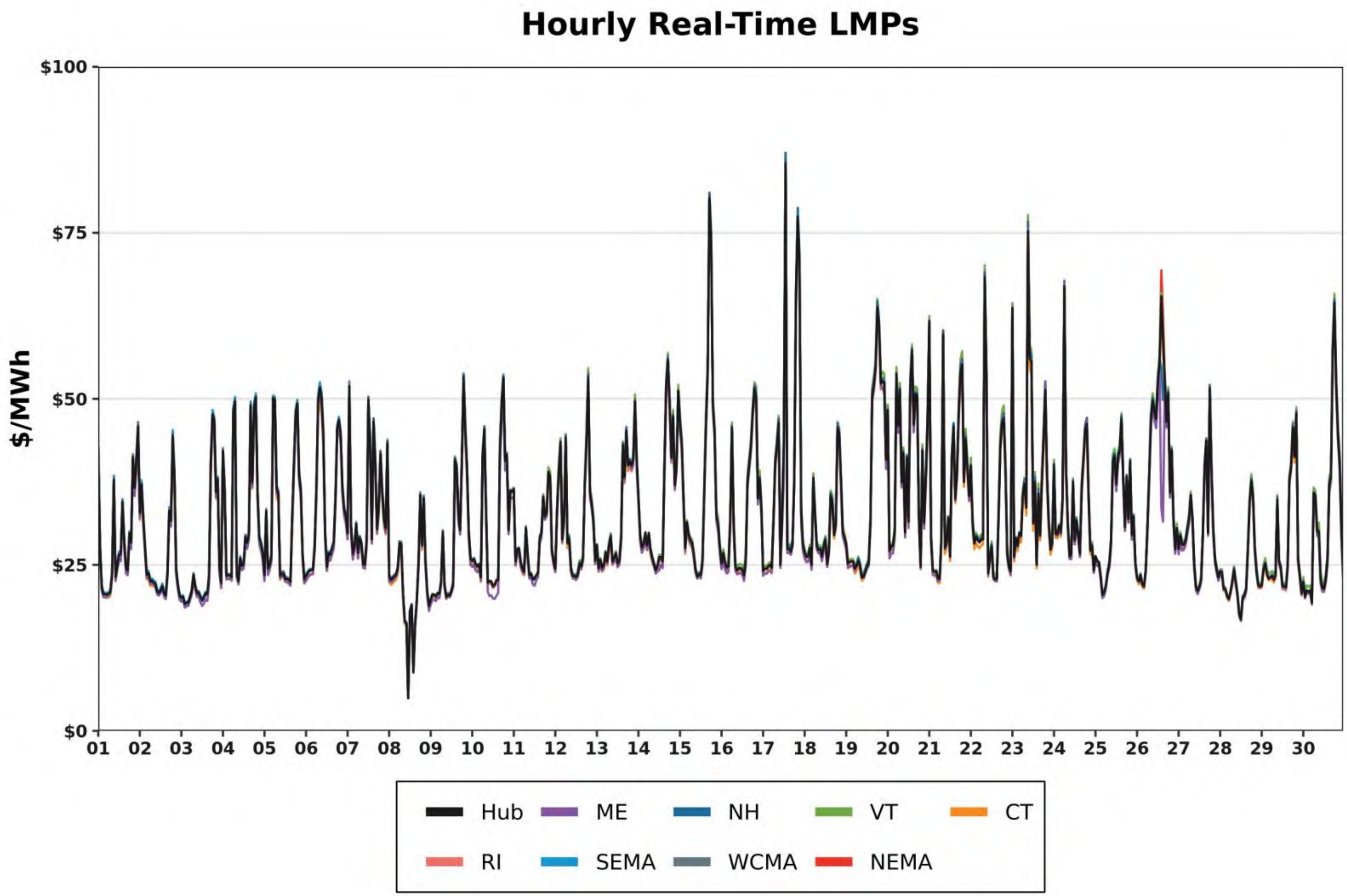
Year 2023	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$85.59	$84.20	$85.77	$84.48	$84.07	$85.39	$86.05	$85.69	$86.12
Real-Time	$84.89	$83.06	$85.05	$83.64	$83.80	$84.69	$85.35	$84.97	$85.40
RT Delta %	-0.82%	-1.35%	-0.84%	-0.99%	-0.32%	-0.82%	-0.81%	-0.84%	-0.84%
Year 2022	Hub	ME	NH	VT	CT	RI	SEMA	WCMA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

September-23	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$30.28	$29.86	$30.54	$30.33	$29.68	$29.90	$30.40	$30.32	$30.61
Real-Time	$32.59	$32.10	$32.84	$32.54	$32.09	$32.26	$32.77	$32.65	$32.99
RT Delta %	7.63%	7.50%	7.53%	7.29%	8.12%	7.89%	7.80%	7.68%	7.78%
September-24	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$32.24	$31.65	$32.32	$32.44	$31.53	$32.18	$32.50	$32.24	$32.50
Real-Time	$32.09	$31.38	$32.22	$32.47	$31.52	$31.72	$32.14	$32.10	$32.31
RT Delta %	-0.47%	-0.85%	-0.31%	0.09%	-0.03%	-1.43%	-1.11%	-0.43%	-0.58%
Annual Diff.	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Yr over Yr DA	6.47%	5.99%	5.83%	6.96%	6.23%	7.63%	6.91%	6.33%	6.17%
Yr over Yr RT	-1.53%	-2.24%	-1.89%	-0.22%	-1.78%	-1.67%	-1.92%	-1.68%	-2.06%

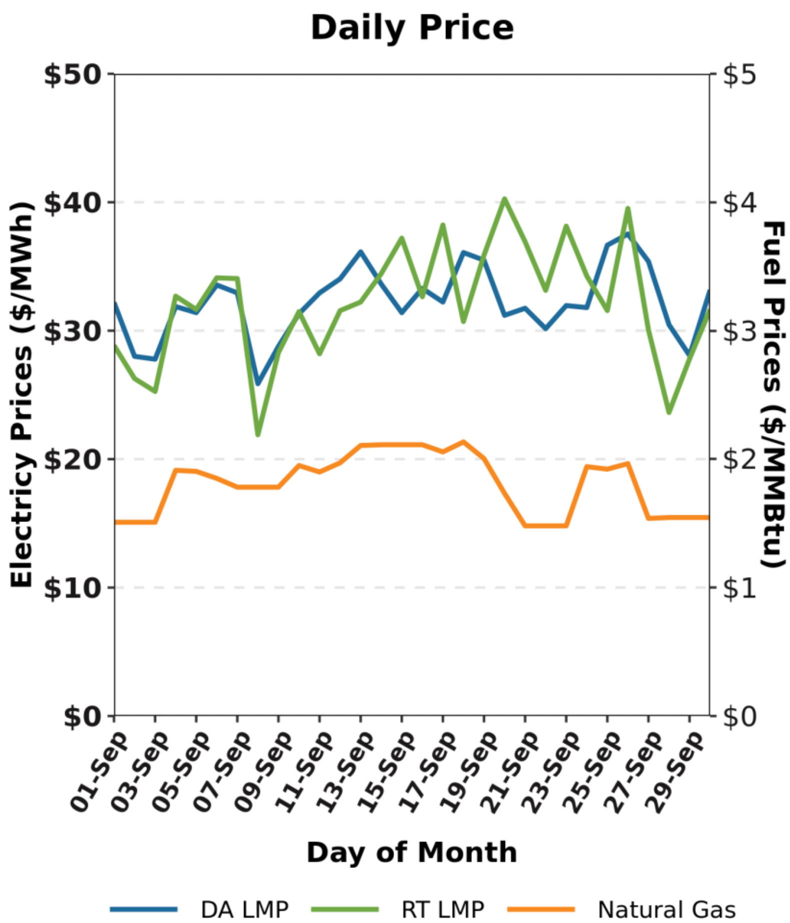
Hourly DA LMPs, September 1-30, 2024

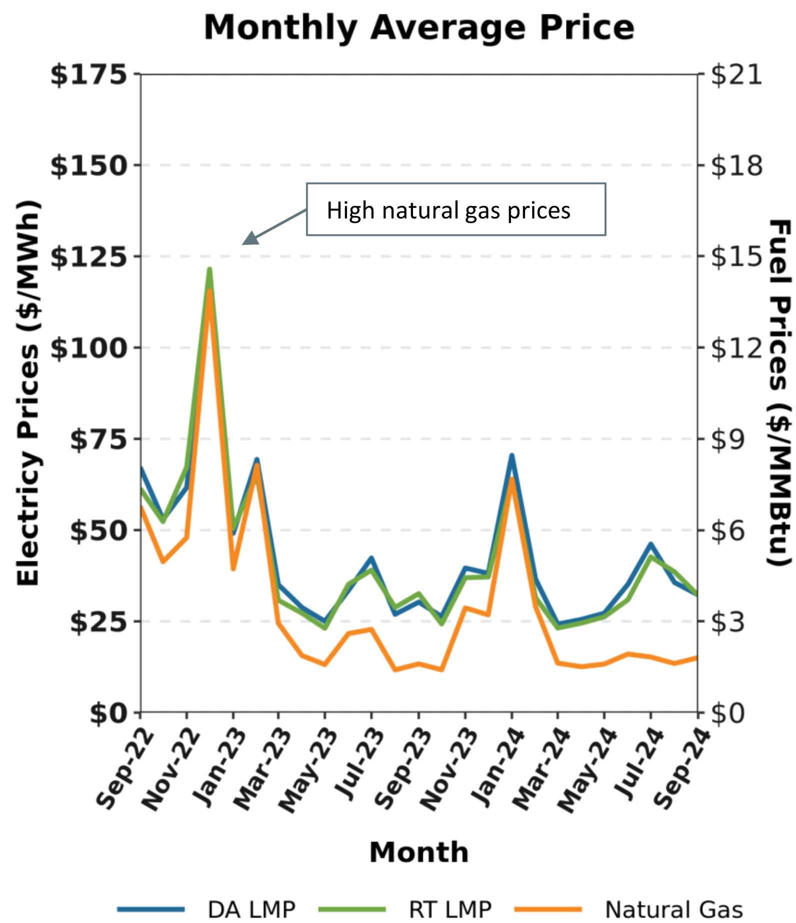


Hourly RT LMPs, September 1-30, 2024



Wholesale Electricity vs Natural Gas Prices by Month

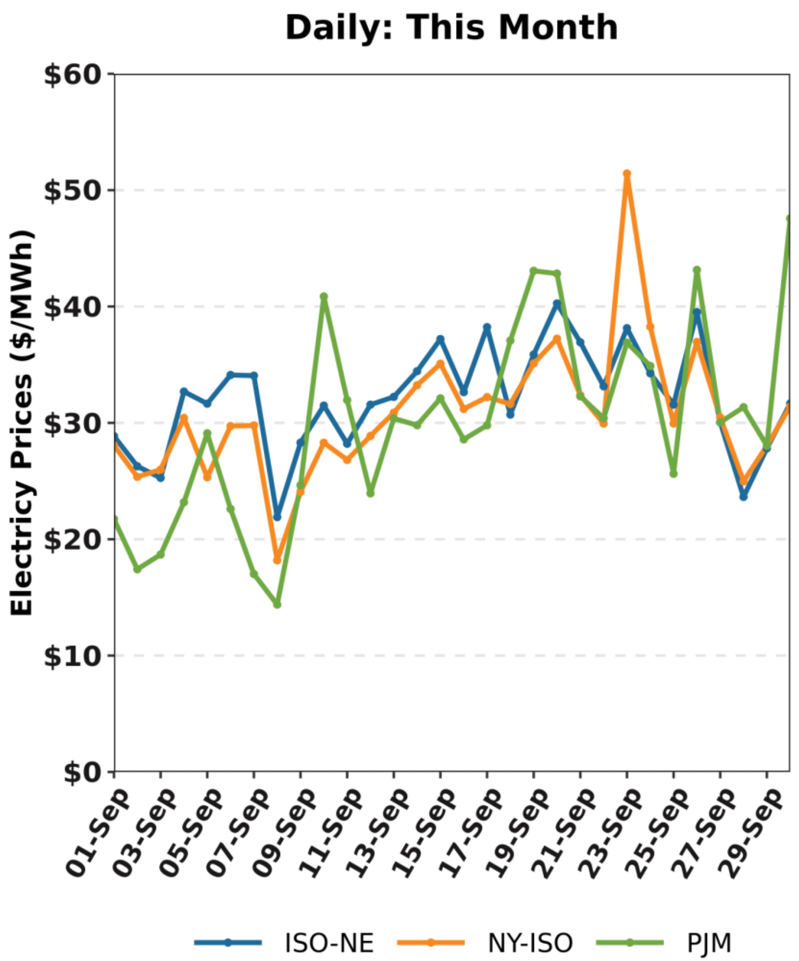


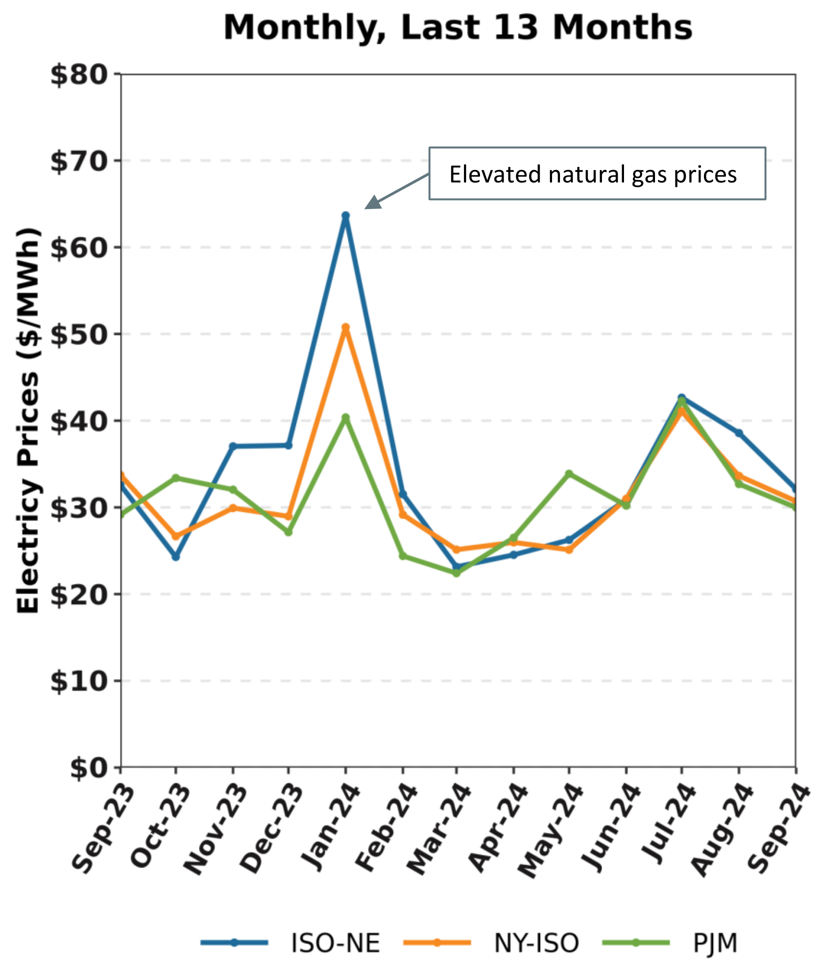


Underlying natural gas data furnished by: ICE Global markets in clear view

Gas price is average of Massachusetts delivery points

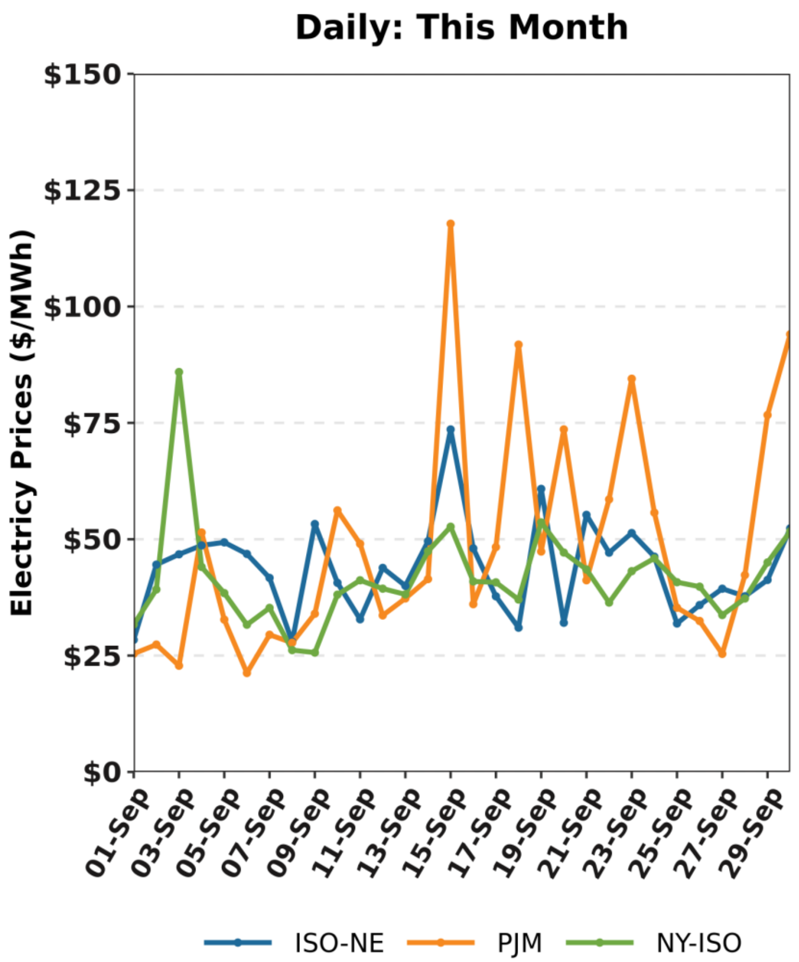
New England, NY, and PJM Hourly Average RT Prices by Month

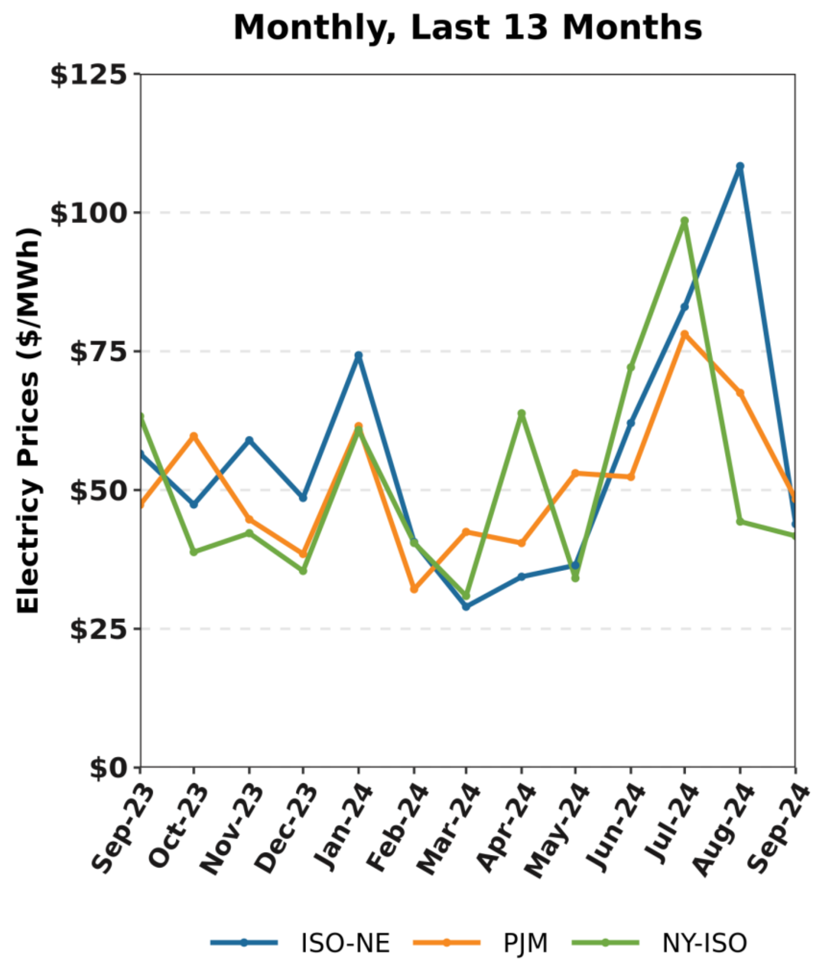




Hourly average prices are shown

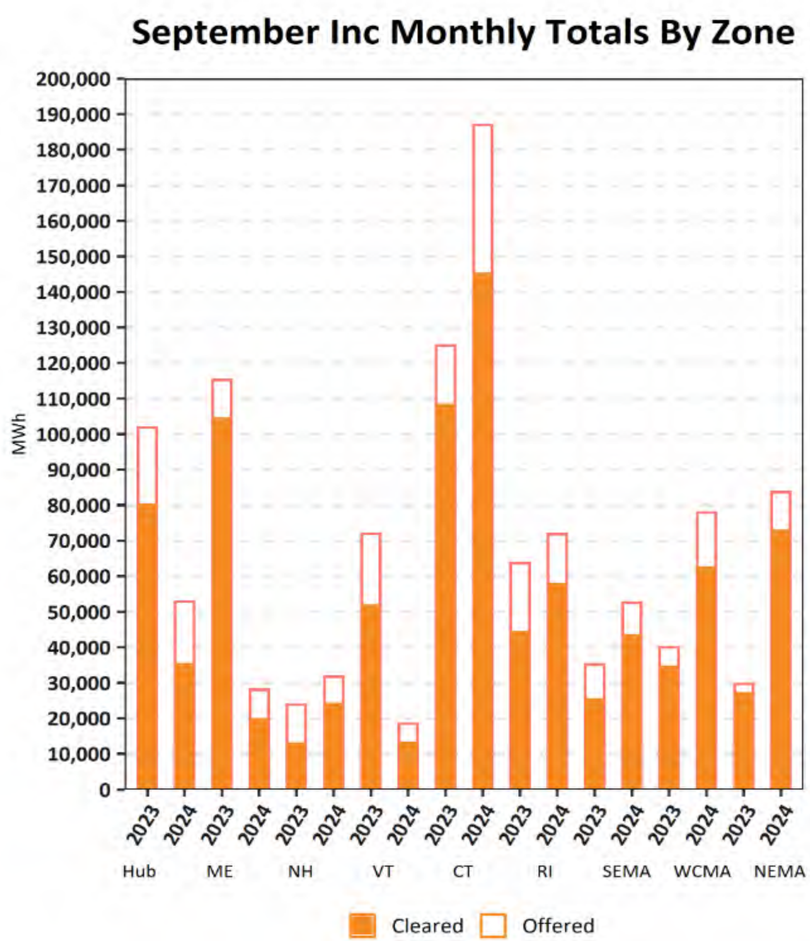
New England, NY, and PJM RT Pricing during New England's Forecasted Daily Peak Hours

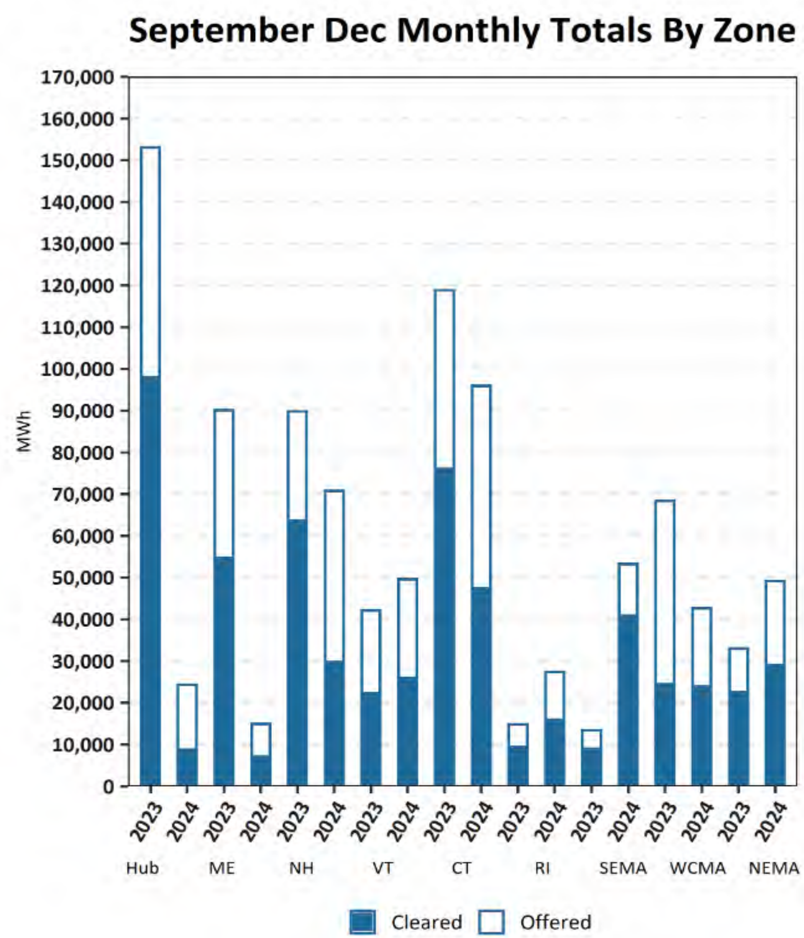




Monthly chart reflects the average of daily values

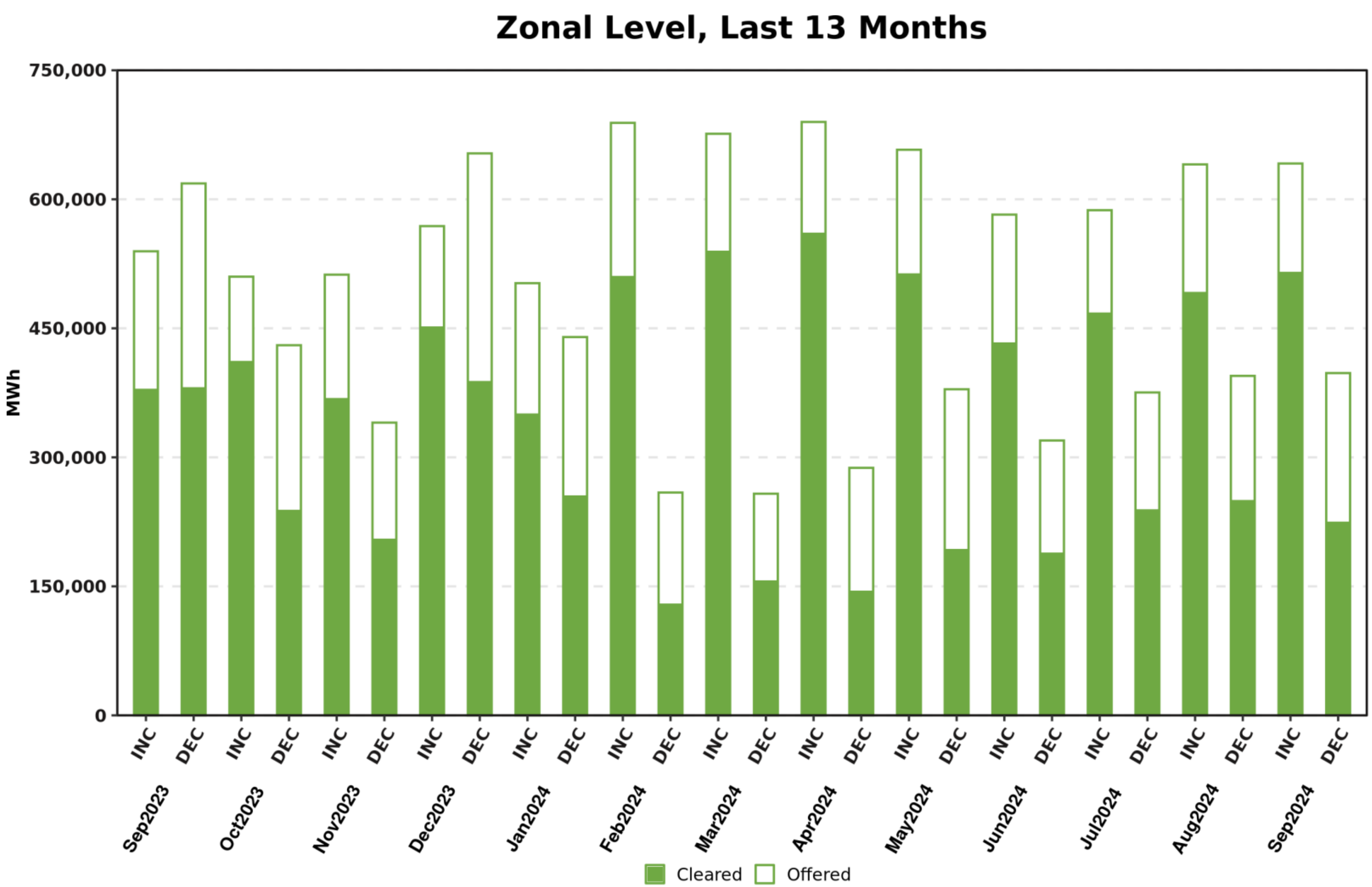
Zonal Increment Offers and Decrement Bid Amounts





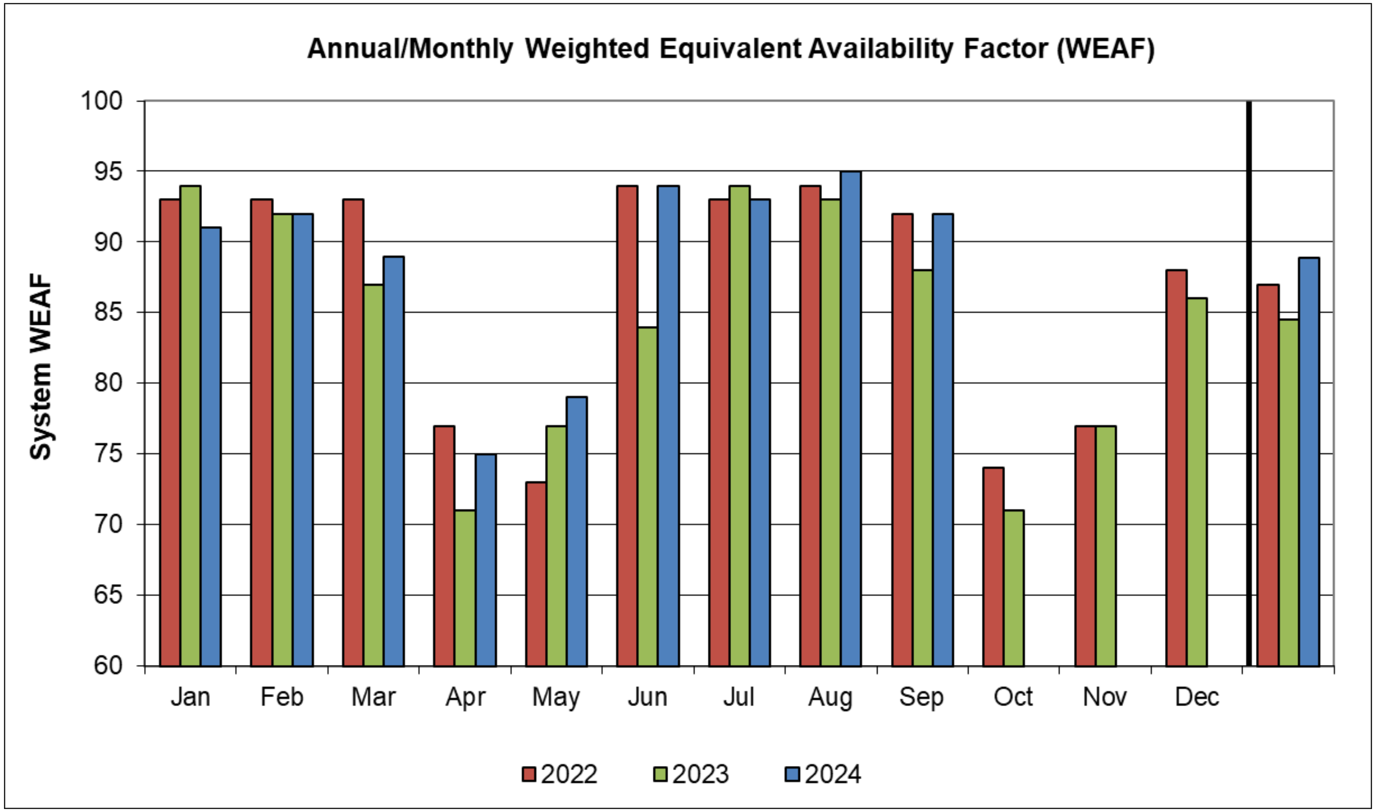
Includes nodal activity within the zone; excludes external nodes

Total Increment Offers and Decrement Bids



Includes nodal activity within the zone; excludes external nodes

System Unit Availability



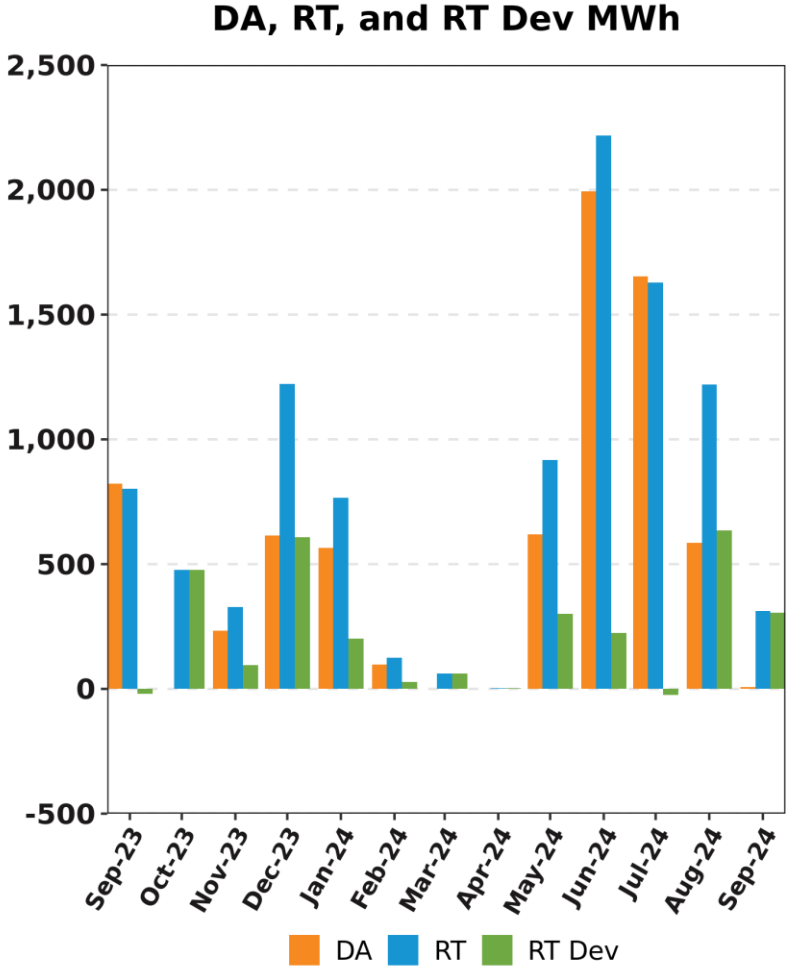
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2024	91	92	89	75	79	94	93	95	92				89
2023	94	92	87	71	77	84	94	93	88	71	77	86	85
2022	93	93	93	77	73	94	93	94	92	74	77	88	87

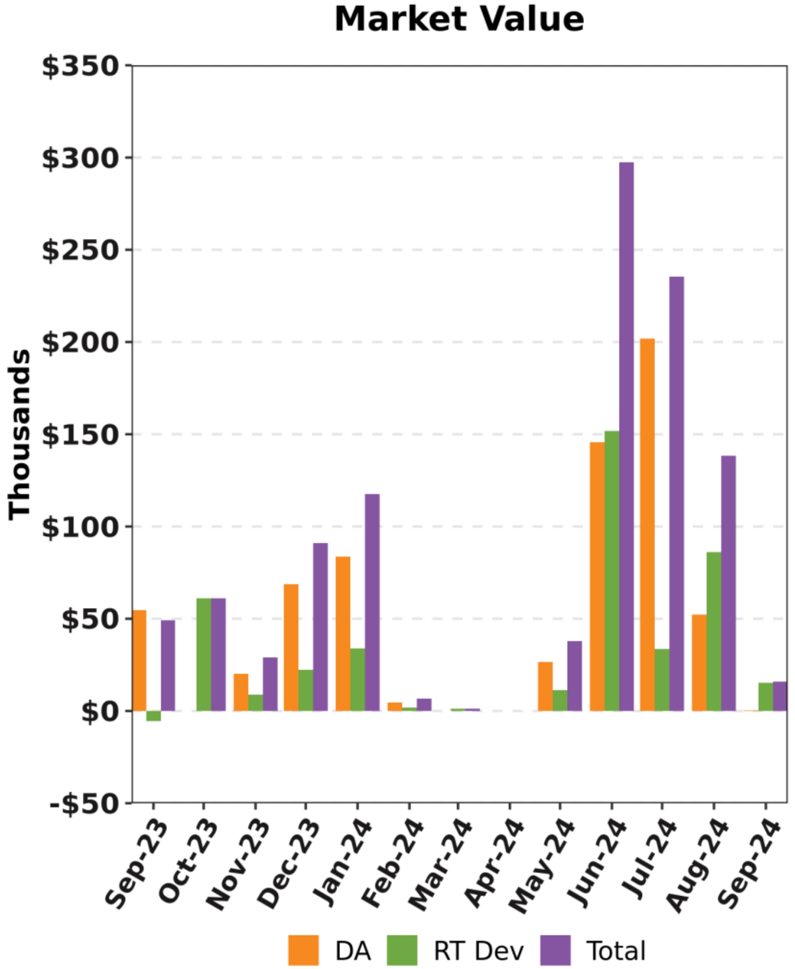
Data as of 10/1/24

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

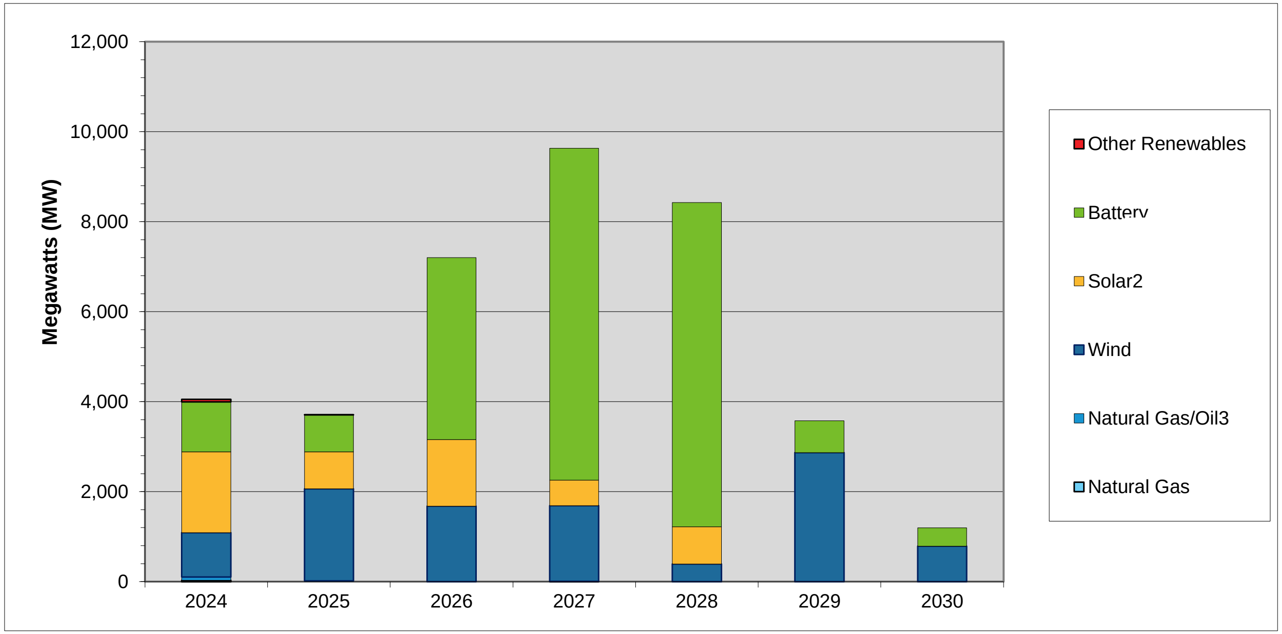
New Generation Update

Based on Queue as of 10/07/24

- 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, 424 generation projects are currently being tracked by the ISO, totaling approximately 45,069 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	0.2
Battery	1,114	825	4,048	7,375	7,210	704	404	21,680	57.4
Solar[2]	1,792	819	1,477	565	823	0	0	5,476	14.5
Wind	989	2,049	1,679	1,687	394	2,870	791	10,459	27.7
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	4,052	3,711	7,204	9,631	8,427	3,574	1,195	37,794	100.0

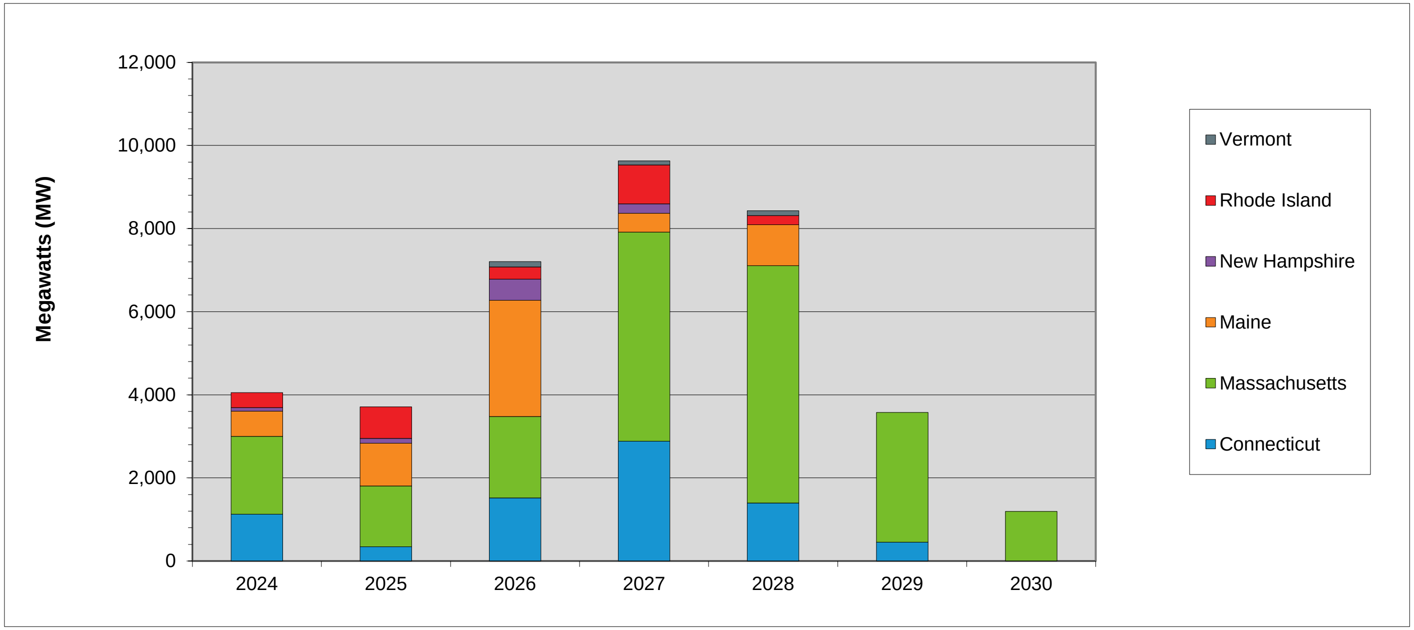
[1] Sum may not equal 100% due to rounding

[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	0.9
Rhode Island	360	758	295	938	221	0	0	2,572	6.8
New Hampshire	88	117	504	226	0	0	0	935	2.5
Maine	607	1,031	2,799	453	984	0	0	5,874	15.5
Massachusetts	1,872	1,461	1,962	5,031	5,710	3,120	1,195	20,351	53.8
Connecticut	1,125	344	1,516	2,882	1,397	454	0	7,718	20.4
Totals	**4,052**	**3,711**	**7,204**	**9,631**	**8,427**	**3,574**	**1,195**	**37,794**	**100.0**

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

New Generation Projection

By Fuel Type

Unit Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0
Battery Storage	138	21,680	2	325	136	21,355
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	248	5,476	14	310	234	5,166
Wind	28	17,734	3	985	25	16,749
Total	424	45,069	21	1,668	403	43,401

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

New Generation Projection

By Operating Type

Operating Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	6	73	2	48	4	25
Intermediate	2	89	0	0	2	89
Peaker	388	27,173	16	635	372	26,538
Wind Turbine	28	17,734	3	985	25	16,749
Total	424	45,069	21	1,668	403	43,401

- Green denotes projects with a high probability of going into service within the next 12 months
- Yellow denotes projects with a lower probability of going into service or new applications

New Generation Projection

By Operating Type and Fuel Type

Unit Type	Total		Baseload		Intermediate		Peaker		Wind Turbine	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0	0	0	0	0
Battery Storage	138	21,680	0	0	0	0	138	21,680	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	248	5,476	0	0	0	0	248	5,476	0	0
Wind	28	17,734	0	0	0	0	0	0	28	17,734
Total	424	45,069	6	73	2	89	388	27,173	28	17,734

- 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
Demand	*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
Generator	*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	504.466	-85.416		
	Passive Demand	2,557.256	2,579.120	21.864	2,574.367	-4.753		
Demand Total		**3,322.606**	**3,169.002**	**-153.604**	**3,078.833**	**-90.169**		
Generator	*Non-Intermittent*	26,805.003	26,643.379	-161.624	26,503.730	-139.649		
	Intermittent	1,178.933	1,146.783	-32.15	989.265	-157.518		
Generator Total		**27,983.936**	**27,790.162**	**-193.774**	**27,492.995**	**-297.167**		
Import Total		**1,503.842**	**1,247.601**	**-256.241**	**1,244.601**	**-3.000**		
Grand Total*		**32,810.384**	**32,206.765**	**-603.619**	**31,816.429**	**-390.336**		
Net ICR (NICR)		**31,645**	**30,585**	**-1,060**	**30,775**	**190.000**		

* 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 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

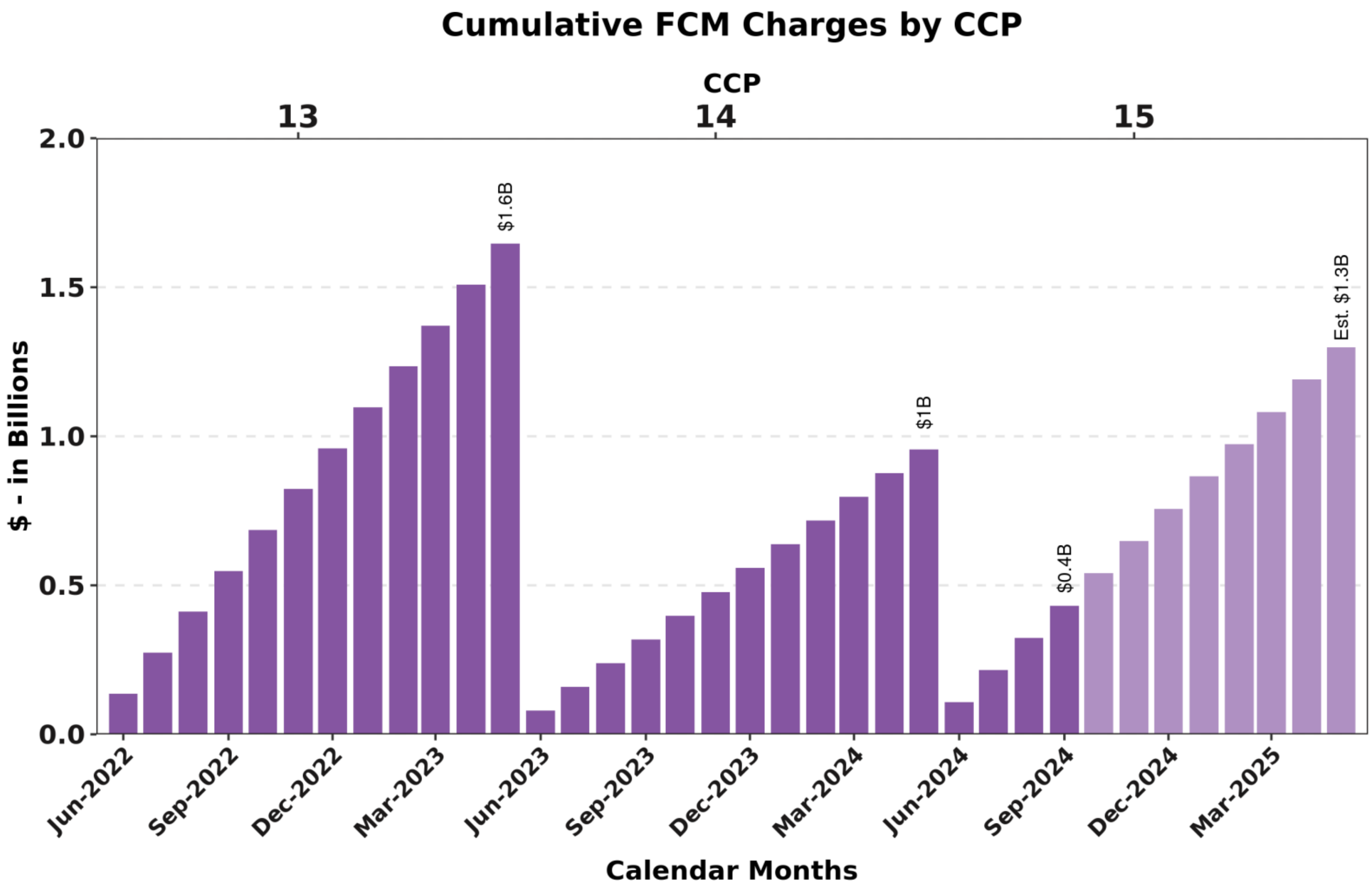
Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes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

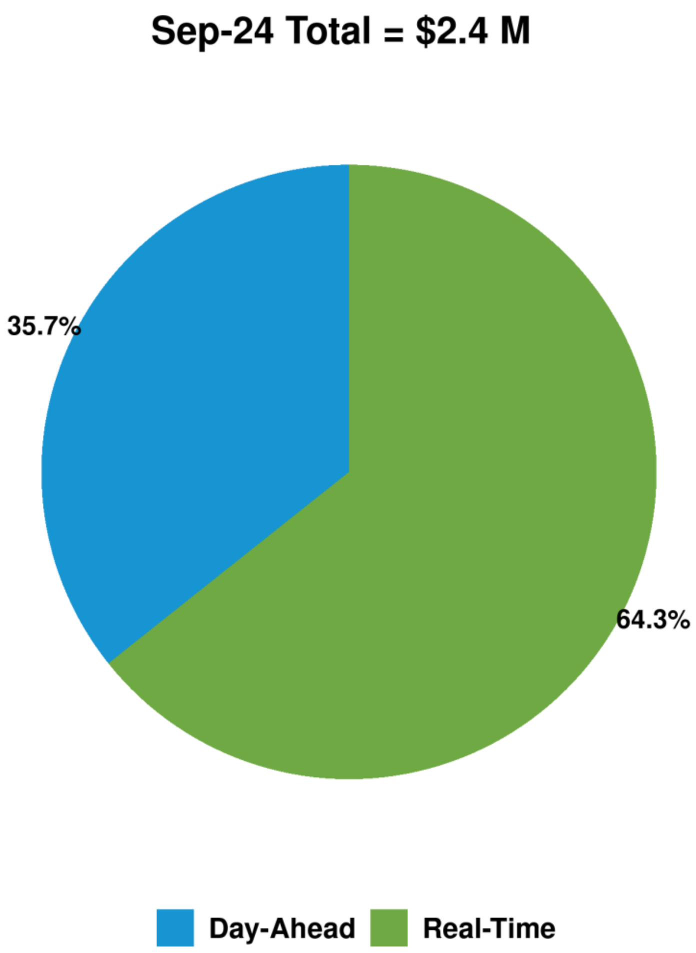
Forward Capacity Market Auctions

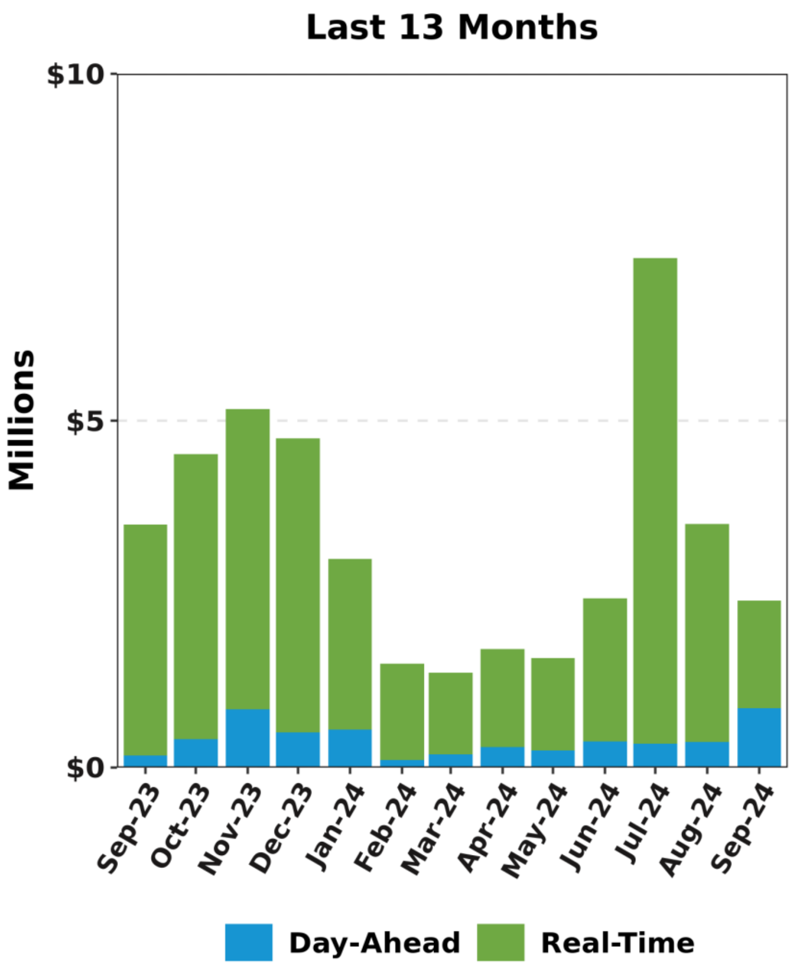


The items in the graph shaded in a lighter color represent the forecast for future months in the Capacity Commitment Period (CCP)

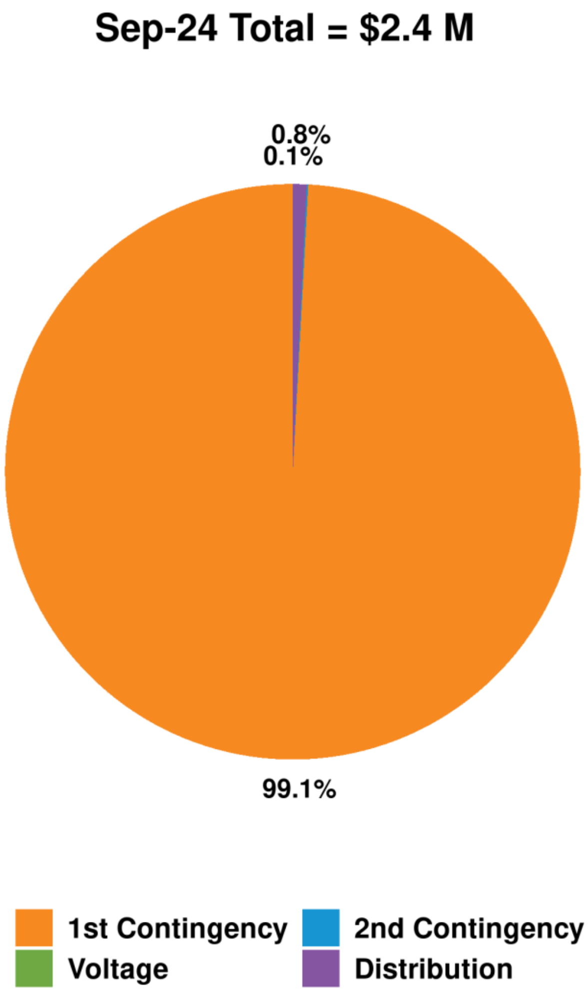
NET COMMITMENT PERIOD COMPENSATION

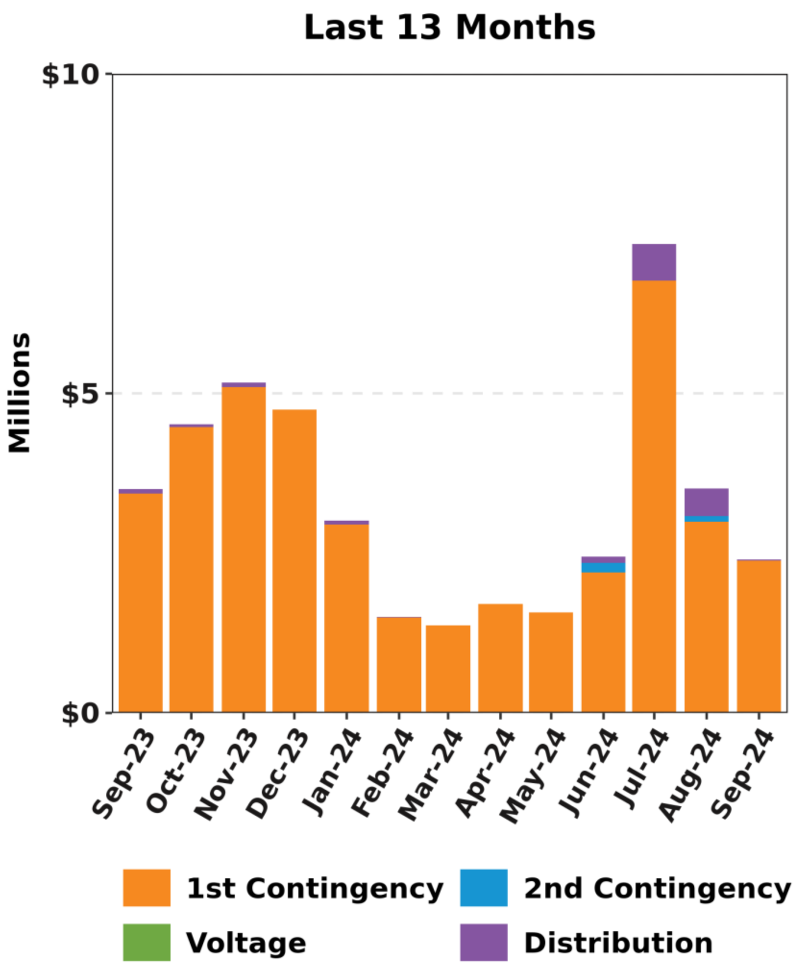
DA and RT NCPC Charges



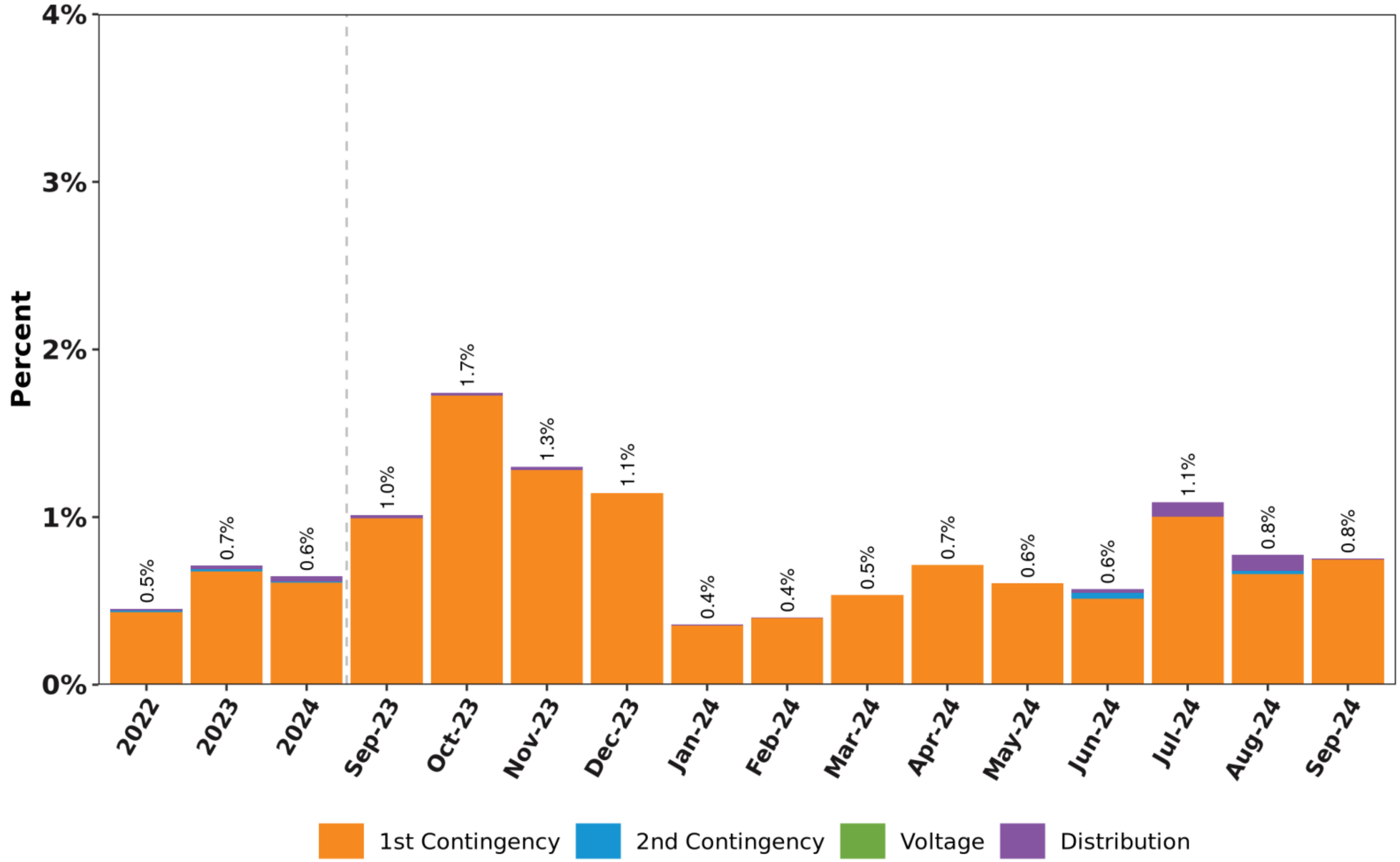


NCPC Charges by Type

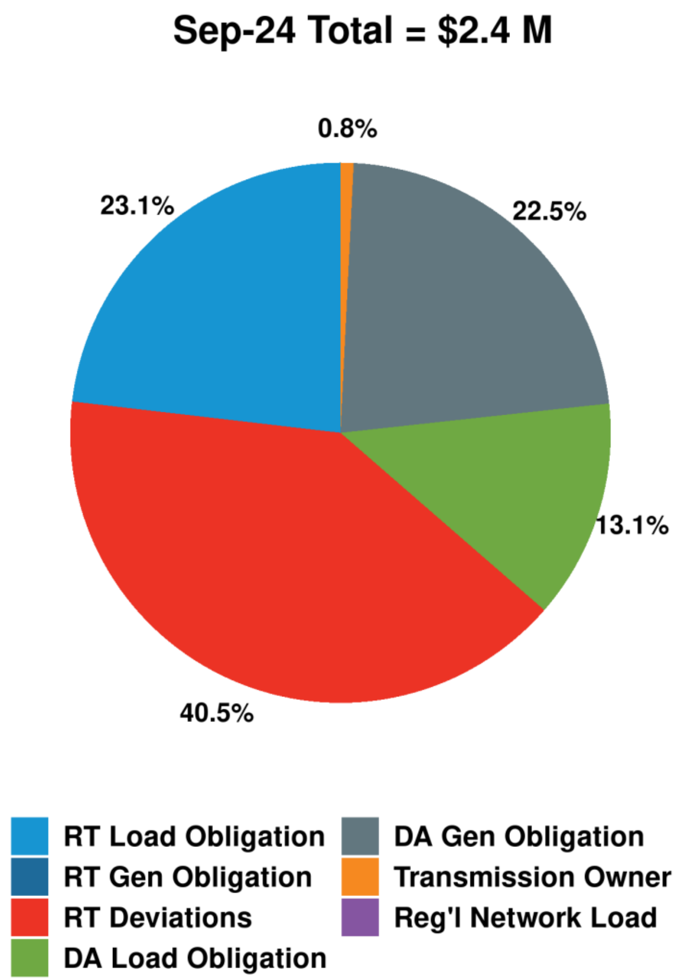


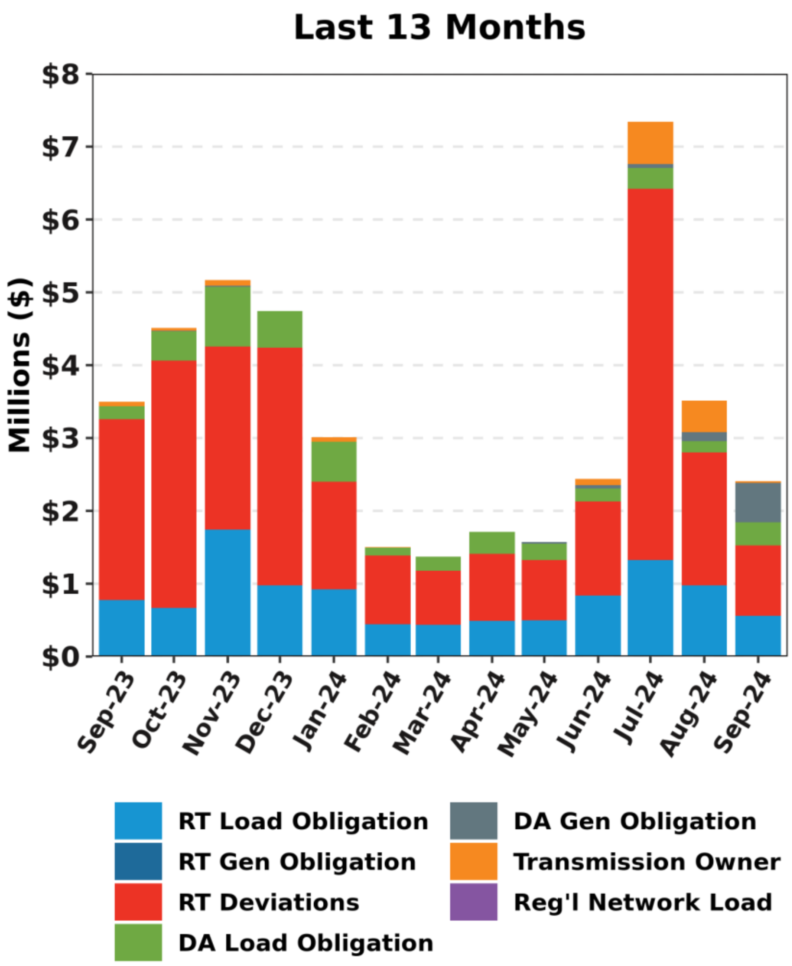


NCPC Charges by Type as Percent of Energy Market Value

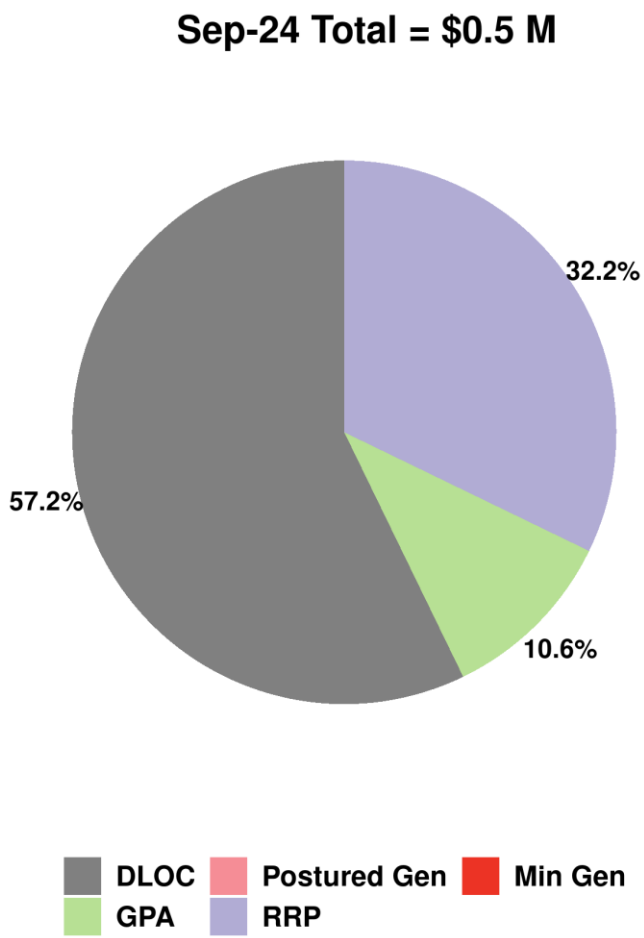


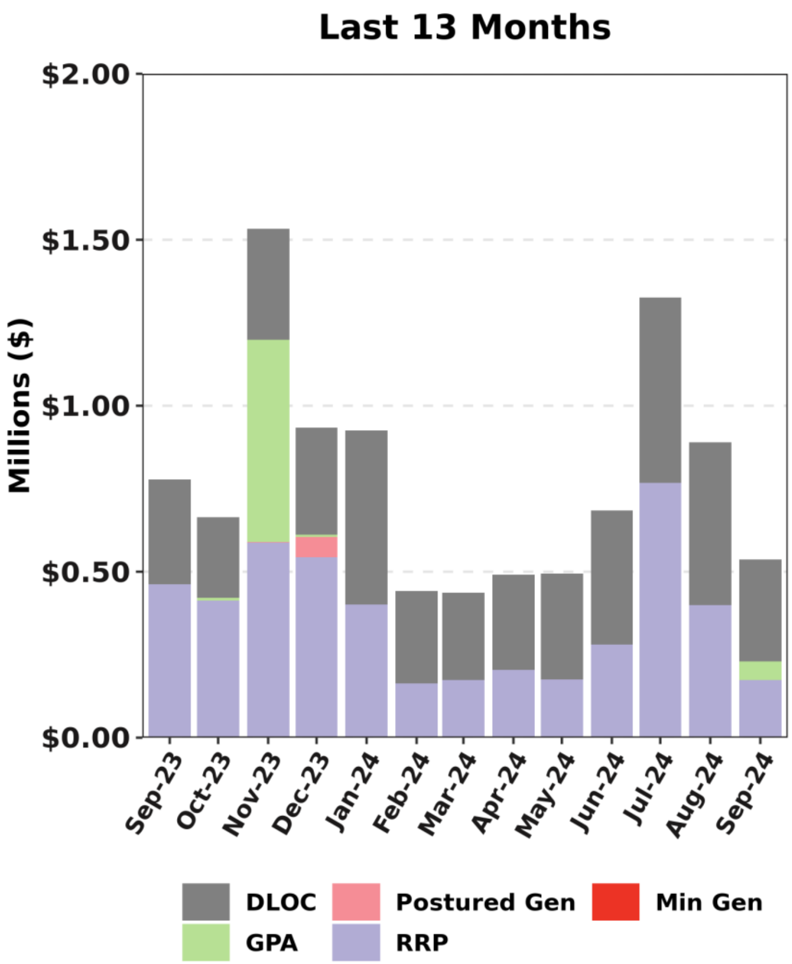
NCPC Charge Allocations





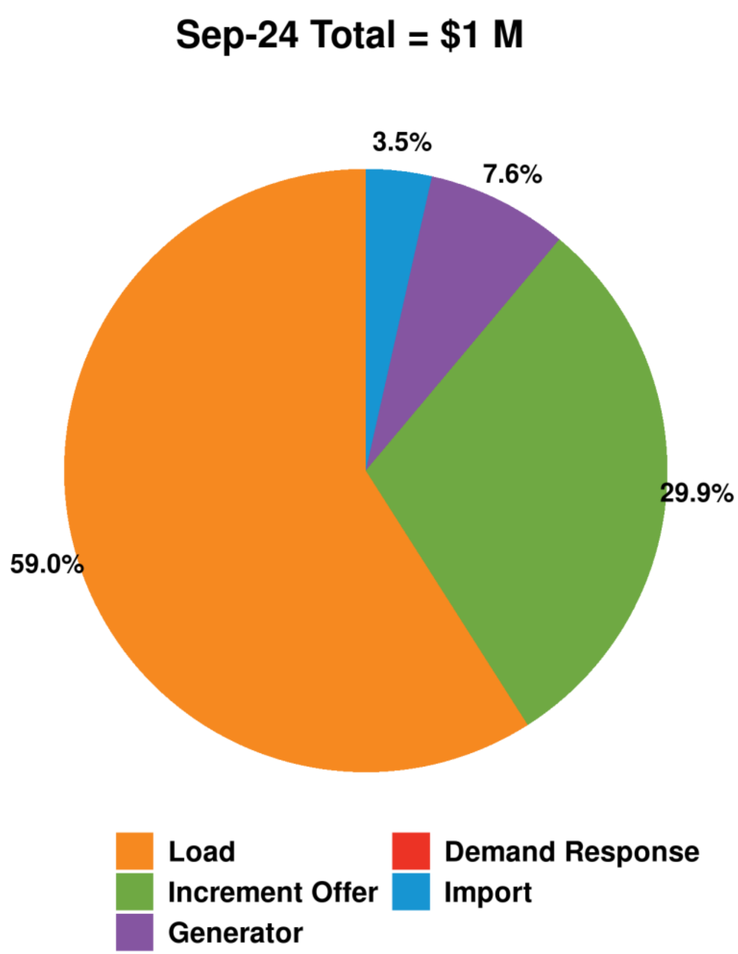
RT First Contingency NCPC Paid to Units and Allocated to RTLO and/or RTGO

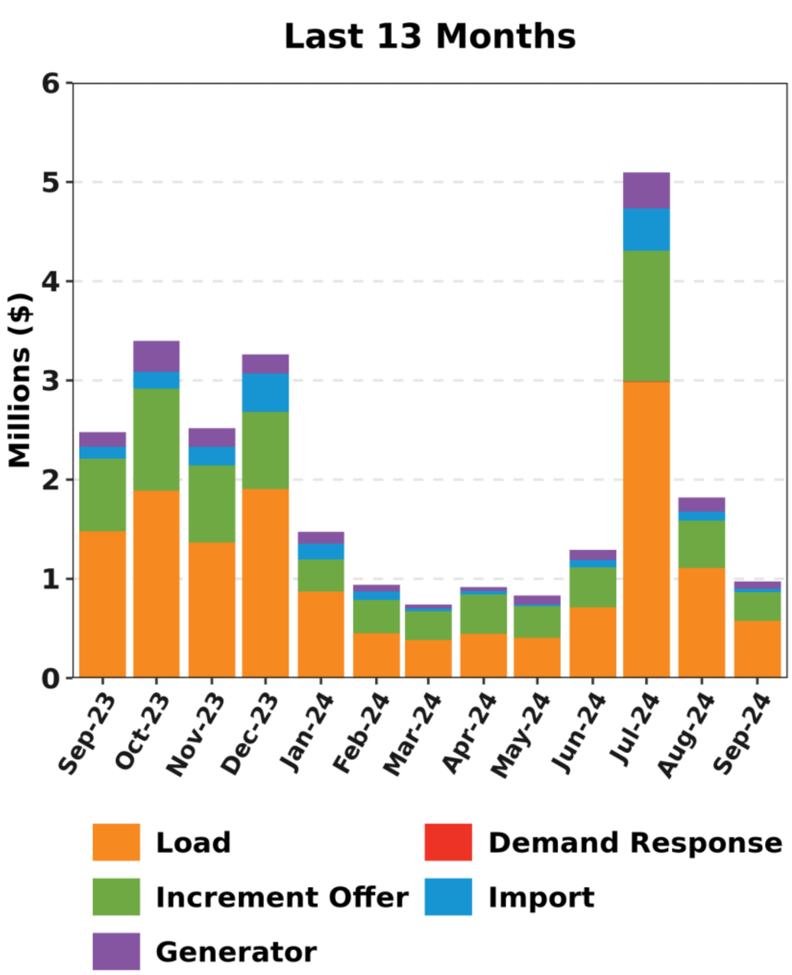




The categories shown above are a subset of those reflected in First Contingency NCPC throughout this report. The above categories are allocated to RTLO, except for Min Gen Emergency credits, which are allocated to RTGO.

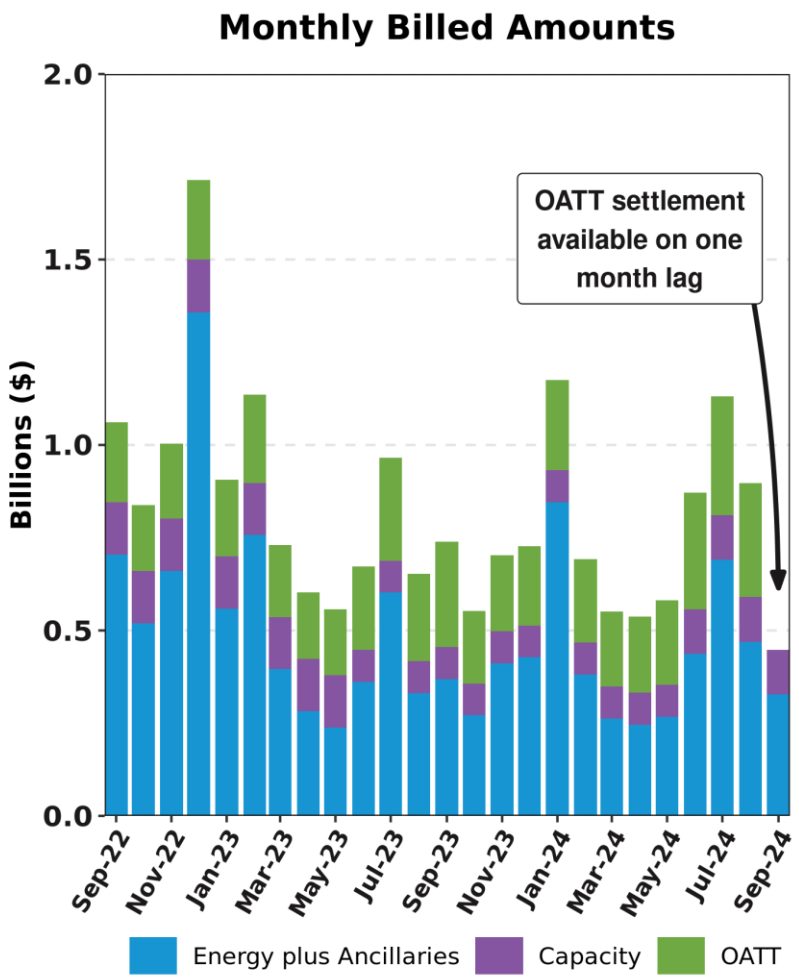
RT First Contingency Charges by Deviation Type

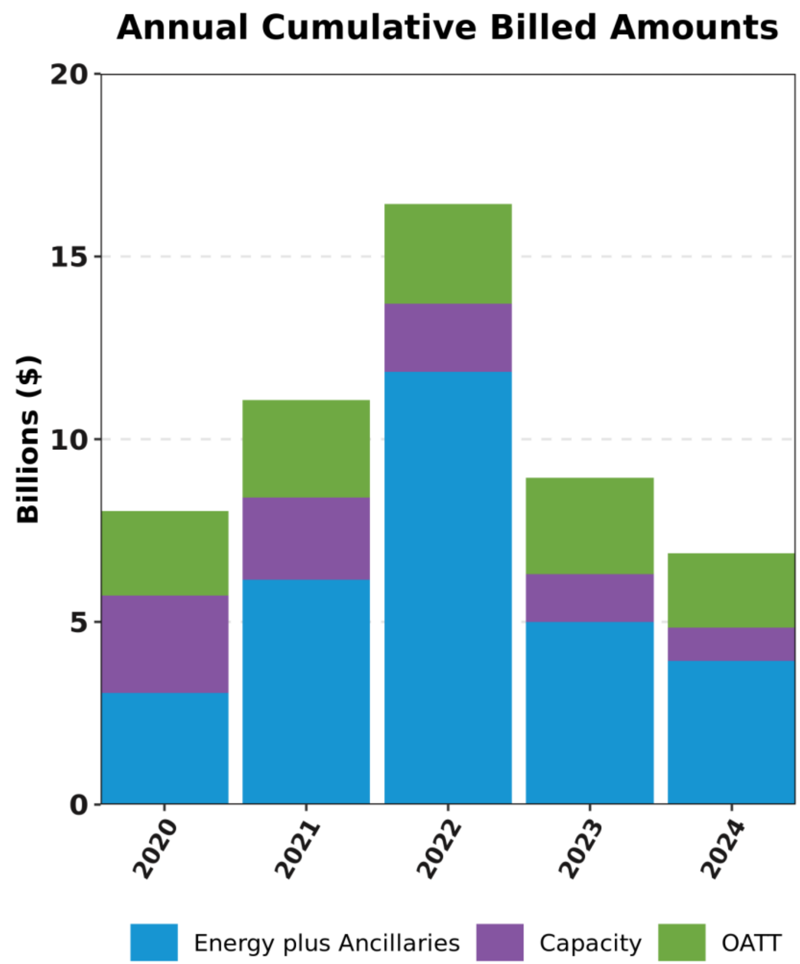




ISO BILLINGS

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)

- October 23 PAC Meeting Agenda Topics*
  - Asset Condition Projects
    - Nashua St. #25 - Substation Asset Condition Refurbishment (NGRID)
    - B-154N/C-155N & B-154S/C-155S ACR (NGRID)
    - Transmission Line Refurbishment - PAC Presentation K19 (VELCO)
    - Eversource Line 387 Asset Condition Structure Replacements Project (Eversource)
    - Eversource - Line X178 Rebuild, Project Update (Eversource)
  - NETO Presentations
    - Asset Condition Project PAC Presentation Template
    - PAC Presentation Template for Transmission Line Asset Condition Projects
    - Asset Condition Process Guide Update
  - Potential 2050 Transmission Needs for Longer-Term RFP (NESCOE)
  - RSP Project List and Asset Condition List - October 2024 Update
  - Economic Study Process Change Phase 2: Interregional Model and Assumptions

* 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 discussed the results of the offshore wind point of interconnection screening and constraint identification analysis at the 8/21/24 PAC meeting
- Draft report on additional analysis to address stakeholder comments is expected to be issued by the end of 2024

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
  - Final PAC presentation was made at the August meeting
  - Draft report was issued on August 16
    - Several sets of comments were received and will be considered in the creation of the final draft

Economic Studies: 2024 Study

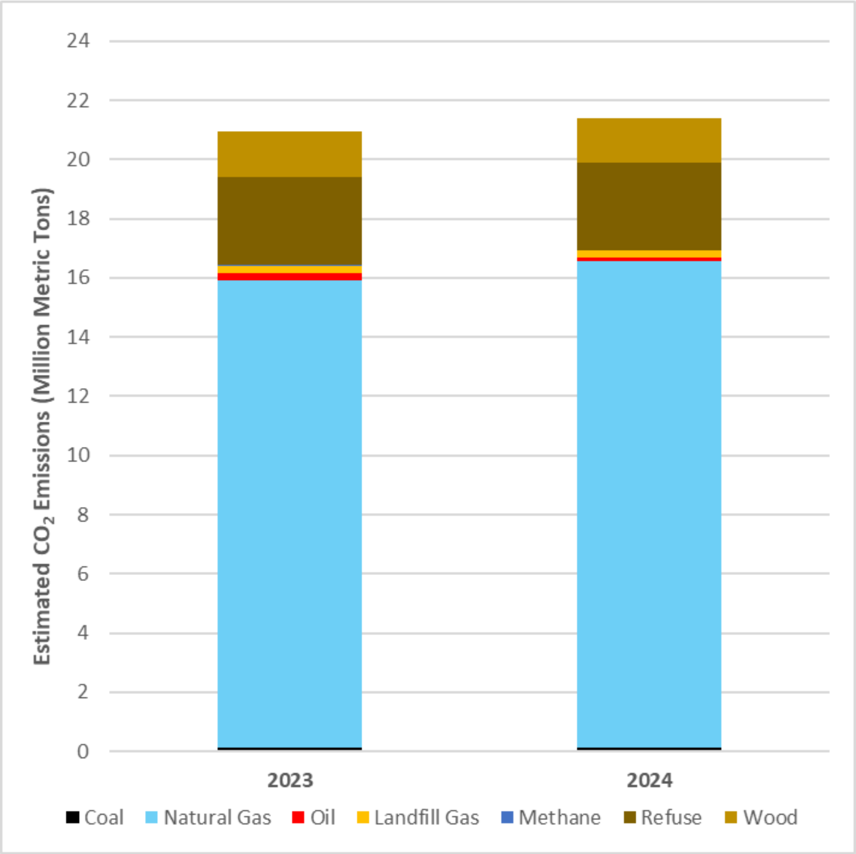
- The 2024 Economic Study
  - This study is the first use of new Economic Study Process Tariff language that was recently updated
    - The study was initiated at the January PAC meeting
  - The Benchmark Scenario has been completed and the Policy and Stakeholder-Requested Scenarios are being analyzed between now and 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 methodology into a seasonal capacity market

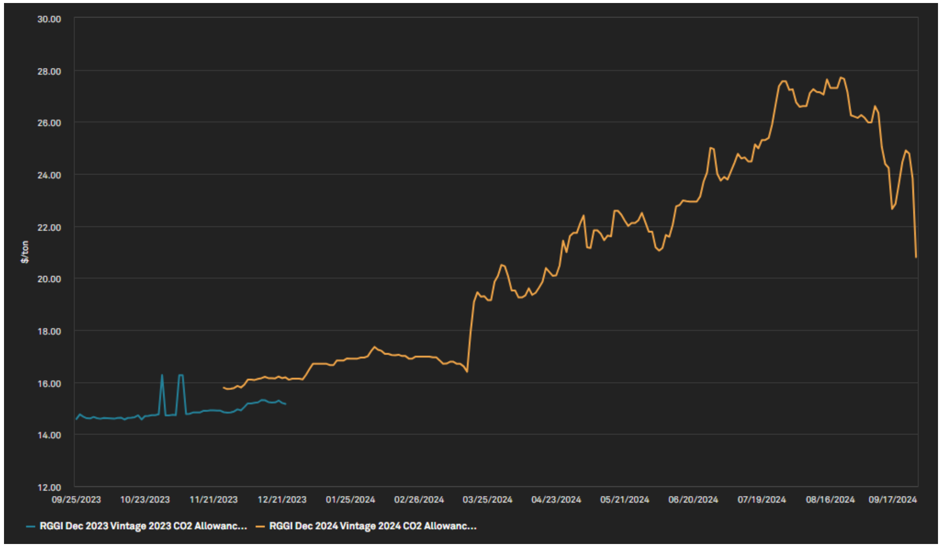
New England Power System Carbon Emissions

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



Data as of 9/15/24

Regional Greenhouse Gas Initiative (RGGI) Allowance Prices



- 9/24/24: RGGI allowance spot price - $20.80
- 9/23/24: RGGI published the Program Review Updates that included:
  - updated modelling results of potential future CO_2 emissions cap
  - updated timeline for the Third Program Review (draft Model Rule scheduled for Fall 2024)
  - request for comments on solutions for accommodating future state participation (comments due 10/13/2024)

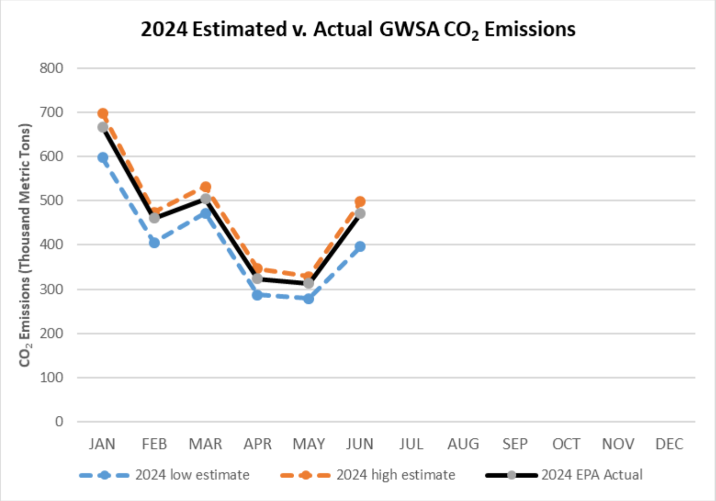
Massachusetts CO_2 Generator Emissions Cap

2024 Estimated Emissions Under CO_2 Cap

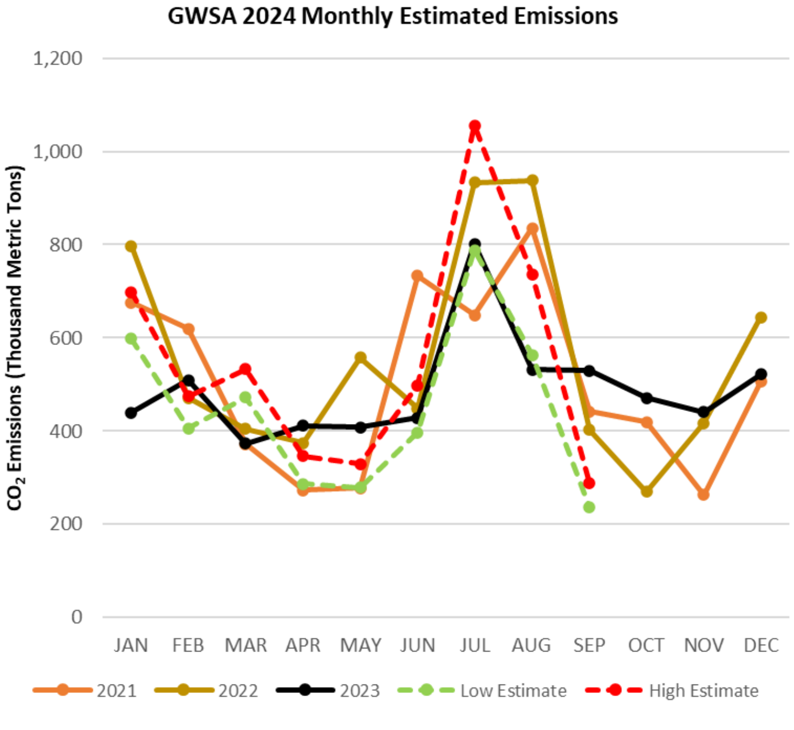
- As of 9/23/24, September estimated GWSA CO_2 emissions range between **235,454** and **287,526** metric tons
  - Year-to-date 2024 estimated emissions range between **52.9%** and **65.2%** of the 2024 cap of 7.61 MMT

2024 Q1/Q2 Actual Emissions Under CO_2 Cap

- According to the EPA CAMPD, Quarter 1 and 2 (January-June) 2024 GWSA CO_2 emissions were **2.74 MMT**, or **36.0%** 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 10/1/2024

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 10/1/2024

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 10/1/2024

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 10/1/2024

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 10/1/2024

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 10/1/2024

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 10/1/2024

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 10/1/2024

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 10/1/2024

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 10/1/2024

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 10/1/2024

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 10/1/2024

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 10/1/2024

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 10/1/2024

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	Dec-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 10/1/2024

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	4
1883	Convert the Highland 115 kV substation to an eight breaker, breaker-and-a-half configuration with a bus connected 115/34.5 kV transformer	Jul-28	1
1884	Install a 15 MVAR capacitor at Belfast 115 kV substation	Jul-28	1
1885	Install a +50/-25 MVAR synchronous condenser at Highland 115 kV substation	Jul-28	1
1886	Install +50/-25 MVAR synchronous condenser at Boggy Brook 115 kV substation, and install a new 115 kV breaker to separate Line 67 from the proposed solution elements	Oct-24	3

Upper Maine Solution Projects, cont.

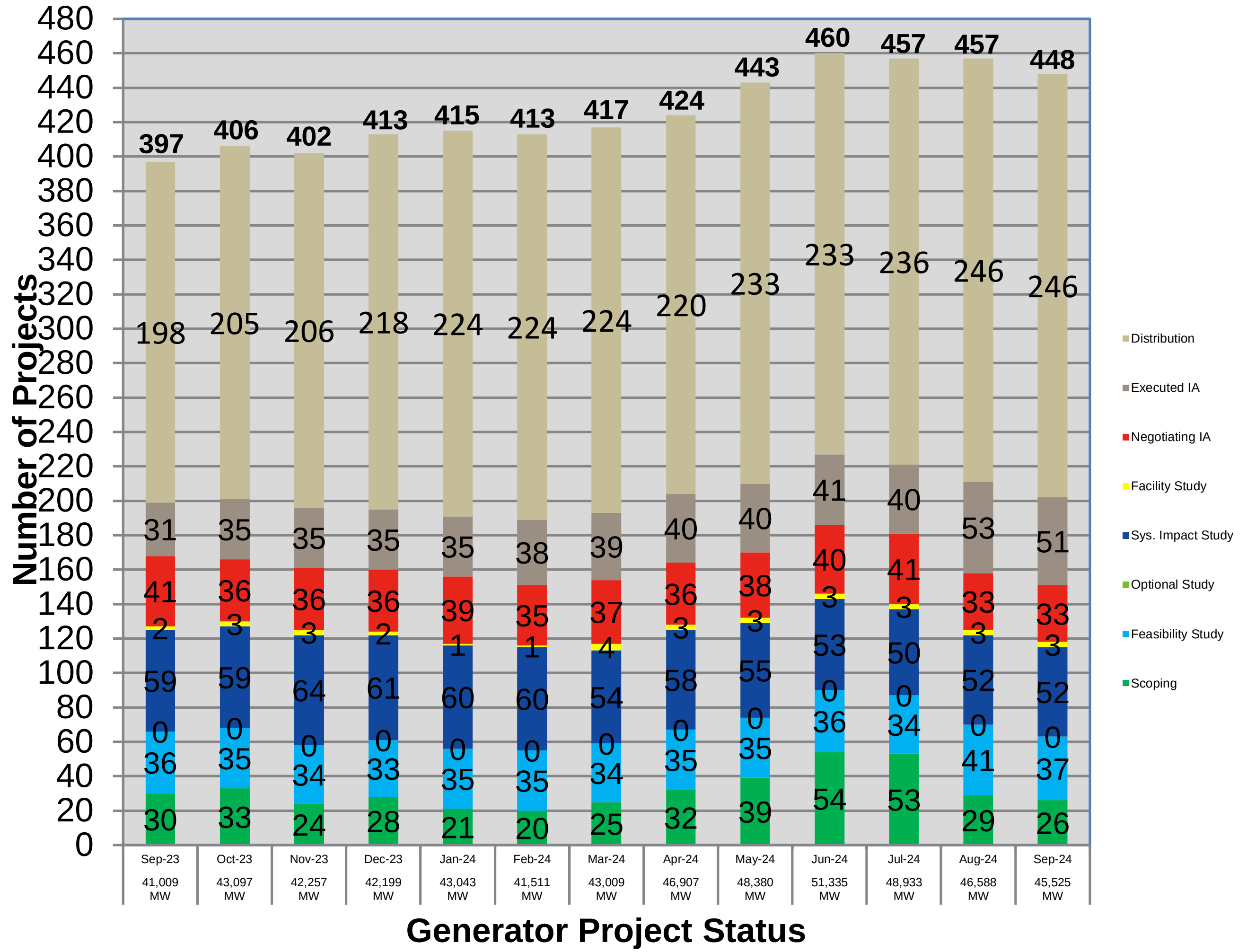
Status as of 10/1/2024

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	Oct-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 October 1, 2024



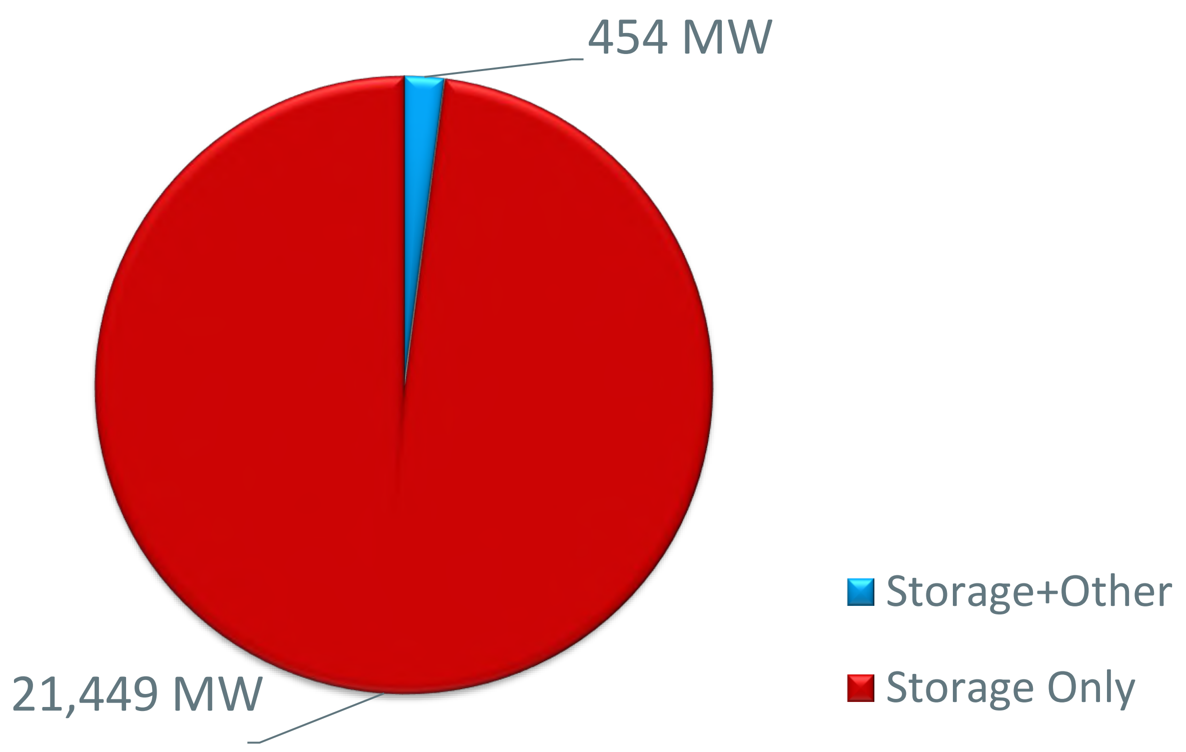
6 ETUs in Scoping, 3 in FS, 3 in SIS, 0 in OIS, 0 in FAC, 1 Negotiating IA, and 4 with Executed IA

Transmission Service Requests needing study: 0

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

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

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



OPERABLE CAPACITY ANALYSIS

Fall 2024 Analysis

Fall 2024 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Oct - 2024[2] CSO (MW)	Oct - 2024[2] SCC (MW)
Operable Capacity MW [1]	28,097	30,030
Active Demand Capacity Resource (+) [5]	388	343
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	925	925
Non Commercial Capacity (+)	18	18
Non Gas-fired Planned Outage MW (-)	6,152	6,454
Gas Generator Outages MW (-)	2,349	3,061
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)	18,127	19,001
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	-819	55

[1] Operable Capacity is based on data as of **Sept 30, 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 **Sept 30, 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.

Fall 2024 Operable Capacity Analysis

90/10 Load Forecast	Oct - 2024[2] CSO (MW)	Oct - 2024[2] SCC (MW)
Operable Capacity MW [1]	28,097	30,030
Active Demand Capacity Resource (+) [5]	388	343
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	925	925
Non Commercial Capacity (+)	18	18
Non Gas-fired Planned Outage MW (-)	6,152	6,454
Gas Generator Outages MW (-)	2,349	3,061
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)	18,127	19,001
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	-1,480	-606

[1]Operable Capacity is based on data as of **Sept 30, 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 **Sept 30, 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.

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

ISO-NE OPERABLE CAPACITY ANALYSIS

September 30, 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 October and November.

Report created: 9/30/2024

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
10/19/2024	28097	388	925	18	6152	2349	2800	0	18127	16821	2125	18946	-819	Y	Fall 2024
10/26/2024	27870	382	1164	16	4964	1997	3600	0	18871	17026	2125	19151	-280	N	Fall 2024
11/2/2024	27870	382	1164	16	3906	2924	3600	0	19002	17140	2125	19265	-263	N	Fall 2024
11/9/2024	27870	382	1164	16	1674	2573	3600	0	21585	17481	2125	19606	1979	N	Fall 2024
11/16/2024	27870	382	1164	16	1977	2143	3600	0	21712	18211	2125	20336	1376	N	Fall 2024
11/23/2024	27870	382	1164	16	860	361	3600	1301	23310	18923	2125	21048	2262	N	Fall 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.

Fall 2024 Operable Capacity Analysis

90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

September 30, 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 October and November.

Report created: 9/30/2024

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
10/19/2024	28097	388	925	18	6152	2349	2800	0	18127	17482	2125	19607	-1480	Y	Fall 2024
10/26/2024	27870	382	1164	16	4964	1997	3600	0	18871	17694	2125	19819	-948	N	Fall 2024
11/2/2024	27870	382	1164	16	3906	2924	3600	0	19002	17812	2125	19937	-935	N	Fall 2024
11/9/2024	27870	382	1164	16	1674	2573	3600	0	21585	18165	2125	20290	1295	N	Fall 2024
11/16/2024	27870	382	1164	16	1977	2143	3600	0	21712	18921	2125	21046	666	N	Fall 2024
11/23/2024	27870	382	1164	16	860	361	3600	2215	22396	19658	2125	21783	613	N	Fall 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 Winter 2024/25 Analysis

Preliminary Winter 2024/25 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Dec - 2024[2] CSO (MW)	Dec - 2024[2] SCC (MW)
Operable Capacity MW [1]	27,919	30,030
Active Demand Capacity Resource (+) [5]	427	343
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 (-)	234	258
Gas Generator Outages MW (-)	17	168
Allowance for Unplanned Outages (-) [4]	3,200	3,200
Generation at Risk Due to Gas Supply (-) [3]	3,716	3,973
Net Capacity (NET OPCAP SUPPLY MW)	22,633	24,228
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	19,849	19,849
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	21,974	21,974
Operable Capacity Margin	659	2,254

[1]Operable Capacity is based on data as of **Sept 30, 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 **Sept 30, 2024.**

[2] Load forecast that is based on the 2024 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **Dec 28, 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 Winter 2024/25 Operable Capacity Analysis

90/10 Load Forecast	Dec - 2024[2] CSO (MW)	Dec - 2024[2] SCC (MW)
Operable Capacity MW [1]	27,919	30,030
Active Demand Capacity Resource (+) [5]	427	343
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 (-)	234	258
Gas Generator Outages MW (-)	17	168
Allowance for Unplanned Outages (-) [4]	3,200	3,200
Generation at Risk Due to Gas Supply (-) [3]	4,391	4,747
Net Capacity (NET OPCAP SUPPLY MW)	21,958	23,454
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,613	20,613
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,738	22,738
Operable Capacity Margin	-780	716

[1] Operable Capacity is based on data as of **Sept 30, 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 **Sept 30, 2024.**

[2] Load forecast that is based on the 2024 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **Dec 28, 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 Winter 2024/25 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

September 30, 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 December through March.

Report created: 9/30/2024

Study Week (Week Beginning, Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 50-50PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 50-50PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
11/30/2024	27919	427	1161	293	1063	832	3200	972	23733	19220	2125	21345	2388	N	Winter 2024/2025
12/7/2024	27919	427	1161	293	573	605	3200	1763	23659	19506	2125	21631	2028	N	Winter 2024/2025
12/14/2024	27919	427	1161	293	407	67	3200	2678	23448	19517	2125	21642	1806	N	Winter 2024/2025
12/21/2024	27919	427	1161	293	389	67	3200	3067	23077	19578	2125	21703	1374	N	Winter 2024/2025
12/28/2024	27919	427	1161	293	234	17	3200	3716	22633	19849	2125	21974	659	Y	Winter 2024/2025
1/4/2025	27919	427	1161	293	26	17	2800	3711	23246	20308	2125	22433	813	N	Winter 2024/2025
1/11/2025	27919	427	1161	293	26	17	2800	3566	23391	20308	2125	22433	958	N	Winter 2024/2025
1/18/2025	27919	427	1161	293	25	17	2800	3117	23841	20308	2125	22433	1408	N	Winter 2024/2025
1/25/2025	27919	427	1161	293	19	17	2800	2818	24146	20088	2125	22213	1933	N	Winter 2024/2025
2/1/2025	27919	427	1161	293	28	17	3100	2519	24136	19824	2125	21949	2187	N	Winter 2024/2025
2/8/2025	27919	427	1161	293	18	17	3100	2220	24445	19796	2125	21921	2524	N	Winter 2024/2025
2/15/2025	27919	427	1161	293	18	17	3100	1771	24894	19536	2125	21661	3233	N	Winter 2024/2025
2/22/2025	27919	427	1161	293	18	17	3100	1472	25193	18560	2125	20685	4508	N	Winter 2024/2025
3/1/2025	27919	427	1161	293	100	174	2200	240	27086	18215	2125	20340	6746	N	Winter 2024/2025
3/8/2025	27919	427	1161	293	101	419	2200	0	27080	18022	2125	20147	6933	N	Winter 2024/2025
3/15/2025	27919	427	1161	293	101	717	2200	0	26782	17661	2125	19786	6996	N	Winter 2024/2025
3/22/2025	27919	427	1161	293	659	870	2200	0	26071	17103	2125	19228	6843	N	Winter 2024/2025
3/29/2025	27711	426	1161	293	1154	1335	2700	0	24402	16516	2125	18641	5761	N	Winter 2024/2025

Column Definitions

1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.
5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 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.

Preliminary Winter 2024/25 Operable Capacity Analysis 90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

September 30, 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 December through March.

Report created: 9/30/2024

Study Week (Week Beginning, Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 90-10PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 90-10PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
11/30/2024	27919	427	1161	293	1063	832	3200	1960	22745	19962	2125	22087	658	N	Winter 2024/2025
12/7/2024	27919	427	1161	293	573	605	3200	2750	22672	20258	2125	22383	289	N	Winter 2024/2025
12/14/2024	27919	427	1161	293	407	67	3200	3797	22329	20270	2125	22395	-66	N	Winter 2024/2025
12/21/2024	27919	427	1161	293	389	67	3200	4213	21931	20333	2125	22458	-527	N	Winter 2024/2025
12/28/2024	27919	427	1161	293	234	17	3200	4391	21958	20613	2125	22738	-780	Y	Winter 2024/2025
1/4/2025	27919	427	1161	293	26	17	2800	4522	22435	21089	2125	23214	-779	N	Winter 2024/2025
1/11/2025	27919	427	1161	293	26	17	2800	4314	22643	21089	2125	23214	-571	N	Winter 2024/2025
1/18/2025	27919	427	1161	293	25	17	2800	4015	22943	21089	2125	23214	-271	N	Winter 2024/2025
1/25/2025	27919	427	1161	293	19	17	2800	4015	22949	20862	2125	22987	-38	N	Winter 2024/2025
2/1/2025	27919	427	1161	293	28	17	3100	3566	23089	20588	2125	22713	376	N	Winter 2024/2025
2/8/2025	27919	427	1161	293	18	17	3100	3267	23398	20559	2125	22684	714	N	Winter 2024/2025
2/15/2025	27919	427	1161	293	18	17	3100	2669	23996	20290	2125	22415	1581	N	Winter 2024/2025
2/22/2025	27919	427	1161	293	18	17	3100	2220	24445	19279	2125	21404	3041	N	Winter 2024/2025
3/1/2025	27919	427	1161	293	100	174	2200	1137	26189	18922	2125	21047	5142	N	Winter 2024/2025
3/8/2025	27919	427	1161	293	101	419	2200	787	26293	18722	2125	20847	5446	N	Winter 2024/2025
3/15/2025	27919	427	1161	293	101	717	2200	0	26782	18348	2125	20473	6309	N	Winter 2024/2025
3/22/2025	27919	427	1161	293	659	870	2200	0	26071	17770	2125	19895	6176	N	Winter 2024/2025
3/29/2025	27711	426	1161	293	1154	1335	2700	0	24402	17166	2125	19291	5111	N	Winter 2024/2025

Column Definitions

1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.
5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 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**

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

4b COO Report – 2025 Annual Work Plan (AWP)

October 10, 2024
Meeting

NEPOOL
NEW ENGLAND POWER POOL
Participants Committee

SEPTEMBER 26, 2024

ISO New England's Draft 2025 Annual Work Plan (AWP)

For Discussion at the October 10, 2024, NEPOOL Participants Committee Meeting

Vamsi Chadalavada
EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

2025 Objectives and Highlights

Advancing a reliable clean-energy transition through innovation and collaboration

- **Anchor Projects and Related Core Implementations** are the highest priority initiatives across the ISO for securing power system reliability while facilitating the integration of clean-energy and distributed-energy resources
  – **Capacity Auction Reforms (CAR):** Designing a set of distinct, highly complex initiatives that restructure the timing of the capacity market and reshape capacity market accreditation methodologies to ensure more efficient reliability and cost outcomes from season to season as the resource mix evolves
  – **Regional Energy Shortfall Threshold (REST):** Establishing an acceptable level of energy shortfall risk during extreme weather events, begin performing seasonal assessments, and evaluating whether exceeding the REST requires solutions to mitigate risks
  – **Longer-Term Transmission Planning and Generator Interconnection Compliance, Implementations, and Enhancements:** Continuing compliance with and implementation of FERC Order Nos. 1920 and 2023 and other ongoing enhancements; implementation of the first LTTP competitive solicitation to help meet state clean-energy goals
  – **IT Development and Implementation of Critical Market and Reliability Initiatives:** Developing the software and systems needed to implement initiatives such as DASI and Order No. 881; ongoing development of the nGEM real-time market clearing engine that is foundational to supporting an exponentially complex system
- **Notable Initiatives** target innovation, advance efficiency, and help manage risks across markets, planning, operations, and software structures

Regional Focus on Anchors Is Essential

The ISO strives to support regional reliability and decarbonization goals in a coordinated manner

- Anchors and implementations will utilize the majority of ISO resources in 2025 and beyond due to their breadth, plus staffing challenges
  - Upfront agreement on priority work, including NEPOOL and state priorities, are intended to keep listed projects and schedules on track
  - Increased or expanded stakeholder requests, regional policy interests, and new issues can affect project schedules of planned efforts
  - Unknown timing and topics of Federal Energy Regulatory Commission (FERC) actions (orders, notices of proposed rulemaking) and policy directives can shift priorities
  - Staffing losses, along with lengthy recruiting and training of replacements in light of the complexity of the system and projects, necessitates the ISO to focus resources
- Note that the AWP identifies key initiatives and not the full ISO workload; the ISO's annual budget incorporates the full volume of ISO work and resourcing, including initiatives in the AWP as well as:
  - Work on smaller projects or projects nearing completion
  - Work to implement projects already through design, stakeholder, and regulatory phases
  - Work representing the ISO's extensive day-to-day operations related to running the grid, markets, IT infrastructure, and its organization

ANCHOR PROJECTS

Enhancements for the Future Grid

Markets Anchor Project

Distinct, highly complex efforts are taking place spanning several years to reform the capacity auction

- **Capacity Auction Reforms (CAR)**: To ensure system reliability and cost-effectiveness as New England's electricity demand and power resource mix undergoes a significant transformation, CAR:
  - Transitions the capacity market from a three-year forward auction to a prompt auction that runs shortly before the capacity commitment period (CCP)
  - Restructures the CCP from annual to seasonal commitment periods
  - Reshapes capacity market accreditation methodologies to more accurately reflect resource adequacy contributions from an evolving resource mix, from season to season
- Design and implementation of the changes required to run the new capacity auction for a CCP that begins in 2028 (CCP 19) will span 2025-2027
  - The current Forward Capacity Market has secured capacity commitments through May 2028 (CCP 18)

Markets Anchor Project

Distinct, highly complex efforts are taking place spanning several years to reform the capacity auction

- CAR's three main reformations are made up of dozens of interconnected design and development projects, which could normally be their own anchor or notable initiative, that must be planned and coordinated in a synchronized manner
  - The next slide is a high-level list of items in scope, details of which are numerous and under discussion through the NEPOOL Markets Committee
  - To expeditiously facilitate benefits of CAR to the region and confidence to the marketplace for CCP 19, the ISO must prioritize the most critical design work necessary to execute a 2028 prompt auction with seasons and accreditation reforms
    - Once initial scoping discussions for CCP 19 are complete, the ISO expects stakeholder discussions on assessments and design to begin in early Q1 2025
    - The exact timing of when stakeholder discussions on each topic begin and how they span the next few years will be fluid initially but will solidify as the CAR assessment and design work unfolds
  - The ISO also plans to communicate with the NEPOOL Markets Committee in Q4 2024, its current thinking on further enhancements and conforming initiatives that may occur beyond the primary CAR scope, for future auctions; refinements and additional discussions are likely over time

Markets Anchor Project

Distinct, highly complex efforts are taking place spanning several years to reform the capacity auction

Current Items in Scope to Design and Implement for CCP 19

- Core prompt
  - Determine market timing, treatment of new resources, retirement process, pre- and post-auction activities schedule
- Core seasonal
  - Define seasons, schedule, seasonal demand curves, assess and update ‘annual’ features
- Core accreditation
  - Finalize accreditation framework and design, conform to prompt and seasonal
- Develop a market constraint to reflect limited gas availability (including treatment of firm gas contracts)
- Assess and establish offer price formation and mitigation
- Change auction format from descending clock to sealed bid
- Establish resource retirement process to take place in advance of the prompt timeframe
- Impact analysis
- Conforming update to existing Net CONE value
- Settlement design
- Update/replace existing data systems used to administer the capacity market
- Separate annual tie benefits into seasonal values; improve modeling inputs from other regions (broader framework changes for tie benefits are not in scope for CAR)
- Assess feasibility of designing either simultaneous or serial clearing for seasons
- Assess potential for further accreditation modeling enhancements per stakeholder request
- Continuing to assess for scope inclusion: Accounting for correlated outages and/or ambient temperatures in Resource Adequacy Assessment modeling

Treatment of Retained Resources in Capacity Market

- **NEPOOL Priority Request for the 2025 AWP**
  - *"NEPOOL recommends that a key priority item to be included within the 2025 Annual Work Plan focuses on the actions necessary to ensure that consideration of capacity market price formation issues around Reliability Must-Run (RMR) agreements and the participation treatment of retained resources be addressed in time for the initial launch of the capacity market reforms."*
- The ISO actively considered this request, along with its own expectations that implementation of the CAR elements on slide 7 would minimize the need to retain resources
- There are aspects of the underlying capacity pricing concerns identified by some market participants that need further assessment, but those assessments would not be part of the CAR scope for CCP 19, as explained on the next few slides
  - While the NEPOOL request did not specify what type of retained resources it was referencing, for completeness, the ISO looked at both the current and prior retention types (e.g. transmission security and energy security) in making its determination

Treatment of Retained Resources in Capacity Market, cont'd

- Under the ISO Tariff, resources can be retained only for a local transmission reliability issue, with those resources treated as price-takers in the associated capacity auction
- The ISO finds this pricing treatment is still appropriate and efficient under the current capacity paradigm for two reasons:
  – First, the price paid to the retained resource does not suppress the prices paid to other capacity resources that cannot provide the commensurate local reliability services (i.e., the transmission need); this is analogous to the capacity pricing treatment in an import-constrained zone (*see* the September 2024 Markets Committee meeting presentation and note further discussion at the upcoming October 2024 Markets Committee meeting)
  – Second, the quantity of retained capacity included as price-taking supply should be based on its expected performance during stressed system conditions, when it is contributing to meeting the region's resource adequacy needs

Treatment of Retained Resources in Capacity Market, cont'd

- In the context of CAR, the existing approach is consistent with the MRI-based accreditation framework that will be applied to all resources, and in doing so, only "counts" each retained resource's expected contributions as capacity supply in a manner similar to resources that sell capacity in the auction
  - This expected performance may be different (greater) than the performance necessary to narrowly satisfy the transmission security need
  - Conversely, not considering the resource's entire expected performance would lead to inefficient over-procurements-that ignore the expected contributions of the retained resource
- However, there are two areas the ISO agrees needs further assessment

Treatment of Retained Resources in Capacity Market, cont'd

1. Transmission Security RMR Treatment: CAR Considerations

- The current treatment is applicable to the annual market structure, but the outcomes may not be the same under a seasonal market design where resources may be evaluated based on different seasonal conditions
- The ISO has not yet constructed its seasonal design, and it remains committed and focused on completing that effort for CCP 19 as part of its core CAR scope
- However, after that foundational part of the initial design and filing is completed around the end of 2026, the ISO will begin to assess and discuss how reliability reviews will conform to the seasonal commitment periods, including any potential pricing implications
  - At this time, the ISO may have more information on actual CCP 19 retirements (depending on the prompt notification design)

Treatment of Retained Resources in Capacity Market, cont'd

2. Energy Security RMR Treatment

- While NEPOOL did not highlight the provisions for RMR agreements for energy security, those retentions and their associated pricing treatment may not be fully analogous to the existing transmission security treatment
  - For energy security retentions, the reliability need that triggers the retention is likely broader and met by many resources that may not be paid comparably to the retained resources
- The ISO does not plan to resurrect the retention provisions; however, if it found itself in a future situation where it needed to again consider retaining resources for energy security, it commits to simultaneously assessing and including a different capacity pricing mechanism for stakeholder consideration
  - As noted on the previous slide, once the CAR design is filed with FERC, the ISO may have more information on CCP 19 retirements that could guide the need for and timing of an assessment and stakeholder discussion
  - PEAT/REST assessments (next slide) may also inform this space
  - The ISO's reflection on this item should not be construed as a signal of the need for any energy security retentions

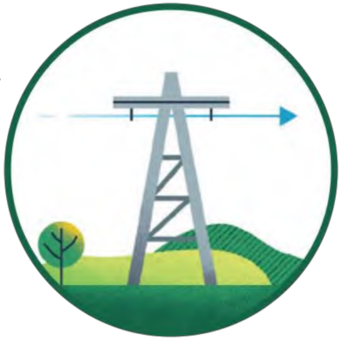
Operations Anchor Project

Identifying and addressing reliability risks from extreme weather events as grid supply and demand transform

- Regional Energy Shortfall Threshold (REST)
  - The ISO is currently discussing with stakeholders updates to the Probabilistic Energy Adequacy Tool (PEAT) and expects the model to be fully operational by the end of 2024
  - Beginning in Q4 2024 and extending into Q1/Q2 2025, the ISO will discuss with stakeholders its REST proposal for establishing an acceptable threshold of energy shortfall risk (i.e., the region's risk tolerance) during low-probability extreme weather events as identified through the PEAT
    - The ISO will gather feedback and seek state and industry agreement on the proposal
  - The ISO plans to begin performing PEAT/REST assessments seasonally, starting with winter 2025/2026
    - Following, annual assessments with longer look-ahead horizons (to be defined) will be considered to inform risk trends over time
  - Results of the first assessment will provide more data on the risk trends to guide the timing and nature of the next phase, which is to evaluate whether the possibility of exceeding the REST requires development of specific regional solutions to mitigate risks
    - Possible solutions could range from market designs to infrastructure investments to dynamic retail pricing and responsiveness by end-use consumers

Planning Anchor & Implementation Projects

Continued longer-term transmission planning and generator interconnection compliance, implementations, and enhancements



- **FERC Order No. 1920: Building for the Future Through Electric Regional Transmission Planning and Cost Allocation**
  - The ISO is assessing the assimilation of the extensive Final Rule with New England's innovative Longer-Term Transmission Planning (LTTP) framework accepted by FERC in July 2024, which went far in complying with the order but with differences
  - Those stakeholder discussions are expected to begin in late Q3 2024; discussions on compliance with the Final Rule will follow and continue into Q3 2025
    - Regional compliance must be filed June 2025, effective June 2026
    - Interregional Transmission Coordination compliance is due August 2025, effective August 2026

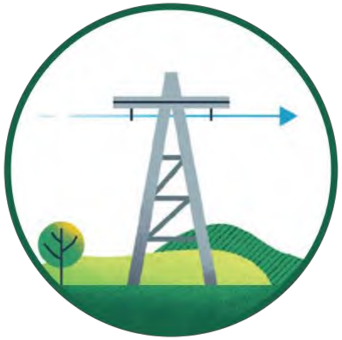
Planning Anchor & Implementation Projects

Continued longer-term transmission planning and generator interconnection compliance, implementations, and enhancements

- **LTTP Phase 3**
  - A NEPOOL Priority request for the 2025 AWP is for the ISO to assess new types of benefits and selection criteria to include in the LTTP framework
  - After Order No. 1920 compliance is accepted by FERC and experience has been gained from completing the first competitive solicitation for an LTTP solution, the ISO plans to begin discussions on the potential for further enhancements to LTTP
    - To the extent the ISO is able to initiate these discussions in 2025, it will endeavor to do so
- **First Competitive Solicitation for LTTP Solution**
  - In 2025, the ISO expects to implement an RFP process in anticipation of a request from the states for a competitively-selected transmission solution to address the future, clean energy needs in connection with the 2050 Transmission Study (the first Longer-Term Transmission Study under the new LTTP framework)
  - The RFP process, from initiation through final recommendation, is expected to take approximately 18 months to complete

Planning Anchor & Implementation Projects

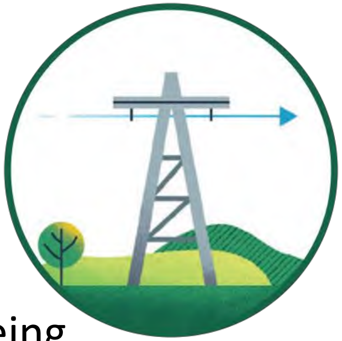
Continued longer-term transmission planning and generator interconnection compliance, implementations, and enhancements



- **Transmission Sizing for the Clean Energy Transition**
  - The ISO, the New England states, and NEPOOL stakeholders seek to develop an approach to sizing transmission projects for the future to support integration of renewables and higher load levels over the life of the transmission asset
  - As indicated in the 2024 AWP, the ISO plans to work with NESCOE and Transmission Owners to establish guidelines for “right-sizing” transmission facilities for the clean-energy transition; guidelines would be applicable to asset condition projects and potentially to transmission developed through other upgrade processes
    - Discussions would address NEPOOL’s priority request for the 2025 AWP to develop methods for distinguishing right-sizing costs from asset condition project costs so that they can be evaluated accordingly
  - Timing on right-sizing discussions are anticipated to move forward after the states and TOs complete their asset condition process improvements initiative

Planning Anchor & Implementation Projects

Continued longer-term transmission planning and generator interconnection compliance, implementations, and enhancements



- **Further Inclusion of Grid Enhancing Technologies (GETs) Into Transmission Planning**
  - This NEPOOL and NESCOE Priority request for the 2025 AWP is being addressed in two parts
  - Order No. 1920 requires the ISO to include rules in the Tariff for when transmission planning assessments must consider Grid Enhancing Technologies (i.e., “when to consider GETs”), which will be included in the ISO’s compliance discussions
    - Consideration of GETs in interconnection assessments is already incorporated in the ISO’s Tariff as part of its Order No. 2023 proposal pending at FERC
  - Separately, stakeholder discussions at the Planning Advisory Committee are expected to begin in Q4 2024 and continue into 2025 on establishing guidelines for the applicability of these technologies in assessments (i.e., “how to apply GETs”)
    - These discussions will commence with a review of how GETs are currently considered in assessments, defining a problem statement that the GETs are intended to solve, determining the benefits of GETs over other technologies, and identifying limitations, risks, and costs

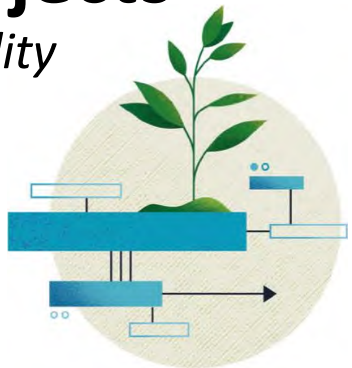
Planning Anchor & Implementation Projects

Continued longer-term transmission planning and generator interconnection compliance, implementations, and enhancements

- **Further Implementation of Order No. 2023 and Interconnection Process Improvements**
  - The complete restructuring of the ISO's generation interconnection study process as mandated by the Final Rule is an intensive multi-year effort by the ISO and New England stakeholders
  - Implementation of the transitional and initial cluster studies as mandated by Order No. 2023 is paused pending a FERC order on the ISO's compliance filing; work is expected to continue through 2025
    - Timing of ongoing stakeholder discussions of conforming changes to planning procedures and other documents will be reassessed once an order has been received and the ISO has assessed the resulting Tariff rules for necessary updates
  - Development work for adding capacity injection capability to the heatmap as required by Order No. 2023 is targeted to be in place before the initial cluster study begins (originally in Q4 2025)
    - Subsequently, per stakeholder request, ISO expects to begin evaluation of additional heatmap functionality, such as energy injection capability

Technology Anchor/Implementation Projects

IT development and implementation of critical market and reliability initiatives to manage an exponentially complex future grid



- **Implementation of Critical Market and Reliability Initiatives**
  - The ISO is developing the software and systems changes needed to implement a number of critical initiatives, of which the most substantial efforts include the following (see slide 29 for others):
    - Day-Ahead Ancillary Services Initiative (Q2 2025)
    - Order 881: Ambient Adjusted Line Ratings for Transmission Lines (Q2 2025)
- **nGEM Real-Time Market Clearing Engine**
  - The ISO has been working to replace its 20+ year old Market Management System (MMS) with the next Generation Electricity Management (nGEM) platform that is foundational to supporting a system with a growing number and type of grid assets, new and more complex market features, multiplying security threats, and advancing IT technologies
    - The day-ahead version of the new market clearing engine (MCE) software and infrastructure is completed
  - Work on the complex processes for customizing and implementing the real-time MCE software and infrastructure will take place throughout 2025, with implementation targeted for Q2 2026; additional phases of nGEM development and implementation are expected through 2028

NOTABLE INITIATIVES

Other Key Initiatives Identified for 2025

Notable Markets Initiative

Improving market signals and incentives for a reliable future grid

- **Flexible Response Services (FRS)**
  - The ISO has been evaluating the system's needs for flexible response capabilities to address greater operational uncertainties with an increasingly weather-dependent resource mix; this evaluation will consider new products in the day-ahead and real-time markets as potential market-based solutions to these flexibility needs
  - The ISO will communicate to stakeholders its findings and next steps in Q1 2025; stakeholder discussions on the design are targeted to begin in Q4 2025
    - Timing is dependent on the availability of workforce resources, which may be affected by ongoing hiring constraints and staffing needed to advance the CAR initiative

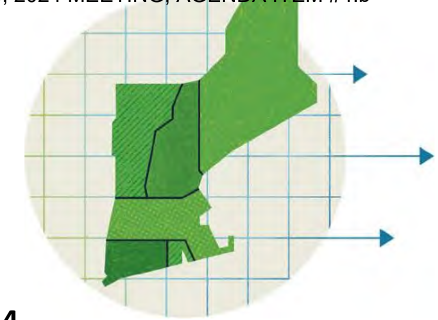
Notable Operations Initiative

Confirming shorter-term energy adequacy

- **Discussion on the Inventoried Energy Program (IEP)**
  - In Q1 2025, the ISO plans to discuss with stakeholders:
    - A review of the data and performance of the IEP program over the past winter
    - Its operational readiness plans for winter 2025/2026
    - And in response to stakeholder requests for updates, the ISO will share its perspectives on whether or not to continue an IEP for winters 2025/2026 until 2028/2029 (winters before DASI, CAR, Flexible Response Services, and possible REST solutions if needed are in effect)
  - If needed, in Q2 2025, the ISO will discuss with stakeholders an update to IEP for the applicable winters and file with FERC

Notable Planning Initiatives

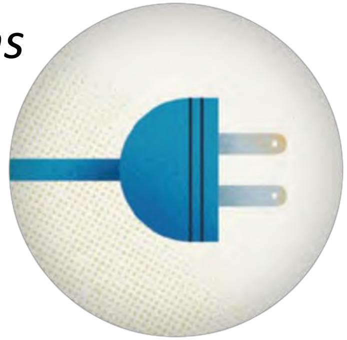
Assessments related to interconnection with neighbors



- **Evaluate Single Source Contingency Limit Increase**
  - With stakeholder agreement, the ISO initiated a study in 2024 with PJM and NYISO to determine whether a MW value higher than the 1,200 MW single source contingency (loss of source) limit could be supported by the current transmission system, and what potential ISO-NE/NYISO/PJM upgrades, including estimated cost, would be necessary to support that increase in the limit
  - The ISO anticipates the study will conclude in Q3 2025, at which time it will present the results to stakeholders; moving forward with upgrades or action items identified from the study would be separately-scoped, subsequent initiatives
- **Evaluate Tie Benefits Winter Modeling Improvements**
  - In 2023 and 2024, as requested by NEPOOL, the ISO conducted and reported on a broad evaluation of tie benefits by reviewing the modeling methodology, evaluating historical performance, and reviewing its neighbors' future plans
  - In Q4 2024 and into 2025, the ISO will continue to reach out to neighboring control areas to further modeling improvements, with a focus on refining winter inputs that could be reflected in the tie benefits calculations, reporting back to stakeholders

Notable Technology & Security Initiatives

Implementing sophisticated technologies and security applications to support the clean-energy transition and mitigate risks

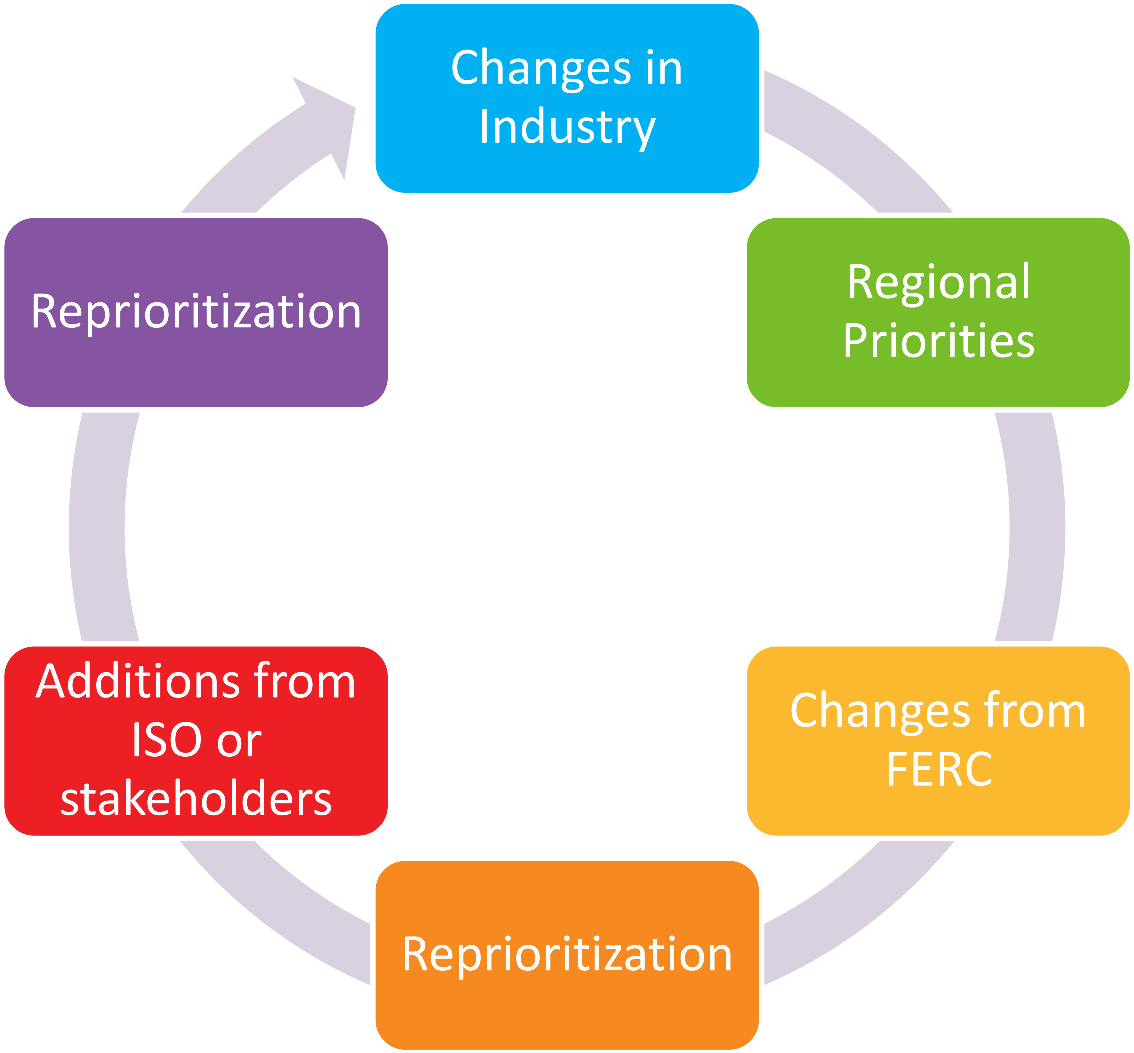


- **Inverter-Based Resource (IBR) Integration & Modeling:** In 2025, the ISO will be developing long-term solutions for an electromagnetic transient (EMT) model management process and model repository, and expanding study capability via hardware optimization, licensing increases, staff training
- **Synchrophasor Enhancements for Future Grid:** By Q4 2025, the ISO expects to implement synchrophasor infrastructure and process improvements to better monitor the performance and dynamic behaviors of IBRs and distributed energy resources during system events in real-time, which includes enhancing and integrating the Oscillation Source Location (OSL) tool and Phasor Measurement Unit situational awareness displays
- **Integrated Market Simulator (IMS)**: In 2025, in addition to enhancing the functionality of the IMS, the ISO will integrate DASI into the IMS baseline mode; IMS is used to study impacts of new energy market designs/initiatives and also for market monitoring
- **Cloud Computing:** The ISO's transition to a cloud environment continues to be a major effort over the next several years to reduce reliance on energy-heavy data centers, make system deployment more efficient as resource numbers increase, and enable faster computing performance as resource data grows
- **Cyber Security:** The ISO has made significant cyber security investments to date and over the next several years will continue to invest in improved monitoring, detection, and recovery tools to keep pace with increasingly sophisticated attack threats

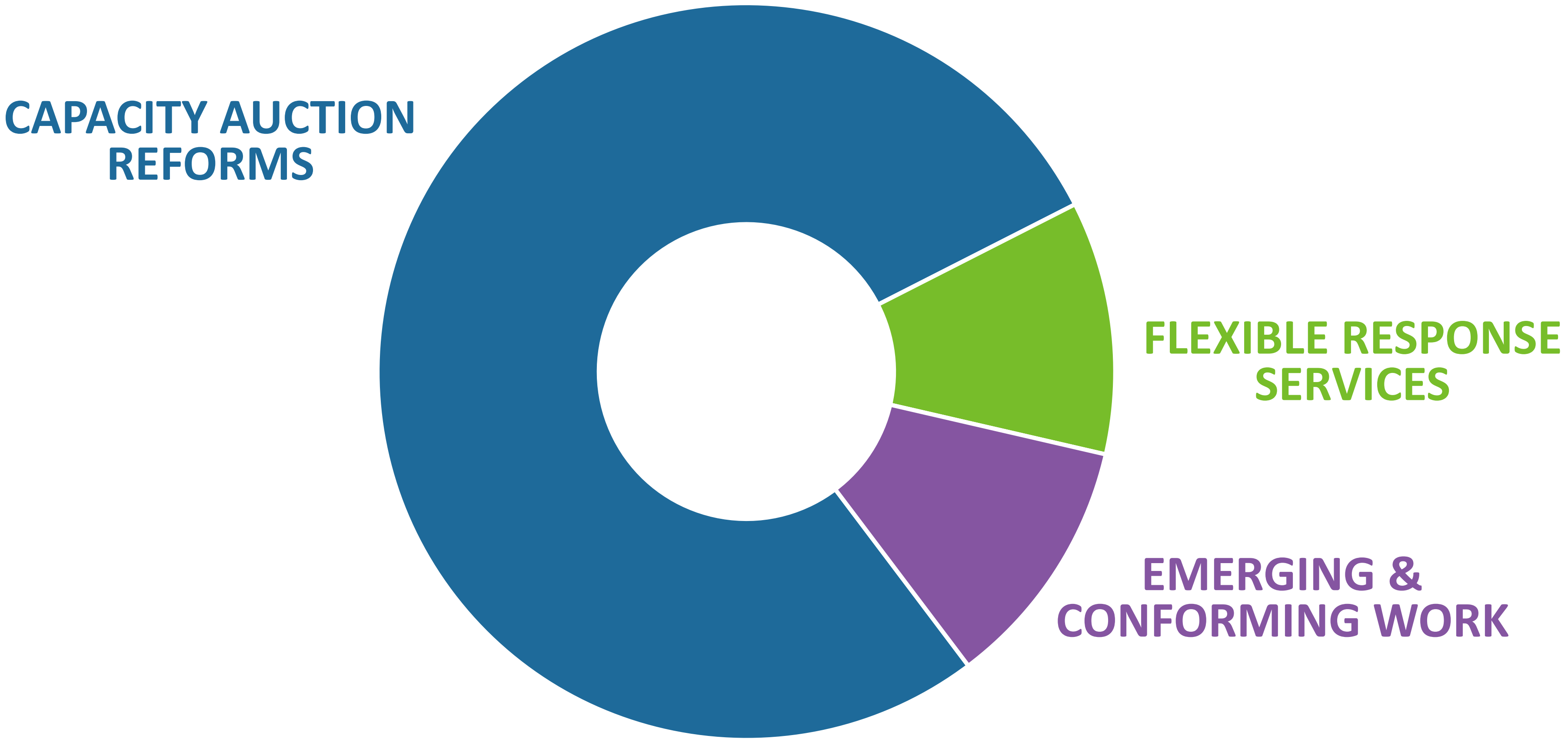
WORK PLAN PRIORITIZATION

Prioritization Process

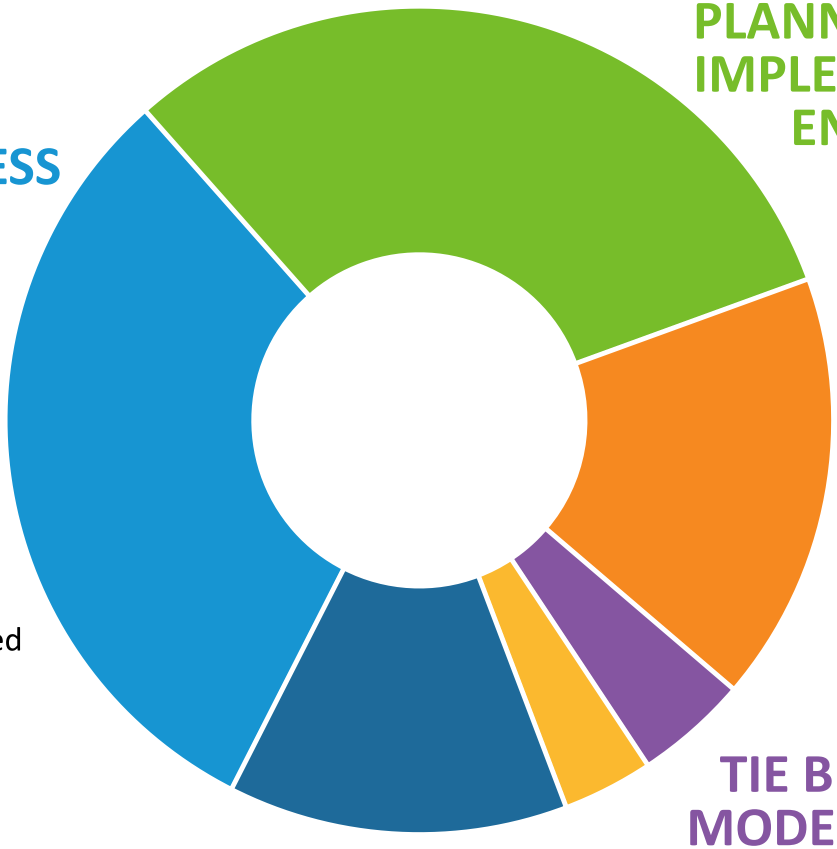
- The ISO adjusts its priorities as needed to best maintain reliable operations, robustly plan for a changing grid, and ensure competitive wholesale markets
- Planned projects are impacted as scopes shift or new projects emerge



Markets-Related Priorities Include:



Planning/Operations Priorities Include:



OTHER PLANNING INITIATIVES & CONTINUING BUSINESS

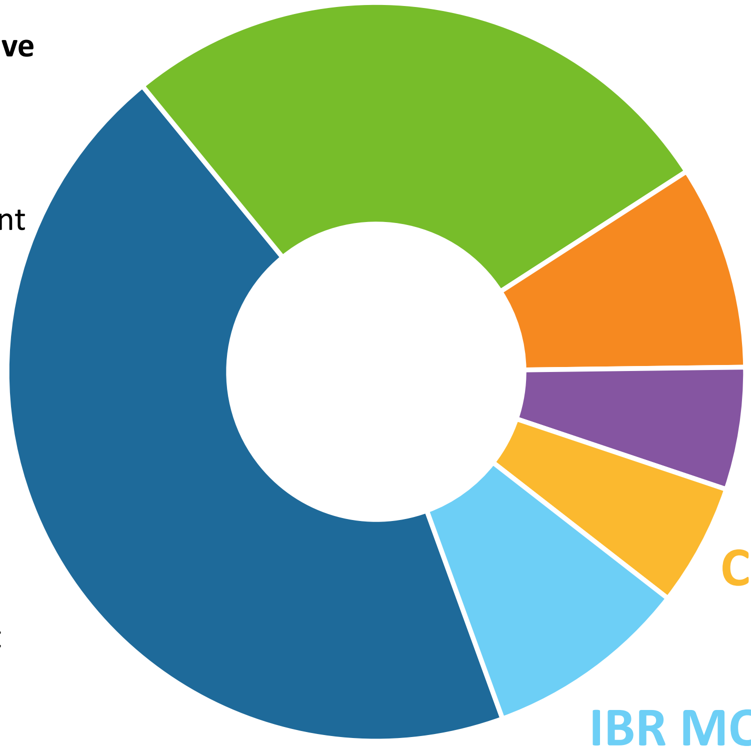
- Technical support to states for DOE RFPs re transmission planning for offshore wind
- Annual Economic Study and process improvements
- Long-term load forecast methodology improvements for CELT 2025 forecast cycle to forecast net of EE load directly
- Developing modeling assumptions for legacy distributed energy resources
- Update of Planning Procedure 4 re: recovery of community benefits agreement costs

Capital Project Priorities Include:

SOFTWARE AND SYSTEMS IMPLEMENTATIONS

- **Day-Ahead Ancillary Services Initiative (March 2025 implementation)**
- **Order 881: Ambient Adjusted Line Ratings (July 2025 implementation)**
- MW Dependent Fuel Price Adjustment (Dynegy Compliance) (Nov. 2025 implementation)
- NECEC External Interface (Dec. 2025 implementation)
- Order 841: Electric Storage Participation in Markets (Jan. 2026 implementation)
- Order No. 2222 (Nov. 2026 implementation)
- Storage as a Transmission-Only Asset (March 2027 implementation)
- Enterprise Software Upgrades

nGEM RT MARKET CLEARING ENGINE



INFRASTRUCTURE ENHANCEMENTS

- Network Modeling Tool Enhancements
- Enterprise Core Network Refresh
- Short-Term Load Forecast Replacement
- Energy Management Platform 3.5 Upgrade
- CAMS Application Software Technology Upgrade

CYBER SECURITY

CLOUD COMPUTING

IBR MODELING/INTEGRATION, SYNCHROPHASOR ENHANCEMENTS, IMS

2025 AWP	Q1	Q2	Q3	Q4
Markets Related	Capacity Auction Reforms			
				FRS
Operations & Planning	Regional Energy Shortfall Threshold			
	FERC Order No. 1920 Compliance, LTTP Phase 3			
	FERC Order No. 2023 Continued Compliance and Implementation			
	First Competitive Solicitation for LTTP Solution			
		Transmission Sizing for the Clean Energy Transition		
	Further Inclusion of GETs Into Transmission Planning			
	Tie Benefits Winter Modeling Evaluation			
			Single Source Contingency Limit Assessment	
	IEP Discussion			
Capital Priorities	Implementation of Critical Market and Reliability Initiatives			
	nGEM Market Clearing Engine			
	Inverter-Based Resource Modeling, Synchrophasor Enhancements, IMS			
	Cloud Computing & Cyber Security			

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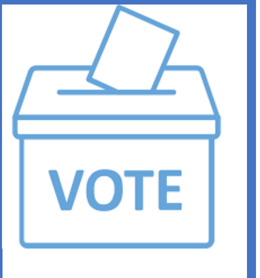
2025 ISO Budgets



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To consider, and take action, as appropriate, on the 2025 ISO Operating and Capital Budgets as presented at this meeting.

RESOLVED, that the Participants Committee supports the Year 2025 operating budget and capital budget proposed by the ISO, as presented at this meeting.

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Rosendo Garza and Pat Gerity, NEPOOL Counsel

DATE: October 3, 2024

RE: 2025 ISO Budgets and 2025 NESCOE Budget

At its October 10, 2024 meeting, the Participants Committee (NPC) will be asked to vote on the ISO's proposed 2025 operating and capital budgets (collectively, the ISO Budgets) and NESCOE's 2025 operating budget (NESCOE Budget). Background materials are included with this memorandum and posted with the meeting's composite materials.

<u>2025 ISO Budgets</u>

The 2025 ISO Budgets were prepared according to the processes included in the Participants Agreement and Settlement Agreement with state agencies in FERC Dockets Nos. ER13-185 and ER13-192. The ISO presented its preliminary budgets to the New England state agencies and attorneys general (States) on June 10, 2024, and to the NPC at its June 25 Summer Meeting. On August 9, the ISO presented the ISO Budgets to the Budget & Finance Subcommittee (B&F) and, on the same day but at a separate meeting, to the States. At the September 5 NPC meeting, Mr. Robert Ludlow, the ISO's Chief Financial and Compliance Officer, provided an overview of, and offered to answer any questions concerning, the ISO Budgets (Sep NPC Presentation). Certain New England state regulators and consumer advocates separately presented questions and comments regarding the ISO Budgets, to which the ISO responded (States Q&As). We have included with this memorandum a memo from Mr. Ludlow providing additional information regarding changes, made since the September 5 NPC meeting, to the ISO Budgets and the Sep NPC Presentation, the updated Sep NPC Presentation, a copy of the ISO's September 23 memorandum regarding its projected costs and allocation among the schedules to the ISO's "Self Funding Tariff" (Tariff Section IV.A),[1] and a copy of the States Q&As.

The 2025 ISO-NE operating budget, prior to true-ups, reflects a 10.7 percent increase over the 2024 operating budget. After accounting for the true-up mechanism in the ISO-NE Tariff, the revenue requirement to fund the 2025 operating budget (i.e., the amount collected under the ISO-NE administrative costs tariff) will increase by 13.6 percent over the amount projected to be collected in 2024. The ISO-NE capital budget for 2025 is $42.5 million. This reflects a $7.5 million increase over the amount of the 2024 capital budget.

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[1] The September 23 memorandum, circulated by the ISO directly to NPC members and alternates and B&F members, addresses the ISO's Projected 2025 Revenue Requirement, including the final true-up for 2023 and a comparison to the 2024 Revenue Requirement, a Draft 2025 Revenue Requirement by activity, and Draft 2025 Rate Components.

The following form of resolution can be used by the NPC for action on the 2025 ISO Budgets:

> RESOLVED, that the Participants Committee supports the Year 2025 operating budget and capital budget proposed by the ISO, as presented at this meeting.

<u>NESCOE 2025 Budget</u>

Ms. Heather Hunt, NESCOE's Executive Director, joined B&F's August 9 meeting and reviewed NESCOE's expected 2025 budget, estimated to be approximately $2.7 million. NESCOE's August 9 B&F presentation was included with the materials for the September 5 Participants Committee meeting. A revised NESCOE 2025 budget presentation, updated to reflect the actual (rather than an estimated) 2025 Schedule 5 Rate, calculated by the ISO to be $0.00716 per kW-mo., is also included and posted with this memorandum. The revised presentation is identical to the August 9 NESCOE presentation, with only slide #12 updated and marked to reflect the final 2025 Network Load factor and final Schedule 5 Rate.

The Participants Committee may use the following form of resolution in its consideration of the proposed 2025 NESCOE Budget:

> RESOLVED, that the Participants Committee supports the Year 2025 NESCOE budget, as presented at this meeting.

memo

To: NEPOOL Participants Committee

From: Robert C. Ludlow, VP & CFO

Date: October 2, 2024

Subject: ISO New England's 2025 Proposed Operating and Capital Budgets

This 2025 operating and capital budgets (the "Budgets") update is intended to provide the NEPOOL Participants Committee with information regarding the changes that have been made to the ISO's 2025 proposed Budgets since the last review of the Budgets at the September 5, 2024 NEPOOL Participants Committee ("NPC") meeting.

Summary of Changes

The 2025 operating budget has not changed from what was presented at the September NPC meeting. In summary, the 2025 operating budget, excluding the true-up, is an increase of 10.7% or $29.5M as compared to the 2024 operating budget. The 2025 operating budget, including the true-up, results in a 13.6% increase to the Revenue Requirement compared to 2024. The budget presentation has been updated to reflect, among other things, that the Compensation and Human Resources Committee of ISO New England's Board of Directors approved budgeted merit and promotional/equity increase amounts of 4.0% and 2.0%, respectively. The budget presentation also reflects changes requested at the August 9, 2024 NEPOOL Budget & Finance meeting to differentiate employee headcount (FTE) amounts for the Market Development & Settlements areas.

The 2025 capital budget amount has not changed, remaining at $42.5M. However, there are changes to the capital projects plan which include the addition of a project for 2025; updates for three recently chartered projects; and updates for certain projects' overall budget, allocation between years, or the estimated go-live date. Specifically, the added project is the Tie Line Telemetry and PCEC Upgrade project (chartered project carrying over from 2024). Changes in the 2025 budget for projects that have been recently chartered include: CAMS Application Software Technology Upgrade, New England Clean Energy Connect, and Microsoft 365 Service Adoption[1]. Projects previously included in the capital budget, for which changes have been made include: nGEM Real-Time MCE Implementation, nGEM Software Development Part III, Managing Transmission Line Ratings, Network Modeling Tool Enhancements, CIP Electronic Security Perimeter Redesign Phase II, and EMS Short-term Load Forecast Replacement.

Materials

The August 9, 2024 budget presentation (the "Budget Presentation") presented to the NEPOOL Budget and Finance Subcommittee has been updated to reflect the changes described above. The updated

[1] The 2025 allocation and overall project budget for the Microsoft 365 Service Adoption project has been reduced significantly from previous amounts presented for this project. Upon project chartering the decision was made to complete portions of the work in a future phase that resulted in this change.

Budget Presentation can be found at the following link: [6-isone-2025-proposed-op-cap-budget-update-10-01-24.pdf (iso-ne.com)]

The 2025 state agencies' written comments and the accompanying responses can be found at the following link: 6_states_2025_budget_comments_isone_response.pdf (iso-ne.com)

Budget Presentation Slide Changes

The following pages have been updated in the Budget Presentation for the changes noted.

Operating Budget Slide page changes:

- To reflect updated compensation documentation and Board process: 55, 106, 109, 110, 118
- To differentiate amounts between Market Development & Settlements: 64, 67, 135 136, 137

Capital Budget Slide page changes:[2]

- Description of additional project noted above: 174
- Other capital budget changes including capital project budget adjustments: 82, 83, 84, 85, 164, 165, 166, 167, 169, 170, 171, 173, 174, 175, 176, 192, 194

Please let me know if you have any questions in advance of our meeting. I look forward to our discussion.

[2] The *order* of the Capital Budget slides containing project descriptions, on slides 165-191 of the updated budget presentation, has changed from the original presentation because of the insertion of the newly chartered projects and changes to the budgeted amounts as noted above.

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Updated 10/01/2024

ISO New England Proposed 2025 Operating and Capital Budgets

NEPOOL Budget & Finance Subcommittee Meeting

Robert Ludlow
CHIEF FINANCIAL OFFICER | ISO NEW ENGLAND

Contents of Presentation

The Presentation Includes:

Contents of Presentation *(cont.)*

The following appendices are also included for reference:

EXECUTIVE SUMMARY

Executive Summary

- The 2025 budget represents the organization’s commitment to supporting the region as it transitions to clean energy and ensuring that its continued operations are efficient and reliable
- Public impetus around addressing climate change through clean energy investments and electrifying transportation and heating sectors is driving substantial changes to the New England power system:
  - Increases to the number of interconnected and behind-the-meter (BTM) generating assets are changing how the transmission and distribution system operate and interact with each other
  - A shift from larger, dispatchable resources to smaller non-dispatchable, weather-dependent ones is changing the complexity involved in dispatching resources to meet demand
  - New daily and seasonal demand patterns are changing the types and timing of such needs
- The changes to the grid represent a step-up in system complexity that the ISO began to address in 2024 and will continue ramping-up in 2025 and throughout the remainder of the decade
  - This step-up in complexity represents a considerable increase to ISO workload

Executive Summary *(cont.)*

- In order to carry out ISO-NE's mission of planning the transmission system, administering the region's wholesale markets, and operating the power system to ensure reliable and competitively priced wholesale electricity, it is necessary to develop new capabilities for supporting the grid of the future
  - As indicated during last year's budgeting process, after years of keeping headcount flat or with minimal additions, the organization has seen the need to continue increasing headcount in order to meet the complexities of the clean energy transition; this is in line with hiring trends observed across other ISOs
- The budget reflects additional investment in information technology (IT) needed to support operations given the changing resource mix, including: new technology, transition cost related to cloud-based infrastructure, and continued improvements to cyber security
- The budget addresses the inflationary and renewal costs for current IT infrastructure and licensing, labor, and professional fees as well as the year-over-year costs of continued operation

Executive Summary *(cont.)*

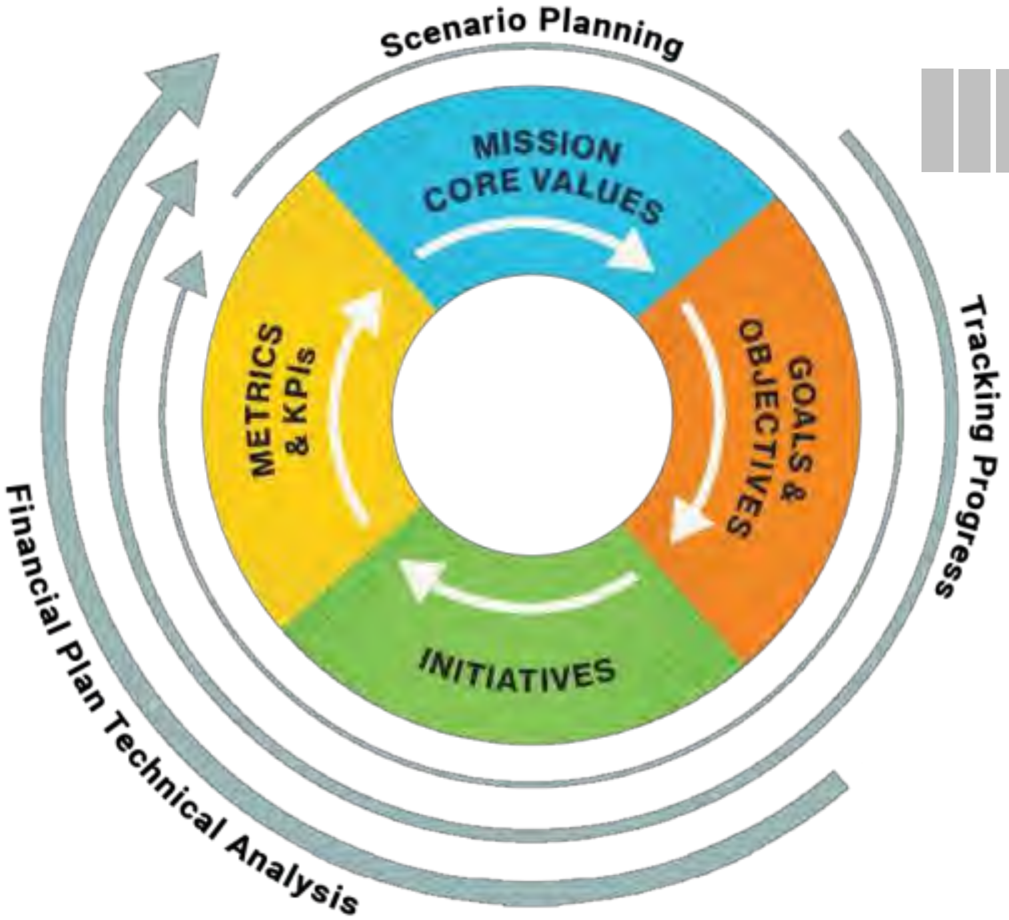
- For the 2025 budget, ISO is proposing adding 46 FTEs driven primarily by:
  - IT support to operationalize internally developed software for market simulation and situational awareness
  - Support the increasingly complex information to stakeholders and the public and to assist the growing and distributed workforce
  - Additions in System Planning for modeling, forecasting, longer-term transmission planning, and addressing current FERC orders;
    - This is the first iteration of a budget representing the need to scale up capabilities in these areas to support the Longer-Term Transmission Studies (LTTS) and necessary tariff changes, as well as the issuance of initiated transmission RFPs that require technical and economic analyses
    - There are still many unknowns, including the volume of RFPs to support and compliance with FERC transmission orders; it is our expectation that the resource requirements will be refined over time as we gain experience with the new processes

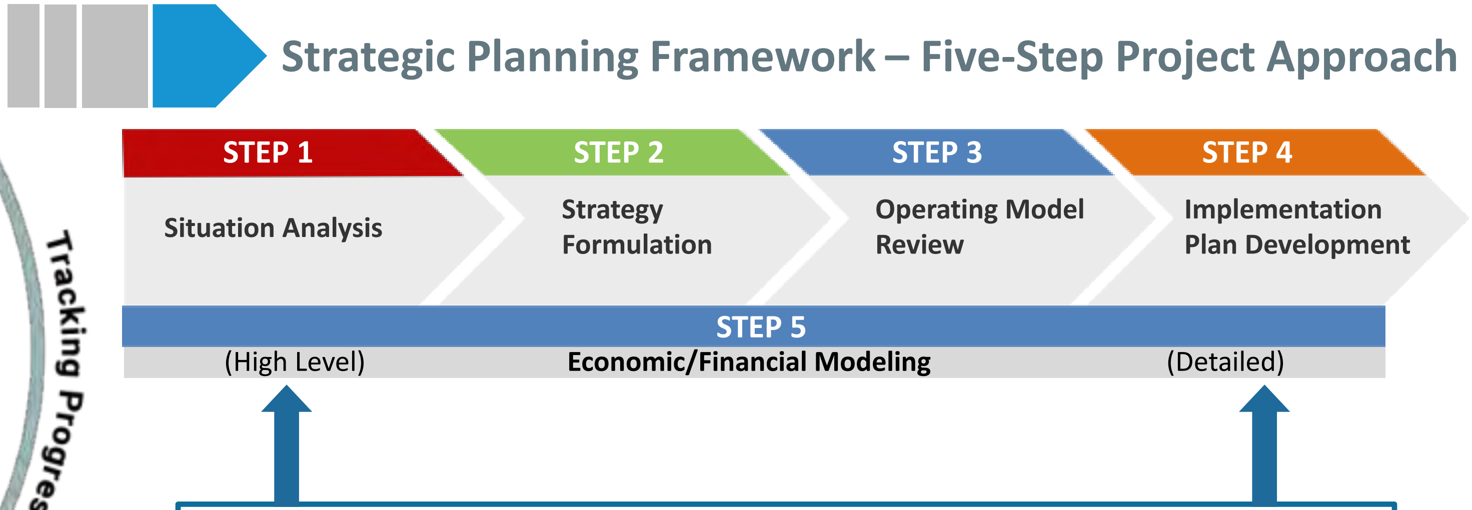
THE STRATEGIC PROCESS

ISO-NE's integrated business and strategic planning framework

Strategic Planning Framework

The 2025 ISO-NE budget represents the needs for the organization's strategy in supporting the region on its path to a decarbonized grid





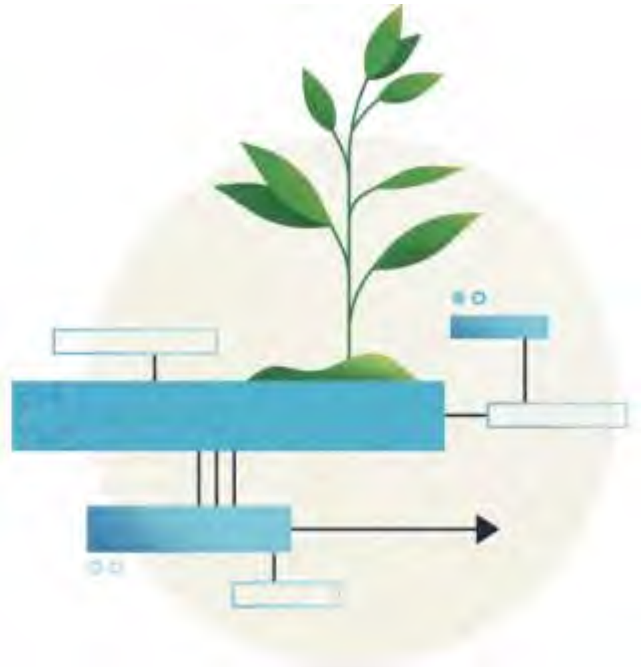
The 2025 budget responds to the emerging needs of the region in achieving their goals of decarbonizing the electric grid

Annual Process – Business and Strategic Planning

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

Our Guidepost: The ISO New England Vision Statement

The ISO-NE Vision Statement is an explicit statement about our intent to achieve a reliable transition to clean energy utilizing competitive markets and transmission planning



Vision Statement:

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

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

Our Responsibility to the Region: ISO's Mission

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

Mission Statement:

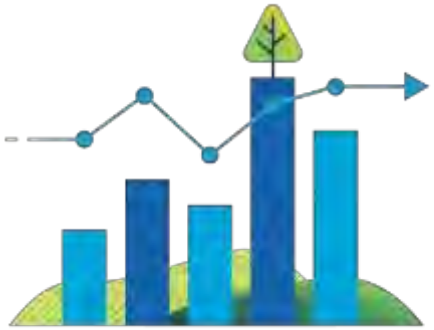
Through collaboration and innovation, ISO New England plans the transmission system, administers the region's wholesale markets, and operates the power system to ensure reliable and competitively priced wholesale electricity

Four Pillars of Supporting a Successful Energy Transition

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

1

Significant amounts of clean energy to power the economy with a greener grid

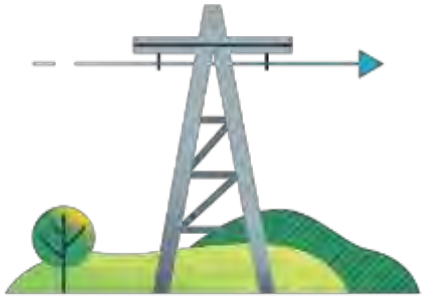


2

Balancing resources that keep electricity supply and demand in equilibrium

3

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



4

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

CLEAN ENERGY TRANSITION & 2040 OUTLOOK

The path to the 2040 (and beyond) decarbonized grid based on state policy goals and assumptions

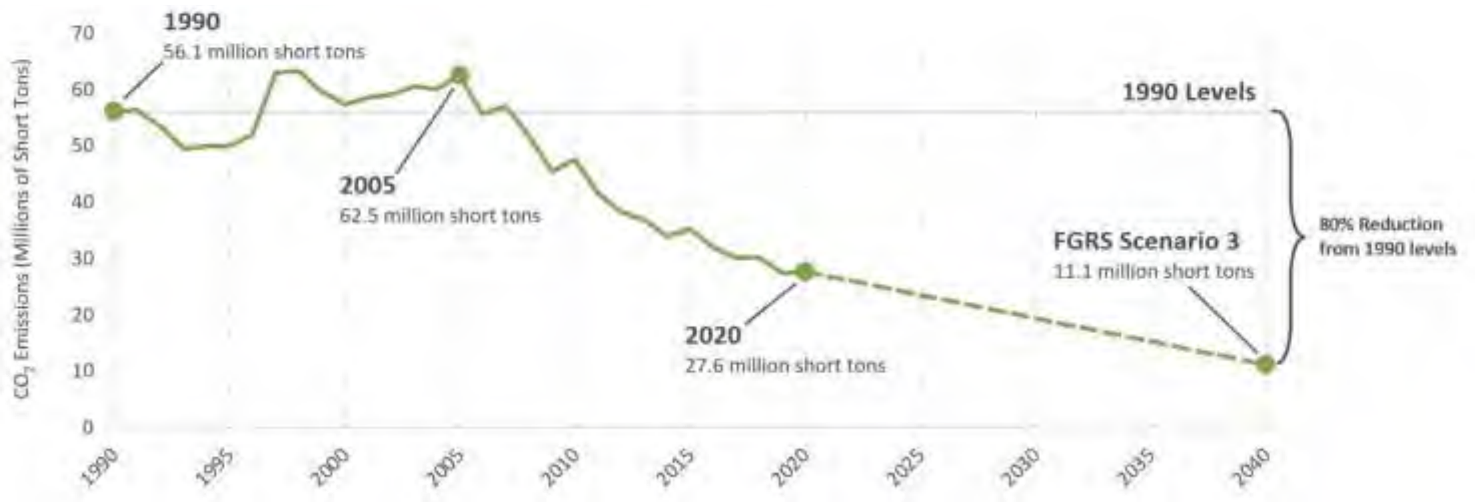
Overview of 2040 Outlook

- Renewables will continue to displace natural gas-fired resources over the next 20 years
  - A shift from centrally dispatched generation to distributed resources
  - A shift from conventional generation to weather-dependent renewable generation
  - Grid will primarily rely on a large number of non-dispatchable, weather-dependent generators, with smaller nameplate capacities
- Significant demand growth as system peak shifts to winter
  - During cold months the system will be at risk of insufficient fuel to support balancing resources (natural gas)
- Escalating variability in supply and demand
  - Most pathways to a low-carbon grid involve high variability in both supply and demand, which will result in either reliability challenges or higher costs
- By 2040, the region could experience consistent negative wholesale energy prices
- As outlined in the ISO-NE 2050 Transmission Study, of the estimated $25 billion needed for transmission upgrades by 2050, upwards of $13 billion will need to be in service by 2040; reducing peak load significantly reduces transmission costs

Emissions Reduction through Decarbonization of the Resource Fleet is the Catalyst for Change to the New England Grid

New England has seen progress in lowering emissions in 2021-2023, but 2024 emissions levels are up from the previous year, mainly due to increased demand

Historical and Extrapolated New England CO_2 Emissions

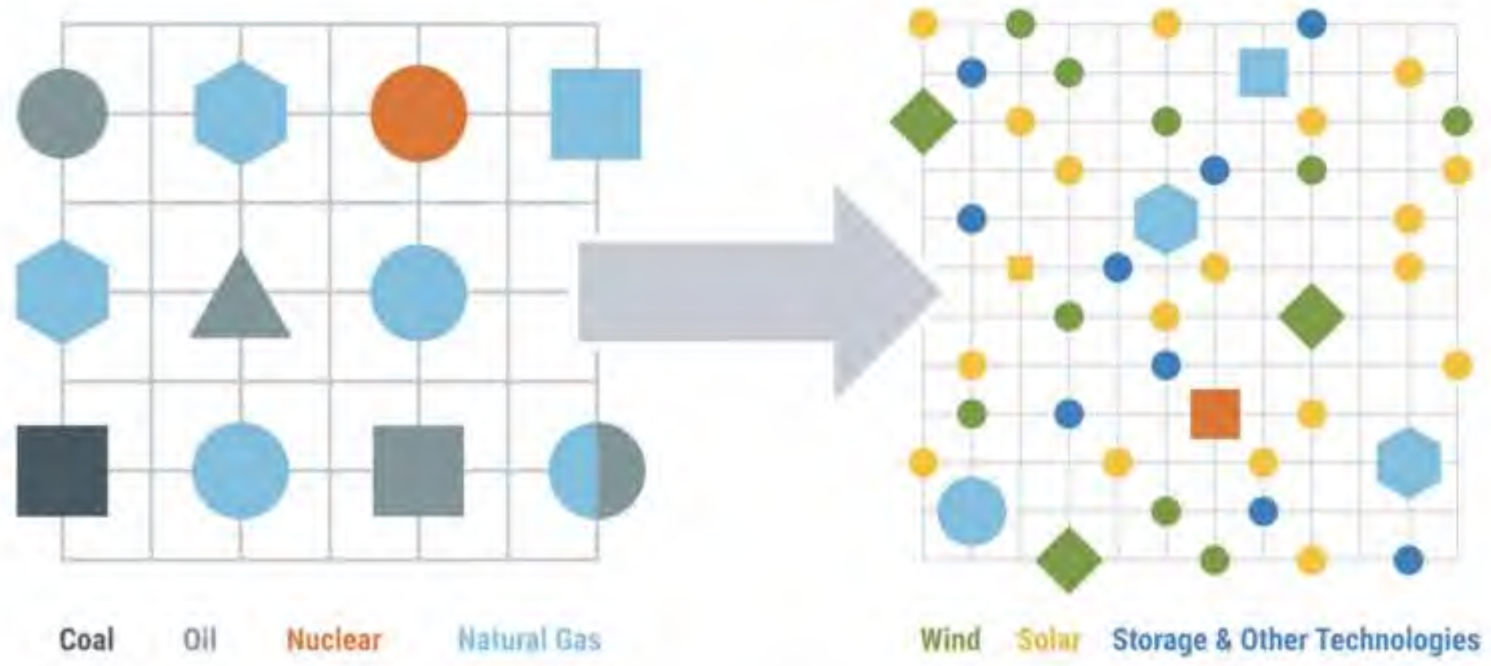


- State policies to address climate change through emissions reduction mandate an 80% reduction from 1990 levels
- These mandates will result in a drastically different generation profile for the region compared to today

Note: The dashed line between 2020 and 2040 illustrates the difference between the known emissions in 2020 and the simulated emissions in 2040 from FGRS Scenario 3. We are not predicting what the annual emissions levels or rate of reduction will be between those two years

- To illustrate the grid of 2040, we drew from the following scenario
  - **The Deep Decarbonization scenario** (Scenario 3 or S3) from the Future Grid Reliability Study – derived from the "All Options Pathway" of the Massachusetts 2050 Deep Decarbonization Roadmap Study outlining heavy renewable penetration and increased electrification loads

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



1 A shift from centrally dispatched generation to distributed resources

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

The 2040 Grid will Primarily Rely on a Large Number of Non-Dispatchable, Weather-Dependent Generators, With Smaller Nameplate Capacities

- **Potential for 1 Million+** non-dispatchable/weather-dependent generators
- **Addition of 17,000 MW** of offshore wind
- **Addition of 28,000 MW** of solar power
- **Nuclear resources clearing FCA** assumed to be staying online in 2040
- **0 GWh** of generation produced from coal, oil, or refuse burning generators
- **2 Additional Tie Lines** for imported electricity from Canada, New England Clean Energy Connect (NECEC), plus an additional new tie-line with Hydro Québec

Historical and Anticipated New Resource Capacity by Fuel Type, 1997 Baseline

Over the next 15 years, in order to meet electrification and clean energy requirements, the region will need to add almost double the amount of new generation as was added to the system in the last 25 years.

Well before the 2040 Outlook (Early 2030s), the ISO Expects to See Substantial Changes to the New England Power System

ISO needs to plan for a power system that by 2030 is projected to be very different than the grid of today:

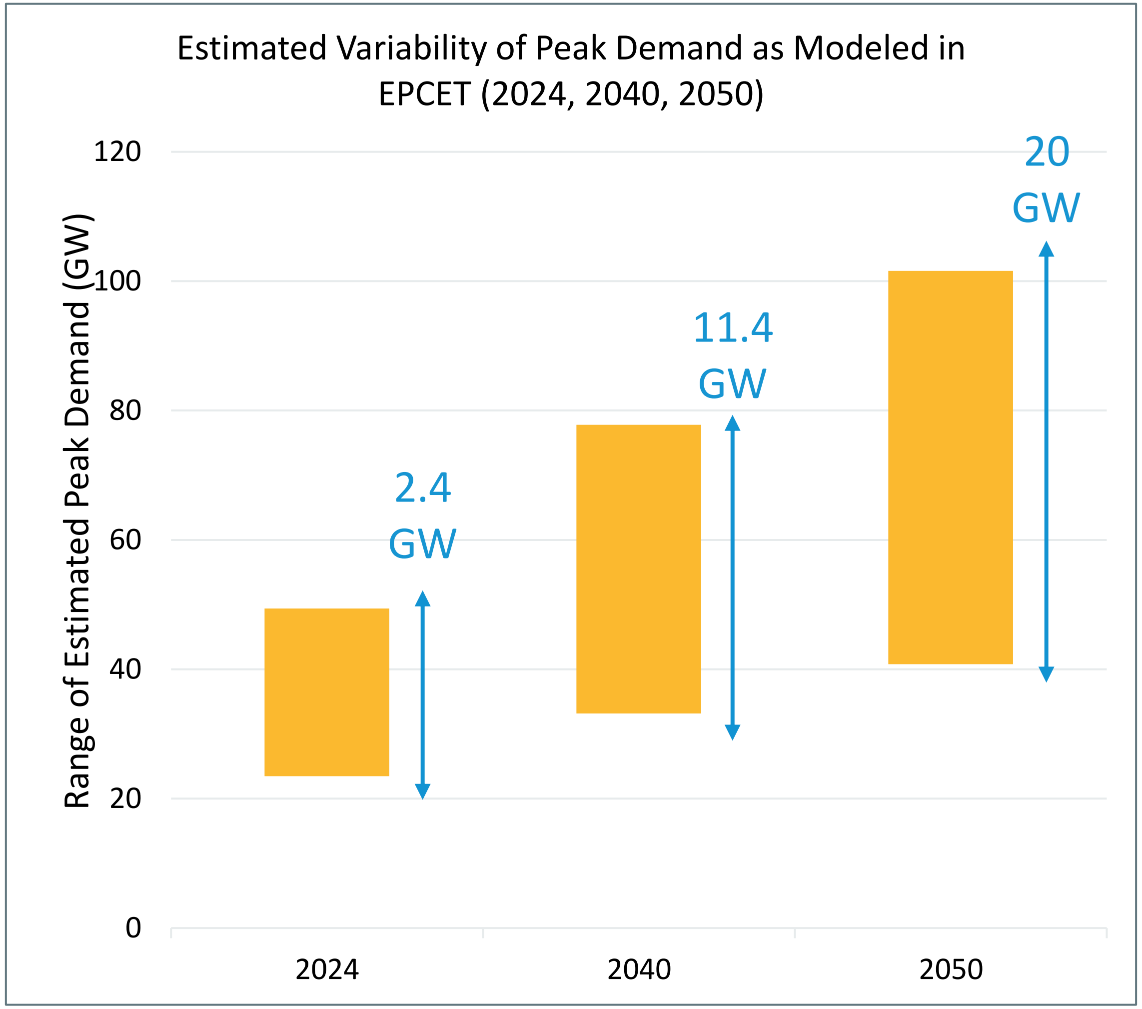
- **Double the installed capacity of solar resources**
- **Development of thousands of MW of offshore wind**
- **Substantial new transmission investment**
  - Supporting inter- and intra-regional transfers, upgrading condition of existing assets, and addressing increasing interaction between transmission and distribution system
- **Enhanced market structures** – accounting for resource mix with different operating characteristics
- **Decarbonization** will change the composition of the power system
  - Increasing numbers of inverter-based resources looking to connect to the New England grid
  - Additional resources are connecting to the distribution system, outside of the ISO's current visibility, that contribute to load variability and forecasting challenges
- **Changing load characteristics** will exacerbate operational complexity
  - Increased load anticipated through electrification of heating and transportation
  - Increased variability through proliferation of BTM generation
  - Increasing load-dependence on weather at a time when weather is becoming more erratic

To support these efforts, the ISO will engage in a slate of work in 2025 and beyond, that directly addresses these developments.

Escalating Variability in Supply and Demand

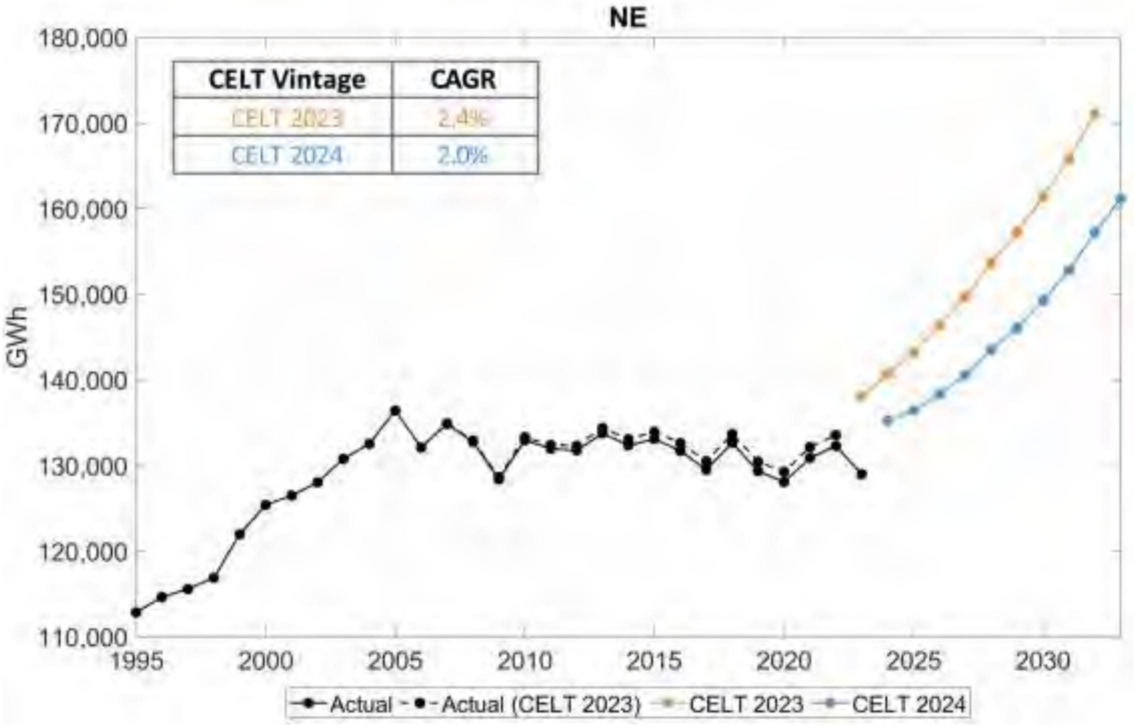
Most pathways to a low-carbon grid involve high variability in both supply and demand, which will result in either reliability challenges or higher costs

- Today's electrical grid experiences only small variations in peak annual demand between years, allowing for efficient planning for a limited number of possible outcomes
- The large variation in demand will require vastly different supply from year to year
  - Some years will require most or all resources to operate; other years, resources will run for just for a few hours of the year, or not at all



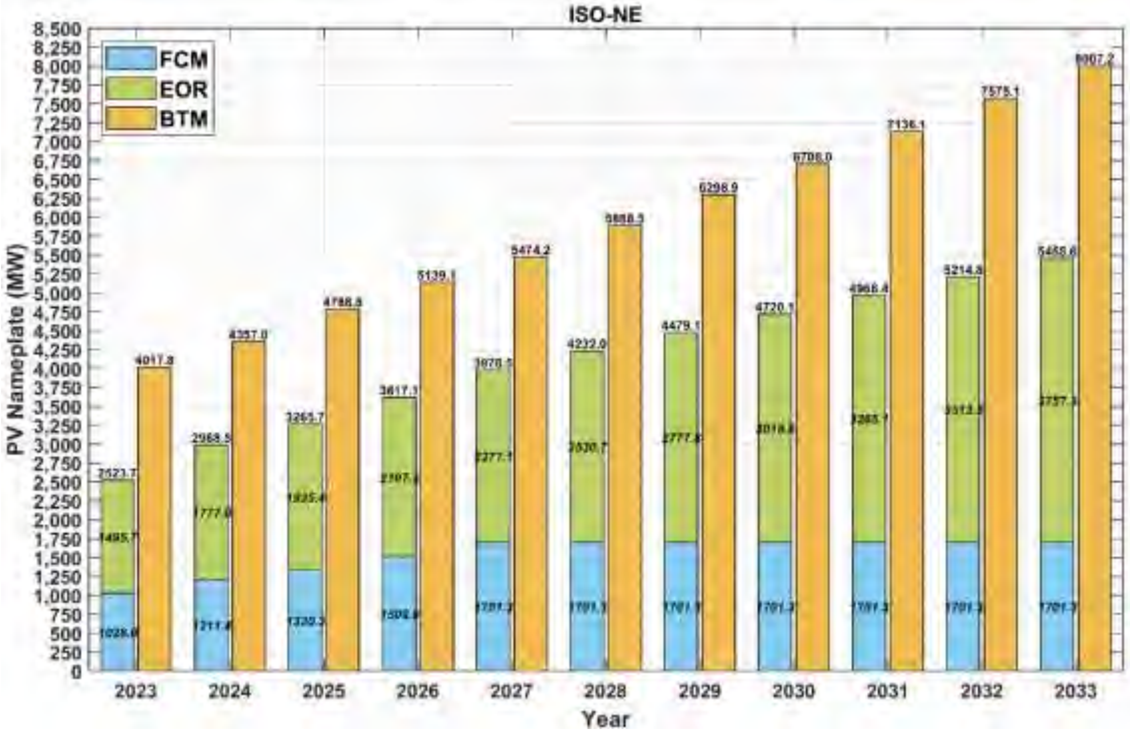
Continued Growth in PV and Peak-Load Estimates Through 2030

Peak load is projected to grow through 2030s



Source: March 2024, Load Forecast Committee: 2024 Final Draft Energy and Seasonal Peak Forecasts

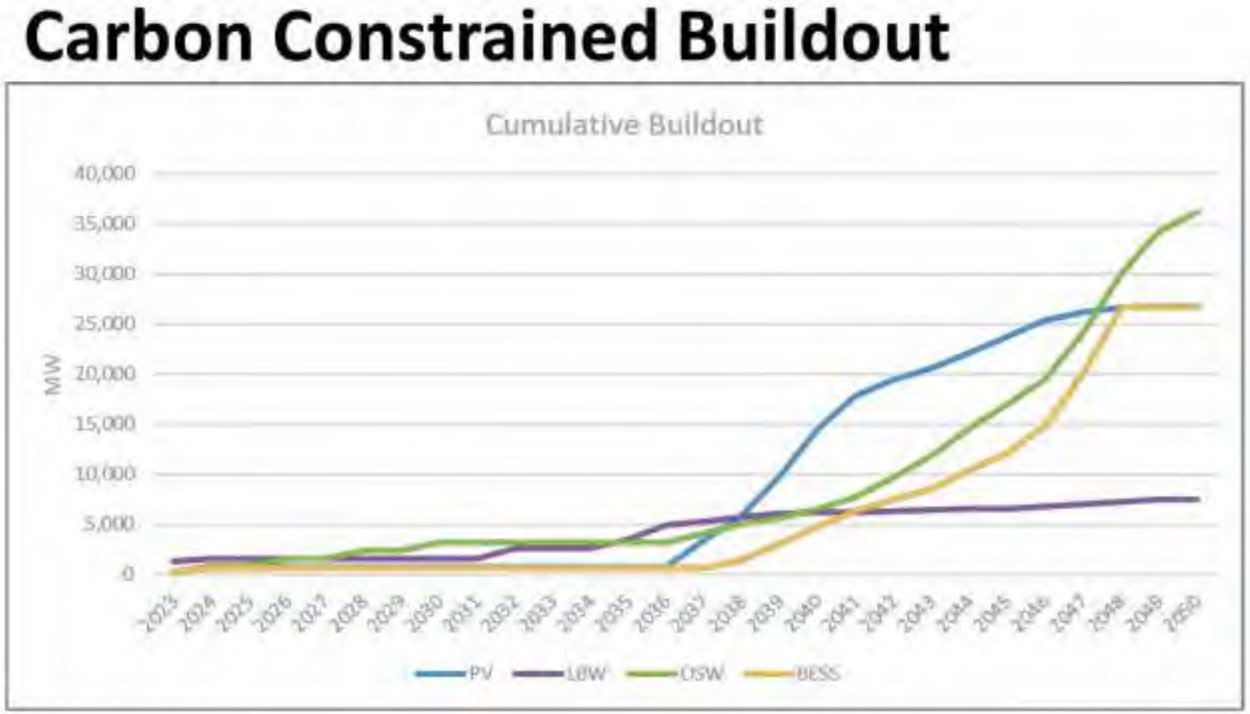
ISO projects PV growth to approximately double over next 10 years



Source: March 2024, Distributed Generation Forecast Working Group: Final 2024 PV Forecast

Grid-level Renewable Capacity Will Need to Increase Substantially in the 2030s

- As load electrifies and grows, carbon constraints require increasing amounts of wind/solar/battery storage
- Despite modeled future systems with significant penetration of wind, PV, and energy storage resources, periods of high net load and depleted energy storage will drive a significant need for dispatchable resources
  - These resources will run less and less over time, but will be relied upon at crucial moments
- The quantities of energy storage needed to ride through wind and PV droughts will be immense

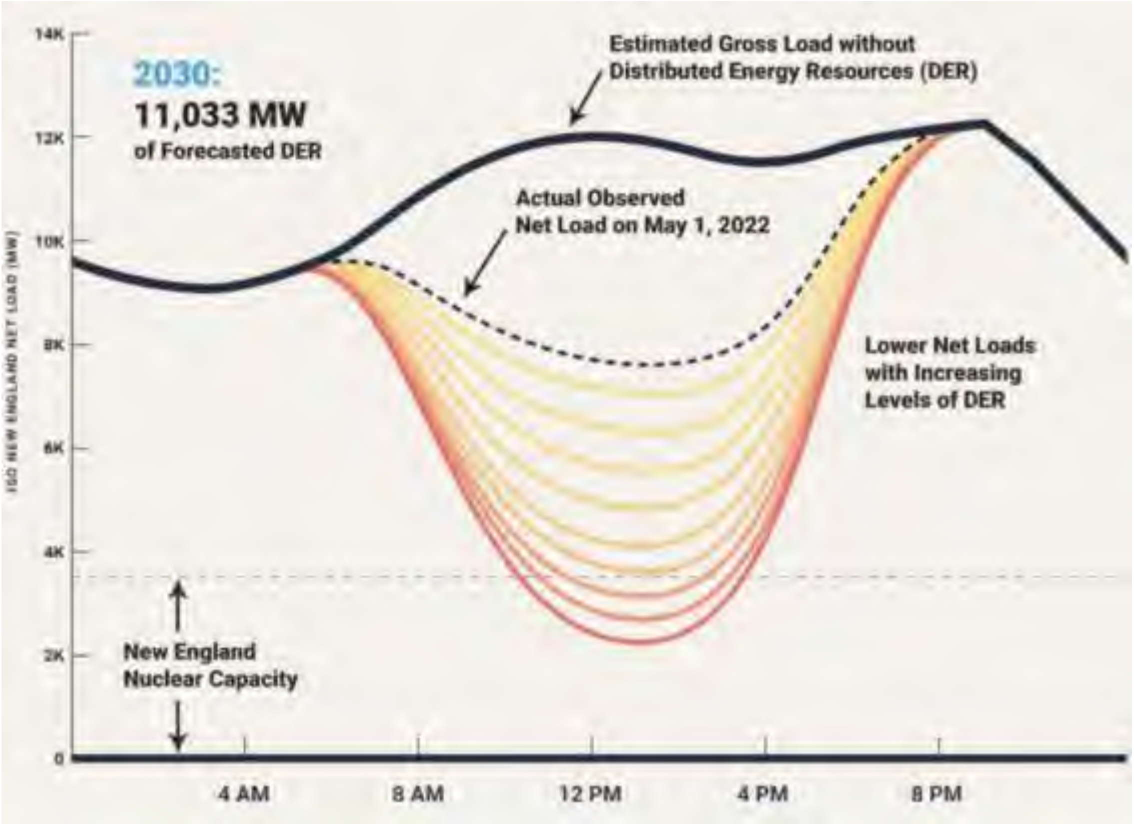


Source: [Economic Planning for the Clean Energy Transition]

By 2030s, the System May Experience Difficult Conditions with Minimum Load

- Due to increased variability in supply and demand, by the early 2030s the system may experience difficult minimum load conditions, unless demand grows during these periods (e.g., battery charging to take advantage of low/negative prices)
- Potential issues include:
  - Low loads dipping below NE nuclear capacity
  - Transmission system experiences more voltage problems
  - High ramping rates

Behind-the-Meter Solar Reduces Grid Demand



By Early-mid 2030s, Heating Electrification is Expected to Turn the Grid Into a Winter-Peaking System

- Over the next 15 years, the region needs to add almost twice as much new generation as it added in the last 25 years
  - By the early 2030s, the annual energy needed to heat buildings and charge electric vehicles is expected to grow to about 20 times the forecast for 2024
- Long duration storage helps alleviate anticipated problems
  - Higher variability in both supply and demand will increase the value of dispatchable resources
- In the medium term (2030 - 2040) when peak load begins to accelerate, there will be an urgent need for dispatchable capacity on the system
  - Anything that is retired in the short-term may have to be replaced at a larger expense in the medium to long-term

Timing of Shift to Winter-Peaking System

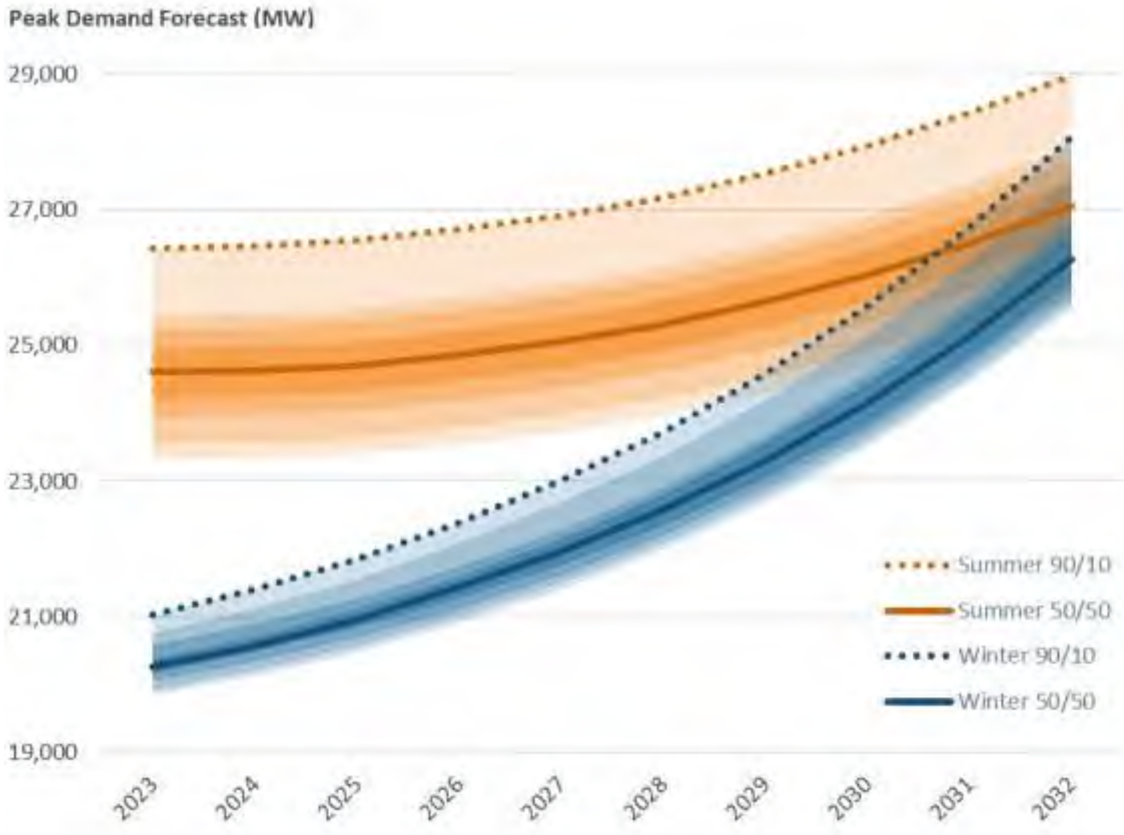


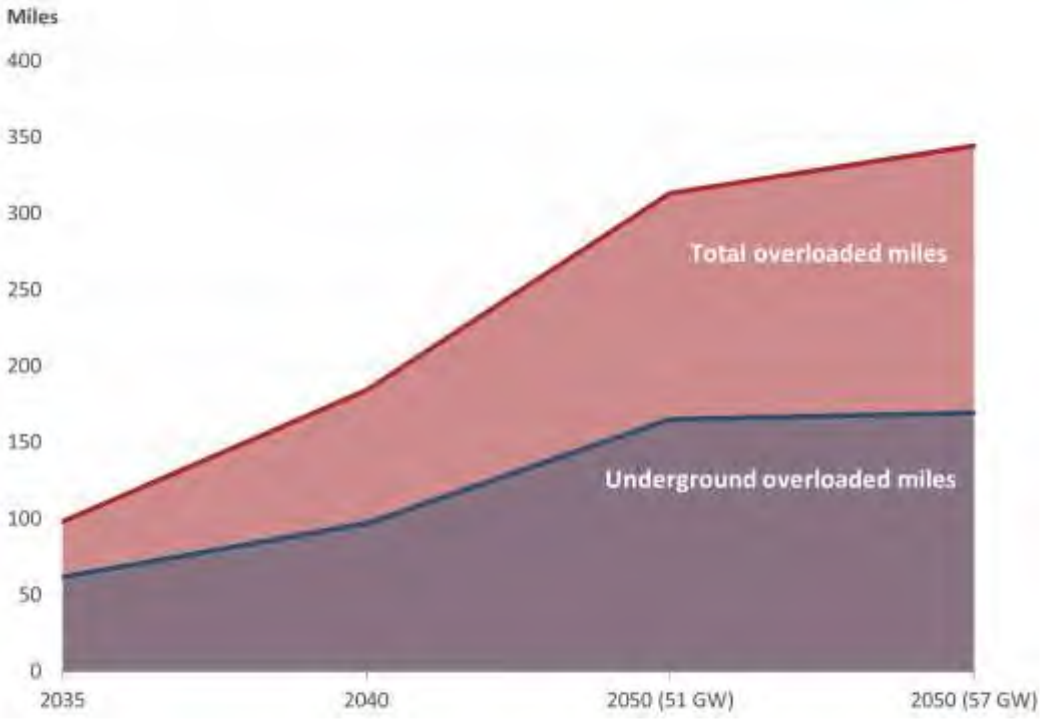
Figure source: 2023 Regional System Plan, Figure 4-9
Data Source: 2023 CELT Report

The Region's Transmission System Will Need Significant Investment

- Assuming pace of renewables continues, and electrification of heating and transportation proceeds as expected, significant upgrades to regional transmission are needed
  - As demand grows over the Clean Energy Transition, the renewable energy to serve that demand will be more geographically dispersed
- Transmission projects that address high-likelihood concerns are likely to bring the greatest benefit for a wide range of possible future conditions as the clean energy transition accelerates
- **Transmission projects to serve 2030s should be in planning stage now**
  - The states have recognized the need, driving the creation of the LTTS planning rules
  - The states, assisted by the ISO, have applied for DOE GRIP funding for two projects

Constraints on the distribution system may also present bottlenecks.

Line Mileage Overloaded in Boston with Generator Interconnection Locations Optimized



Source: 2050 Transmission Study, Figure 2-1

To Ensure the Four Pillars are Robust in the Long-Term, We Must Have a Focused Effort to Ramp-Up Capabilities *Now*

- New England is transitioning to a cleaner electric grid in an effort to mitigate the impacts of climate change and meet the need for a reliable, cost-effective and environmentally sustainable bulk electric system
- To ensure this successful transition, the ISO must focus on the near-term and what the organization must do to strengthen reliability today while keeping New England on the path to the clean, reliable grid of the future
- Successful management of this unprecedented transition requires us to look very carefully toward both the short and the long term
  - The short term because we must maintain reliability during the transition to a carbon-free grid, and lay the foundation for the longer term
  - The longer term because we need to make sound decisions now that will help us reach that destination in the most reliable and cost-effective way

In 2025, the ISO has identified a set of initiatives that make progress towards the goals supporting the organization’s mission and vision; the 2025 budget represents a needed step-up in preparing for the anticipated changes.

2025 BUDGET OVERVIEW

2025 Budget Overview

- Key drivers supporting the proposed increase are (see further details on the following pages):
  - Continuing to **enhance capabilities to address the modeling, analysis, processing, and communication** needs directly resulting from the clean energy transition
  - **Addressing the effects of inflation** on products/licenses, labor, and professional fees as well as the year-over-year costs of continued operation
- The 2025 Proposed Budget reflects the resources needed to support the clean energy transition and to continue carrying out the work to fulfill ISO's mission and continuing operations
- The proposed 2025 revenue requirement *before true-up* is $306.4M, an increase of 10.7% over 2024; when including the net true-up, an increase of $7.8M, the total revenue requirement increase is 13.6% year over year

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

2025 Budget Overview *(cont.)*

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

- The proposed 2025 budget presented today is the bottom-up detailed budget (prepared with input from each ISO business unit and refinements to preliminary estimates), compared to the top-down budget presented in June (that included preliminary estimates); the detailed bottom-up budget resulted in a $0.3 million increase compared to the preliminary top-down version:
  - Increases include: additional funding for regional study work on raising the minimum loss of source value for New England; Information Technology staff augmentation; higher medical renewal rates; and for interest expense
  - Decreases, that largely offset the noted increases, include: lower salary rates due to staff turnover; and the removal of capacity auction licensing fees due to FERC approved two year FCA 19 delay

Clean Energy Transition Driving 2025 ISO-NE Budget

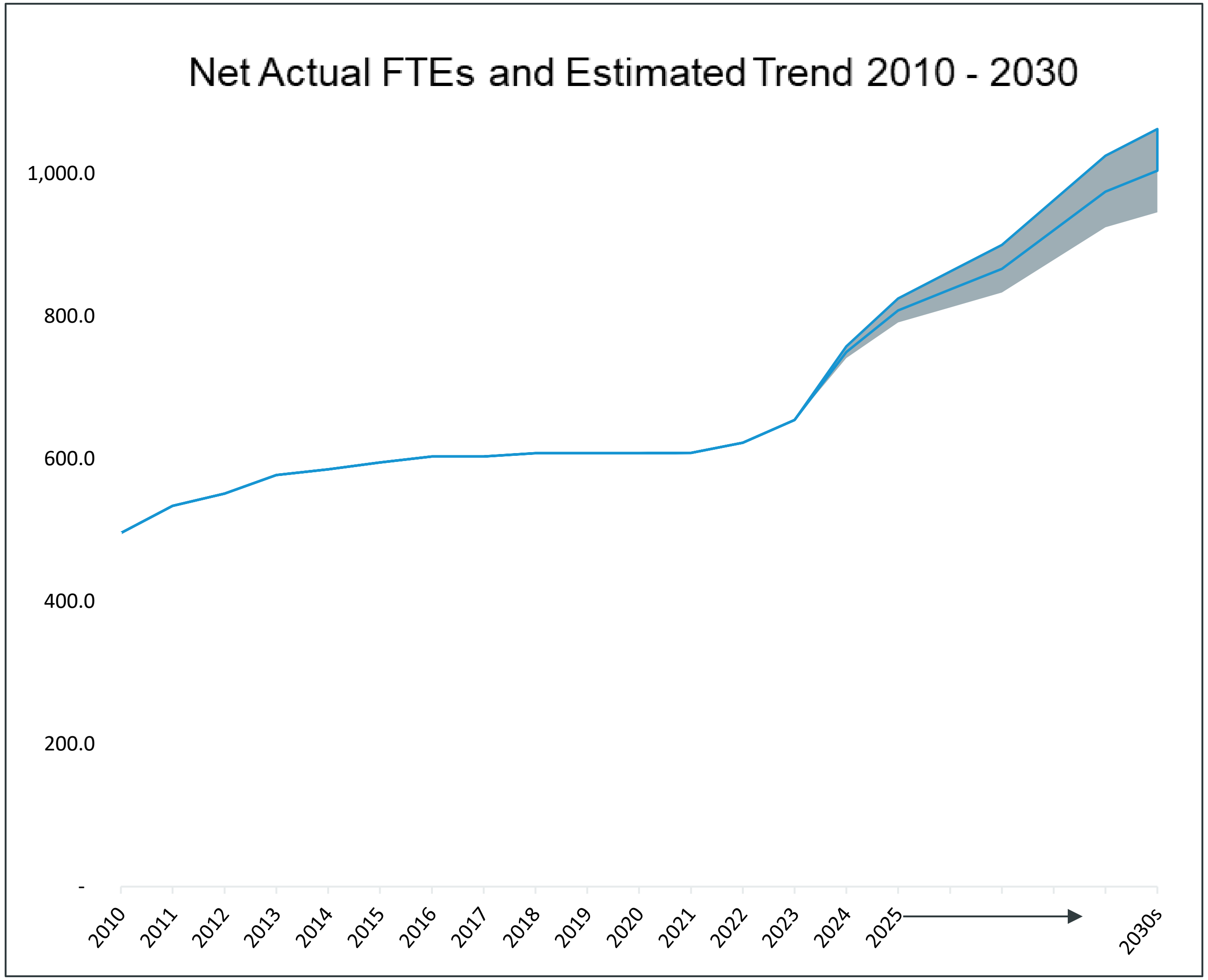
Driver: The main drivers of the 2025 budget are the need to add personnel and make technology investments for the organization to address the modeling, analysis, processing, operational and communication needs directly resulting from the clean energy transition, and includes:

- Continuing to **upgrade our IT infrastructure** to support increasing cybersecurity risk mitigation, data analysis, and rapid technology evolution (often driven by vendors)
  - Capitalize on increased computing power offered through the move to the cloud environment in order to process the volume of data and complexity of analyses that will be needed to support the changing grid
  - Maintaining the internal development and critical software developed by ISO's Advanced Technology Solutions
- **Advancements in modeling and forecasting** to account for net load characteristics and trends that have rapidly evolved in recent years and are anticipated to change even more significantly in the coming decades
- **Market design** work responding to changing system needs, public policies, and new energy technologies
- Development of a team to support **longer-term transmission planning** and administering of transmission RFPs, including analytical support for determining the Benefit to Cost Ratio (BCR) for proposed projects
- Staying compliant with and responding to increasingly **complex federal and state mandates and requests**
- **Investing in more sophisticated operational tools (including updating the EMS)** to support the control room's ability to manage rapidly increasing grid and resource complexity

After Years of Flat Headcount, in 2023, ISO-NE Began Plan to Increase Hiring to Address Clean Energy Transition

Clean energy transition driving FTE needs:

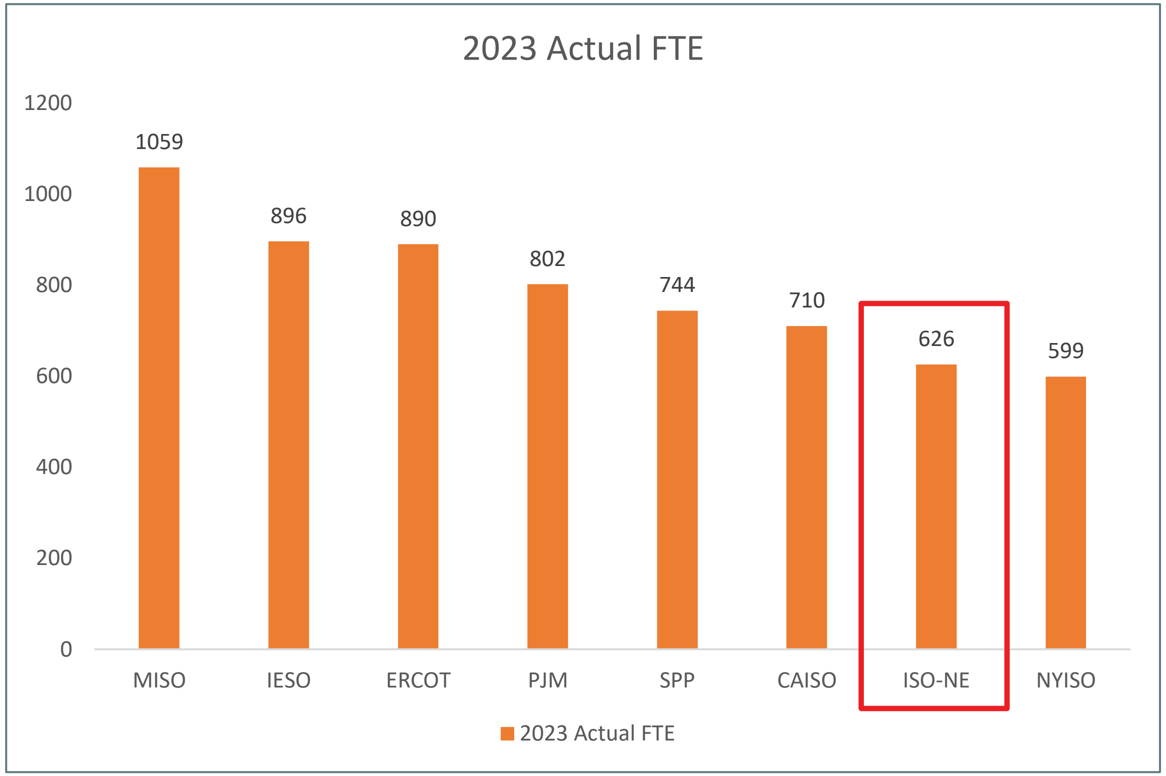
- Increasing number of resources to be interconnected, studied, and incorporated into modeling and forecasting
- New roles for the ISO including assisting states with transmission RFPs
- Increasing compliance needs to address FERC orders, and assess their impacts on operations – 2222, 841, 881, 901,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



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

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

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



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

Other Factors Driving Increases to the 2025 Budget

In addition to the budget increases, for added personnel and technology, to support clean energy as described in the previous slides, the other primary factor to the 2025 budget is inflationary cost increases and for continued operations

Driver: addressing the effects of inflation on products/licenses, labor, and professional fees as well as the year-over-year costs of continued operation

- This includes the need to supplement the bench strength in certain departments to compensate for turnover and retirements

The region is committing to invest tens of billions of dollars in the clean energy transition over the next three decades and much of that investment will not only drive work for the ISO, but change the way we work; in order for the region to fully realize the benefits of that investment, the ISO needs to be prepared to reliably operate in that future paradigm

- Like the region it services, the ISO is an organization that is in transition – including operational needs, inflation, and workforce composition – and because of that, our budget estimates over the ensuing years will increase and should be expected to fluctuate due to the volatility of the input assumptions
- The transition – and work flow – will be dynamic, as will other budget assumptions (e.g., various inflationary forces, turnover rates due to the competitive market, headcount needs for yet-to-be-determined market designs, and business processes); therefore long-term budget forecasts will fluctuate

For the ISO to Manage the Transition to Clean Energy, a Significant Investment is Required in The Near-Term

The main factors for the increases to the 2025 ISO budget are:

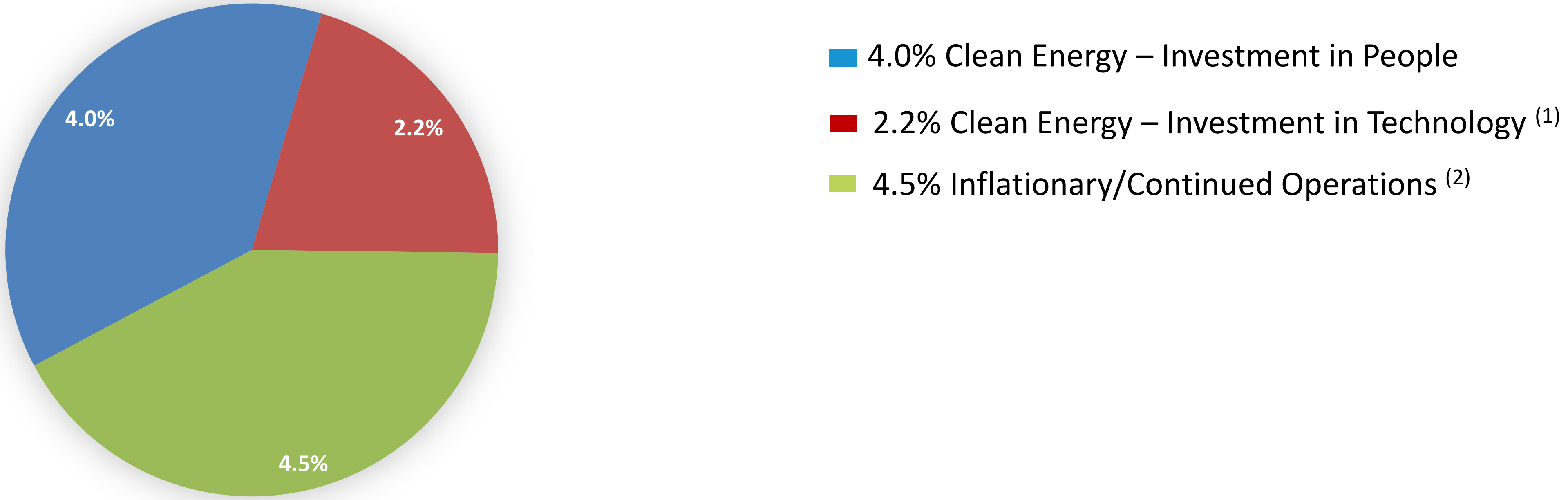
1. The transition to clean energy:
   - Adding full-time employees (FTEs) and other resources to address work directly related to the transition to clean energy
   - Additional investment in information technology (IT) for enhanced modeling, emerging technologies and forecast methods, and the transition to cloud-based infrastructure
2. Inflationary and continued operations drivers:
   - Standard salary increases to keep pace with the labor market in order to retain and attract employees, to address cybersecurity, and for other miscellaneous cost increases

Factor	% Increase	$ Amount	$KWh Rate	Average Monthly Consumer Cost Impact *
Clean Energy Transition	6.2 %	$16,898,100	$0.00012	$0.09
Inflationary/ Continued Operations	4.5 %	$12,610,100	$0.00009	$0.07
Total:	**10.7 %**	**$29,508,200**	**$0.00021**	**$0.16**

**Average Monthly Consumer Cost Impact* is based on average consumption of 750 kWh per month.
Note: See chart on the following slide with an allocation of expense by factor, including a depiction of Clean Energy between investment in people and technology

Key Factors to the 2025 ISO-NE Budget

Key 2025 Budget Drivers



(1) The Clean Energy Investment in Technology represents $1.7M of Computer Services increases for improved modeling, load forecasting, and moving to a cloud environment. The Clean Energy Investment in Technology also includes: increases for Depreciation Expense including that for new market features and enhancement related projects such as Day-Ahead Ancillary Services Improvements and nGEM Software Development Part III; and Network Operations increases for transition of communication lines to new technologies

(2) Inflationary/Continued Operations includes $4.3M of Computer Services increases representing $2.3M of existing product increased costs and/or licensing and $2.0M related to Cyber Security additions and enhancements

Note: See slides 36 and 37 for additional information on Computer Services and technology

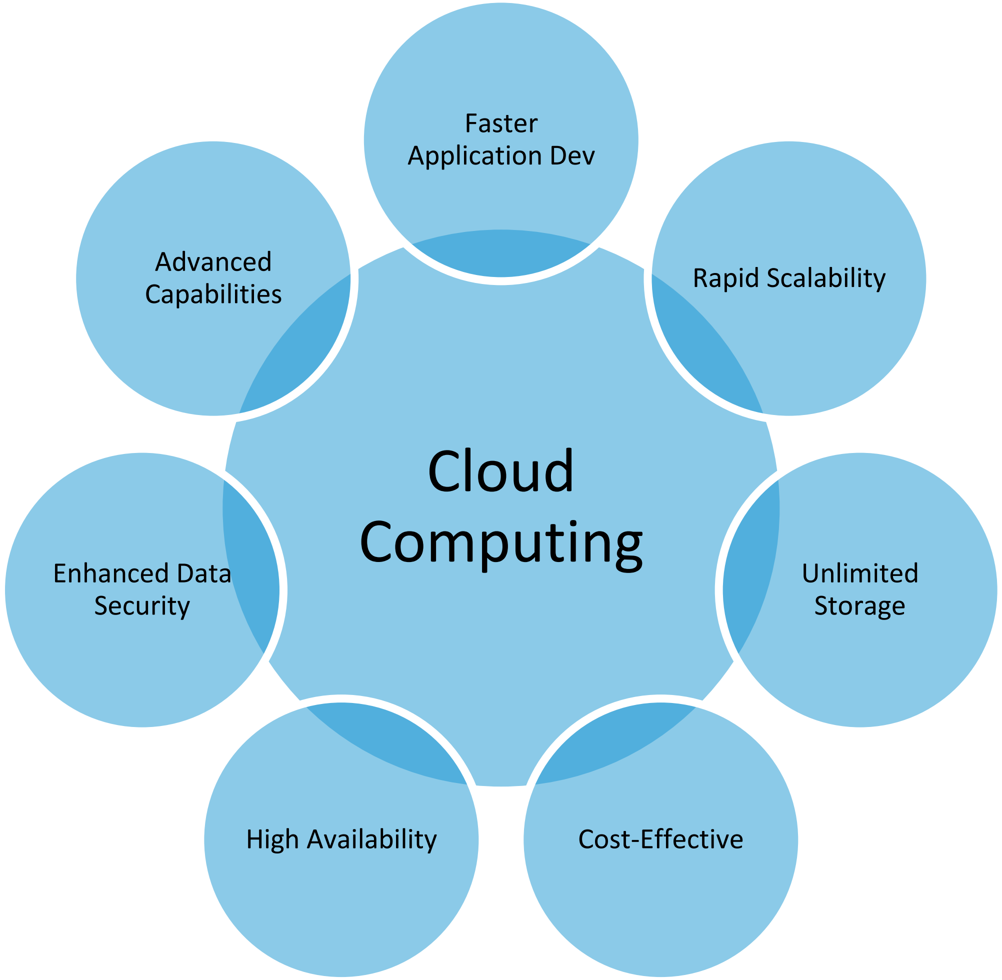
Budget Driver: The Need to Enhance Computer Services and Technology Stack

Computer services driving budget costs in 2025:

- ISO moving to cloud environment
  - Changes the organization's technology stack
  - Enhances efficiencies and capabilities
  - Necessitates new roles within IT
- New/increasing licensing and products
  - Increases in user licenses or central processing units
  - Vendor and product inflation

Existing staff will be trained to support new platforms and tools.

Benefits of moving to the cloud

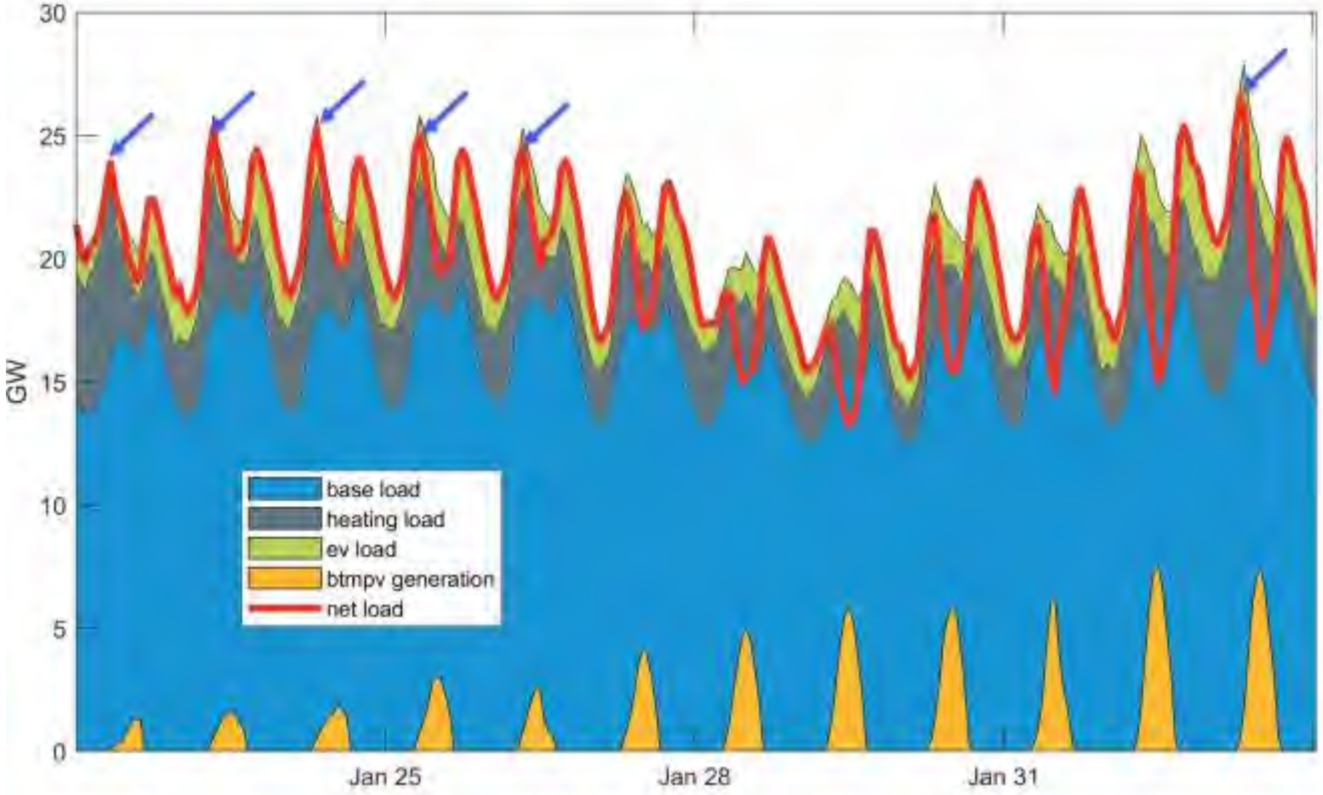


Budget Driver: Technology Improvements for Forecasting Demand and Increasing Complexity of Planning Studies

- Emerging trends require **enhanced modeling and accounting** to resolve net impacts on demand and to forecast full range of demand during all seasons and grid conditions
  - DER PV and DER storage
  - Electrified heating
  - EV managed charging
  - Retail-based active demand response
- **Keep pace with emerging technologies and forecast methods**
- Increasing need for **studying non-typical peak hour insights**
  - Midday minimum loads
  - Sub-regional, "non-coincident" load characteristics
  - Seasonal peaks occurring on weekends, holidays, or atypical months
- Growing emphasis on **load shape and short-term energy requirements in studies**

Need Explicit Accounting of Load Shape

Our current forecasting methodology does not capture the morning peaks we are observing



Source: Data from 2023 CELT Report

Budget Driver: Designing Markets and Supporting Analyses for the Clean Energy Transition

- Hiring to support the development and maintenance of new market mechanisms for the changing resource mix:
  - Capacity Auction Reforms:
    - Resource Capacity Accreditation
    - Move to a prompt/seasonal market
      - *The extent there are personnel efficiencies from the shift to a prompt/seasonal market, the ISO will redeploy existing staff to areas of need*
  - Ramping and flexible response products
  - Day-Ahead Ancillary Services Initiative
- Hiring to support the effects of evolving resource mix on market analyses
  - New and more frequent energy analyses
  - Growing number of transmission and interconnection studies
  - Need to support transmission RFPs with economic analyses

Budget Driver: Compliance with Increasingly Complex Stakeholder, State, and Federal Requests

The clean energy transition will necessitate new roles and capabilities at the ISO including supporting states' requests (including longer-term transmission planning and RFPs), staying compliant with federal mandates, and hiring new skillsets geared specifically towards engaging stakeholders

In addition to the personnel needed to address the workload associated with the modeling, forecasting, and technology needs of the changing grid, addressing the related federal, state, and stakeholder requests will drive budget needs in 2025:

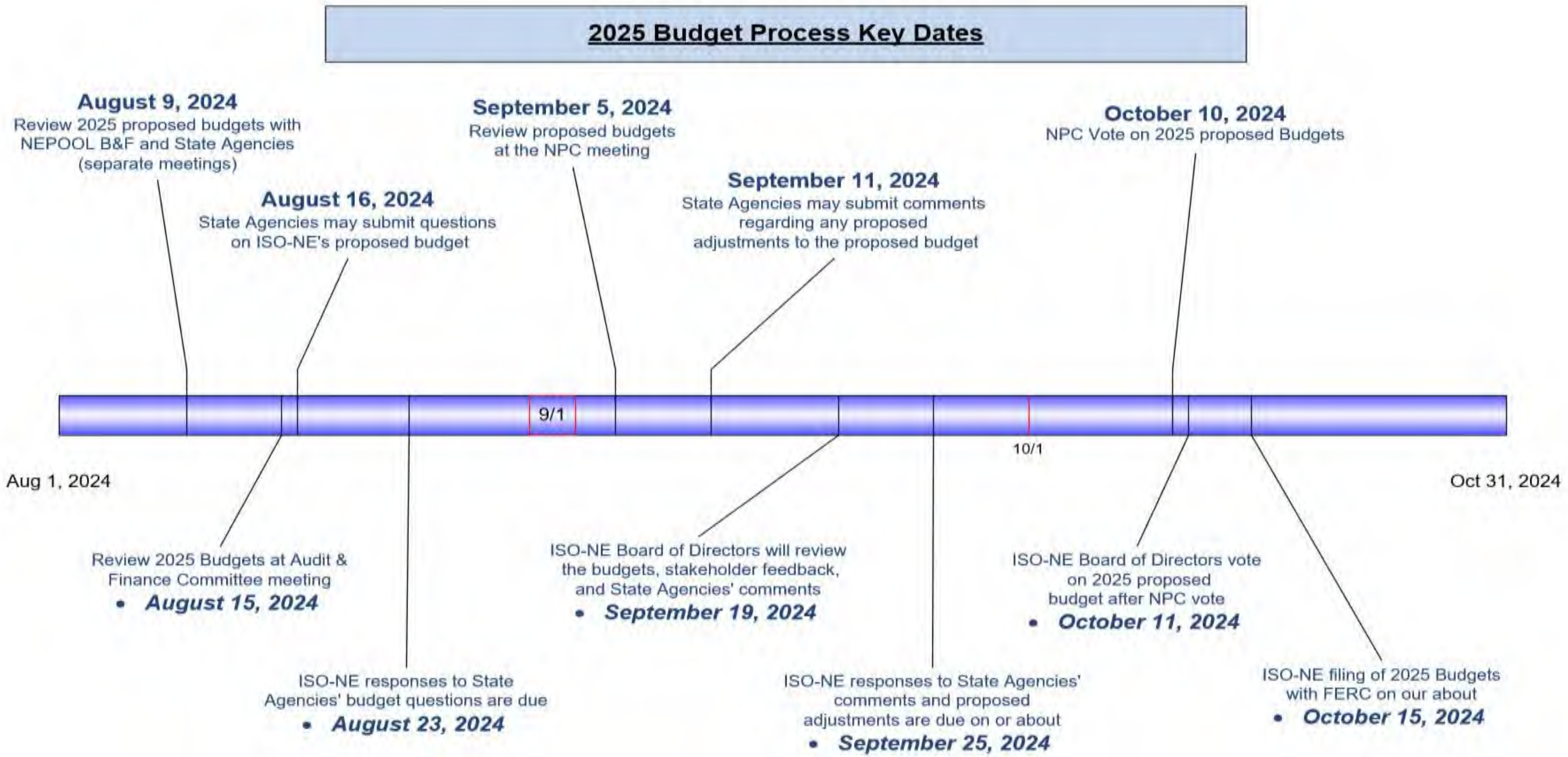
- Development of capabilities to assist states in the transmission RFP and long-term transmission planning processes, **which will necessitate the addition of a new team at the ISO**
  - **This new capability will require a buildout over the course of a few years beginning in 2025**
- Implementation and evaluation of FERC orders: FERC Orders 2222, 841, 881, 901, 1920, and 2023
  - Including elements of implementing outcomes from Regional Energy Shortfall Threshold and Day-Ahead Ancillary Services
- Hiring new skillsets to service stakeholder needs, requests, and communication of increasingly complex grid and market information

2025 Budget Overview

The 2025 Capital Budget is also presented in summary form

- The 2025 Capital Budget has increased from $35M in 2024 to $42.5M in 2025
  - The 2025 capital budget is $2.5M above the $40M presented in the preliminary 2025 budget as a result of incorporating the workspace changes needed to satisfy short-term constraints for the next couple of years; as discussed in the preliminary budget, the Holyoke campus was designed to support 560 headcount therefore creating a need to redesign the Holyoke facilities to accommodate the larger workforce; after exploring financing options with TD Bank, ISO determined this was the most cost efficient way to finance the short-term needs; the costs will be covered under the $75M private placement which will be in effect in 2024; additionally, this will allow ISO to save on closing costs
  - The increased capital budget need is being driven by four primary drivers as explained in further detail on slides 75-79
  - The increased capital spending will result in higher interest expense costs and depreciation expense in future years as capital projects go into service and are included in operating budgets and rates
- The 2025 proposed capital budget of $42.5M is provided with a list of projects by strategic goal that are currently chartered and on-going or in planning/conceptual design (See Slides 82-85)
- Detailed project descriptions are presented in Appendix 7

2025 Budget Process – Key Dates



2025 Budget – 5 Year Comparison

(Budget Amounts are in Millions)	2025	% Change	2024	% Change	2023	% Change	2022	% Change	2021
Operating Budget Before Depreciation	$269.4	10.3%	$244.3	16.8%	$209.2	10.7%	$189.1	5.8%	$178.6
Capital Budget	42.5	21.4%	35.0	4.5%	33.5	4.7%	32.0	14.3%	28.0
Total Cash Budget	**$311.9**	**11.7%**	**$279.3**	**15.1%**	**$242.7**	**9.8%**	**$221.1**	**7.0%**	**$206.6**
Operating Budget Before Depreciation	$269.4	10.3%	$244.3	16.8%	$209.2	10.7%	$189.1	5.8%	$178.6
Depreciation	$37.0	13.6%	32.6	5.1%	31.0	19.1%	26.0	(1.2)%	26.3
Revenue Requirement Before True-up	306.4	10.7%	276.9	15.3%	240.2	11.7%	215.1	4.9%	205.0
True up	4.8		(3.0)		(14.6)		1.1		0.2
Revenue Requirement	**$311.2**	**13.6%**	**$273.9**	**21.4%**	**$225.6**	**4.4%**	**$216.1**	**5.4%**	**$205.1**
Forecast – TWhs (1)	**136.5**	**(3.0)%**	**140.7**	**(1.6)%**	**143.0**	**(1.0)%**	**144.4**	**(2.0)%**	**147.4**
$/KWh Rate	**$0.00228**	**17.1%**	**$0.00195**	**23.4%**	**$0.00158**	**5.4%**	**$0.00150**	**7.5%**	**$0.00139**
Average Monthly Consumer Cost (2)	**$1.71**		**$1.46**		**$1.18**		**$1.12**		**$1.04**

(1) 2025 Forecast based on May 2024 CELT Report (Schedule 1.5.2 - Net Annual Energy - Gross (without reductions)). All other years based on CELT Report for the applicable year, which can be found on www.iso-ne.com.

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

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

2025 STRATEGIC GOAL INITIATIVES

2025 Initiatives: Responsive Market Designs

Support reliability through competitive market mechanisms

1. Capacity Auction Reforms
   - Transition to a Prompt/Seasonal Capacity Market
   - Resource Capacity Accreditation Reforms
2. Implement Day-Ahead Ancillary Services
3. Guide stakeholder discussions on specific new flexible response services
4. Finalize decision to extend or terminate IEP post 24/25 winter

Administer FERC Orders Supporting DER

1. Complete Business Requirements for all affected software and beginning development for Order No. 2222
2. Begin Implementation of Day-Ahead Market Storage Enhancements for Order 841

2025 Initiatives: Progress and Innovation

Improve modeling for emerging technology resources

1. Development of nGEM Real-Time Market Clearing Engine
2. Completion of nGEM Phase III program development
3. Integrate EMT Study Tools into Engineering Processes
4. Enhance data collection for co-located and hybrid resources to improve modeling/visibility

Continue to develop forecasting capabilities to support clean energy transition

1. Develop Probabilistic Forecast Capabilities for Wind, Solar, and Load
2. Integrate Probabilistic Energy Adequacy Tool (PEAT) analysis into seasonal forecasts
3. Improve load forecasting methodology

2025 Initiatives: Operational Excellence

Maintain Reliability and Forecasting for Operation of the Bulk Power System

- Evaluate Single Source Contingency Limit Increase
- Continue to evaluate tie benefits
- Implement ambient adjusted line ratings (FERC Order 881)
- Address trend of increasing DER/decreasing springtime load
- Enhance synchrophaser applications

Implement internal process and technology improvements to address increasing operational complexity

- Increase the usability and broaden usage of ISO-developed innovations to enhance control room situational awareness and market efficiency related to grid complexity
- Enterprise resource planning system replacement
- Evaluate the impacts of FERC Order 2023 on streamlining interconnection queue

Continue to modernize IT assets, technologies, and tools to mitigate cybersecurity threats

- Modernize tools for escalating cybersecurity threats
- IT Asset Workflow (ITAW) Integration and Updates
- IT Support for specific projects (e.g., market design evolution; enhancements to system operator situational awareness/modeling tools)
- Cloud Computing

2025 Initiatives: Stakeholder Engagement

Communicate Power System and Wholesale Markets Performance & Needs

1. Implement Extended Term/Longer Term Transmission Planning Phase 2
2. Coordinate regional discussions around Transmission Owners' asset replacement for the clean energy transition
3. Engage States/FERC to determine implementation path for Regional Energy Shortfall Threshold (REST)
4. Economic studies coming out of the Economic Planning for the Clean Energy Transition (EPCET) Study

Provide high-quality services to stakeholders and the public

1. Develop new communications materials, expand access to regional energy information and conduct outreach to new audiences
2. Survey stakeholders' satisfaction for ISO services
3. Enhance communications about clean energy transition

2025 Initiatives: Attract, Develop, and Retain Talent

Maintain Competitiveness in Labor Market

1. Advance competitive pay benchmarking and associated salary adjustments and structure
2. Continue critical talent retention strategies inclusive of pay, development, and succession planning
3. Additional investment in early career talent programs
4. Improve employee experience- onboarding, coaching and development, flexible work (hybrid), change management
5. Deliver competitive benefit programs with a focus on emotional, physical, and financial wellness

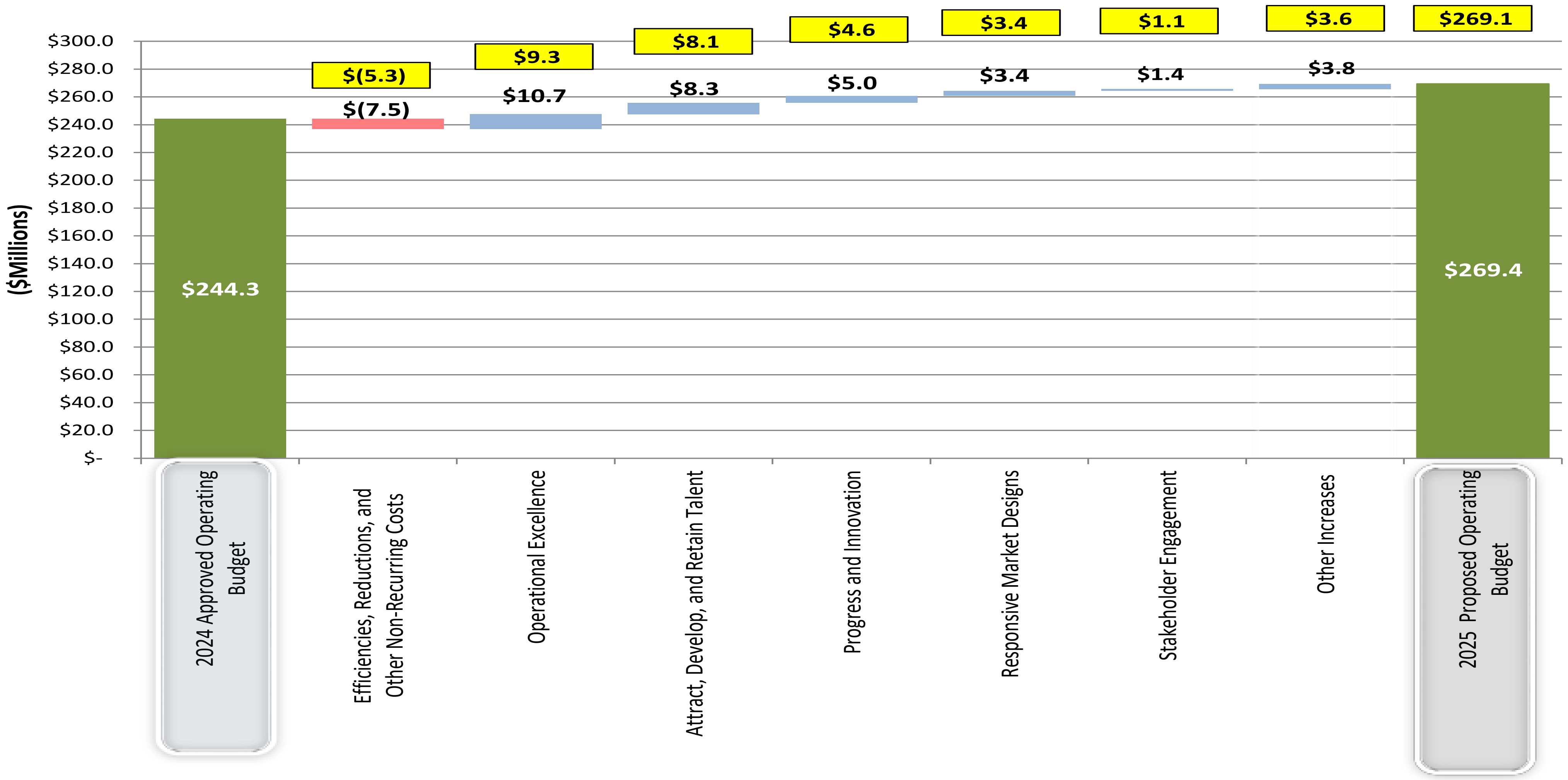
Support the Professional Development of the ISO Workforce

1. Advance Diversity and Inclusion – raising awareness, employee networks, focus on culture
2. Advance leadership capability through the design and delivery of leadership development opportunities and programs
3. Support the organization change, upskilling, and reskilling required to achieve business outcomes
4. Refresh and administer HR Policies and Programs

2025 Detailed Budget Changes by Strategic Goal

2025 Budget

Changes in budget by Strategic Goal



Note: Items in yellow above represent the estimate that was included in the 2025 preliminary budget presented in June 2024.

2025 Budget Details

Efficiencies, Reductions, and Other Non-Recurring Costs

Reductions include: ($7.5M)

- Reductions for consulting professional fees for 2024 studies or other non-recurring work including:
  - Utilization of external support for New England States' requests to be offset by ISO-NE internal staff
  - Funding for FCA 21 Cost of New Entry (CONE) parameter updates
  - Reduction in funding for the assessment of a conceptual framework for a Prompt Seasonal Capacity Market
  - Removal of professional fees funding in Market Administration & Auctions and Market Monitoring, and capacity auction licensing fees due to the FERC approved two year delay of FCA 19
  - For Distributed Energy Resource and minimum load studies for assistance in determining requirements on how to ensure reliability on the system under conditions where it is powered solely by inverter-based resources
  - Reductions in Market Development study and project management support
  - For Energy Resource Opportunity cost support in Market Monitoring

2025 Budget Details

Efficiencies, Reductions, and Other Non-Recurring Costs

Reductions: *(cont.)*

- Lower support costs, upon contract renewal, for Participant Support management software
- Lower salary rates due to employee turnover and retirements
- Increase in Interest Income due to raising of interest rates for 2025 to 2.75% compared to 1.00% in 2024 budget

2025 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2025 Initiatives

Goal 3: Operational Excellence: $10.7M

- Computer service and leasing increases for: cyber security (security logging, firewall updates, network collaboration tool, network traffic segmentation, encryption software, and risk management); leasing of servers as part of data center refresh; photovoltaic and demand response forecast products; licensing for System Planning and Operations applications; performance monitoring software; Enterprise Resource Planning software; compliance software; and inflationary and vendor increases across our portfolio of computer service products ($6.4M)
- Funding for 11.0 FTEs* related to this goal across Information and Cyber Security Services for Cloud Computing transition including architecture, security and infrastructure support, and FinOps management, for IT modeling and software development, and support for enterprise and settlement applications; for Participant Training support; and for Finance and Market Credit Risk support to the organization ($2.5M)
- Network Operations increases for transition of communication lines to new technologies, for data redundancy, and for inflationary and communication line increases ($0.6M)

* FTE totals and related funding on slides 53-60 reflect partial funding for 2025 positions (30 FTEs), as well as a partial carryover for 2024 positions (20 FTEs).

2025 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2025 Initiatives

Goal 3: Operational Excellence: *(cont.)*

- Information and Cyber Security Services staff augmentation inflationary rate increases ($0.5M)
- Addition of an professional fees for an Audio Visual Engineer to support the Information Technology Service Delivery team ($0.2M)
- Internal Audit support for cloud applications and NERC Critical Infrastructure Protection (CIP) programs ($0.2M)
- Travel and training due to full renewal of in-person meetings, higher travel costs, and training of staff to support new platforms and tools ($0.2M)
- Information Technology administrative staff augmentation consulting support ($0.1M)

2025 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2025 Initiatives

Goal 5: Attract, Develop, and Retain Talent: $8.3M

- Merit and Promotion increases (6.0% Total): for annual merit (4.0%) and for standard and targeted equity/promotions (2.0%), less timing of 2024 equity/promotion adjustments and allocation of amounts between operating and capital/reimbursable work ($4.7M)
- Increases in employee benefit costs, primarily for medical trend, increased number of employees in Defined Contribution Benefit Plan, and higher 401K match due to overall employee salaries ($1.8M)
- Increase for employee incentive target amounts including adjustments based on compensation study review ($1.4M)
- Funding for 6.0 FTEs* related to this goal across Human Resources, Legal, and Corporate Communications (in HR for talent and project management, early career associates, and learning coordinator; in Legal for corporate counsel to support employee related matters; and in Corporate Communications for a communications specialist to expand external communications to attract talent) ($1.0M)

* FTE totals and related funding on slides 53-60 reflect partial funding for 2025 positions (30 FTEs), as well as a partial carryover for 2024 positions (20 FTEs).

2025 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2025 Initiatives

Goal 5: Attract, Develop, and Retain Talent: *(cont.)*

- Higher recruiting and benefits administration related expenses including relocation, recruiter fees, and employee experience consulting ($0.5M)
- Leasing of land adjacent to Holyoke facility in conjunction with Space Utilization project ($0.3M)
- Human Resources support for instructional design and executive coaching ($0.2M)
- A reduction for the increase of employee vacancy from 5% to 6% (reduction of $1.6M)

2025 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2025 Initiatives

Goal 2: Progress and Innovation: $5.0M

- Funding for 16.0 FTEs* including Information and Cyber Security Services and Advanced Technology Solutions for bringing ISO-NE developed advanced technologies into the operating environment to increase our situational awareness capabilities; System Operations and System Planning positions for forecasting and energy analysis across different timespans as the system's resource mix continues to evolve, and for modeling and electromagnetic transient analyses for market and reliability operating limits of Inverter Based Resources; and in Transmission Planning and Services for RFP processing and long-term studies ($3.4M)
- Funding for a transmission planning system assessment under NERC Transmission Planning Standard TPL-001 ($0.5M)
- Increased utilization of cloud computing with more products moving to the cloud including the Customer and Asset Management System (CAMS), Forward Capacity Tracking System (FCTS), and internal development software application ($0.5M)
- Funding to support transmission planning and analysis studies to establish facility out transfer capability for Northern New England and NECEC ($0.3M)

* FTE totals and related funding on slides 53-60 reflect partial funding for 2025 positions (30 FTEs), as well as a partial carryover for 2024 positions (20 FTEs).

2025 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2025 Initiatives

Goal 2: Progress and Innovation: *(cont.)*

- Funding for Planning Services benchmarking and validation of generator outage data ($0.1M)
- Fees for a battery storage modeling application being utilized by Internal Market Monitoring staff ($0.1M)
- For research by Advanced Technology Solutions with outside firm on impacts of Inverter Based Resources on the system based on differing scenarios including location, timing, and volumes ($0.1M)

2025 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2025 Initiatives

Goal 1: Responsive Market Designs: $3.4M

- Funding for 11.0 FTEs* related to this goal including for: Market Development in design of market overhauls including Capacity Auction Reforms (prompt seasonal capacity market, and resource capacity accreditation), and flexible response services; Operations Training to design and support trainings for Operations and Market Administration and Auctions staff for new market features; Information and Cyber Security Services and Advanced Technology Solutions staffing to support and integrate new market features into applications and tools; and Planning and Transmission Services to align with new market designs, for identifying enhancements to existing reliability modeling and researching, and developing modeling techniques for emerging technologies ($2.4M)
- nGEM vendor support with the Day-Ahead Market Clearing Engine production application that is being supported at the same time as the legacy Real-Time application (forecasted to go live in 2026) ($0.6M)
- Support in Advanced Technology Solutions for Integrated Market Simulator system support and enhancements ($0.3M)
- Support for Market & Credit Risk modeling ($0.1M)

* FTE totals and related funding on slides 53-60 reflect partial funding for 2025 positions (30 FTEs), as well as a partial carryover for 2024 positions (20 FTEs).

2025 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2025 Initiatives

Goal 4: Stakeholder Engagement: $1.4M

- Funding for 3.5 FTEs* in Participant Relations and Services for project services (gathering, managing, and supporting the assessment of participant requests), for data analytics on key trends, for technical readiness on participants inquiries and proposals, and for technical writing and instructional design work for broader and deeper training for new market features and initiatives scheduled for 2025 and 2026 ($0.7M)
- Funding for 1.5 FTEs* in System Planning for Economic Study and Environment Outlook and Interconnection Study work; and 1.0 FTE* in External Affairs for increased support and substantive interactions with the states and facilitating engagement of ISO subject matter experts on matters related to renewable and clean energy development, transmission and interregional planning, generator interconnections, and integration of demand-side solutions and distributed resources ($0.5M)
- Increase in funding for a regional study with PJM and NYISO for 1,200MW single source contingency limit appropriateness and determine upgrades required to support 2,000MW single source limit ($0.2M)

* FTE totals and related funding on slides 53-60 reflect partial funding for 2025 positions (30 FTEs), as well as a partial carryover for 2024 positions (20 FTEs).

2025 Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2025 Initiatives

Other Increases: $3.8M

- The allocation of NPCC and NERC dues ($1.2M)
- An increase in Interest Expense and fees with changes to: Private Placement debt in late 2024 at higher balance and expected higher rate than previous debt; tax exempt debt due to higher rate slightly offset by decrease in principal balance; with a partial offset on the working capital borrowing ($1.1M)
- An increase in the CEO Emerging Work Allowance ($1.0M)
- Insurance policy rate increase ($0.5M)

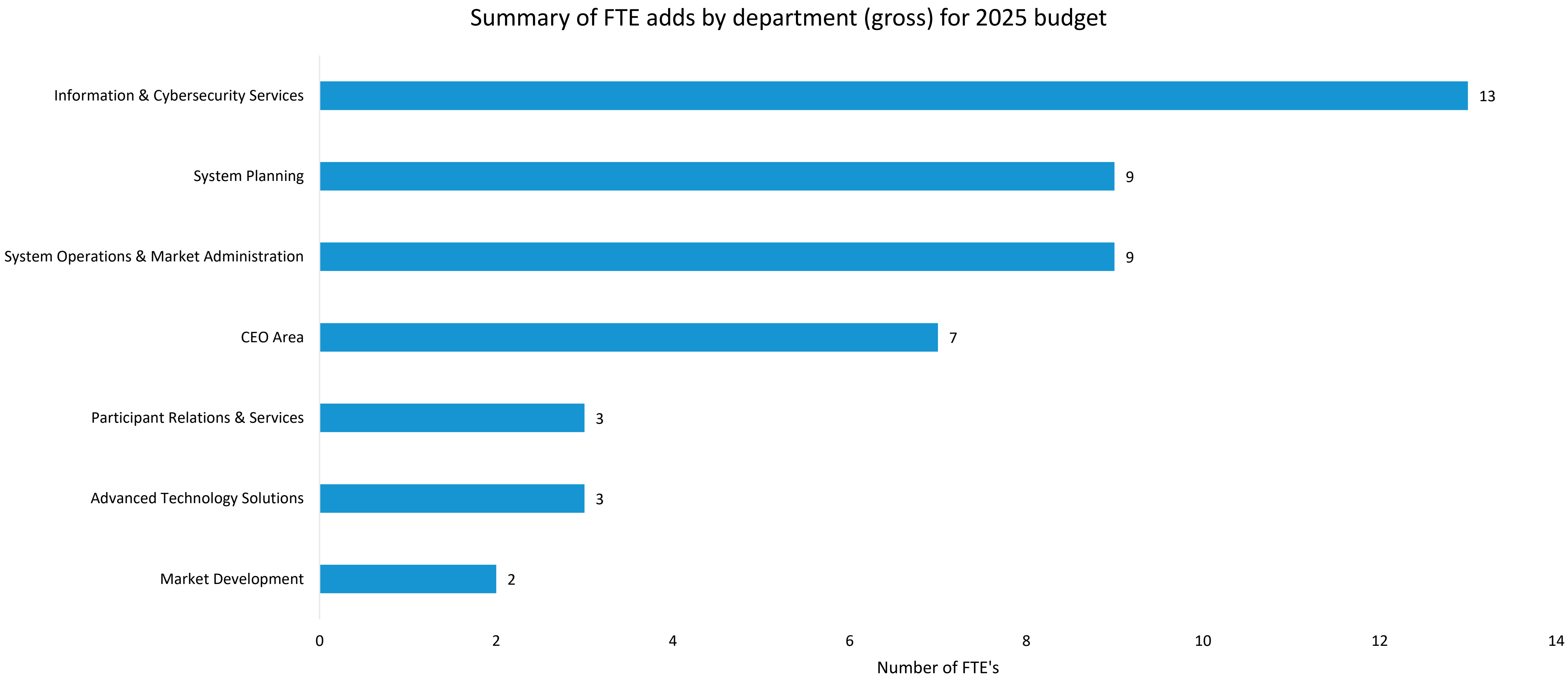
2025 BUDGET RESOURCING NEEDS

2025 Budget Resourcing Needs

Repurposed Positions

- The ISO evaluates each position that becomes vacant to determine the continued need in that area and for possible repurposing for use in other areas of the organization
  - Since 2018 this has resulted in 40 positions, including 4 to-date in 2024, being repurposed for other work where a more urgent need existed
  - Positions repurposed since 2018 include: 9 for Information Technology for Software Development, Cyber Security, Power System Modeling, Application Support, Infrastructure and Digital Transformation; 7 for System Operations & Market Administration for Energy Security, Asset Registration & Auditing, Control Room Operations, and Operations Training; 6 for Market Development analysis and market design work; 4 for Human Resources for recruiting support and to replace contract positions; 2 for Advanced Technology Solutions; 2 for Market Monitoring; 2 for Market & Credit Risk; 2 for Participant Support; 2 for Corporate, Media, and Digital Communications; 1 for Load Forecasting to replace a contract position; 1 for Resource Studies & Assessments; 1 for Settlements; and 1 for Corporate Strategy

Requested Additional Headcount for 2025



Note: CEO Area headcount additions include those for External Affairs, Human Resources, Finance, Market & Credit Risk, and Legal

2025 Budget Resourcing Needs *(cont.)*

In 2025 there are 46 FTE (gross) additions as follows:

FTEs	Department / Description	Clean Energy Pillar(s) (*)	Strategic Goal(s)
13.0 FTEs	**Information and Cyber Security Services**		
	Resources to support advanced technology solution tools as well as the Integrated Market Simulator, Prompt/Seasonal Markets; Development efforts including the nGEM system, and integration of Day Ahead Ancillary Services; IT Architecture to support leveraging cloud technologies; infrastructure support to alleviate understaffing pressures; and resources to break teams into smaller pods that support the growing number of IT products and services (7 FTEs Support the Clean Energy Transition)	N/A	Operational Excellence; Responsive Market Designs; Progress and Innovation
9.0 FTEs	**System Planning**		
	Resources to support continued growth and development of PSCAD modeling capability, Resource Capacity Accreditation and use of probabilistic analysis, to accommodate evolving study and forecasting needs and increased complexity associated with the clean energy transition, resources to support expected increases in transmission RFPs, support stakeholder requests for long-term transmission studies, to address FERC order on long-term transmission planning for asset condition based replacement and future-sizing of the transmission system (9 FTEs Support the Clean Energy Transition)	Energy Adequacy; Balancing Resources; Robust Transmission	Progress and Innovation; Operational Excellence; and Attract, Responsive Market Design
9.0 FTEs	**System Operations and Market Administration (SOMA)**		
	Resources to support the evolving project needs of the SOMA department, support improvements to Outage Coordination, and additional analytical requirements to perform complex and evolving Electromagnetic Transient analyses; resources for the performance of energy analysis across varying time horizons, and for Operations Training coordinate with SOMA business groups to proactively identify gaps and challenges with integrating significant amounts of clean energy and energy storage to work with Advanced Technology Solutions and IT to develop necessary tools and solutions (9 FTEs Support the Clean Energy Transition)	Clean Energy Resources; Energy Adequacy	Responsive Market Designs; Operational Excellence; Progress and Innovation

(*) See the Four Pillars of the Clean Energy Transition on Slide 13

2025 Budget Resourcing Needs *(cont.)*

In 2025 there are 46 FTE (gross) additions as follows: (cont.)

3.0 FTEs Advanced Technology Solutions	Clean Energy Pillar(s)	Strategic Goal(s)
Resources to serve as the company-wide SME on synchrophasor technology, conduct research and development on emerging power system issues such as large scale renewable integration, and resources to analyze and assess market designs or operations processes to include the development of models for market design and optimization problems (3 FTEs Support the Clean Energy Transition)	Clean Energy Resources; Energy Adequacy	Progress and Innovation
3.0 FTEs Participant Relations & Services		
Resources to conduct data analysis of key trends embedded in participant inquiries to discover critical knowledge gaps, resources to provide required technical readiness and real-time support to participants on notable corporate initiatives scheduled for 2025/26 and an additional resource to address the required development of new and increasing participant training needs for new initiatives and products (3 FTEs Support the Clean Energy Transition)	Robust Transmission	Stakeholder Engagement
2.0 FTEs External Affairs		
Given the increasing expectations from the New England states to have the ISO provide support in achieving their state policy goals, the External Affairs team is being called upon increasingly to support substantive interactions with the states and facilitate engagement of ISO SMEs on matters related to renewable and clean energy development. One resource is to oversee the day-to-day responsibilities of the team's state policy advisors and one resource to enable more substantive interactions with the states and alleviate the need for involvement from SMEs. (2 FTEs Support the Clean Energy Transition)	Clean Energy Resources	Stakeholder Engagement

2025 Budget Resourcing Needs *(cont.)*

In 2025 there are 46 FTE (gross) additions as follows: (cont.)

	Clean Energy Pillar(s)	Strategic Goal(s)
2.0 FTE Market Development		
Resources for increasing data analytics capacity and capability, focused on Prompt/Seasonal Capacity Market, Resource Capacity Accreditation Reforms, and future Flexible Response Services, as well as ongoing data-intensive priority work on Storage Modeling Enhancements, Multi-Interval Optimization, and other projects (2 FTEs Support the Clean Energy Transition)	Support	Responsive Market Designs
2.0 FTE Human Resources		
Resources to support department and organizational change and effectiveness efforts, foster a diverse, inclusive and engaging work environment, as well as centralizing coordination of learning activities and administration into a single role (1 FTE Supports the Clean Energy Transition)	Support	Attract, Develop, and Retain Talent
1.0 FTE Finance		
For a FinOps Manager to provide financial and analytical support, assist in the development of department budgets as well as act as a liaison between IT departments and the finance and budget departments	Support	Operational Excellence
1.0 FTE Market & Credit Risk		
For an experienced credit analyst to assess and monitor the creditworthiness of banks and market participants due to changes to the Financial Assurance Program (FAP) made in 2023 as well as planned changes to the FAP regarding parental/affiliate guarantees in the Forward Capacity Market (pending FERC approval)	Robust Transmission	Operational Excellence
1.0 FTE Legal		
Support for growing legal needs in Human Resources including employee relations and benefit plan changes	Support	Attract, Develop and Retain Talent
46.0 FTE's Total 2025 Proposed FTE Additions		

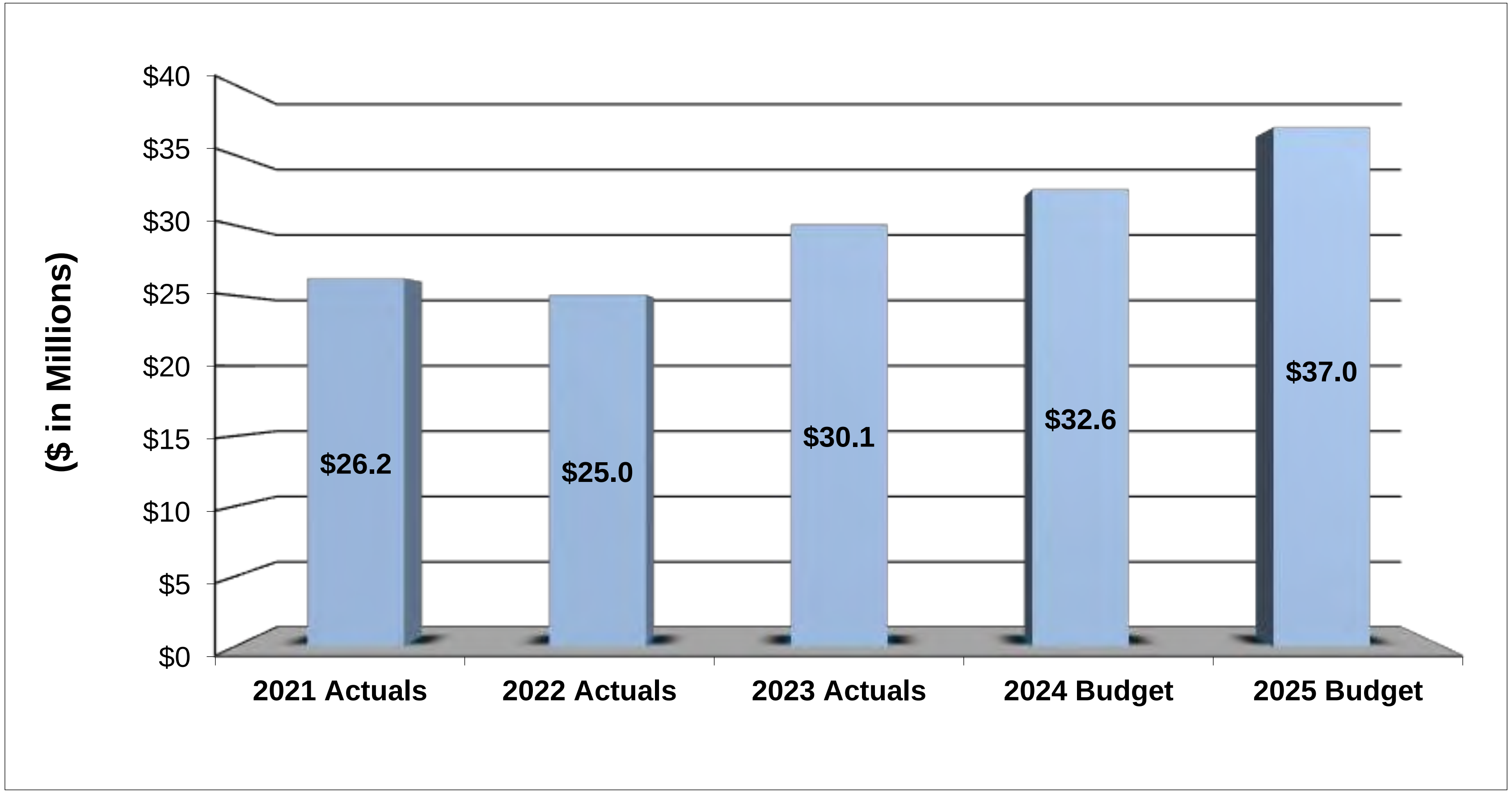
2025 OPERATING BUDGET RISKS

2025 Operating Budget Risks

- Additional funding may be required to enhance new models to study extreme weather and contingencies; to conduct new studies related to the integration of variable resources and emerging technologies; and for long-range transmission planning studies including request for proposals (RFP) process for finding competitive solutions to identified transmission needs in the region
- Resources may be needed as operations evolve (e.g., energy forecasting, load management) due to the changing resource mix occurring
- Information Technology software licensing and maintenance costs, and cloud migration costs may each require additional funding
- Insurance policy renewals may be higher than increases estimated in the budgets
- Interest Rates may impact the ISO floating rates on tax-exempt debt, pension and post-retirement benefit plans liability costs, and interest income on settlement float balance
- Legal costs from material litigation that may arise during the course of the year would pose a risk to the ISO’s ability to operate within the approved budget
- Federal and state policy directives/changing policies could result in additional cost associated with new requirements
- Workforce sourcing and related pay rates and supply chain disruption may each have budgetary impacts

DEPRECIATION

ISO New England Depreciation



ISO New England Depreciation *(cont.)*

Depreciation expense is an accounting method used to allocate the cost of a tangible or physical asset over its useful life. Below is a table of the ISO's asset classes and depreciable lives.

Asset Class	Depreciable Life
Computer Hardware, Software, and Accessories	3-5 Years
Software Development Costs	3-5 Years
Furniture and Fixtures	7 Years
Machinery & Equipment	7 Years
Building Improvements	Useful life of the improvement
Leasehold Improvements	Useful life of the improvement or remaining life of the lease
Building	25 Years (economic useful life determined during bond offering)
Vehicles	3-7 Years

ISO New England Depreciation *(cont.)*

- The Capitalization Policy – Highlights
  - Costs are capitalized when dollar threshold has been meet and the item has a useful life beyond one year
  - Interest and fees associated with borrowings that the Company has entered into for the acquisition of assets related to a project that has a material effect on the Company's financial position are capitalized as required by the Accounting of Certain Types of Regulation Topic of the Financial Accounting Standards Board ("FASB") Accounting Standards Codification
  - Software development costs are capitalized as required by the Cost of Computer Service Software Development Topic of the FASB Accounting Standards Codification
  - The capitalized cost of new hardware or software includes the first year of maintenance for hardware and software
  - Time spent on project management and software testing for capital projects and business analysts' time in the Project Management department are capitalized and specifically noted in the Annual Administrative Costs Services and Capital Budget Filing

Forward Looking Capital Budget Spending

Forward Looking Capital Budget Spending

- The capital budget over the next five years and beyond will continue to support the Company's strategic goals with specific focus on four primary drivers:
  - nGem platform (replacing the current market system)
  - Major market and reliability related efforts
  - Cyber security
  - IT asset and infrastructure replacement
- In order to achieve these goals and to accommodate the expanded workspace, ISO has increased the capital spending over the last few years with spending of $35M in 2024, and increasing to $42.5M in 2025, and at a $40M level in 2026 and beyond; the capital costs are dependent on various factors, including regulatory orders and approvals and the use of professional services or internal staff
  - The ISO will continue with its current practice of providing a rolling two-year look-ahead window

Forward Looking Capital Budget Spending *(cont.)*

nGEM Platform Replacement (*)

- The nGEM program (next Generation Markets Management) will upgrade the core market software by supporting a system with a growing number and type of grid assets, new and more complex market features, ever multiplying security threats, and advancing IT technologies
  - GE Solutions is developing nGEM in collaboration with ISO-NE, MISO, and PJM; the portion of the software upgrade unique to each ISO will be shouldered by each ISO individually
- With the completion of the infrastructure and the day-ahead version of the new market clearing engine (MCE) in 2023, the ISO is continuing work on the complex processes for customizing and implementing the next phases, which include the infrastructure and real-time version of the MCE; this work is expected to continue until 2026 with an estimated cost of $15M
- Additional phases for nGem are expected in 2025 thru 2028 with an estimated cost of $45M

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

Forward Looking Capital Budget Spending *(cont.)*

Major Market and Reliability Related Efforts

- The capital budget will support ISO's market design objectives for 2024 and beyond of moving toward clean energy, balancing resources, energy adequacy, and robust transmission
- Many of these projects are complex efforts that will have long lead times to complete and have dependencies of stakeholder and regulatory approval; the following projects have been identified for 2025 and beyond but may fluctuate depending on stakeholder/FERC priorities:
  - Day-Ahead Ancillary Services Improvements Design: This project seeks to develop market constructs for procuring and transparently pricing ancillary service capabilities needed for a reliable, next-day operating plan with an evolving resource mix; the ISO plans to develop day-ahead flexible response services to enable the system to recover from sudden source-loss contingencies and respond quickly to fluctuations in net load during the operating day
  - FERC Order 2222: The ISO will be building software systems to integrate distributed energy resources into the wholesale markets

Forward Looking Capital Budget Spending *(cont.)*

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

- Significant Capacity Market Reforms: The ISO is currently recommending the move from a forward capacity auction construct to a prompt and seasonal capacity auction construct; this is a substantial scope of work that will better position the ISO to mitigate energy adequacy risks as the power system evolves
- Managing Transmission Line Ratings: This project is in response to recent FERC orders and will require substantial IT and database work to collect and appropriately use data in planning and operations
- Market Simulator, 21 Day Energy Simulator, Inverter-Based Resource Modeling: There are various research and development efforts at the ISO that are expected to result in significant improvements to ISO modeling capabilities and situational awareness
- Stakeholder Priorities: The ISO has embarked on an improved prioritization process with stakeholders; each year, the ISO expects stakeholders to highlight three key priorities; some of these priorities will require the development of new software and associated applications
- Other Market Design Projects Identified in the ISO’s Multi-Year Work Plan: The ISO plans to continue to make improvements to existing ancillary services, and design new ancillary services products; new ancillary products may include replacement reserves and ramping products

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

Forward Looking Capital Budget Spending *(cont.)*

Cyber Security & IT Asset and Infrastructure Replacement

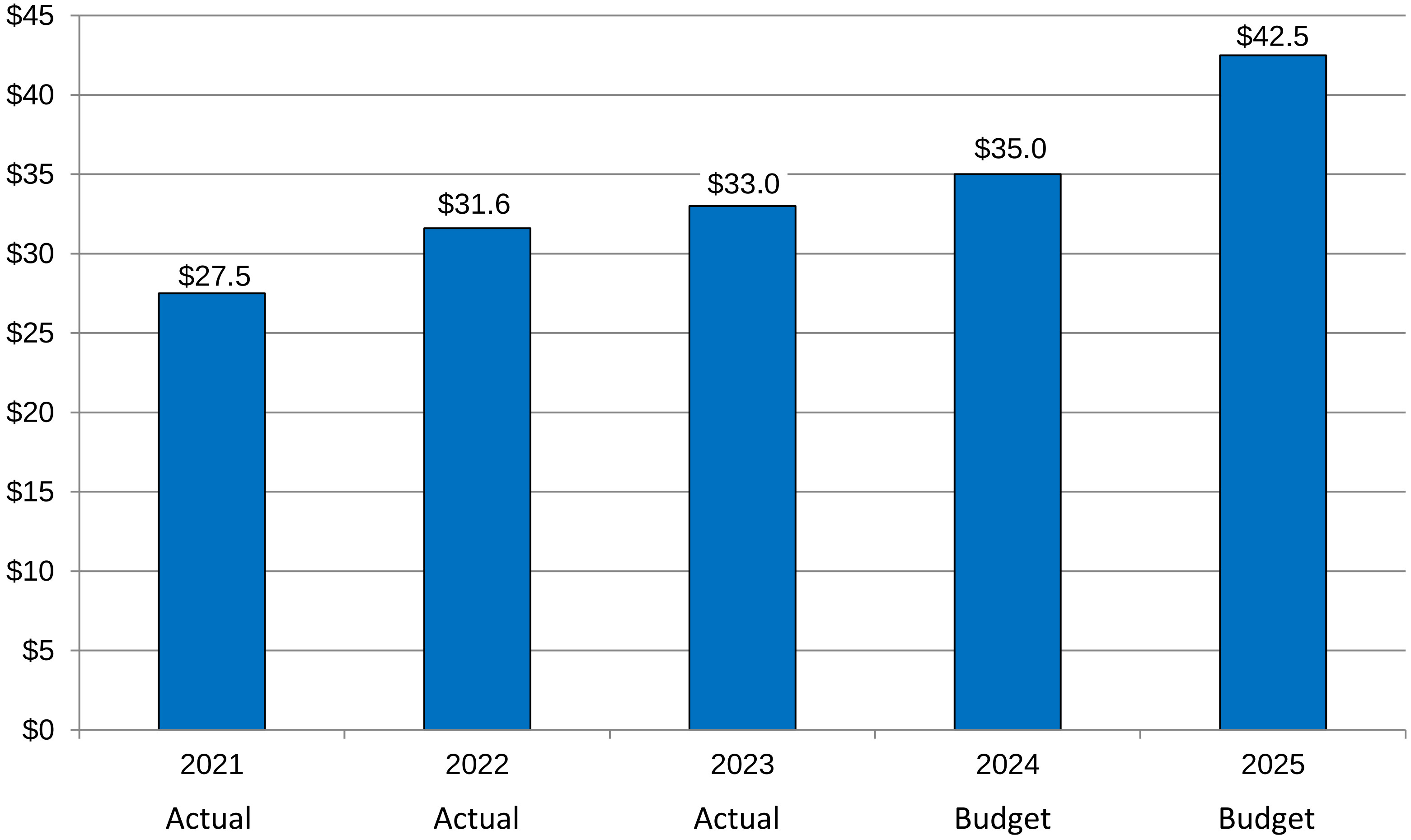
- Capital spending on improvements to cyber security and IT assets and infrastructure will support the ISO's strategic goals of Operational Excellence and Progress and Innovation
- ISO's cyber security maturity level has been an ongoing major investment and will continue over the next 3 - 5 years; ISO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

CAPITAL BUDGET SUMMARY

Capital Budget

Historical Comparison Capital Expenditures

Average +/- $33.9M



Capital Budget
2025 Expenditures

Goal: Responsive Market Designs

Project	2025 Budget	Total Project Cost	Estimated Completion Date	Project Stage
. FERC Order 841	$2.0 M	$2.9 M	10/25	Conceptual Design
. Day-ahead Ancillary Services Improvements	$1.5 M	$9.1 M	03/25	In Development
. FERC Order 2222	$1.0 M	$6.0 M	11/26	Conceptual Design
. Solar Do Not Exceed Dispatch Phase III	$0.3 M	$0.3 M	11/25	Conceptual Design
. Storage as Transmission Only Asset	$0.4 M	$1.4 M	03/27	Conceptual Design
Total:	**$5.2 M**			

Goal: Progress and Innovation

Project	2025 Budget	Total Project Cost	Estimated Completion Date	Project Stage
. nGEM Real-Time MCE Implementation	$4.0 M	$14.8 M	06/26	In Development
. nGEM Software Development Part III	$2.9 M	$4.5 M	04/25	In Development
. Integrated Market Simulator Enhancement	$1.5 M	$1.5 M	12/25	Conceptual Design
. nGEM Software Development Part IV	$1.0 M	$2.0 M	06/26	Conceptual Design
. EMS Short-term Load Forecast Replacement	$0.1 M	$1.4 M	02/25	In Development
Total:	**$9.5 M**			

Capital Budget
2025 Expenditures *(cont.)*

Goal:Operational Excellence

Project	2025 Budget	Total Project Cost	Estimated Completion Date	Project Stage
. Space Utilization Project Phase I	$2.0 M	$3.0 M	08/25	Conceptual Design
. Enterprise Core Network Refresh	$2.0 M	$2.0 M	12/25	Conceptual Design
. Enterprise Resource Planning System Replacement	$1.9 M	$4.1 M	12/25	Conceptual Design
. Managing Transmission Line Ratings	$1.7 M	$7.7 M	11/25	In Development
. EMP 3.5 Upgrade	$1.5 M	$5.5 M	12/26	Conceptual Design
. Windows Server Replacement Phase II	$1.5 M	$1.7 M	12/25	Conceptual Design
. MW Dependent Fuel Price Adjustment	$1.0 M	$1.1 M	11/25	Conceptual Design
. 2025 Issue Resolution Project	$0.8 M	$0.8 M	09/25	Conceptual Design
. CAMS Application Software Technology Upgrade	$0.7 M	$1.4 M	06/25	In Development
. Network Modeling Tool Enhancements	$0.5 M	$1.3 M	07/25	In Development
. Tie Line Telemetry and PCEC Upgrades Phase II	$0.5 M	$0.5 M	07/25	Conceptual Design
. Circuit Inventory Management Platform	$0.4 M	$0.6 M	10/25	Conceptual Design
. Microsoft 365 Service Adoption	$0.1 M	$0.7 M	11/24	In Development
. Tie Line Telemetry and PCEC Upgrade	$0.1 M	$0.3 M	06/25	In Development

Continue to the next page

Capital Budget
2025 Expenditures *(cont.)*

Goal:Operational Excellence

Project	2025 Budget	Total Project Cost	Estimated Completion Date	Project Stage
. CIP Electronic Security Perimeter Redesign Phase II	$0.3 M	$5.0 M	06/25	In Development
. Replace Employee & Pager Application	$0.3 M	$0.4 M	10/25	Conceptual Design
. Adoption of NERC CIP Compliance of Synchrophasor Systems	$0.3 M	$1.0 M	10/26	Conceptual Design
. Automatic Ring Down Circuit Continuity Modernization and Reliability Enhancements	$0.3 M	$0.9 M	08/25	In Development
. New England Clean Energy Connect	$0.3 M	$0.5 M	12/25	In Development
. Non-Project Capital Expenditures	$5.0 M			
Total:	**$21.1 M**			

Capital Budget
2025 Expenditures Summary

2025 Capital Budget Expenditure Summary

Allocation Category	2025 Budget
Goal: Responsive Market Designs	$5.2 M
Goal: Progress and Innovation	$9.5 M
Goal:Operational Excellence	$21.1 M
Other Emerging Work	$5.7 M
Capital Interest	$1.0 M
Total:	**$42.5 M**

CAPITAL STRUCTURE AND CASH FLOW

Capital Structure and Cash Flow

- In order to support the markets and reliability efforts, ISO will increase the capital spending from $35M in 2024 to $42.5M in 2025, and at $40M in 2026 and beyond
  - The areas driving the increase in spending are dependent on various factors such as regulatory approvals, use of professional services versus internal staff, estimated range of spending, inflationary cost and longer lead times to complete
  - Longer lead time to complete capital projects results in a greater period of time from when the ISO spends capital funds to tariff recovery through depreciation expense of these projects

- Capital project costs are largely funded by $50M in Private Placement Notes set to expire in November 2024; in order to support the future capital program, we have determined that another $25M in available capital project funding is needed to support a higher sustained level of capital spend; consequently, ISO worked through the stakeholder and Board process to get approval for $75M Private Placement Note and is working to complete the offering in Q3 of 2024

Capital Structure and Cash Flow *(cont.)*

The ISO received FERC approval on July 19, 2024 to enter into $75M Private Placement Note. The ISO is current in the process of going out to market to secure funding that will be issued and available by the time the $50M balloon payment on the current note is due in November.

ISO New England
2024 - 2028 Debt Service Cash Flow

	2024 Forecast	2025 Budget	2026 Forecast	2027 Forecast	2028 Forecast
Cash flows from operating activities:					
Operating Cost Recovery *	$ 228,956	$ 268,509	$ -	$ -	$ -
Non Cash Items:					
Depreciation, Amortization & G/L on Disposals	32,659	36,975	42,132	40,296	39,786
Amortization Term Loan Fees	61	96	96	96	96
Chg in Deferred Revenue-Depreciation	(100)	-	-	-	-
Chg in Accrued Expenses	120	-	-	-	-
Interest Expense	(3,570)	(4,475)	-	-	-
Operating Expenses, net of CEO Emerging Work & Allowance & Board Contingency *	(233,487)	(264,859)	-	-	-
Net cash provided by operating activities	24,639	36,247	42,228	40,392	39,882
Cash flows from investing activities:					
Capital expenditures	(35,000)	(42,500)	(40,000)	(40,000)	(40,000)
Net cash used in investing activities	(35,000)	(42,500)	(40,000)	(40,000)	(40,000)
Cash flows from financing activities:					
Net Proceeds/(Repayment) - Revolving Credit Line	-			-	
Repayment of Principal - Private Placement	(50,000)	-	-	-	-
Proceeds - Private Placement	75,000	-	-	-	-
Repayment of Principal - Tax Exempt Bonds	(3,180)	(3,180)	(3,180)	(3,180)	(3,180)
Net cash provided by (used by) financing activities	21,820	(3,180)	(3,180)	(3,180)	(3,180)
Net increase/(decrease) in cash	11,459	(9,433)	(952)	(2,788)	(3,298)
Cash & Cash Equivalents on Hand - Beginning of Period	16,207	27,666	18,233	17,281	14,493
Change in Cash & Cash Equivalents Available	11,459	(9,433)	(952)	(2,788)	(3,298)
Cash & Cash Equivalents on Hand - End of Period	$ 27,666	$ 18,233	$ 17,281	$ 14,493	$ 11,195
Debt Maturity Schedule					
Tax Exempt Bond - BCC	1,360	1,360	1,360	1,360	1,360
Tax Exempt Bond - MCC	1,820	1,820	1,820	1,820	1,820
Total Year Repayment	$ 3,180	$ 3,180	$ 3,180	$ 3,180	$ 3,180

*= Operating Cost Recovery for 2024 has decreased by an overcollection in 2022 of $3,006 which was not amortized in 2023 but included in the 2024 tariff. The undercollection of $4,844 for 2023 will be filed with the 2025 tariff and will be reflected in the Operating Cost Recovery for 2025. The Operating Cost Recovery for 2026-2028 is projected to offset Operating Expenses for 2026-2028. The Operating Cost Recovery amount for 2026-2028 has not yet been established at this point.

Capital Structure and Cash Flow *(cont.)*

- The ISO currently has two revolving credit lines with TD Bank that are set to expire July 1, 2028; the first is a $40 million working capital line to support the ISO’s short-term operational needs and cash flow risks, which may include draws to support lower than projected load driving decreased Tariff collections, a continued increase in budgetary needs over the next 3 - 4 years, and more recently the issuance of FERC Order 2023 which may increase withdrawals of system impact studies (i.e., reducing cash available to the ISO); the second is a $4 million line to support the short-fall funding arrangements necessary to support twice- weekly billing of the ISO New England markets
- For the six months ended June 30, 2024, the ISO’s total weighted average cost of capital was 4.04%, excluding fees charged on the various debt financing; fees ranged from .075% to .38%

APPENDIX 1: OTHER OPERATING BUDGET DETAILS

Operating Budget Details - Budget Categories

(see next slides for detail on certain categories)

($ in thousands)	2021 Actual	2022 Actual	2023 Actual	2024 Budget	2025 Budget
Salaries	$90,069	$94,438	$104,324	$122,140	$134,822
Burden	28,329	30,117	32,993	36,069	39,138
Professional fees and consultants	19,695	19,833	22,200	29,257	27,777
Building services	2,832	3,348	3,339	3,430	3,492
Rents/leases	777	696	719	781	2,123
Network Operations	2,802	2,958	3,138	3,652	3,936
Computer services	15,952	17,482	20,469	25,373	31,336
Insurance expense	2,153	2,633	2,927	3,394	3,887
Board of Directors Expense	1,592	1,674	1,543	1,607	1,637
Meetings & Related Expenses	536	1,015	990	1,511	1,637
Education & Training	891	1,062	1,032	1,332	1,433
NPCC and NERC Dues	6,062	6,437	7,277	8,052	9,253
Interest Expense	2,120	2,249	2,834	3,459	4,571
Contingency Funds	-	-	-	2,700	3,700
Other Expense	1,758	1,931	1,863	2,498	2,469
Interest Income & Other Revenue	(443)	(1,267)	(2,055)	(917)	(1,783)
Net Expense before Depreciation	**175,125**	**184,606**	**203,595**	**244,337**	**269,430**
Depreciation	26,221	25,046	30,056	32,559	36,975
Total ISO Tariff Recovery	**$ 201,346**	**$209,652**	**$233,651**	**$276,897**	**$306,405**
Revenue True-up	151	1,071	(14,589)	(3,006)	4,844
Revenue Requirement	201,497	210,723	219,062	273,891	311,249
Network Load (GWh)	139,423	142,463	143,042	140,711	136,500
Grid Market Charge $/KWh	$0.00145	$0.00148	$0.00153	$0.00195	$0.00228
Headcount (FTE's) (2) (3)	573.5	589.5	614.5	644.5	688.5

(1) Net Expense Before Depreciation of $269.4 million for 2025 agrees to slide 42 of the presentation.
(2) 2021, 2022 and 2023 reflect December 31 actual headcount for those years. 2024 and 2025 reflect planned headcounts of 698.5 and 746.5, respectively, less vacancy (of 5.0% for 2024 and 6.0% for 2025) and the impact of layering in new positions to account for recruiting and onboarding.
(3) Funding of $6.4 million of Salaries and $2.3 million of Burden exists for 2025 internal capital development and reimbursable study time of ISO-NE Employees. Total Salaries and Burden including these and operating costs equal $182.6 million.

Operating Budget Details - Budget Categories *(cont.)*

The following are explanations of budgeted items that are included in the *Other Expense* and *Interest Income & Other Revenue* lines of the budget details by category (as shown on the previous slide):

- *Other Expense* – This line includes Data Services & Office expenses which include subscriptions for industry and general information, professional dues, printing, office supplies and equipment, and postage and courier; this line also includes payment in lieu of taxes, bank fees, and business & license fees
- *Interest Income & Other Revenue* – This line includes interest income on accounts, purchase discount (primarily from utility expense), and miscellaneous service revenue

The following are line items that contain budget increases in 2025 which are greater than 5% or $500,000 and a brief explanation of what is driving the change:

- *Salaries ($12.7M or 10.4%)* – Increases include salary related to annual merit and promotional increases to align compensation according to compensation study results, funding for the addition of 50 full-time equivalent positions including funding for 30 in 2025 and carryover of 20 FTE’s from 2024, and for employee incentive target amounts including adjustments based on compensation study review. These increases were partially offset by a reduction for employee rates due to employee turnover and retirements, and an increase in the vacancy rate (from 5.0% to 6.0%)
- *Burden ($3.1M or 8.5%)* – Increases for payroll taxes related to noted salary increases including for the additional 50 full-time equivalent positions funded in 2025; also contributing to increased expenses is higher employee benefits including those for medical trend, and defined contribution and 401K (match) plans due to both higher salaries and increased participants

Operating Budget Details - Budget Categories *(cont.)*

- *Rents/Leases ($1.3M or 171.8%)* – Increase for leasing tranche of blade servers for data center replacements that is more favorable than buying, as well as leasing of land adjacent to Holyoke facility in conjunction with Space Utilization project
- *Network Operations ($0.3M or 7.8%)* – Increases for transition of communication lines to new technologies, for data redundancy, and for inflationary and communication line increases
- *Computer Services ($6.0M or 23.5%)* – Increases for: cyber security (security logging, firewall updates, network collaboration tool, network traffic segmentation, encryption software and risk management); photovoltaic and demand response forecast products; licensing for System Planning and Operations applications; performance monitoring software; Enterprise Resource Planning software; compliance software; and inflationary and vendor increases across our portfolio of computer service products (The $6.0M increase includes $2.3M for existing product costs and/or licensing, $2.0M for Cyber Security additions/enhancements, and $1.7M for Clean Energy technology investments).
- *Insurance Expense ($0.5M or 14.5%)* – Increased premiums across insurance lines
- *Meetings & Related Expenses ($0.1M or 8.3%)* – Meetings & related expenses increased primarily due to full renewal of in-person meetings, higher travel costs, and travel for offsite training of additional staff and for new platforms and tools
- *Education & Training ($0.1M or 7.6%)* – Training of additional staff and for education of new platforms and tools
- *NPCC and NERC Dues ($1.2M or 14.9%)* – Increases for both Northeast Power Coordinating Council and North American Electric Reliability Corporation dues assessed to the ISO

Operating Budget Details - Budget Categories *(cont.)*

- *Interest Expense ($1.1M or 32.1%)* – For Private Placement debt in late 2024 at higher balance and expected higher rate than previous debt; tax exempt debt due to higher rate slightly offset by decrease in principal balance; with a partial offset on the working capital borrowing
- *Interest Income & Operating Revenue ($0.9M or 94.4%)* – Increase in interest income due to raising of interest rates for 2025 to 2.75% compared to 1.00% in 2024 budget
- *Depreciation Expense ($4.4M or 13.6%)* – Depreciation expense increases primarily driven by 2025 implementations of Day-Ahead Ancillary Services, nGEM Software Development Phase III, and CIP Electronic Security Perimeter Redesign Phase II projects

Operating Budget Details - Budget Categories *(cont.)*

ISO True-Up Mechanism

Description of True-Up Mechanism:

As set forth in Section IV.A.2.2 of the ISO's Tariff, the 2025 revenue requirement will include an adjustment for deviations between actual collections and expenses for calendar year 2023. In general, the amount of the true-up is added to (in the case of a revenue shortfall) or subtracted from (in the case of a revenue over-recovery) the ISO's total estimated budgeted amounts for the upcoming budget year.

The $4.8 million true-up amount, that is increasing the 2025 revenue requirement, is based on the following:

The final 2023 revenue requirement was an under-collection of $4.8 million, which will increase the 2025 requirement. The under-collection resulted from lower collections that were partially offset by lower expenses. Specifically, 2023 collections under Section IV.A of the ISO-NE tariff were $11.4M below what was included in the 2023 budget/tariff filing, while expenses were $6.6 lower than budgeted. Please see the next slide for further detail and a reconciliation making up the $4.8 million under-collection.

Operating Budget Details - Budget Categories *(cont.)*

The following is a reconciliation of the $4.8 million true-up amount, that is increasing the 2025 revenue requirement ($ in thousands):

2023 Revenue Requirement True-Up Reconciliation - ISO New England Inc.
(Dollars in thousands)

Spending Variances (Dollars in thousands):	$ Amounts (credits are savings)	Totals (credits are savings)
Contingencies:		
Board Contingency	$ (700.0)	
CEO Emerging Work Allowance	$ (2,000.0)	
Net Savings in Contingencies		$ (2,700.0)
Professional and Legal Fees Changes:		
Information Technology - decreases include Energy Management System and other Information Technology consultant support that was reallocated for capital development work (nGEM and Day-Ahead Ancillary Services Improvements projects), lower rates for Information Technology positions, and higher than forecasted vacancy of consultants	$ (1,705.8)	
Legal - reduced need for external legal counsel to supplement ISO-NE staff, and lower use of the External Market Monitor (budgeted through Legal) for Day-Ahead Ancillary Services Initiative (DASI) project implementation and Forward Capacity Auction parameter review work	$ (877.8)	
All Other Areas	$ (151.4)	
Net Changes in Professional and Legal Fees		$ (2,735.0)
Interest Income - increase due to higher than forecasted rates on settlement and operating fund balances		$ (1,412.6)
Depreciation Expense - reductions due to the timing of project completion or lower actual spending for various projects including Priveleged Account Management Security Enhancments 2023, Inventoried Energy Program, Forward Capacity Tracking System Infra. Conversion Part III, IMM Data Analysis Phase III, E-mail List Server Technology Refresh and New Cyber Security Operations Center		$ (919.6)
Interest Expense - reduction is due to higher allocation of interest expense to multi-year work-in-progress capital projects due to higher interest rates, and lower forecasted borrowing on the working capital line of credit. These reductions were partially offset by higher expense due to higher rates on tax-exempt debt.		$ (303.3)
Salaries and Overheads - Increases include salary raises outside of the annual merit and promotional cycle which has been largely driven by compensation benchmarking data for identified critical or hard to fill roles; for retention, overtime, and succession planning; and due to lower reimbursable study work. Partially offsetting the increases are reductions due to higher and from lower employee pay rates than previous incumbents.		$ 2,615.4
Net Change across all other Expense Lines: Includes several line items with variances between $100 and $300 (thousand)		$ (1,098.8)
Net Savings in Expenses:		**$ (6,553.9)**
Tariff Collections (under collection): Tariff collections came in 5.0% below plan, which were driven primarily by lower than budgeted load related factors.		**$ 11,397.5**
Total 2023 True-Up		**$ 4,843.6**

Operating Budget Details

Professional Fees

(See next slides for details)

	($ in Millions) 2025	2024
Corporate Center	$ 6.6	$ 6.0
Legal	3.2	3.2
Operations	17.9	20.0
Total Professional Fees	**$ 27.8**	**$ 29.3**

Operating Budget Details
Professional Fees – Corporate Center

($ in Millions)	2025	2024
Corporate Center	$ 6.6	$ 6.0
Legal	3.2	3.2
Operations	17.9	20.0
Total Professional Fees	**$ 27.8**	**$ 29.3**

($ in Millions)	2025	2024
Benefits and Hiring		
Recruiter Fees and Background Checks	$ 0.4	$ 0.4
Relocation	0.7	0.5
Temp Help	0.3	0.3
Compensation Surveys	0.4	0.4
Other Consulting for Pension & Benefits	1.4	1.0
Total Benefits and Hiring	3.2	2.5
Financial Support (Payroll processing, Temp Help, etc.)	0.4	0.5
Audits (i.e., SOC 1, financial statement, IT systems, federated authentication)	1.3	1.2
Corporate Communications (see following slide)	0.2	0.2
External Affairs (see following slide)	0.5	0.5
Market and Credit Risk Support (New margin models)	0.4	0.3
Strategy, Risk and Operation Compliance (Professional Consulting Support for the Governance/Risk/Compliance tool, Record Storage and Destruction, and Procedure Writing)	0.2	0.2
Market Monitoring and Mitigation - Application Support, and Energy Market Consultation	0.4	0.8
Total Included in Budget	**$ 6.6**	**$ 6.0**

	($ in Millions)	
	2025	2024
Corporate Center	$ 6.6	$ 6.0
Legal	3.2	3.2
Operations	17.9	20.0
Total Professional Fees	**$ 27.8**	**$ 29.3**

Operating Budget Details

Professional Fees – External Affairs/Corporate Communications

	($ in Millions)	
	2025	**2024**
State Educational Outreach / Legislative Monitoring	$ 0.3	$ 0.3
Media Relations / General Support	0.2	0.2
Federal Educational Outreach / Legislative Monitoring	0.1	0.1
Total Included in Budget	**$ 0.7**	**$ 0.7**

Operating Budget Details

Professional Fees – External Affairs

($ in Millions)	2025	2024
Corporate Center	$ 6.6	$ 6.0
Legal	3.2	3.2
Operations	17.9	20.0
Total Professional Fees	**$ 27.8**	**$ 29.3**

- Purpose: To inform state and federal government stakeholders and policymakers on the performance and needs of the power system and wholesale markets
- Activities:
  - – Timely information on the status of the power system including:
    - Emergency communications during power supply deficiencies
    - Continuous information on the current and future needs of the power system region-wide and on a state and sub-regional basis
  - – Facilitate state regulatory input into the transmission system and market design processes
  - – Monitor state energy initiatives to inform the wholesale market and transmission planning development processes

Operating Budget Details

Professional Fees – External Affairs *(cont.)*

($ in Millions)	2025	2024
Corporate Center	$ 6.6	$ 6.0
Legal	3.2	3.2
Operations	17.9	20.0
Total Professional Fees	**$ 27.8**	**$ 29.3**

- Resources
  - Internal staff resources are focused on providing information to regulatory commissions, governors' offices, state legislatures, federal congressional offices, consumer advocates, business and industry organizations, academic institutions and general public outreach
    - Nine professional staff, including new position, policy advisor for environmental and community affairs, to support environmental justice discussions
    - For the first seven months of 2024:
      - 60 utility commission / state agency meetings & briefings
      - 50 state policymaker meetings & briefings
      - 20 federal policymaker / regulator meetings & briefings
      - 40 industry conferences, speaking engagements & meetings supported / attended by ISO-NE staff
      - 8 academic group virtual visits or lecture series participated in / attended by ISO-NE staff
      - 2 Consumer Liaison Group meetings
  - External resources are focused on monitoring state and federal legislation initiatives, organizing educational opportunities, and distributing timely information
    - Contract consultants in each state, and in Washington, DC

Operating Budget Details
Professional Fees – Legal

($ in Millions)		2025		2024
Corporate Center	$	6.6	$	6.0
Legal		3.2		3.2
Operations		17.9		20.0
Total Professional Fees	**$**	**27.8**	**$**	**29.3**

($ in Millions)		2025		2024
Independent Market Advisor	$	1.4	$	1.3
Market Rule and Tariff/OATT Proceedings		1.4		1.4
Labor Matters		0.1		0.1
Other		0.4		0.4
Total Included in Budget	**$**	**3.2**	**$**	**3.2**

Operating Budget Details

Professional Fees – Operations

	($ in Millions)	
	2025	**2024**
Corporate Center	$ 6.6	$ 6.0
Legal	3.2	3.2
Operations	17.9	20.0
Total Professional Fees	**$ 27.8**	**$ 29.3**

	($ in Millions)	
	2025	**2024**
Information Technology (SMS/SAS/EMS/CAMS Support, Network Model and Model-On-Demand, Energy Management System Support, Software License Management & Reporting Support, Website Support, Cyber Security and Vulnerability Testing, Desktop and Database Services Support, RTU and NX9/NX12 Network Model Support, and other Temp Help)	$ 10.1	$ 9.7
FCA and FCM Analysis Support	0.2	1.6
System and Transmission Planning Regional study with PJM and NYISO on single source transmission limits, TPL-001 System Assessment, Transmission Planning / Non-Transmission Alternatives, Interconnection Studies, Short Circuit Analysis, Integrating Emerging Technologies and Distributed Generation into Load Forecasting, and develop and execute long range transmission planning studies in conjunction with the states	3.4	4.0
Market Development for Medium Term Energy Adequacy and Project Management	1.3	1.4
Capacity Auction Reforms	1.2	2.5
Project Management (Impact Analysis, R&D, Project Work and Initiatives)	1.5	0.7
System Operations Support (New England Clean Energy Connect Project)	0.3	0.0
Participant Support and Training	0.1	0.3
Total Included in Budget	**$ 17.9**	**$ 20.0**

Operating Budget Detail

2025 Budget for Board Compensation

2025 Original Budget (1)

• Annual retainers for Board Committee membership (2) ($115K/Board Member)	$1.0M
• Annual retainers for Chair positions (2) ($40K Chairman and $10K Committee Chair)	$0.4M
Total Board Compensation (3)	$1.4M
• Meetings and Travel Expenses	$0.2M
Total Board of Directors Expenses	$1.6M

(1) The budget contemplates 9 members for 2025 not including the CEO who is the 10th member of the Board

(2) Effective Feb 15, 2024, the Board of Directors compensation structure has transitioned from a meeting fee structure to a retainer only structure. The revised policy eliminates all references to meeting fees and now specifies the annual retainers for Board Committee membership and Chair positions

(3) Board Compensations are evaluated using independent surveys, similar to process used for determining executive compensation

APPENDIX 2: COMPENSATION

Process for Establishing Salary Budget Increases

- Each year, ISO-NE reviews comprehensive salary budget planning data compiled by nationally-recognized compensation consulting firms
  - The firms used for 2025 are Mercer, WorldatWork, WillisTowersWatson, Payscale, Empsight, KornFerry, Conference Board, and PearlMeyer
  - These surveys are typically published later in the summer and reflect planned salary budget increases of over 2,300 employers, including more than 100 utility companies
    - The data is often presented by region, industry, and by employee group (executive, management, exempt, and non-exempt employees)
    - Salary budget data may be further classified into two categories: merit increases and promotional/equity increases. Several surveys indicate that less than half of respondent companies formally budget for promotions and/or adjustments.
- ISO-NE will also review expected salary increases of other ISOs/RTOs

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

- Merit Increases
  - Merit pools are the percentage of total employee salaries that companies intend to use for broad-based salary increases in the coming year
    - At ISO-NE, this pool funds the annual performance-based increases for eligible non-bargaining unit employees
    - Individual percentage increases vary based on employees' performance, with some receiving less than and some receiving more than the budget percentage
- Promotional/Equity Increases
  - Historically, a separate, smaller pool of monies used in select circumstances to fund promotions and base salary adjustments for critical positions
    - At ISO-NE, this pool more recently has been increased to fund any required salary adjustments based on our benchmarking initiative and to allow for targeted compensation adjustments to enable us to retain key talent

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

- In 2022, to address competitive challenges related to the clean energy transition, particularly those specified on Slide 111, ISO engaged a compensation consulting film to conduct more discrete, 1-for-1 job-specific benchmarking to establish competitive rates of pay for our highly skilled and in-demand workforce
- Supplementing the salary budget survey data with job-specific benchmarking allows us to better ensure that we are providing competitive rates of pay to our current employees, as well as attracting the necessary talent to be successful in the future
  - In 2022, we assessed compensation levels for our most technical engineering and IT roles, approximately 1/3 of our organization
  - In 2023, we assessed another 1/3 of the organization, with continued focus on IT and other roles requiring significant technical expertise
  - In 2024 and 2025, we plan to assess the remainder of the roles in the organization

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

- A summary of the available survey results and management's recommendation is presented to the Compensation and Human Resources Committee of the Board of Directors
  - The Committee reviews the data at its September meeting and establishes the annual merit and promotional/equity adjustment increase percentages
- The table on the next slide compares annual survey data to ISO-NE's budgeted increases for the past ten years

ISO New England Salary History

Comparison: Survey Data to ISO New England Salary Increase Budgets						
Year	*Merit Increase Budgets (survey results represent averages of all participating companies)*			*Promotion/Equity Increase Budgets (survey results represent averages of all participating companies)*		
	Survey Results		ISO-NE Budget	Survey Results		ISO-NE Budget
	Utility Industry	General Industry		Utility Industry	General Industry	
2025 *	3.6%-4.0%	3.5%-4.0%	**4.0%**	0.7%-2.0%	0.7%-2.0%	**2.0%**
2024	3.7% - 4.0%	3.5% - 3.7%	**4.0%**	0.0% - 0.5%	0.5% - 1.0%	**4.0%**
2023	3.5% - 4.0%	3.1% - 4.0%	**4.0%**	0.5% - 1.0%	1.0% - 1.2%	**1.75%**
2022	3.0% - 3.0%	3.0% - 3.0%	**3.0%**	0.5% - 1.0%	0.0% - 1.0%	**0.5%**
2021	2.9% - 3.1%	2.8% - 3.0%	**2.5%**	0.0% - 1.5%	0.15% - 1.1%	**0.5%**
2020	3.0% - 3.1%	2.9% - 3.2%	**3.0%**	0.5% - 1.0%	0.5% - 1.0%	**0.5%**
2019	2.8% - 3.1%	2.9% - 3.0%	**2.75%**	0.0% - 1.0%	0.0% - 1.0%	**0.75%**
2018	2.8% - 3.2%	2.9% - 3.0%	**2.75%**	0.5% - 0.8%	0.5% - 1.0%	**0.75%**
2017	2.8% – 3.1%	3.0% - 3.0%	**2.75%**	0% - .05%	0.5% - 0.5%	**0.75%**
2016	2.8% - 3.0%	3.0% - 3.0%	**2.75%**	0% - 0.8%	0.5% - 1.0%	**0.75%**
2015	2.9% - 3.0%	2.9% -3.1%	**2.75%**	0.5% - 1.0%	0.5% - 1.0%	**0.75%**

* As of the date of this presentation, the ISO is still awaiting one survey response. The above chart reflects data received to date.

Competitive Challenges

- As described in industry literature and shared with NEPOOL in the past, ISO-NE and utility employers face significant challenges associated with the retirement of a seasoned, technical workforce
  - Approximately 19% of the ISO-NE workforce is retirement-eligible
- The clean energy transition has increased the demand for highly specialized personnel required to address the modeling, analysis, processing, and operational needs of the transition
  - Hiring and retaining highly specialized technical talent has become more challenging and costly
- This competition will only intensify as the region becomes increasingly involved with new and emerging technologies
  - More employees, with different skillsets will be needed to address the volume of market design changes and operational/planning complexities
  - Major investments in new technologies to create and support the core business applications and processes, including increased computational capacity to deal with increased grid complexity, will require the requisite staff to complete this work

Executive Compensation

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

Executive Compensation *(cont.)*

- The Compensation and Human Resources Committee of the Board of Directors and the full Board of Directors review the Mercer Reasonableness Opinion and use it to finalize their decisions regarding each executive's compensation
- Executive compensation is reported in ISO-NE's annually filed IRS Form 990
  - This public filing is required for all tax-exempt companies and depicts officer compensation in detail
  - In addition to annual compensation, the data includes incremental increases in accrued pension benefits and other potential future compensation not yet received by the executive
- 2025 Budget for Executive Salaries $5.2M
  - Executive Salaries comprise the base salaries of the officers on the IRS Form 990

Pension and Defined Contribution Benefit Plans in 2025

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

Pension and Defined Contribution Benefit Plans in 2025 *(cont.)*

- Defined Benefit Pension Plan: In 2016, for the Pension Plan, ISO-NE modified the funding approach that it had consistently employed since 1997
  - ISO-NE previously calculated the budgeted Pension Plan expense amount in accordance with the Financial Accounting Standards (FAS)
  - This amount was included in the filed rates and contributed to the Pension Plan
  - In 2014 ISO-NE began looking into a level funding approach for the Pension Plan; ISO-NE engaged its actuaries and its investment consulting firm to perform analyses on implementing a change to the current funding approach
  - In 2016, ISO-NE implemented the level funding approach for making contributions and for inclusion in the filed rates
  - ISO-NE's actuaries refreshed the analysis in 2019 and the conclusion was to continue to fund the Pension Plan at the originally established level funding amount of $10,000,000 per year. ISO is in process of having this analysis refreshed and preliminary results show $10,000,000 continues to be an appropriate level of funding to cover the service cost of the plan and the fluctuating interest rate environment
  - The Pension Plan expense that is included in the 2025 budget is $10,000,000 compared to the projected FAS expense of $5,480,000

Pension and Defined Contribution Benefit Plans in 2025 *(cont.)*

The table below identifies the number of active ISO-NE employees, at each year-end, that are included in the Defined Benefit Pension Plan and the Defined Contribution Plan:

Date	Defined Benefit Pension Plan	Defined Contribution Plan
12/31/2021	328	246
12/31/2022	306	286
12/31/2023	287	339

Note: The Defined Benefit Pension Plan was closed to employees hired or rehired after December 31, 2013.

Postretirement Medical Benefit Plan in 2025

- In 2014 ISO-NE looked at making changes to its benefit plan offerings; to better align with the industry, the decision was made to close the Postretirement Benefit Plan to new hires, effective January 2016; in addition, a modification was made to the criteria for when this benefit could start for those employees in the plan prior to January 1, 2016; the age and years of service requirements were increased, thereby reducing future benefits that could be paid
- Consistent with previous years' budgets, ISO-NE's actuaries prepared estimated 2025 Financial Accounting Standards (FAS) Expense for the Postretirement Benefit Plan
- Actuaries utilized the FTSE Pension Discount curve, and reflected the change in discount rates as of May 31, 2024 to estimate the discount rate used in the calculation of the Postretirement Benefit Plan; current rates approximate the forward curve rates
  - Discount Rates Selected:
    - Postretirement Benefit Plan 5.33%
  - Salary Scale assumption (weighted Avg.) 3.00%
  - Projected 2025 annual earnings rate 6.25% (approximately)
- The calculated FAS expense amount for the Postretirement Benefit Plan of $880,000 is included in the 2025 budget

Operating Budget Details

Staffing - Salary and Benefits Costs

The $15.8M increase in salary and burden costs is driven by the following factors:

2025 Merit & Promotion - (budgeted 6.0% increase (4.0% merit and 2.0% promotion/equity), which was approved by the Board Compensation and Human Resources Committee)	$	6.3		
Salary Impact of Funding for 50 Additional FTEs (1)		10.6		
Increase for employee incentive compensation target amounts including adjustments based on compensation study review		1.4		
Increase in Vacancy Rate (from 5.0% to 6.0%)		(1.6)		
Salary Rate Changes		(1.5)		
Other Salary Changes		(1.3)		
Total Salary Impact			$	13.9
Change in Employee Benefit Costs			$	1.9
Total Salary and Burden Increase			$	15.8

(1) The 2025 budget includes the recruitment of 46 additional positions with funding for 30 full-time equivalents, in addition to the carryover of deferred funding of 20 positions from the 2024 budget.

Operating Budget Details

Staffing – Authorized, Budgeted, and Actual Headcount

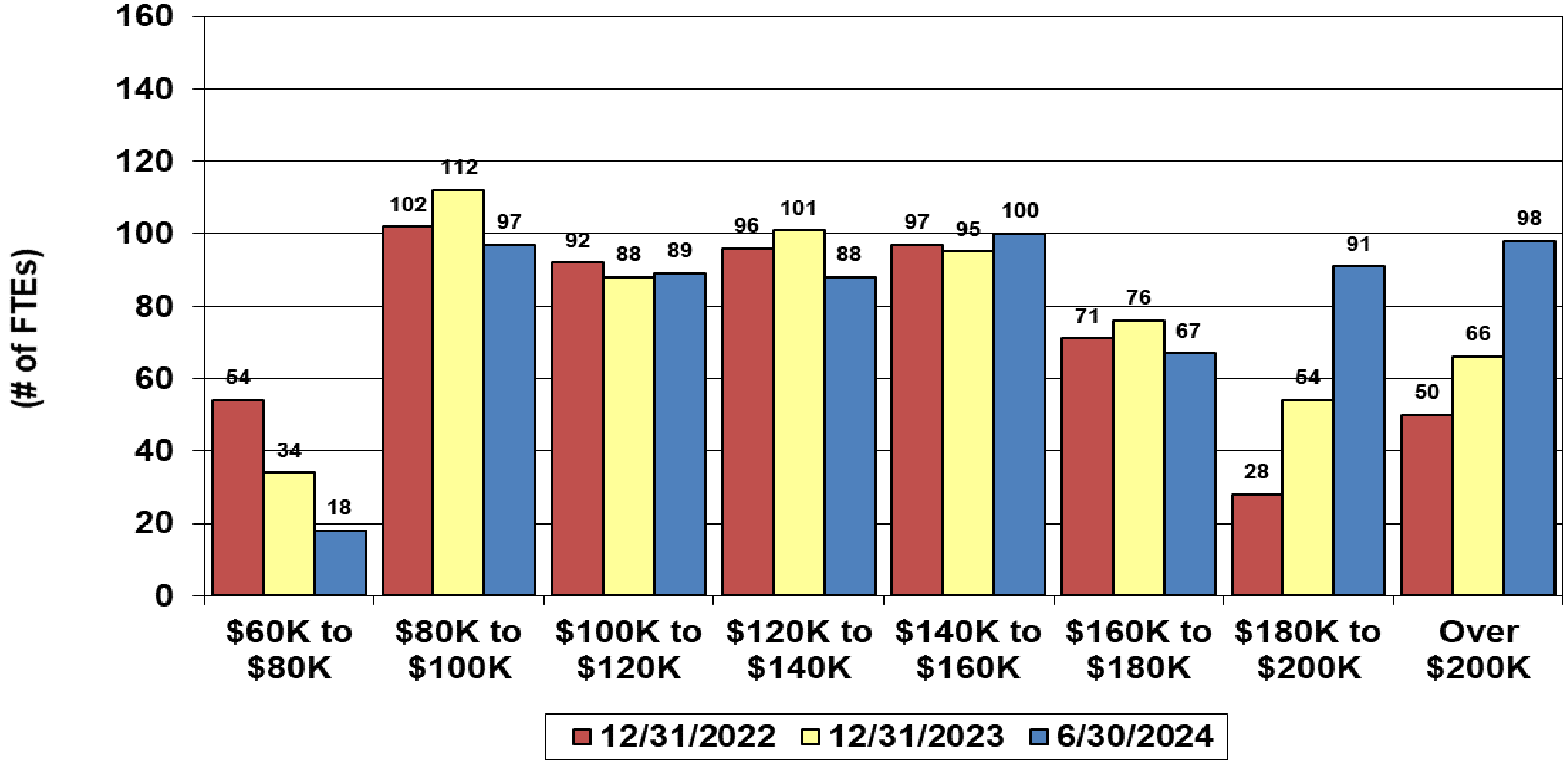
The following is historical full-time equivalent (FTE) headcount information:

Year	Authorized total FTE's	Budgeted FTEs	Actual FTEs (1)	Budgeted Vacancy %	Actual Average Vacancy
2015	595.0	577.0	584.5	3.0%	3.2%
2016	603.5	585.5	572.5	3.0%	3.8%
2017	603.5	585.5	583.5	3.0%	4.1%
2018	608.0	587.5	584.5	3.4%	3.9%
2019	608.0	583.5	587.0	4.0%	3.5%
2020	608.0	583.5	577.5	4.0%	3.8%
2021	608.0	583.5	573.5	4.0%	4.1%
2022	622.5	593.0	581.5	4.0%	5.8%
2023	654.5	614.5	625.5	5.0%	4.9%
2024	698.5	644.5	647.5	5.0%	6.1%
2025 (2) (3)	746.5	688.5	N/A	6.0%	N/A

(1) Actual FTEs is the number as of December 31st for each year with the exception of 2024 which represents the number as of June 30th
(2) The 2025 budget includes the recruitment of 46 additional positions, with funding for 30 full-time equivalents with onboarding expected to occur throughout the year. All other existing positions have been budgeted with an estimated 6.0% vacancy.
(3) The 2025 budget includes the conversion of 2 FTE consultant positions to ISO-NE employees (FTE's) with no overall $ impact on the 2025 budget (compared to 2024)

Operating Budget Details

Staffing – Number of Employees by Salary Band



Operating Budget Details

Staffing - Salary and Benefits Cost Comparison

The following provides actual Salary and Benefit related costs compared to budget for the two most recent completed years, 2023 and 2022, by component ($ in Thousands):

Description	2023			2022		
	Actual Expense	Approved Budget	Incr/(Dec)	Actual Expense	Approved Budget	Incr/(Dec)
Salaries and Wages - Base	$ 85,725.0	$ 85,304.6	$ 420.4	$ 76,075.0	$ 78,194.8	$ (2,119.8)
Salaries and Wages - Overtime	3,210.5	2,662.6	547.9	3,325.6	2,666.7	658.9
Salaries and Wages - Incentive/Bonus	15,389.0	14,224.8	1,164.2	15,037.5	13,723.0	1,314.5
Employee Benefits - Pension (1)	11,905.2	11,149.2	756.0	11,299.3	10,821.3	478.0
Employee Benefits - Post-Ret Benefits	739.2	927.8	(188.6)	328.0	554.0	(226.0)
Employee Benefits - Health Insurance	8,468.3	8,473.4	(5.1)	7,189.2	7,300.5	(111.3)
Employee Benefits - Dental Insurance	523.6	508.5	15.0	481.7	485.5	(3.8)
Employee Benefits - 401(K) Match	3,342.4	3,567.0	(224.6)	3,071.2	3,174.8	(103.6)
Salary Burden - Payroll Taxes	7,346.4	7,205.8	140.7	7,207.4	6,659.1	548.3
Other Benefit/Burden <$200K	667.9	678.4	(10.6)	540.5	566.8	(26.3)
Total Salaries & Burden Expense	**$ 137,317.5**	**$ 134,702.1**	**$ 2,615.3**	**$ 124,555.4**	**$ 124,146.6**	**$ 408.8**

(1) Pension costs include funding for both the Defined Benefit and Defined Contribution plans.

APPENDIX 3: 2023 DELIVERABLES AND SELECT METRICS

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

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

Mission Statement:

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

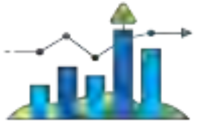
In 2023 the ISO Delivered on a Large Number of Complex and Novel Initiatives Addressing the Clean Energy Transition

ISO initiatives illustrate our commitment to advancing our vision to support the region's clean energy transition

Clean Energy Pillar

- Supported the changing grid and adapted to increasing system complexity through:
  - Acquiring new and more granular data about weather and end-use customer behavior
  - New modeling techniques to assimilate increasingly complex data sets
- Supported policy-makers considerations about how to achieve the goals of the clean energy transition
  - 2050 Transmission Study
  - Economic Planning for the Clean Energy Transition (EPCET)

Balancing Resources Pillar



- Filed Day-Ahead Ancillary Services Initiative (DASI)
- Completed an internal assessment of moving to a prompt and/or seasonal capacity market construct
- Took significant steps to reform how ISO accredits resource capacity with its Resource Capacity Accreditation work

In 2023 the ISO Delivered on a Large Number of Complex and Novel Initiatives Addressing the Clean Energy Transition

ISO initiatives illustrate our commitment to advancing our vision to support the region's clean energy transition

Energy Adequacy Pillar

- Developed advanced forecasting and modeling processes to drive actionable decision-making around power system needs
  - Quantified region's energy adequacy vulnerabilities
  - Developed Probability Energy Adequacy Tool (PEAT)
  - Established Regional Energy Shortfall Threshold (REST)
- ISO recognized for its leading-edge actions developing a systematic approach to determine risk of extreme weather conditions on energy adequacy
  - ISO employees awarded by EPRI for their work to develop metrics and methods for maintaining grid stability with inverter based resources
  - ISO employees participating in NERC energy adequacy standard drafting effort

Transmission Pillar

- The 2050 Transmission Study highlighted for stakeholders the high value of taking steps in the nearer term to mitigate long-term transmission needs:
  - Encouraged state regulators to further enable demand reductions to reduce peak loads
  - Gave greater consideration to the location and size of new generation
  - Identifies the important incremental upgrades and priorities to address high-likelihood concerns
- Filing on Extended/Longer-Term Transmission Planning Phase 2 accepted by FERC in Q3 2024
  - Enables development of transmission infrastructure to address the findings of a Longer-Term Transmission Study
    - Codifies NESCOE and the ISO's respective roles throughout the process
    - Establishes the cost recovery methodology for resulting transmission
    - Provides for ISO supporting States' RFPs

Responsive Market Designs

Improve the current market structure and continue to evolve and reposition the market design to support the states' objectives and transition to high levels of renewables and distributed resources. Maintain a robust fleet of balancing resources and preserve the ability of the market to guide the orderly entry and exit of resources.

Wholesale energy market is structurally competitive

- Operating reserve margins remain relatively high
- Residual Supply Index (RSI) scores meet expectations
- Energy market mitigation is relatively infrequent
- Markups in RT and DA markets were close to zero or negative
- In 2023, withheld economic capacity relatively low

Wholesale capacity market structurally competitive

- RSI and Pivotal Supplier Test scores: no pivotal suppliers
- Overall competitiveness increased with decrease in SENE zonal load forecast & increase in import capability limit

Wholesale Ancillary Services generally performing well, and the regulation market structurally competitive.

In 2024, ISO filed and obtained approval from FERC to implement changes for the 2024 Forward Reserve Auction to address previous years' findings that the Forward Reserve Market (FRM) was structurally uncompetitive.

Note: *See IMM 2023 Annual Markets Report for detail*

2025 continue to focus on enhancing market design for capacity, energy, and ancillary services markets to send more accurate price signals – addressing changing resource mix, associated operating complexity, and the region's winter security risks.

Note: *See Annual Work Plan & Wholesale Markets Plan for detail*

Progress & Innovation

Evolve capabilities to support the grid as the region transitions to clean energy, including improved power system and market modeling. Support investments in transmission infrastructure to enable renewable energy. Facilitate the integration of distributed energy resources. Provide data and information-based services.

Improve day-ahead load forecasting accuracy

- Average accuracy for peak hours of the month meets ISO's standards, *but* average accuracy across all hours of month does not. *See Monthly COO report to NEPOOL for detail*
- Implemented Day-Ahead nGEM Platform in 2023

Enhance programs to incorporate state policy objectives

- Reflect state energy efficiency goals; PV and electrification growth in long-term forecasting methodology. *See NEPOOL Load Forecast Committee & Planning Committee working groups*
- In 2024, ISO filed and obtained approval from FERC to enhance longer-term transmission planning program

Interconnect and register new resources to meet FERC established timeframes

- Order 2023 Reporting metrics (to be implemented)
- Analyzing the impacts of FERC Order 2023 on the interconnection process
- Streamlined DER process through transferring all distribution system interconnection to state processes

2025 focus is on integrating recent studies and analyses into existing tools and programs to improve modeling of emerging technology resources and develop forecasting solutions and load management solutions for weather dependent resources:

- Collect more detailed information about resources' operating characteristics, reflecting increased complexity and limited energy of resources
- Methods for tracking and forecasting amount and impact of electrification of heating (space & water) and transportation (vehicle classes)

Operational Excellence:

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

Maintain NERC Standards compliance

- Operate bulk electric system reliability, e.g., within frequency limits; to avoid instability, cascading outages or uncontrolled separation
- Maintain accurate planning models and update planning studies
- Oversee facility interconnection studies

Accurately settle markets with no errors

- Satisfactorily complete annual SOC 1 audit
- Administer hourly market operations with minimal LMP corrections and zero provisional DAM results adjustments

Maintain IT uptime and ensure business continuity

- Continuous assessments of cyber security threats and risks against CIP Standards; NIST Framework; DHS Known Exploited Vulnerabilities; phishing attempts

Maintain accurate quarterly budget forecasts, comparing projected costs/revenues against actual financial results.

2025 focus is on improving business operations across organization

- Implement internal process and technology improvements to address increasing grid complexity, including:
  - Broadening usage of ISO-developed innovations to enhance control room situational awareness and market efficiency
  - Addressing the trend of increasing DER/decreasing springtime load
  - Examining the single-source contingency limit
- Continue to modernize IT assets, technologies, and tools to mitigate cybersecurity threats
- Migrate ISO systems to the cloud

Stakeholder Engagement:

Collaboratively understand and anticipate needs, demonstrate thought leadership through high-quality analysis and communication, and nurture productive relationships with FERC, the states and market participants in supporting the four pillars of the clean energy transition

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

- Focus in 2025 includes:
  - Building on novel analyses performed in 2023-24 to update assessments of regional energy adequacy vulnerabilities
    - Regional Energy Shortfall Threshold (REST)
    - Economic Planning for the Clean Energy Transition (EPCET) Study
  - Continue to work with States and stakeholders to improve asset condition process, and establish a criteria for right-sizing transmission investments to support integration of renewables and higher load levels
  - Continue to provide technical support to States, as requested, on clean energy and transmission RFP

APPENDIX 4: CYBER SECURITY AND CIP COMPLIANCE HISTORY AND COSTS

Cyber Security and CIP Compliance

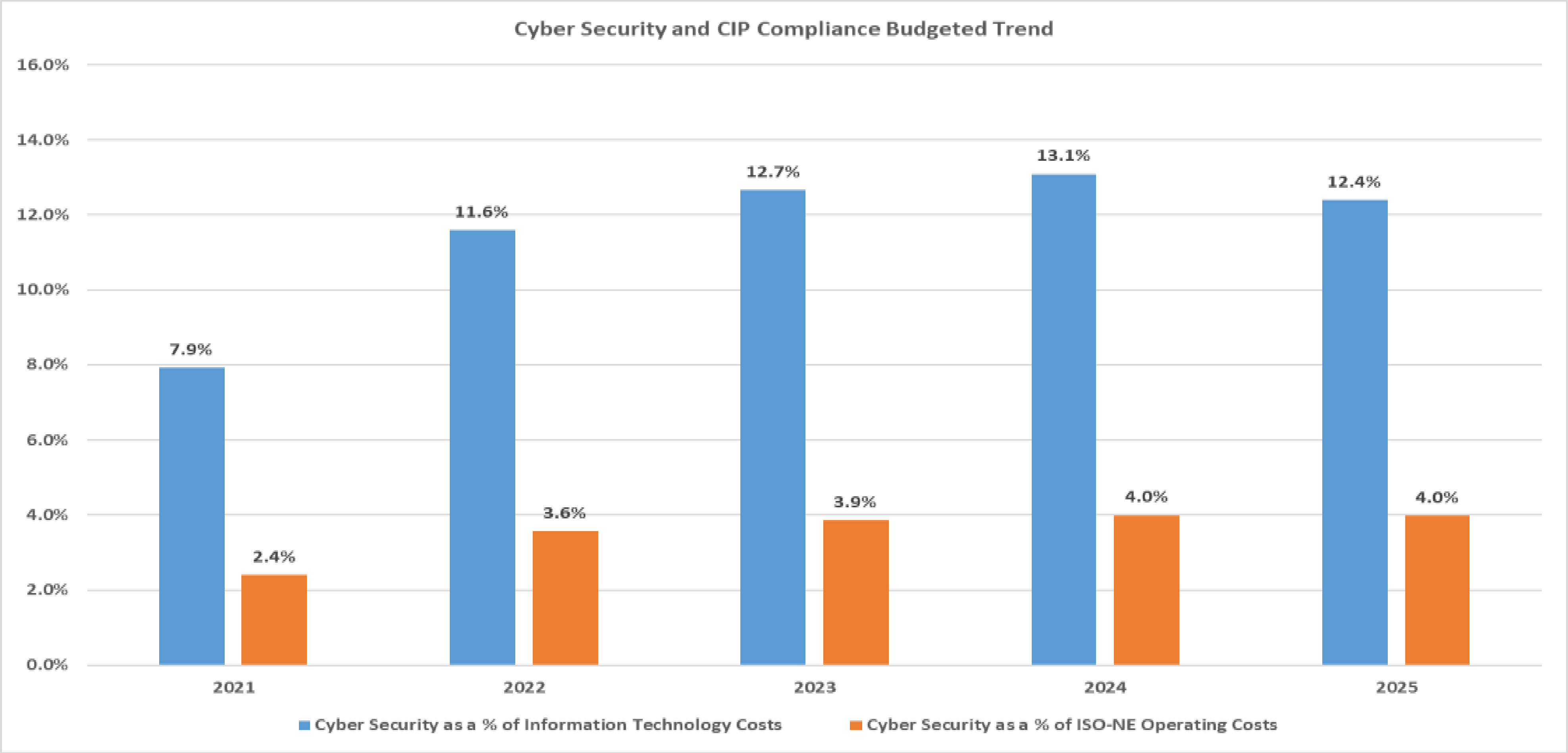
- Background
  - Information technology has become an indispensable tool for efficiently and reliably operating the increasingly complex regional power system, administering the billion-dollar markets where wholesale electricity is bought and sold in New England, and engaging and collaborating with our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

Cyber Security and CIP Compliance *(cont.)*

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

Cyber Security and CIP Compliance *(cont.)*

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



APPENDIX 5: 2025 BUDGET RESOURCES BY FUNCTIONAL AREA

2025 Budget Resources By Functional Area

ISO-NE provides a vast array of services to market participants and the New England region. Slides 136 through 160 include a description of the most significant services by area and provide the costs for Salaries and Burden, Professional Fees, and Computer Services for each area. Below is a reconciliation of the costs for each area and other support costs that make up the 2025 Operating Budget.

Area/Item	Amount in millions	Area/Item	Amount in millions
System Operations & Market Administration	35.3	Rents & Leases	2.1
System Planning	23.0	Network Operations	3.9
Market Development	12.6	Computer Services	31.3
Settlements	6.5	Data Services & Office Expenses (1)	2.2
Information Services	58.1	Insurance Expense	3.9
Program Management, Adv Tech Solutions, and NEPOOL Relations	17.6	Board of Directors Expense	1.6
Market Monitoring & Mitigation	6.9	Meetings & Related Expense	1.6
Legal Services	8.2	Education & Training	1.4
External Affairs and Corporate Communications	5.9	Taxes, Permits, Licenses & Fees (1)	0.3
Compliance, Risk Management, Finance, and Internal Audit	14.8	NPCC Dues	9.3
Human Resources	9.0	Interest Expense	4.6
CEO and COO and Support Staff	3.1	CEO Emerging Work Allowance and Board Contingency	3.7
Building Services	4.3	Misc. Revenues, Interest Income, and Purchase Discounts	(1.8)
		Total Operating Budget	**$ 269.4**

(1) Comprises the $2.5 million total of *Other Expense* on Slide 91

2025 Budget Resources By Functional Area

The table below lists full-time equivalent (FTE) headcount by area. The *20XX Budgeted FTEs* represent estimated net headcount by area after the budgeted vacancy % is applied. Actual vacant positions will vary by area.

Area	2022 Total FTEs	2022 Budgeted FTEs	Positions Filled 12/31/2022	2023 Total FTEs	2023 Budgeted FTEs	Positions Filled 12/31/2023	2024 Total FTEs	2024 Budgeted FTEs	Positions Filled 6/30/2024	2025 Total FTEs	2025 Budgeted FTEs
System Operations & Market Administration	135.0	127.5	127.0	137.0	128.5	134.0	138.0	127.5	135.0	147.0	135.5
System Planning	66.0	62.5	57.0	70.0	65.5	73.0	85.0	78.5	75.0	94.0	87.0
Market Development	20.0	19.0	20.0	29.0	27.0	24.0	33.0	30.5	23.0	35.0	32.5
Settlements	35.0	32.5	35.0	35.0	33.0	33.0	35.0	32.5	35.0	35.0	32.0
Information Services	184.0	175.5	179.0	193.0	181.0	181.0	200.0	185.0	189.0	217.0	200.0
Prog Mgt, Adv Tech Solutions, & NEPOOL Relations	54.5	52.0	51.5	58.5	55.0	54.0	64.5	59.5	58.0	70.5	65.0
Market Monitoring & Mitigation	21.0	20.0	18.0	21.0	19.5	19.0	21.0	19.5	20.0	21.0	19.0
Legal Services	18.0	17.5	18.0	18.0	17.0	18.0	18.0	16.5	17.0	19.0	17.5
Ext Affairs and Corp Comm	19.0	18.0	17.0	21.0	19.5	18.0	23.0	20.5	21.0	25.0	23.0
Compliance, Risk Mgt, Finance & Internal Audit	44.0	43.0	41.0	44.0	41.5	45.0	47.0	43.5	47.0	50.0	46.0
Human Resources	16.0	15.5	16.0	18.0	17.0	17.0	24.0	22.0	18.0	23.0	21.0
CEO and COO Support Staff	5.0	5.0	5.0	5.0	5.0	5.0	5.0	4.5	5.0	5.0	5.0
Building Services	5.0	5.0	5.0	5.0	5.0	5.0	5.0	4.5	5.0	5.0	5.0
Totals	**622.5**	**593.0**	**589.5**	**654.5**	**614.5**	**626.0**	**698.5**	**644.5**	**648.0**	**746.5**	**688.5**

Budgeted Vacancy %'s are as follows: 2022 – 4.0%; 2023 and 2024 is 5.0%; 2025 is 6.0%.

2025 Budget Resources By Functional Area

The table below lists expense $'s and full-time equivalent (FTE) amounts for *outside consultants* by area with Information Services broken out separately for Cyber Security and Compliance. Actual amounts are reflected for 2022 and 2023, current forecasted amounts for 2024, and proposed budget amounts for 2025.

Area	2022		2023		2024		2025	
$ amounts in thousands	Expense	FTE Equiv	Expense	FTE Equiv	Expense	FTE Equiv	Expense	FTE Equiv
System Operations & Market Adm.	$ 156.9	1.1	$ 732.2	5.0	$ 1,194.4	7.9	$ 273.0	1.7
System Planning	2,044.1	10.0	2,530.4	11.9	3,686.0	16.6	3,563.4	15.4
Market Development	2,428.0	10.0	2,062.3	8.2	3,085.6	11.7	2,381.5	8.7
Settlements	-	-	-	-	-	-	-	-
Information Services	5,235.4	25.3	5,513.4	25.6	6,488.3	29.0	6,551.7	28.1
Info. Services - Cyber Security	1,231.8	6.0	1,724.9	8.0	3,028.9	13.5	3,517.7	15.1
Prog Mgt, Adv Tech Solutions, & NEPOOL Relations	1,515.0	6.2	1,717.2	6.7	1,648.1	6.2	1,649.0	6.0
Market Monitoring	1,967.8	10.2	1,776.1	8.9	1,610.3	7.7	1,806.0	8.3
Legal Services	1,276.6	4.7	956.7	3.4	1,620.7	5.6	1,877.0	6.2
Ext Affairs & Corp Comm	668.2	3.5	726.9	3.7	660.8	3.2	669.9	3.1
Compl., Risk Mgt, Finance & Int Audit	1,293.2	6.3	2,105.1	9.9	2,925.2	13.2	2,331.3	10.1
Human Resources	2,015.6	7.8	2,354.2	8.7	2,384.9	8.5	3,156.4	10.8
CEO & COO & Support	-	-	-	-	-	-	-	-
Building Services	-	-	1.0	-	-	-	-	-
Total	**$ 19,832.8**	**91.0**	**$ 22,200.4**	**100.0**	**$ 28,333.2**	**123.2**	**$ 27,776.9**	**113.7**

Note: Outside consulting in the capital budget is done per project and not by functional area. Consultant spending on all capital projects totaled $14,147.8 or approximately 65 FTEs for 2022 and $13,794.6 or 62 FTEs for 2023. Budgeted/forecasted amounts for 2024 or 2025 cannot be provided since several projects are in the Planning/Conceptual Design phase and their specific requirements have not been fully established.

2025 Budget Components By Functional Area

System Operations & Market Administration – 147.0 FTEs

Salaries (fully burdened)	$ 35.0M
Professional Fees	$ 0.3M

System Operations is responsible for the 24/7/365 reliable and efficient operation of New England's Bulk Electric System (BES) and coordination with NERC Reliability Coordinators. System Operations provides near term engineering and outage coordination services, market transaction management as well as wind, solar and load forecasting services, and asset commitment services. The control room performs all Reliability Coordination (RC), Balancing (BA), and Transmission Operation (TOP) services under the NERC Standards for the New England Participants.

Market Administration is responsible for the day-to-day operations of the wholesale electricity markets in New England as well as the completion of asset registration, new generation coordination, and asset capability auditing. This includes developing market operating procedures to ensure compliance with FERC requirements. In addition, System Operations & Market Administration performs training, project integration, and analytical and auditing services for the corporation and its participants.

Description

- *Control Room Operations* – Around the clock operation of the BES and ISO real-time markets. This includes the Reliability Coordination, Balancing Authority and Transmission Operator for the New England Region including services for 400 Generating Stations and 9000 miles of transmission assets. Develop the New England Operating Plan including forecasting load, as well as resource scheduling, contract management, dispatch services and transmission operations services for the New England Participants.

2025 Budget Components By Functional Area

System Operations & Market Administration *(cont.)*

Description
• *Design, Develop and Deliver Engineering Operating Guides and Studies* - Design, develop, and deliver engineering operating guides, studies, and services regarding voltage, stability, and thermal constraints for use by the Company and Local Control Centers to reliably and efficiently operate the BES.
• *Transmission & Generation Outage Coordination* - Includes both short-term and long-term outage scheduling and coordination services looking out 2 years.
• *Training* – The Operational Performance, Training & Integration (OPTI) group provides new and ongoing training and simulation for system operators (+-160 hours per year, per operator), Designated Entities, and all Local Control Center Operators on an ongoing basis.
• *Procedure and Process Development and Maintenance* - All ISO Operating Procedures, Master Local Control Center Procedures, Control Room Operating Procedures, System Operating Procedures, Transmission Operating Guides, Operating Manuals, and the Open Access Same-Time Information System (OASIS). This activity includes the committee approval processes at the RC, MC, PC, and MLCC.
• *Integration* - OPTI provides corporate project support for the department which consists of development, integration, and testing of market design changes into system and market operations; this includes development and maintenance of business procedures and operating manuals to ensure continuous compliance with the ISO New England Transmission, Markets, and Services Tariff.
• *Gas-Electric Coordination and Energy Assessments* - Coordination and information sharing with gas pipelines, energy analysis across different years, seasons and in real-time based on information gathered from fuel surveys and pipelines, establishing operating plans to deal with different system conditions, and communicating with stakeholders and regulators on a regular basis regarding all fuel types.

2025 Budget Components By Functional Area

System Operations & Market Administration *(cont.)*

Description
• *NERC/NPCC/FERC Compliance* - Ensure operational compliance with new and existing federal, regional, and New England Standards. Review and update processes, procedures, and training to ensure compliance.
• *NERC/NPCC/NATF and ISO Committee* - System Operations represents the ISO on national, regional, and New England task forces.
• *Reliability Coordination*- System Operations implements all reliability coordinating agreements with Hydro Quebec, NYISO, and New Brunswick System Operator and staffs the coordinating committee(s) to maintain the agreements.
• *Market Administration* – Administers the Hourly and Monthly markets including Day-Ahead, Financial Transmission Rights (FTR), Forward Reserve and Forward Capacity annual and monthly reconfiguration markets; administering the Forward Capacity Auctions and supporting related FERC filings; and Real-Time price monitoring and finalization.
• *Asset Registration* – Performs the tasks associated with the registration of assets as defined in the New England Markets, such as Generation, Loads, Tie Lines, Asset Related Demand, Demand Response Assets, Alternative Technology Regulation Resources, and On-Peak and Seasonal Peak Demand Resources.
• *Auditing* – Performs the tasks associated with the various types of audits as defined in the New England Markets, such as Passive On-Peak and Seasonal Peak Demand Resources, Active Demand Response Assets, Generation CCA (Establish & Seasonal) and Dual Fuel Audits, Blackstart, Claim 10/30, Reactive Power. In addition perform the continuous review of meter data quality for Demand Response Assets and periodic review of Measurement and Verification documentation for On-Peak and Seasonal Peak Demand Resources.
• *New Gen Coordination* – Manages and performs the tasks associated with the new generation coordination, modeling changes to existing generators and pnode activations/deactivations processes.

2025 Budget Resources By Functional Area

System Planning – 94.0 FTEs (7.5 FTEs are allocated to reimbursable studies)

Salaries (fully burdened)	$ 19.4M
Professional Fees	$ 3.6M

System Planning is responsible for development of the Regional System Plan, implementing the regional transmission planning process, administration of the generator interconnection process, developing findings for allocating transmission costs, interregional planning with our neighbors, and supporting New England's capacity markets. A more detailed breakdown of services is provided below.

Description
• *Transmission Planning Studies* – Study and support for requests to add or change interconnection and transmission service and ensure compliance with federal and regional reliability criteria as it pertains to planning of the New England Power System. Support regional transmission owners in state siting proceedings for major transmission projects. Issue and support RFP's for competitive transmission per FERC Order 1000. Review and enhance generator interconnection policies and practices; continue to support state agencies on their RFPs for clean energy resources. Develop and execute long-range transmission planning studies in conjunction with the states (e.g., 2050 Study).
• *Forward Capacity Market Administration* – Includes establishing regional and zonal capacity requirements; reviewing show-of-interest applications; qualifying new resources (generation, demand resources, and imports); supporting administration of the Forward Capacity Auctions and supporting related FERC filings; performing all reliability analysis in review of retirement requests, de-list bids, reconfiguration auctions, and bilateral contracts.
• *Eastern Interconnection Planning Collaborative (EIPC)* – Model Roll-up and Evaluation (contingency analysis and/or transfer analysis); participation in all levels of the EIPC structure including Technical Team, Economic Analysis Working Group, Coordination Committee, and Executive Committee. Support EIPC in management of the Multi-regional Modeling Working Group process.
• *Attachment K Economic Studies* – Carry out the regional economic planning process as requested by stakeholders on an annual basis for up to three economic studies per year.

2025 Budget Resources By Functional Area

System Planning *(cont.)*

Description

- *Energy-Efficiency (EE) Programs* - Develop annual EE forecasts across the ten-year planning horizon and work with the EE Forecast Working Group to review and refine the EE forecast process for development of future forecasts.
- *Solar PV Forecast* - A similar process for state investments in distributed generation is now in place, and an annual forecast of solar PV across the ten-year planning horizon is developed annually.
- *Electrification Forecast* – Annually develop a forecast that predicts the increase in demand due to the adoption of air-source heat pumps (ASHPs) in the winter months and use of electric vehicles. This forecast is incorporated into the ten-year load forecast used for the FCM and transmission planning.
- *Installed Capacity and Local Sourcing Requirements* - Develop the regional Installed Capacity Requirement, and Zonal Local Sourcing Requirement and Maximum Capacity Limit values that establish the requirements within the Forward Capacity Market. These values are reviewed within the NEPOOL committee structure; advisory input is provided by the Reliability Committee and Participants Committee, and the values are subsequently filed with FERC.
- *Regional System Plan* - Initiate a biennial planning report that documents all regional and interregional planning activities, and identifies resources and transmission facilities needed to maintain the reliable operation of New England's bulk electric power system over a ten-year horizon. ISO administers much of the regional planning process through interaction with the Planning Advisory Committee. Continue regional dialogue on Grid Transformation.

2025 Budget Resources By Functional Area

System Planning *(cont.)*

Description

- *Interregional Planning* - Participate in joint planning activities with NYISO and PJM through the Inter-Area Planning Stakeholder Advisory Committee stakeholder process. This process results in development of a periodic report of activities in the Northeast Coordinated System Plan. This process has been updated in compliance with FERC Order 1000. Active participation in various NERC committees and standard drafting teams, and provide leadership to the EIPC.
- *Compliance* - Active involvement in NERC and NPCC Committees and related activities in support of compliance with established federal and regional reliability standards and interregional planning activities.
- *Training* - Support ISO-led training activities for the Forward Capacity Market, State Regulator, and Market Participant training on the overall System Planning Process, and State Regulator Training on Transmission Planning criteria and analysis.
- *Other* - Conduct ten-year forecasting of seasonal peak demand and energy requirements and support operations daily forecast models including the solar PV forecast; support regional dialogue on strategic planning issues through various types of system operations analysis; develop annual marginal emissions report; process and maintain Generating Availability Data System database; monitor and evaluate emerging state and federal environmental and renewable energy standards; support the North American Energy Standards Board standards development process; and support individual state planning activities.

2025 Budget Resources by Functional Area

Market Development & Settlements - 70.0 FTEs* (0.5 FTEs are allocated to the capital budget)

Salaries (fully burdened)**	$ 16.7M
Professional Fees	$ 2.4M

Market Development & Settlements is responsible for the design and development of Wholesale Electricity Markets and Wholesale Markets Strategy, Demand Resources Strategy, reporting and analysis of market results, and the settlement of all ISO-administered markets, programs, and fees consistent with the ISO Tariff.

Description

- *Market Assessment* – Development of enhancements to the current markets and introduction of new markets and market products to address existing problems or emerging issues identified by ISO staff, the market monitors, stakeholders, and FERC.
- *Support Market Change Recommendations* – Support recommended changes in materials presented to stakeholders and in filings with FERC; support internal ISO implementation teams in designing new and enhanced markets and products.
- *Tariff Updates and Compliance* – Analysis of necessary updates to the ISO New England Transmission, Markets, and Services Tariff.
- *Demand Response and Distributed Energy Resources* – Development of market designs that enable Demand Response Resources and Distributed Energy Resource Aggregations to provide all wholesale services they are technically capably of providing.
- *Market Analysis and Reporting* – Designing, developing, and issuing weekly and monthly reports and public data files detailing market activities and outcomes, including load cost reports; delivering data and producing analyses of market activity requested from market participants, states, FERC, and other government officials.

*Note: Amounts and FTEs include Market Development & Settlements noted on slide 135 - 137
**Note: Direct Market Development & Settlement costs for Internal Capital Development are included in the Capital Budget. The cost noted above only includes operating costs.

2025 Budget Components By Functional Area

Market Development & Settlements *(cont.)*

Description

- *Market Settlements* – Settlement of all Market Participant obligations, charges, and fees in the ISO-administered markets and ISO Tariff, including: the Day-Ahead and Real-Time markets, Bilateral energy transactions, Forward Transmission Rights Markets, Congestion Revenue accounting, Net Commitment Period Compensation Payments and charges, all market-based and OATT-based Ancillary Services, the Forward Capacity Market credits and charges, and other charges and payments due under the Open Access Transmission Tariff.
- *Market Participant Settlement Support* – Conduct timely analysis, investigation, and resolution of individual market participant inquiring about ISO invoices, statements and bills.
- *Audit and Compliance Settlements Support* – Extensive support for internal and external annual audits of the ISO's Market Settlement systems and execution, to ensure confidence in the ISO-administered markets and all participants' credits/charges
- *Training* - Support ISO-led training activities for Market Participants and federal and state regulators on the ISO-administered markets, new market designs, project integration, participant settlement obligations, and participants' Market Information System reports.

2025 Budget Resources By Functional Area

Information and Cyber Security Services – 217.0 FTEs (23.0 FTEs are allocated to the capital budget)

Salaries (fully burdened)*	$ 48.0M
Professional Fees	$ 10.1M

The ISO's Information and Cyber Security Services group is responsible for the information and data integrity of the organization as well as all information systems functions, including data centers, technical service centers, cyber security, production scheduling, software development, and systems operations. Total IT license and maintenance fees support 1,387 product versions, 1,657 servers, 1,279 desktop systems, 1,157 network devices, and 597 appliances.

Description	Amount ($ in Millions)
Information Technology (IT) Software Development and Power System Support - (133.0 FTEs) Staff perform the following functions: • Application Architectural Design, Technology Evaluation, and Selection • Corporate, Markets and Energy Management System Support including: − Power System Network Modeling and Maintenance • Includes NX9 (Transmission) and NX12 (Generation) Systems − Energy Management Systems Maintenance and Support • Includes Inter-Control Center Communications Protocol (ICCP)	See following slide

*Note: Direct Information Services costs for Internal Capital Development are included in the Capital Budget. The Information Services costs noted on Slides 146 through 149 only include operating costs.

2025 Budget Resources By Functional Area

Information Services *(cont.)*

Description	Amount ($ in Millions)
Information Technology (IT) Software Development and Power System Support, *(cont.)* • Energy Market Applications Maintenance and Support – Includes Day-Ahead and Real-Time Energy Markets, Financial Transmission Rights (FTRs), the Testing and Training Simulator Environment (TTSE), the Dispatcher Training Simulator (DTS), and ISO specific specialized systems (FCM Tracking System, Wind Integration, and Synchrophasor Monitoring) • Data Architecture, Database Administration, and Business Intelligence • Web Application Support • Software and Maintenance support for Market Administration, Market Monitoring, Settlements, Transmission Planning, Finance/Payroll, and Human Resources	
Total IT Software Development and Power System Support:	**$ 32.3M**

2025 Budget Resources By Functional Area

Information Services *(cont.)*

Description	Amount ($ in Millions)
Information Technology (IT) Management, Cyber Security, and Infrastructure Services (84.0 FTEs)	

Staffing and Consultants perform the following functions:

- Direct Management of Infrastructure & Service Delivery, Cyber Security, and Software Testing (including change management)
- Cyber Security, including:
  - Policy and Procedure Development
  - Controls Assessment
  - Security Compliance & Reporting
  - Virus/Malware Response & Reporting
  - Intrusion Monitoring & Response
  - Security Software Tools Maintenance & Support
  - Critical Infrastructure Protection Compliance & Monitoring
  - Security Metrics Collection & Reporting
  - Change Control Testing & Reporting
  - Security Awareness & Training, Software Change Management, and Quality Assurance Control
- Software Testing Control

2025 Budget Resources By Functional Area

Information Services *(cont.)*

Description	Amount ($ in Millions)
Information Technology (IT) Management, Cyber Security, and Infrastructure Services, (cont.) • Desktop, Host Computer hardware/software, and networking hardware support • Data Communications including Main Control Center, Backup Control Center, and communications with Local Control Centers and other external touch points • System Administration for Unix and Windows • IT Asset and License Management	
Total IT Management, Cyber Security, and Software Testing:	**$24.8M**
Total Information Services Staffing, Consulting, and Computer Services:	**$57.1M**

2025 Budget Resources By Functional Area

Program Management, Advanced Technology Solutions, and Participant Relations & Services – 70.5 FTEs (9.0 FTEs are allocated to the capital budget)

Salaries (fully burdened)*	$ 15.9M
Professional Fees	$ 1.6M

The Program Management Office (PMO) is responsible for oversight and management of the Capital Budget. PMO and Advanced Technology Solutions are responsible for implementing program and system changes for the broad range of services and related applications that run the New England bulk electric power system, the wholesale electricity markets, and other supporting ISO New England Systems. The Participant Relations & Services (PRS) Department is responsible for leading the company's engagement, training, and support of industry stakeholders on proposed changes to and implementation of ISO's planning, operational, and market initiatives.

Description

- *Evaluation of New Projects* – Review and determine need and possible solutions for proposed emerging work requirements to be presented to senior management for approval.
- *Project Management* – Develop formal processes and procedures for the evaluation of capital project work including the value of proposed projects and determination of impacted business users; develop project scope and necessary resources; development and ongoing analysis of project budget, timeline, progression, risks and opportunities; and ensure proper project testing and business user acceptance.

*Note: Direct Project Management costs for Internal Capital Development are included in the Capital Budget. The cost noted above only include operating costs.

2025 Budget Resources By Functional Area

Program Management, Advanced Technology Solutions, and Participant Relations & Services *(cont.)*

Description
• *Business Analysis and Product Management* – Work with all business units to assess and review issues and opportunities for improvement, and manage implementation issues identified under the Corrective Action/ Preventative Action program to minimize disruption to business and system process. • *Advanced Technology Solutions* – Develop both short-term and long-term solutions for market and system technology improvements, market clearing models to implement various market designs and improve market efficiency, algorithms and tools to improve system reliability, auction clearing software for forward capacity market, and simulation software. • *PRS: NEPOOL Relations* - Leads the ISO's engagement with market participants and other stakeholders to collaborate on ISO's projects for market designs and reliability improvements. Administers the NEPOOL Technical Committees and related working groups, and serves as the ISO's primary liaison for NEPOOL members. • *PRS: Participant Support & Solutions* – Manages and supports user experiences in the ISO markets, transmission planning processes, and other business functions to resolve industry stakeholder issues. • *PRS: Participant Training Services* – Develops and delivers the ISO's external training programs for industry stakeholders to participate in all ISO systems and do business within ISO New England's footprint. • *PRS: Project Services* – Develops and coordinates internal and external plans, work flows, and information on corporate projects across multiple departments to integrate the ISO's market, planning, and operations initiatives. Regularly publishes updated reports to industry stakeholders on corporate initiatives.

2025 Budget Resources By Functional Area

Market Monitoring & Mitigation – 21.0 FTEs

Salaries (fully burdened)	$ 5.1M
Professional Fees	$ 1.8M

Market Monitoring is a FERC-mandated function of each Regional Transmission Organization (RTO). Per FERC, RTO Market Monitors must report directly to the Board of Directors to assure independence from management.

Description

The ISO's Internal Market Monitoring area is responsible for:

- Analysis of and report to stakeholders, FERC, and ISO Management on market performance.
- Administer market power mitigation and other mitigation provisions in the Tariff.
- Monitor for and identify instances of rule violations (including uncompetitive participant behavior), investigate and refer potential violations to FERC Office of Enforcement.
- Identify issues with current and proposed market design and provide recommendations for improvement.

Additionally, ISO-NE retains an External Market Monitor that also reports to the Board of Directors on its review of market outcomes and market design changes. External Market Monitor funding is included in the Legal and Professional Fees budget; however for purposes of Functional Area presentation it is included in the Market Monitoring & Mitigation amount above.

2025 Budget Resources By Functional Area

Legal Services - 19.0 FTEs

Salaries (fully burdened)	$ 6.3M
Legal Fees	$ 1.9M

The ISO New England Legal Services budget includes funding for staff attorneys, a paralegal, support staff, and external counsel to augment ISO Legal staff or for use where a particular expertise is needed.

Description

Both internal and external counsel cover work for:

- Development of market rule, Tariff and operating/planning procedure changes; support for the stakeholder process; and related regulatory and appellate litigation.
- Support for the market monitoring department.
- Tracking federal and state legal developments.
- Negotiating interconnection agreements and supporting the qualification of new assets.
- Refining the financial assurance and billing policies.
- Filing and supporting the administrative and capital funding tariffs.
- Advising on finance, tax, intellectual property, and contract matters.
- Handling labor, employment, and ERISA matters.
- Support for NERC and NPCC rulemakings and other compliance support.
- Responsible for corporate governance, including support for the Board of Directors and standing committees.

2025 Budget Components By Functional Area

External Affairs and Corporate Communications - 25.0 FTEs

Salaries (fully burdened)	$ 5.3M
Professional Fees	$ 0.7M

ISO New England's External Affairs and Corporate Communications are responsible for outreach to and communications with public officials, consumer representatives, the media, ISO employees, and the general public.

Description

The Department:

- Responds to media inquiries and communicates regional electric grid and wholesale markets information to media outlets.
- Develops and coordinates ISO publications (e.g., Regional Electricity Outlook, Regional System Plan) and conference presentations.
- Manages Web Design, Web Content, ISO Newswire, the ISO App and social media.
- Informs public officials on the performance and needs of the power system and wholesale markets.
- Manages emergency and crisis communications to public officials, stakeholders, and the media, including the status of the power system during abnormal and emergency situations.
- Facilitates state feedback on the transmission system and wholesale market design.
- Monitors state and federal policy initiatives, to inform the market development and system planning process.
- Manages the Consumer Liaison Group, including meetings, presentations and the annual report.
- Manages internal employee communications, including the company’s intranet.
- Assists other departments with communications materials (e.g., Human Resources recruitment marketing).
- Assesses environmental policies and advises company on implications and conducts outreach to community groups.

2025 Budget Resources By Functional Area

Compliance, Strategy, Risk Management, Finance/Market and Credit Risk, and Internal Audit - 50.0 FTEs

Salaries (fully burdened)	$ 12.5M
Professional Fees	$ 2.3M

Reliability & Operations Compliance, Enterprise Risk Management, Finance, and Internal Audit provide services in support of the ISO's mission as described below.

Description

- *Compliance* – Works to ensure compliance with FERC approved tariffs; NERC and NPCC compliance, certifications, and audits; and coordination with and support of national and regional compliance reliability standard-setting authorities and related committees.
- *Enterprise Risk Management* – Programs and processes include corporate-level risk identification, assessment, monitoring and reporting; support of corrective action programs and Operation Excellence activities; Business Process Documentation Standards and Change Management; Records Management and Retention policy; Business Continuity planning; Corporate Strategy; Tariff change coordination; and information governance.
- *Finance/Market and Credit Risk* – Responsible for payroll administration, procurement, accounts payable, budgeting and forecasting, accounting, financial statement and financial filings, corporate tax reporting, treasury, cash management, capital adequacy, settlement billing and cash clearing, development and administration of the Financial Assurance Policy; financial reporting; and Insurance Program Management.
- *Internal Audit* - Conducts and coordinates audits and reviews across the organization, at key vendors, and at LCC's to ensure compliance with company policy and a sound system of internal controls, maintain certifications for market system changes, and meet assurance requirements for external parties. Audits conducted by internal staff include internal controls and compliance audits in the areas of operations, IT and cyber security, system development projects, and adherence to company finance and human resources administrative policies. Coordination activities for external audits and reviews include the System and Organization Controls (SOC 1) engagement, the Financial Statements Audit, the Benefits Plans Audits, and market system software certifications.

2025 Budget Resources By Functional Area

Human Resources - 23.0 FTEs

Salaries (fully burdened)	$ 5.9M
Professional Fees	$ 3.2M

The ISO's Human Resource group is tasked with attracting, retaining, and developing the company's uniquely qualified and highly skilled workforce.

Description

Responsibilities include:

- Recruiting candidates for full-time, part-time, and temporary positions at all levels from summer interns to executives. Recruitment costs include expenses for the company's formal university relations, summer intern, and co-op programs and costs for external recruiter fees, background checks (initial and required updates), candidate travel, drug screening, visa processing, and testing of potential new hires (for certain positions).
- Determining an appropriate compensation structure for the organization and appropriate compensation levels for all new and existing hires. HR participates in ongoing benchmarking surveys and works with external compensation consultants to benchmark remuneration for employees, executives and the Board of Directors. HR annually benchmarks and administers pools for merit and promotional increases, as well as the company's incentive programs.
- Establishing and administering competitive benefit programs including the selection, design, and administration of all health and welfare benefits (e.g., medical, life insurance, etc.), working with providers and brokers, and designing and administering the company's 401k and pension plans. The department benchmarks all benefits on an ongoing basis. Relocation benefits for new hires (for certain positions) are administered from HR and associated costs are contained in the HR budget.

2025 Budget Resources By Functional Area

Human Resources *(cont.)*

Description

- Designing, benchmarking, and administering general Human Resource policies and programs, including those for annual performance reviews and development plans, employee recognition, and employee issue resolution. The department supports the company's union employees and negotiates the union contract every three years. The HR department also manages all succession processes and programs to ensure the work environment is diverse and inclusive, that key talent is developed to support critical positions within the organization, and that knowledge is retained despite talent attrition.
- Supporting organizational effectiveness through the alignment of strategy, goals, scorecards, performance and rewards as well as consultation on enhancing employee engagement, optimizing team performance and organizational design, and elevating leadership capabilities.
- Designing, developing, and delivering both industry-specific, leadership, and general training that is provided both as "live" (virtual and in person) classroom and self-paced web-based courses. The department manages the company's tuition reimbursement program.
- Designing and facilitating programs to embrace and celebrate the diversity of our ISO community and to educate employees on the value of maintaining a workplace that is diverse, equitable, and inclusive. The department oversees the ISO New England Council for Diversity & Inclusion, Employee Resource Groups, and diversity recruitment efforts.
- Deepening employee engagement by developing and enhancing programs for employee onboarding, career progression, diversity and inclusion, employee well-being, and employee communications as related.

2025 Budget Resources By Functional Area

Human Resources *(cont.)*

Description

- Managing back-end employee information including personnel files and payroll administration, while owning and developing HRIS system(s).
- Managing the ISO Reception function, including registration of numerous stakeholders and visitors to our secure facility.
- Offering input as a key advisor towards workplace safety, employee relations, and positive employee experience.

Description

CEO, COO, and Support Staff – 5.0 FTE's

Salaries (Fully Burdened)	$ 3.1M

2025 Budget Resources By Functional Area

Building Services $4.3M

Building Services includes funding for physical security including compliance with relevant NERC standards and building services for both the Main Control Center and Backup Control Center including: utilities, maintenance, upkeep, cleaning, landscaping, snow, and trash removal.

Description	Amount ($ in Millions)
• Salary and benefits – 5.0 FTEs	$ 0.8
• Utilities	1.6
• Repairs and Maintenance, Cleaning Services, Snow Removal, Landscaping, and Trash Removal	1.0
• Security	0.9
Total Building Services	**$ 4.3**

2025 Budget Resources By Functional Area

Meetings & Related Expenses and Education & Training $3.1M

Includes travel, meals, lodging, incidentals, and course/seminar fees (where applicable) for stakeholder meeting costs, travel for regulatory meetings (FERC/NERC/NPCC), state agency meetings, technical and general training costs, attendance at industry and other conferences, education reimbursement, and offsite ISO-sponsored market training for participants.

Description	Amount ($ in Millions)
• *Corporate Training* – Enterprise wide training programs including supervisory leadership development, professional development, Power System Engineering Program, and business skills.	$ 0.4
• *Technical and NERC Certification Training* – NERC certification training and other job required training for the development, administration, or maintenance of IT Systems.	0.6
• *Industry and Other Conference Attendance* – Attendance to speak, or provide industry expertise, attend joint ISO/RTO conferences, and attend other miscellaneous conferences.	0.4
• *Regulatory* – Travel and related expense for regulatory meetings and support including FERC, NERC, NPCC, and state agencies.	0.3
• *Stakeholder Meetings* – Travel and related expense for ISO employees to attend stakeholder meetings throughout the region.	0.4
• *Market Training* - Costs for offsite ISO sponsored market participant training classes. Includes facility and equipment rental and meals for participants. These costs are fully reimbursed by participant attendance fees (fees are included in Interest Income and Other Revenue line).	0.1
• *Education Reimbursement* – Reimbursement for employment related degree programs approved by the Human Resources department and other job-related certification exams approved by the employees' manager.	0.2
• *Other* – Includes miscellaneous travel reimbursement and employee service recognition.	0.7
Total Meetings & Related Expenses and Education & Training	**$ 3.1M**

APPENDIX 6: INTEREST RATE RISK

Interest Rate Risk

- Fluctuating interest rates can have an impact on the costs of the ISO in several ways. Specifically, the ISO earns interest on the settlement funds it collects from market participants, pays a floating interest rate on its tax-exempt bonds, and uses assumptions on interest rates to establish liabilities and costs for its pension and post-retirement benefit plans
  - ISO-NE earns interest on the settlement account float
    - Interest income rates are also dependent on market conditions with rate fluctuations impacting the effectiveness of the settlement float hedge; during the majority of 2020-2021, the interest income rates have exceeded floating debt rates; since 2022 we have seen multiple rate increases with the rise is tax exempt debt outpacing interest income rates. As of June 30, 2024, the tax-exempt debt rate is 3.9% and settlement float rate is 2.75%
      - These costs could exceed what's predicted on Slide 91
    - Unlike the interest rate that is currently lower that the tax-exempt debt rate, the average float in the settlement account is higher than the outstanding principal of the tax-exempt debt therefore has been an effective hedge against interest expense rates.
  - ISO-NE pays a floating interest rate on its tax-exempt bonds
  - ISO-NE utilizes interest rate assumptions in establishing liabilities and related costs for its postretirement benefit plans (See Slide 117)

APPENDIX 7: CAPITAL EXPENDITURES BUDGET DETAIL

Capital Budget – 2025 Capital Projects Schedule

($000's)	Project-To-Date	Current Year (2024) Cost to Complete [1]	2025 Cost to Complete	Future Year Cost to Complete	Total Project Costs	Estimated Complete Date
Capital Projects - Approved Charters						
. nGEM Real-Time MCE Implementation	$ 5,916.6	$ 2,748.3	$ 4,043.6	$ 2,043.7	$ 14,752.2	06/26
. nGEM Software Development Part III	1,288.8	240.6	2,937.5	-	4,466.8	04/25
. Managing Transmission Line Ratings [3]	3,654.0	2,324.6	1,722.6	-	7,701.2	11/25
. Day-ahead Ancillary Services Improvements	6,560.7	984.0	1,526.8	-	9,071.5	03/25
. CAMS Application Software Technology Upgrade	350.8	337.2	667.9	-	1,355.9	06/25
. Network Modeling Tool Enhancements	359.3	397.3	523.4	-	1,280.0	07/25
. New England Clean Energy Connect	35.4	139.8	316.9	-	492.1	12/25
. Automatic Ring Down Circuit Continuity Modernization and Reliability Enhancements	489.3	130.9	277.0	-	897.2	08/25
. CIP Electronic Security Perimeter Redesign Phase II	4,395.4	311.7	270.2	-	4,977.3	06/25
. Tie Line Telemetry and PCEC Upgrade	53.7	176.4	88.1	-	318.2	06/25
. EMS Short-term Load Forecast Replacement	1,007.3	393.2	38.5	-	1,439.0	02/25
. Microsoft 365 Service Adoption	276.6	429.4	7.7	-	713.7	11/24
Sub Total Projects with Approved Charters	**24,387.8**	**8,613.3**	**12,420.2**	**2,043.7**	**47,465.0**	
Planning/Conceptual Design [2]						
. FERC Order 841	89.2	851.3	2,000.0	-	2,940.5	10/25
. Space Utilization Project Phase I	475.1	476.9	2,000.0	-	2,952.0	08/25
. Enterprise Core Network Refresh	-	-	2,000.0	-	2,000.0	12/25
. Enterprise Resource Planning System Replacement	1,598.9	574.2	1,900.0	-	4,073.1	12/25
. EMP 3.5 Upgrade	-	-	1,500.0	4,000.0	5,500.0	12/26
. Windows Server Replacement Phase II	151.6	80.8	1,500.0	-	1,732.4	12/25
. Integrated Market Simulator Enhancement	-	-	1,500.0	-	1,500.0	12/25
. FERC Order 2222	-	-	1,000.0	5,000.0	6,000.0	11/26
. nGEM Software Development Part IV	-	-	1,000.0	1,000.0	2,000.0	06/26
. MW Dependent Fuel Price Adjustment	24.6	75.4	1,000.0	-	1,100.0	11/25
. 2025 Issue Resolution Project	-	-	750.0	-	750.0	09/25
. Tie Line Telemetry and PCEC Upgrades Phase II	-	-	500.0	-	500.0	07/25
. Storage as Transmission Only Asset	-	-	400.0	1,000.0	1,400.0	03/27
. Circuit Inventory Management Platform	13.7	186.3	400.0	-	600.0	10/25
. Replace Employee & Pager Application	49.0	1.0	349.0	-	399.0	10/25
. Adoption of NERC CIP Compliance of Synchrophasor Systems	38.5	11.5	300.0	600.0	950.0	10/26
. Solar Do Not Exceed Dispatch Phase III	-	-	270.0	-	270.0	11/25
. Long-term FTRs [4]	907.5	-	-	-	907.5	TBD
. Other Emerging Work	-	-	5,710.8	-	5,710.8	
Sub Total Conceptual Design	3,348.1	2,257.5	24,079.8	11,600.0	41,285.4	
. Non-Project Capital Expenditures	2,183.0	2,427.0	5,000.0	-	9,610.0	
. Capitalized Interest & Loan Fees	645.7	854.3	1,000.0	-	2,500.0	
Total Capital Expenditures (Including Capitalized Interest)	**$ 30,564.5**	**$ 14,152.1**	**$ 42,500.0**	**$ 13,643.7**	**$ 100,860.4**	

[1] The amounts under the "Current Year (2024) Cost to Complete" list only includes those projects with budgeted costs in 2025 and beyond.
[2] The 2025 Budget for Projects in Planning and Conceptual Design is not final. Once the project scope and timeline have been determined the budget will be finalized.
[3] The Managing Transmission Line Ratings project was previously known as the FERC Order 881 Compliance project.
[4] The Long-term FTRs project has been indefinitely deferred pending the development of appropriate credit requirements.

Capital Budget

2025 Expenditures/Major Projects in Development

nGEM Real-Time Market Clearing Engine Implementation $4.0M

ISO-NE's Market Management System (MMS) is based on GE Grid Solution's suite of market applications known as the Next Generation Markets (nGEM) program. GE is redeveloping the Market Clearing Engine (MCE), a central component of the MMS.

Pursuant to a separate capital project, the Day-Ahead MCE has been developed and is in production. The nGEM Real-Time Market Clearing Engine (RT MCE) project will build on the Day-Ahead MCE to develop and deploy the Real-Time MCE, including ISO-NE customizations.

During the first phase of the nGEM RT MCE project, two of the legacy RT MCE study modes (the Real-Time Unit Commitment (RTUC) and Coordinated Transaction Scheduling Pricing Engine (CTSPE) functions) will be replaced and the transition from EMS to MMS interfaces has started. The nGEM RT MCE project will provide performance improvements by enabling more intensive market clearing formulations; eliminate reliance on .CSV flat files for communication of data between the MCE and other parts of the MMS; and enhance installation, patching, and upgrades of MCE's in ISO infrastructure.

The target completion date for this project is June 2026.

Capital Budget

2025 Expenditures/Major Projects in Development

nGEM Software Development Part III & Part IV $3.9M

ISO-NE is co-funding the core product development for GE Grid Solutions' nGEM software development. The nGEM Software Development project will enhance data transfer technology; Day-Ahead and Real-Time market clearing engines; and bidding micro services. It will also include various software upgrades.

Part I delivery, completed in October 2020, included enhanced data transfer technology and the elimination of the Habitat platform. Part II, completed in June 2023, included Day-Ahead market clearing engine enhancements, bidding micro services, and Real-Time market clearing engine replacements.

Part III will implement advanced storage support in the nGEM Market Clearing Engine (MCE) and Market CIMNet Simultaneous Feasibility Test software; enhance the nGEM MCE to further support real-time study modes and other components; and replace the Oracle based workflow controller with software designed as part of the Part II phase of the project. The targeted completion date for Part III is April 2025, with budgeted 2025 funding of $2.9M.

Part IV is still in the design stage and will build upon efforts made in the first three nGEM phases. The targeted completion date for Part IV is June 2026, with budgeted 2025 funding of $1.0M.

Capital Budget

2025 Expenditures/Major Projects in Development

Managing Transmission Line Ratings $1.7M

In Order No. 881, FERC adopted reforms that impose certain obligations and compliance requirements on transmission providers and public utility transmission owners with respect to transmission line ratings in order to ensure wholesale rates more accurately reflect the cost of the wholesale service being provided.[1]

ISO-NE will implement various Order 881 requirements as part of the Manage Transmission Line Ratings project, including implementation of a new GE product for submission of line ratings and other system improvements to the Real-Time and Day-Ahead energy markets and the network model application which provides authorized users an entry system with real-time access to one-line diagrams.

As part of this project, GE will provide four deliverables: a Limit Exchange Portal (LEP), which serves as an exchange portal to allow submission of new ratings and query of current/resolved ratings; an enhanced EMS to address Order 881 compliance requirements; network modeling customizations, including modifications to various forms and customizations; and customizations to support WebFG modeling, which is the software used for modeling one-line diagrams.

The targeted completion date for this project is November 2025.

[1] See Managing Transmission Line Ratings, Order 881, 177 FERC ¶ 61,179 (2021), P. 29.

Capital Budget

2025 Expenditures/Major Projects in Development

Day-Ahead Ancillary Services Improvements $1.5M

The Day-Ahead Ancillary Services Improvements project will implement the market design for procuring and transparently pricing the ancillary service capabilities needed for a reliable, next-day operating plan with an evolving generation fleet.

As part of the design, a new Day-Ahead ancillary service will be introduced to cover the “gap” when the Day-Ahead Energy Market’s physical energy supply awards are below the ISO’s forecast Real-Time load. A second component is to procure Day-Ahead flexible response services to ensure the system is prepared to recover from sudden source-loss contingencies and can respond quickly to fluctuations in net load during the operating day.

The Day-Ahead Ancillary Services Improvements project will develop and implement complex software changes to numerous ISO-NE systems to establish this new market functionality. The changes and integration efforts will ensure proper and timely data flow among key internal systems, including the Market Management System, Market Information System, and Financial Assurance Management system. To ensure quality outcomes, comprehensive testing will be conducted and training programs will be developed to educate Market Participants on the new Day-Ahead ancillary market.

The targeted completion date for this project is March 2025.

Capital Budget

2025 Expenditures/Major Projects in Development

CAMS Application Software Technology Upgrade $0.7M

The Customer Asset Management Systems (CAMS) is the primary system for ISO's management of customer, asset, relationship, and person-entitlement records. It is integrated with several other applications in order to collectively handle essential functions such as the Customer Registration, Asset Registration, Asset Auditing, Market Monitoring, and Customer Personally Identifiable Information (PII) Management application. The current architecture, relying on on-premise servers, poses challenges in data integrity, vulnerability management, patching, testing, and monitoring.

This project will migrate CAMS and associated applications to ISO-NE's Amazon Web Services (AWS) cloud environment, establishing a foundation for future market applications and reducing costs associated with maintaining on-premise hardware.

The targeted completion date for this project is June 2025.

Capital Budget

2025 Expenditures/Major Projects in Development

Network Modeling Tool Enhancements $0.5M

ISO-NE currently uses an energy management system (EMS) WebFG modeling tool to update and maintain the network model in use in the Control Room and in study applications by transmission outage coordinators. This tool is 25 years old and has tabular displays, antiquated command line entry interfaces, and limitations that force repeated updates for duplicative information across databases.

The Network Modeling Tool Enhancements project will adopt a new modeling platform, the GE Eterra Source platform, which is used by many other independent system operators and utilities. This new platform has capabilities that simplify topology checking, reducing the likelihood of modeling errors. The new tool also allows for bulk data uploads, easier engineering change reviews, and is less reliant on other internal resources for validations.

The development of a new EMS modeling tool will require deployment of servers, cycle testing of the new platform, configuration, development of user templates, and user training.

The targeted completion date for this project is July 2025.

Capital Budget

2025 Expenditures/Major Projects in Development

New England Clean Energy Connect $0.3M

The New England Clean Energy Connect (NECEC) project is focused on integrating a new transmission line between Hydro Quebec and Maine, which is slated to participate in the New England Markets by January 2026. This transmission line will play a key role in supporting the region's key access to clean energy and achieving broader environmental goals.

As part of this project, the ISO will undertake a thorough review and modification of relevant processes and systems. This includes making necessary adjustments to tariffs, legal frameworks, and operational procedures to ensure the seamless integration of NECEC into the existing electrical grid and market operations.

The ISO will update various applications and complete all necessary software and operational adjustments in time for test power delivery in late 2025. Additionally, new inter-operating agreements and coordination agreements will be developed and filed with FERC, along with necessary updates to the ISO's Tariff and several operational manuals. Further revisions to numerous Operating Procedures, Standard Operating Procedures (SOPs), and Market Participant Operating Procedures (MPOP) will be required to reflect NECEC's inclusion.

The targeted completion date for this project is December 2025.

Capital Budget

2025 Expenditures/Major Projects in Development

Automatic Ring Down Circuit Continuity Modernization and Reliability Enhancements $0.3M

The Automatic Ring Down Circuit Continuity Modernization and Reliability Enhancements project addresses the discontinuation of traditional analog Automatic Reclosing Device (ARD) circuits and the reliance on T-Mobile's Long-Term Evolution (LTE) service for ISO-NE's Energy Dispatch (ED) network. The project will involve migrating ARD circuits to the ED network and transitioning to AT&T's FirstNet, a protected LTE network for first responders. ISO-NE will collaborate with external engineering resources for this migration and upgrade.

The targeted completion date for this project is August 2025.

Capital Budget

2025 Expenditures/Major Projects in Development

CIP Electronic Security Perimeter Redesign Phase II $0.3M

The CIP Electronic Security Perimeter Redesign project is a multi-phase project that will redesign ISO-NE's electronic security perimeter (ESP) networks to enhance ISO-NE's overall network security posture to align with industry best practices regarding resiliency, recovery, and change management. This project will also facilitate compliance with North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) standards. Phase I completed in July of 2021, involved the reconfiguration of both ISO-NE facility data centers, the isolation and protection of management control functions, changes to network designs and firewalls to reduce complexity, and installation of conduit encryption for all inter-physical security perimeter connections.

The second phase will improve ESP network CIP compliance and will enhance ISO-NE's overall network security posture. Phase II efforts will consolidate ISO-NE's production and integration networks into one ESP, with fewer electronic access points; modernize ISO-NE's firewall platform; implement a modern access control mechanism for CIP networks, replacing a legacy terminal-server based system; and standardize ISO-NE's IP address scheme to enable easier network management. This project is also foundational for future CIP compliance projects.

The targeted completion date for this project is June 2025.

Capital Budget

2025 Expenditures/Major Projects in Development

Tie Line Telemetry and PCEC Upgrades Phases I & II $0.6M

ISO-NE's current Pool Control Error Calculator (PCEC) is a crucial tool for control room operators to manage area control errors. However, it relies on outdated analog telemetry for tie-lines, which is now at the end of its manufacturer support. Additionally, the servers supporting the PCEC system will no longer receive extended support coverage or security patches after June 2024. Upgrading the tie-line telemetry equipment will provide greater communication flexibility, consolidate equipment to remove failure points, and improve the overall resilience of the PCEC system.

Phase I is focused on replacing the PCEC and its components, with targeted completion scheduled for June 2025, with budgeted 2025 funding of $0.1M.

Phase II is still in the design phase and will focus on updating the tie-line telemetry and frequency metering equipment. The targeted completion date for Phase II is July 2025, with budgeted 2025 funding of $0.5M.

Capital Budget

2025 Expenditures/Major Projects in Development

EMS Short-term Load Forecast Replacement $0.1M

The Energy Management System's short term load forecast (STLF) is a critical input to Real-Time unit commitment and unit dispatch software. The existing STLF software is unable to address the emergence of behind-the-meter solar to account for load patterns of weather and clouds, requiring significant manual intervention by control room operators in order to minimize market and reliability impacts. This issue has been growing in severity over the past several years and a variety of small-scale initiatives have been completed in order to allow system operators to manually adjust the STLF to account for behind-the-meter solar activity during the operating day. Because of the significant manual adjustments and rapid growth of behind-the-meter solar, replacement of the STLF engine is required for efficiency and accuracy.

The development of a new forecasting system to replace the current STLF will improve the price formation for Coordinated Transaction Scheduling, provide a more accurate input for Real-Time unit commitment and dispatch software; and reduce the time Control Room operators spend monitoring and manually intervening in the STLF results, allowing operators to focus more on system conditions and reliability. This project will also develop and deliver a new forecasting system with a dynamic modeling process that will create a real-time load data feed and incorporate real-time behind-the-meter photovoltaic data for use in forecasting; develop new forecasting models; establish the necessary development, integration, and production environments for the load forecasting platform; train ISO personnel regarding the new system; and update the relevant internal procedures and process documentation.

The targeted completion date for this project is February 2025.

Capital Budget

2025 Expenditures/Major Projects in Development

Microsoft 365 Service Adoption $0.1M

The capabilities and resiliency of ISO's on-premise enterprise software (e.g., directories, file shares, and mail servers) can be improved and consolidated using the cloud-based Microsoft 365 Services. Adoption of Microsoft 365 Services for certain enterprise software will significantly increase ISO's business continuity posture and will allow employees to work more productively with natively built-in tools and features.

The successful migration to Microsoft 365 will improve employee collaboration, streamline information technology operations with new management tools and automation, improve protection of end users and information with platform-wide security solutions, and reduce overhead associated with maintaining physical information technology infrastructure.

Future Microsoft 365 Service Adoption project efforts are expected to be completed in a future phase(s). While this initial phase will focus on transitioning to cloud-based services, the second phase will build on these efforts by enhancing system integrations, introducing additional cybersecurity tools, supporting a wider adoption of Microsoft 365 applications, as well as the integration of additional management tools and automation solutions.

The targeted completion date for this project is November 2024.

Capital Budget

2025 Expenditures/Major Projects in Conceptual Design

FERC Order 841 $2.0M

The FERC 841 project will modify ISO-NE's electric storage resources participation model to account for State of Charge and duration characteristics consistent with the final FERC rule. The project will allow the ISO to introduce four new bidding parameters in the Day-Ahead Energy Market: (1) Initial State of Charge, (2) Maximum State of Charge, (3) Minimum State of Charge, (4) Round-Trip Efficiency; and (5) Derived State of Charge parameter.

The targeted completion date for this project is October 2025.

Capital Budget

2025 Expenditures/Major Projects in Conceptual Design

Space Utilization Project Phase I $2.0M

The Space Utilization project will redesign and update ISO-NE's Holyoke (MCC) and Windsor (BCC) campuses, to accommodate the expected employee growth as the region transitions to clean energy. The first phase of this project will include modest changes to the Windsor campus to accommodate a temporary relocation of 75-100 employees and reprograming of the Holyoke campus. The changes at the Windsor campus include upgrades to add audio visual capabilities in conference rooms, upgrades to wireless technology, the replacement of the current guard building, and updates to the kitchen facilities. Changes at the Holyoke campus will include minor upgrades to facilitate changes in floor plans to accommodate employee growth.

Phase I of this project is targeted to be complete by August 2025.

Capital Budget

2025 Expenditures/Major Projects in Conceptual Design

Enterprise Core Network Refresh $2.0M

ISO-NE's core network infrastructure requires an upgrade as it is over a decade old with hardware and software nearing the end of support. This project will involve researching and implementing the latest network and security technologies. The upgrade will help ISO-NE adopt zero-trust security principles and improve efficiency, reliability, security, and cost-effectiveness for its key technology infrastructure.

The targeted completion date for this project is December 2025.

Capital Budget

2025 Expenditures/Major Projects in Conceptual Design

Enterprise Resource Planning System Replacement $1.9M

ISO-NE's current financial Enterprise Resource Planning (ERP) system reaches end-of-life in April 2026 and will need to be replaced. ISO-NE's ERP system provides the core framework for recording and reporting financial transactions and is a key component of settling the wholesale electricity markets, securing the necessary funding for ISO-NE operations, and maintaining strict compliance with reporting and filing requirements (including FERC reporting requirements).

ISO-NE has selected a new cloud-based software as a service (Saas) solution as our future ERP system that will modernize our ERP capabilities by providing enhanced workflows, integrated contract management, a comprehensive financial forecasting system, and robust enterprise reporting. Use of the new software will also reduce risks and dependencies on third-party software.

The targeted completion date for this project is December 2025.

Capital Budget

2025 Expenditures/Major Projects in Conceptual Design

EMP 3.5 Upgrade $1.5M

ISO-NE's Energy Management System (EMS) relies on GE's suite of Energy Management Platform (EMP) applications. Customization to GE's EMP software are necessary in order to meet the business requirements of ISO-NE's System Operations and Market Operation groups. GE released a new version of its EMP application (EMP 3.5) in Q1 2025 and ISO-NE must upgrade to GE's latest platform to continue receiving support. The upgrade will involve significant effort to port ISO-NE's customized software to the new EMP platform.

The targeted completion date for this project is December 2026.

Capital Budget

2025 Expenditures/Major Projects in Conceptual Design

Windows Server Replacement Phase II $1.5M

A team of ISO IT personnel are in charge of providing consistent, standard, and modern deployments of the Microsoft (MS) Windows Server Operating System to meet ISO-NE's business objectives. Phase I of the project, known as the Windows Server 2019R2 Deployment project, was completed in December 2023, and laid the groundwork for deploying Windows Server 2019.

Phase II of the project will enhance our deployment process to include the modern and supported Windows Server 2019 operating system. By upgrading to Windows Server 2019, we extend our support lifecycle to January 2029. Additionally, the new build process will establish a more consistent, detailed, and secure configuration that complies with the Center for Internet Security (CIS) standards. This will ensure a higher level of security and reliability for our IT infrastructure.

The targeted completion date for this project is December 2025.

Capital Budget

2025 Expenditures/Major Projects in Conceptual Design

Integrated Market Simulator Enhancement $1.5M

The Integrated Market Simulator Enhancement project will enhance the functionality of the Integrated Market Simulator (IMS) based on Market Development's user experience. The enhanced IMS will introduce new features to better simulate real market conditions. These improvements will support business users by providing more accurate and comprehensive tools for their purposes and studies, and deliver significant advancements in market simulation capabilities.

The targeted completion date for this project is December 2025.

Capital Budget

2025 Expenditures/Major Projects in Conceptual Design

FERC Order 2222 $1.0M

FERC's Order 2222 requires that independent system operators and regional transmission organizations remove barriers to the participation of distributed energy resource aggregations (DERAs) in wholesale electricity markets. In accordance with Order 2222, ISO-NE proposes to expand its current energy market models and add two new energy market participation models for DERAs: Settlement Only Distributed Energy Aggregation, and Demand Response Distributed Resource Aggregation. Additionally, the introduction of a new resource type, Distributed Energy Capacity Resource, will allow DERAs to participate in the Forward Capacity Market.

Compliance with Order 2222 will span two projects. The first project, Forward Capacity Market Order 2222, which was completed in February 2024, implemented the necessary software changes to support the qualification and participation of Distributed Energy Capacity Resources in the Forward Capacity Market. The FERC Order 2222 project will include the software changes to allow for the integration of DERAs in the wholesale markets and operations systems and any remaining compliance obligations of the order.

The targeted completion date for this project is November 2026.

Capital Budget

2025 Expenditures/Major Projects in Conceptual Design

MW Dependent Fuel Price Adjustment $1.0M

ISO-NE is proposing changes to the energy market mitigation rules that govern the fuel price adjustment (FPA) process. These changes, known as "MW-dependent FPAs," will allow resources to reflect up to two different fuel prices in their cost-based reference levels, which will improve the accuracy of energy market mitigation and enhance energy market efficiency.

The MW Dependent Fuel Price Adjustment project involves updating ISO-NE's energy market software to allow participants to submit an FPA with one or two fuel prices and to allow for participants to specify how the requested price(s) apply to their supply offer. The software enhancements will address issues raised in the May 5, 2023, FERC Show Cause Order.

The targeted completion date for this project is November 2025.

Capital Budget

2025 Expenditures/Major Projects in Conceptual Design

2025 Issue Resolution Project $0.8M

ISO-NE uses an Application Modification Request (AMR) approach (previously known as CAPA) to identify and track needed enhancements to existing systems and processes to more efficiently administer the market rules and procedures.

The 2025 Issue Resolution Project will focus on resolving AMRs that enhance various software systems. Software changes can span a wide range of functionality including user interface improvements, internal and external reporting modifications, and other market related improvements.

The targeted completion date for this project is September 2025.

Capital Budget

2025 Expenditures/Major Projects in Conceptual Design

Storage as Transmission Only Asset $0.4M

In October 2023, FERC approved a proposal from ISO-NE, which enables electric storage facilities to be planned and operated as transmission only-assets to address system needs identified in the regional system planning process. The rules allow transmission companies to own and maintain energy storage assets for supporting the transmission system. These assets are called Storage as Transmission Only Assets (SATOAs).

SATOAs are different from energy storage assets that participate in the ISO-NE's wholesale markets and generate revenue in that they serve a transmission function only. Unlike energy storage assets, SATOAs are selected as transmission solutions through the regional system planning process administered by ISO-NE, and are subject to ISO-NE's operational authority. They do not participate in the wholesale markets other than for limited purposes specified in the rules.

Like other regional transmission facilities, transmission companies will own and maintain SATOAs. However, ISO-NE systems operators will manage the actual operation of these assets. The main purpose of SATOAs is to ensure the reliable transmission of electricity from power plants to consumers. Because they are designed solely for this purpose, SATOAs are not expected to influence wholesale market prices. This project will integrate the operation of SATOAs into ISO-NE's operation applications.

The targeted completion date for this project is March 2027.

Capital Budget

2025 Expenditures/Major Projects in Conceptual Design

Circuit Inventory Management Platform $0.4M

The ISO-NE IT Communications Projects team (ITComms) requires a centralized platform for Communications and Information Management (CIM) that meets the everyday needs of the ITComms team and facilitates the sharing of telecom data with other departments within the organization.

The goal of the Circuit Inventory Management Platform project is to acquire and implement a centralized platform, ensuring it is tailored for optimal use by the ITComms team and capable of effectively integrating and distributing telecom data across the organization. Completion of this project will allow for enhanced collaboration, streamline processes, and improve overall efficiency in managing communications and information.

The targeted completion date of this project is October 2025.

Capital Budget

2025 Expenditures/Major Projects in Conceptual Design

Replace Employee & Pager Application $0.3M

The access rights and employee request applications are essential for managing identity and access within the organization. These applications allow workforce members to model, request, approve, and implement access to various information technology assets, such as servers, systems, shared drives, and badged physical access. To adhere to industry best practices and address several recommendations from ISO-NE staff, these systems needed new functionality.

Phase I of the project, known as Identity and Access Management Phase I, involved purchasing and implementing the necessary hardware and software to update the current access rights process.

Phase II, known as Identity and Access Management Phase II, focused on integrating the new hardware and software with ISO-NE systems. This phase also implemented new authorization roles and added features to protect the system from unauthorized access.

The Replace Employee & Pager Application project is the third phase and will replace the current employee and pager applications, develop one or more new applications to enhance system capabilities, and identify potential automation efficiencies.

The targeted completion date for this project is October 2025.

Capital Budget

2025 Expenditures/Major Projects in Conceptual Design

Adoption of NERC CIP Compliance of Synchrophasor Systems $0.3M

Phasor Measurement Units (PMUs) are essential for monitoring real-time grid dynamics. This is increasingly important as the electrical grid faces more uncertainties, operates closer to stability limits, and integrates more inverter-based resources at unprecedented levels. Although the ISO has made significant progress in adopting Synchrophasor technology in both planning and operations, the organization has not fully utilized its potential in real-time operations due to Critical Infrastructure Protection (CIP) requirements.

The Adoption of NERC CIP Compliance of Synchrophasor Systems project aims to enhance the infrastructure related to Synchrophasor applications and ensure they adhere to NERC CIP compliance protocols. Additionally, it will help us utilize the full potential of Synchrophasor technology in real-time operations while maintaining compliance with the necessary security standards.

The targeted completion date for this project is October 2026.

Capital Budget

2025 Expenditures/Major Projects in Conceptual Design

Solar Do Not Exceed Dispatch Phase III $0.3M

The amount of solar energy generation in New England is growing and expected to continue increasing. Integrating these solar resources requires developing rules, processes, forecasts, and tools to incorporate them into the Do-Not-Exceed (DNE) dispatch processes.

In Phase I, GE enhanced ISO-NE's Renewable Plan (Rplan) software. This allows Market Participants to submit medium and long-term data on future power generation availability. The upgrades support the inclusion of solar power forecasts, alongside wind forecasts from multiple vendors.

In Phase II, remote terminal units (RTU) were installed and tested at solar units to support DNE dispatch signals. Additionally, several applications, including PWRFLOW and RTGEN were also updated to support the new DNE functionality.

To accommodate the anticipated growth of solar resources, further development is needed. This involves aligning ISO-NE internal applications with changes from the initial project phases. In Phase III, updates are planned for TARA Case Builder, STOCM, Jasper Reports, and the Operator Training Simulator (TTSE).

The targeted completion date for this project is November 2025.

Capital Budget

2025 Expenditures/Major Projects in Conceptual Design

Non-Project Capital Expenditures $5.0M

Non-Project capital expenditures fund external and internal capitalized labor necessary to program System Improvement Requests ($2.5M); non-project related hardware purchases ($2.0M); and Building Improvements, Machinery & Equipment, and Furniture & Fixtures ($0.5M).

Other Emerging Work $5.7M

This category is primarily intended to address emerging work requests during 2025 that result from operational needs, compliance obligations, or stakeholder feedback.

Refer to the following slide for further detail on Non-Project Capital Expenditures.

Capital Budget

2025 Non-Project Capital

The budget forecast for each of the non-project capital categories is informed by historical level expenditures and an assessment of planned investments for the upcoming year. The budgeted expenses for Non-Project Capital Expenditures, like the ISO-NE operating budget categories, are zero-based each year. The 2025 amounts and description of funding included for each category is provided as follows:

- **$2.5 million – System Improvement Requests**: Annually, ISO-NE's Information Services ("IS") department addresses several hundred small requests to improve existing software infrastructure. The IS department deploys a combination of ISO-NE internal employees, consultants, and vendors to address the list of open system improvements. Each year, the forecasted budget is reviewed to ensure the resources dedicated to this effort are not in conflict with slated major projects.
- **$2.0 million – Non-Project Hardware**: ISO-NE has a critical investment in servers, storage, networking, and monitoring systems in our data center environment that support ISO-NE's critical roles of Grid Operation, Market Administration, and Power System Planning; as well as general corporate needs. ISO-NE is required to ensure that existing deployed infrastructure is current with vendor established end-of-support and end-of-life timelines. These continual refresh activities are essential to ensure ISO-NE data center services remain supported with security and maintenance contracts, as well as meet IT reliability service levels. In 2025, ISO-NE will continue to replace and upgrade IT Infrastructure as required. Projects include: (1) to continue refreshing ISO-NE's virtualization server infrastructure to replace servers reaching end-of-life; (2) replace aging storage infrastructure supporting database and virtualization workloads; and (3) upgrades to the network security infrastructure that support remote access, including firewall replacements and security controls integration.
- **$0.5 million - Building Improvements, Machinery & Equipment, and Furniture & Fixtures**: Annually, ISO-NE's Building Services department invests in the upkeep and upgrading of ISO-NE's Holyoke and Windsor facilities. The 2025 budget funding includes replacement of the Holyoke North Building roof, converting an Information Technology work lab into a more functional workspace, upgrading the lighting fixtures at the Windsor Facility, and replacing the exit gate at the Windsor Facility.

Capital Budget

Resource Allocation for 2025 Projects with Approved Charters

The following projects included in the 2025 budget have approved charters with specific funding requirements established. For each project the breakdown of costs and full-time equivalent (FTE) positions is provided by year and between internal labor and outside consultants. Amounts include actual and future forecast/budget.

	2022 Actual				2023 Actual				2024 Actual & Remaining Forecast (1)				2025 Budget			
Capital Projects - Approved Charters	Int Labor $	FTE Equiv	Consult $	FTE Equiv	Int Labor $	FTE Equiv	Consult $'s	FTE Equiv	Int Labor $	FTE Equiv	Consult $	FTE Equiv	Int Labor $	FTE Equiv	Consult $	FTE Equiv
. nGEM Real-Time MCE Implementation (2)	$ 208,132	1.0	$ 655,554	2.4	$ 302,113	1.4	$1,731,311	6.4	$ 391,171	1.8	$3,250,666	12.0	$ 645,000	3.0	$ 3,398,642	12.6
. nGEM Software Development Part III	-	-	-	-	98,719	0.5	936,013	3.5	65,463	0.3	429,123	1.6	45,000	0.2	2,892,480	10.7
. Managing Transmission Line Ratings	-	-	-	-	38,830	0.2	109,050	0.4	615,225	2.8	3,916,719	14.5	380,037	1.7	1,303,273	4.8
. Day-ahead Ancillary Services Improvements	53,628	0.2	416,579	1.5	305,483	1.4	3,257,406	12.0	1,524,766	7.0	1,986,844	7.3	446,000	2.0	1,080,790	4.0
. CAMS Application Software Technology Upgrade	-	-	-	-	37,294	0.2	-	-	475,910	2.2	174,800	0.6	485,320	2.2	149,620	0.6
. Network Modeling Tool Enhancements	-	-	-	-	38,785	0.2	163,230	0.6	257,129	1.2	296,300	1.1	241,230	1.1	282,193	1.0
. Automatic Ring Down Circuit Continuity Modernization and Reliability Enhancements	-	-	-	-	18,574	0.1	15,743	0.1	101,328	0.5	71,818	0.3	106,895	0.5	170,329	0.6
. CIP Electronic Security Perimeter Redesign Phase II	6,092	0.0	-	-	52,387	0.2	1,183	0.0	205,789	0.9	247,395	0.9	150,000	0.7	120,200	0.4
. Tie Line Telemetry and PCEC Upgrade	-	-	-	-	20,050	0.1	-	-	50,883	0.2	58,000	0.2	48,136	0.2	40,000	0.1
. EMS Short-term Load Forecast Replacement	16,765	0.1	-	-	69,955	0.3	13,072	0.0	162,066	0.7	303,248	1.1	38,500	0.2	-	-
. Microsoft 365 Service Adoption	-	-	-	-	-	-	-	-	72,086	0.3	633,936	2.3	7,680	0.0	-	-

Assumptions for FTE Equiv = Int Labor Fully Burdened = $105/hr.; Consultants = $130/hr.

(1) 2024 includes actual results through August as well as the remaining forecast for the rest of the year. Actual amounts through August are: nGEM Real-Time MCE Implementation - $2,290.1K; nGEM Software Development Part III - $254.0K; Managing Transmission Line Ratings - $2,249.4K; Day-ahead Ancillary Services Improvements - $2,527.6K; CAMS Application Software Technology Upgrade $313.5K; Network Modeling Tool Enhancements of $156.1K; Automatic Ring Down Continuity Modernization and Reliability Enh of $53.9K; CIP Electronic Security Perimeter Redesign Phase II of $191.5K; Tie Line Telemetry and PCEC Upgrade $33.6K, EMS Short-term Load Forecast Replacement of $331.3K, and Microsoft 365 Service Adoption $276.7K

(2) The nGEM Real-Time MCE Implementation has $2,043.6K, of costs beyond 2025.

(3) The above amounts exclude hardware and/or software amounts of: nGEM Real-Time MCE Implementation of $2,126.0K; Managing Transmission Line Ratings of $1,338.1K; CAMS Application Software Technology Upgrade of $33.0K; Network Modeling Tool Enhancements of $1.1K; Automatic Ring Down Continuity Modernization and Reliability Enh of $412.5K, CIP Electronic Security Perimeter Redesign Phase II of $4,194.3K, Tie Line Telemetry and PCEC Upgrade of $101.1K, and EMS Short-term Load Forecast Replacement of $835.4K

APPENDIX 8: EMERGING WORK ALLOWANCE & PURCHASING POLICIES AND CONTROLS

Emerging Work Allowance

- ISO New England does not have “equity” or reserves to utilize but must fund unforeseen and newly defined work that arises after the budget is established
- The CEO Emerging Work Allowance (the Fund) is used to fund requests for required activities that were not specifically funded in the original budget and changes to initial cost estimates
- A risk is recorded on the Risks and Opportunities Report (R&O Report) when (i) unbudgeted new work is identified, or (ii) when staff becomes aware that budgeted work may exceed the original estimate; likewise, when potential savings on a budgeted item are anticipated, an opportunity is identified
- The R&O report contains information about the item and the probability of the occurrence of the item and is updated at least monthly

Emerging Work Allowance – Process for Deposits and Withdrawals

- During the quarterly updates to the forecasts, cost center managers review the current amounts forecasted to determine the continued accuracy of their forecasts for the subsequent six months
- Cost center managers will integrate into their updated forecasts highly probable risks or savings that may have been previously identified on the R&O report or may be newly defined
- An explanation is required by the cost center manager for why amounts are being deposited to the Fund (from savings identified) or why there is a need for a withdrawal from the Fund
- All information pertaining to potential deposits to the Fund or withdrawals from the Fund, stemming from the updated quarterly forecast, is compiled and the detail is reviewed by the Manager of Budgeting and Financial Reporting and the Controller and Director, Accounting for reasonableness and/or the need for additional explanation and approved by the CFO and CEO

Purchasing Policies and Controls

- The Company has established a Purchasing Policy with guidelines to follow when committing the funds of the ISO to any vendor, including the placing and handling of purchase orders, requests for proposals and quotes, contracts, and approval limits
- The Purchasing Department is responsible for all purchasing decisions related to materials, equipment, and services
- The Purchasing Department works to minimize costs of purchased goods and services where possible, while maximizing quality
- All purchases require a fully approved purchase order unless a specific exception is noted in the Purchasing Policy (e.g., utility bills and regulatory fees); regardless of whether a purchase is exempt from the purchase order requirement, a rigorous review of the validity and accuracy of the charges is performed
- The Purchasing Department is the only department authorized to purchase goods and/or services for the ISO and all contracts must be approved by the ISO legal department (with limited exceptions)
- The Purchasing Policy is available on the ISO’s website

APPENDIX 9: 2025-2028 PRO-FORMA STATEMENTS

2025 - 2028 Pro-Forma Budgets

(Dollars in Millions)	2025	2026	2027	2028
Operating Budget (1)	$269.4	$289.5	$298.2	$307.1
Capital Project Budget	$42.5	$40.0	$40.0	$40.0
Total	**$311.9**	**$329.5**	**$338.2**	**$347.1**
Operating (1)	$269.4	$289.5	$298.2	$307.1
Depreciation (1)	$37.0	$42.1	$40.3	$39.8
True-Up	$4.8	($1.0)	($1.0)	($1.0)
Revenue Requirement	**$311.2**	**$330.6**	**$337.5**	**$345.9**
TWh Forecast (2)	136.5	138.4	140.6	143.5
$/KWh Rate	**$0.00228**	**$0.00239**	**$0.00240**	**$0.00241**

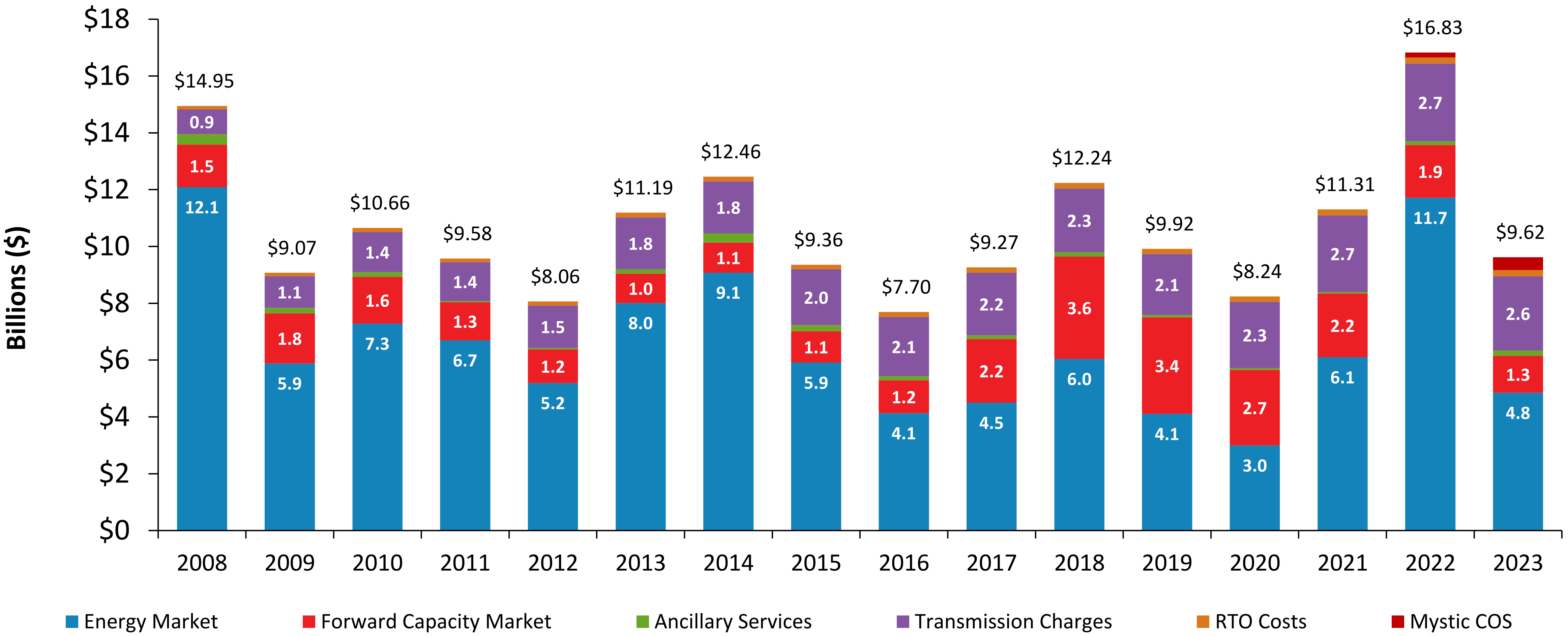
(1) 2026 – 2028 assumes an inflationary increase in Operating costs, however, there is no inflationary increase for interest expense and interest income, and the budgets do not contemplate new mandated activities, or the potential for uncertainties in implementation complexity for existing initiatives (e.g. the new System Planning activities and the Prompt/Seasonal capacity market).

(2) For 2025 – 2028, the May 2024 CELT Report was used.

APPENDIX 10: NEW ENGLAND WHOLESALE ELECTRICITY COSTS AND RETAIL ELECTRICITY RATES

New England Wholesale Electricity Costs*

Annual wholesale electricity costs have ranged from $7.7 billion to $16.8 billion



(The total costs for each year include Ancillary Services and RTO costs)

Source: ISO New England; ***2023 data is preliminary and subject to resettlement**

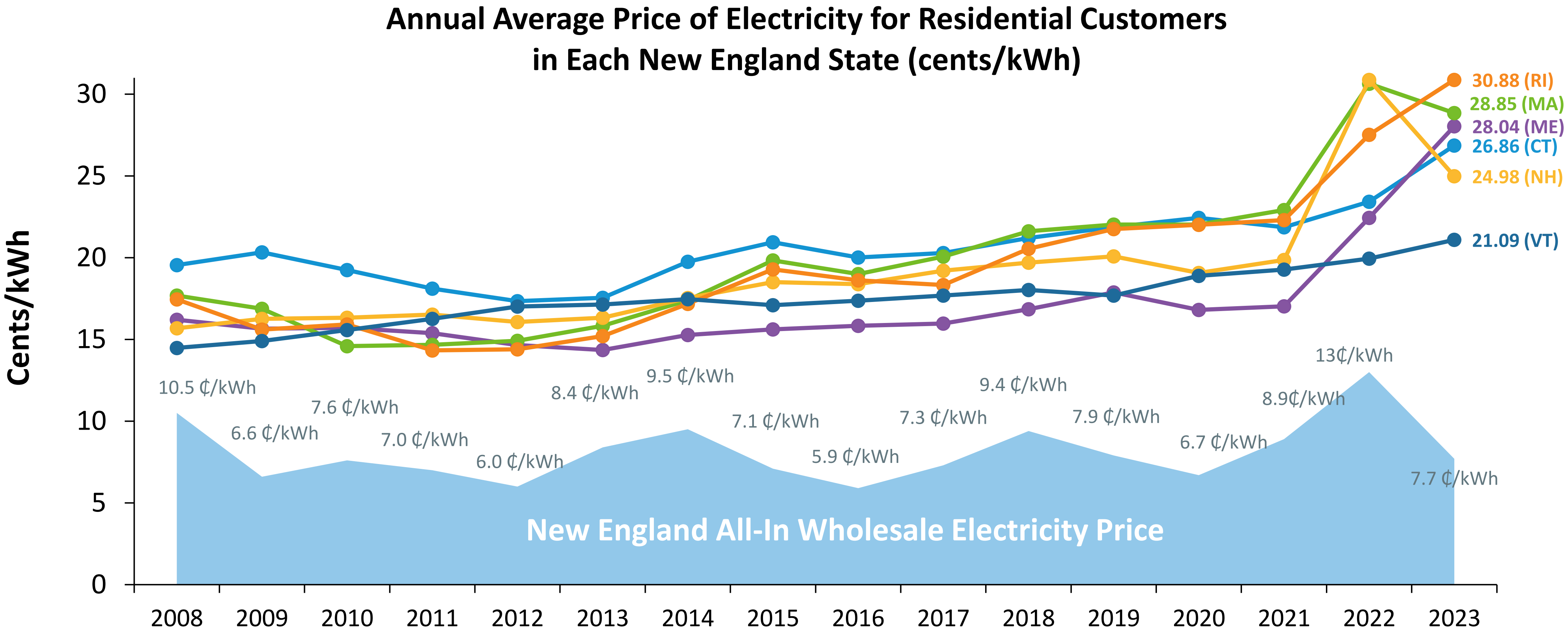
Note: Forward Capacity Market values shown are based on auctions held roughly three years prior to each calendar year.

New England Wholesale Electricity Costs[a]

	2018		2019		2020		2021		2022		2023*	
	$ Mil.	¢/kWh	$ Mil.	¢/kWh	$ Mil.	¢/kWh	$ Mil.	¢/kWh	$ Mil.	¢/kWh	$ Mil.	¢/kWh
Wholesale Market Costs												
Energy (LMPs)[b]	$6,041	4.7	$4,105	3.3	$2,996	2.4	$6,101	4.8	$11,712	9.0	$4,847	3.9
Ancillaries[c]	$147	0.1	$83	0.1	$62	0.1	$52	0.0	$124	0.1	$182	0.1
Capacity[d]	$3,606	2.8	$3,401	2.7	$2,662	2.2	$2,243	1.8	$1,864	1.4	$1,308	1.1
Subtotal	*$9,794*	*7.6*	*$7,589*	*6.0*	*$5,720*	*4.7*	*$8,404*	*6.6*	*$13,701*	*10.5*	*$6,338*	*5.1*
Transmission charges[e]	$2,250	1.7	$2,146	1.7	$2,331	1.9	$2,688	2.1	$2,739	2.1	$2,612	2.1
RTO costs[f]	$196	0.2	$184	0.1	$191	0.2	$216	0.2	$214	0.2	$214	0.2
			Mystic Cost of Service Agreement						$173	0.1	$460	0.4
Total	**$12,240**	**9.4**	**$9,918**	**7.9**	**$8,242**	**6.7**	**$11,308**	**8.9**	**$16,828**	**13.0**	**$9,624**	**7.7**

(a) Average annual costs are based on the 12 months beginning January 1 and ending December 31. Costs in millions = the dollar value of the costs to New England wholesale market load servers for ISO-administered services. Cents/kWh = the value derived by dividing the dollar value (indicated above) by the real-time load obligation. These values are presented for illustrative purposes only and do not reflect actual charge methodologies. ***The wholesale values for 2023 are preliminary and subject to resettlement.**
(b) Energy values are derived from wholesale market pricing and represent the results of the Day-Ahead Energy Market plus deviations from the Day-Ahead Energy Market reflected in the Real-Time Energy Market.
(c) Ancillaries include first- and second-contingency Net Commitment-Period Compensation (NCPC), forward reserves, real-time reserves, regulation service, and a reduction for the Marginal Loss Revenue Fund.
(d) Capacity charges are those associated with the Forward Capacity Market (FCM).
(e) Transmission charges reflect the collection of transmission owners' revenue requirements and tariff-based reliability services, including black-start capability, voltage support, and FCM reliability.
(f) RTO costs are the costs to run and operate ISO New England and are based on actual collections, as determined under Section IV of the *ISO New England Inc. Transmission, Markets, and Services Tariff*.
*2023 figures are preliminary

Retail Electricity Prices Follow Wholesale Prices, But Are Also Influenced by Individual State Policies



Source: U.S. Energy Information Administration, *Electric Power Monthly*, Table 5.6.B Average Price of Electricity to Ultimate Customers by End-Use Sector, by State (Through Dec. 2023); the New England all-in wholesale electricity price is derived by dividing total wholesale electricity costs by real-time load obligation (presented for illustrative purposes; does not reflect actual charge methodologies)

APPENDIX 11: ISO/RTO FINANCIAL COMPARISON

Financial Results Summary

ISO/RTO Financial Summary - 2023 Actual Results

Operating Expense and Capital Expenditures for Calendar Year 2023, and Outstanding Debt as of December 31, 2023 (1)

(Amounts in Millions)

	ISO-NE (2)	PJM	NYISO	CAISO	IESO (3)	MISO	SPP	ERCOT
Operating Expense - 2023	$ 235.6	$ 437.9	$ 231.6	$ 273.4	$ 280.4	$ 449.4	$ 254.9	$ 286.2
Less: Amortization & Depreciation	(30.0)	(37.7)	(17.7)	(28.7)	(24.1)	(30.4)	(16.8)	(34.7)
Regulatory Fees	(7.3)	(81.3)	(17.6)	-	-	(67.4)	(31.3)	-
Grant Expenses	-	-	-	-	-	-	-	-
Net Operating Expense - 2023	$ 198.3	$ 318.9	$ 196.3	$ 244.7	$ 256.3	$ 351.6	$ 206.8	$ 251.5
Other Financial Data								
Capital Expenditures for 2023	$ 35.4	$ 43.2	$ 16.3	$ 20.9	$ 72.6	$ 34.6	$ 14.3	$ 32.4
Outstanding Debt as of 12/31/23	$ 86.6	$ 5.0	$ 73.9	$ 156.7	$ 203.0	$ 274.4	$ 130.7	$ 2,514.0
Actual full-time equivalent headcount as of 12/31/23	625.5	802.0	599.0	710.0	896.0	1059.0	744.0	890.0

(1) Applicable amounts were taken from each entity's 2023 audited financial statements.

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

(3) Amounts are in Canadian dollars

APPENDIX 12: 2022 AND 2023 ACTUAL TO BUDGET VARIANCE ANALYSIS

ISO New England Actual-to-Budget Variance Analysis for 2022 and 2023

The following pages provide actual-to-budget variance analysis for 2022 and 2023. The information provided includes overall results, a table that breaks down salary into base salaries and wages, overtime wages, incentive or bonus payments, and each employee benefit program with an annual cost greater than $200,000. Professional fees and consultant costs are stated separately by department, and an explanation is provided for each variance in excess of $1,000,000.

Amounts in the tables below are in thousands.

2022 (Overall Results)

Description	2022 Actuals	2022 Original Budget	Variance Inc/(Dec)
Operating Expense			
Salaries and Overheads	$ 124,555.4	$ 124,146.5	408.9
Professional Fees & Consulting	17,056.1	16,963.9	92.2
Professional Fees & Consulting - Legal	2,776.6	2,872.0	(95.4)
Building Services	3,348.3	3,075.1	273.2
Rents & Leases	695.5	929.8	(234.3)
Network Operations	2,958.5	3,181.3	(222.9)
Computer Services	17,482.2	17,908.1	(425.9)
Data Services & Office Expenses	1,728.8	1,848.8	(120.0)
Insurance Expense	2,632.9	2,585.8	47.2
Board of Directors Expense	1,674.0	1,480.5	193.5
Meeting & Related Expenses	1,015.3	1,240.5	(225.2)
Education & Training	1,061.9	1,208.3	(146.4)
Taxes, Permits, Licenses & Fees	202.2	189.9	12.3
Total Operating Expense	**177,187.8**	**177,630.4**	**(442.6)**
Revenues, Other Income	**(1,267.1)**	**(492.6)**	**(774.5)**
Operating Expenses net of Revenue	**175,920.7**	**177,137.9**	**(1,217.2)**
CEO Emerging Work Allowance	-	2,000.0	(2,000.0)
Board Contingency	-	700.0	(700.0)
NPCC/NERC Dues & Expense	6,437.0	6,445.5	(8.5)
Interest Expense	2,248.7	2,774.0	(525.3)
Net Expense Before Depreciation	**184,606.4**	**189,057.4**	(4,451.0)
Depreciation Expense	25,047.3	25,953.3	(906.0)
Gain/Loss on Fixed Asset Disposal	(1.5)	60.0	(61.5)
Total Depreciation and Debt Services	**25,045.8**	**26,013.3**	**(967.5)**
Total Expense for ACT Recovery	**$ 209,652.2**	**$ 215,070.7**	**(5,418.5)**

2022 (Salaries & Burden)

Description	Actual 2022 Expense	Approved Budget 2022	Incr/(Dec)
Salaries and Wages - Base	$ 76,075.0	$ 78,194.8	$ (2,119.8)
Salaries and Wages - Overtime	3,325.6	2,666.7	658.9
Salaries and Wages - Incentive/Bonus	15,037.5	13,723.0	1,314.5
Employee Benefits - Pension	11,299.3	10,821.3	478.0
Employee Benefits - Post-Ret Benefits	328.0	554.0	(226.0)
Employee Benefits - Health Insurance	7,189.2	7,300.5	(111.3)
Employee Benefits - Dental Insurance	481.7	485.5	(3.8)
Employee Benefits - 401(K) Match	3,071.2	3,174.8	(103.6)
Salary Burden - Payroll Taxes	7,207.4	6,659.1	548.3
Other Benefit/Burden <$200K	540.5	566.8	(26.3)
Total Salaries & Burden Expense	**$ 124,555.4**	**$ 124,146.6**	**$ 408.8**

2022 (Professional Fees)

Department	2022 Actuals	2022 Original Budget	Variance Inc/(Dec)
System Operations & Market Admin.	$ 156.9	$ 158.0	$ (1.1)
System Planning	2,044.1	1,484.8	559.3
Market Monitoring	467.8	715.0	(247.2)
Information Technology	6,467.3	8,483.4	(2,016.2)
Market Development & Settlements	2,428.0	1,310.3	1,117.7
Human Resources	2,015.6	2,051.8	(36.2)
Finance Operations	438.2	435.5	2.7
Internal Audits	855.0	899.8	(44.8)
Corp Comm and Public Affairs	668.2	591.9	76.3
Advance Technology Solutions	1,375.8	205.7	1,170.1
All Other	139.2	627.7	(488.5)
Total	17,056.1	16,963.9	92.1
Legal Professional Fees	2,776.6	2,872.0	(95.4)
Total Professional Fees	**$ 19,832.7**	**$ 19,835.9**	**$ (3.3)**

2022 Actual vs. Budget variance explanations for items > $1,000,000

- Salaries and Overheads were $408,900 higher than the original budget. Significant increases included funding for higher incentive/bonus amounts for retention efforts of employees due to the labor market environment and higher turnover rate experienced in 2022 as well as increased overtime in some departments; these increases were partially offset by higher than forecasted vacancy and lower salary rates for new hires compared to previous incumbents.

- Professional Fees & Consulting were $3,300 lower than the original budget. The Information Technology segment was $2,016,200 lower primarily due to consultant vacancy as a result of a number of IT augmentation positions being vacant. Offsetting the decrease were increases of $1,170,100 in Advanced Technology Solutions for Resource Capacity Accreditation and Gas Constraint modeling work and $1,117,700 in Market Development & Settlements to undertake a review of the Inventoried Energy Program to evaluate the program's likely performance with changes in market conditions in addition to a Pathways Study to evaluate alternative policy approaches to decarbonizing the New England Grid.

- Because ISO-NE is a non-profit organization with no equity available there is $2,000,000 of funds (the "CEO Emerging Work Allowance") built into the budget to cover unknown or unforeseen costs that emerge during the year. Additional funding needs can be created as a result of refined estimates for work, new activities, or changes in accounting estimates. Similarly, to the extent that these changes result in an "under" expenditure, the CEO Emerging Work Allowance is increased. Requests for funds from the Emerging Work Allowance are reviewed by senior management, and require CFO and CEO approval prior to the spending authorization. No actual amounts are charged to this line item as it is only used for budget/forecast purposes.

2023 (Overall Results)

Description	2023 Actual	2023 Original Budget	Variance Inc/(Dec)
Operating Expense			
Salaries and Overheads	$ 137,317.5	$ 134,702.1	2,615.4
Professional Fees & Consulting	19,743.7	21,600.9	(1,857.2)
Professional Fees & Consulting - Legal	2,456.7	3,334.5	(877.8)
Building Services	3,339.2	3,122.5	216.7
Rents & Leases	719.3	897.6	(178.4)
Network Operations	3,138.4	3,269.9	(131.5)
Computer Services	20,469.2	20,397.8	71.5
Data Services & Office Expenses	1,628.0	2,015.1	(387.1)
Insurance Expense	2,927.0	3,140.2	(213.1)
Board of Directors Expense	1,542.9	1,516.5	26.4
Meeting & Related Expenses	989.9	1,272.4	(282.5)
Education & Training	1,032.1	1,326.9	(294.8)
Taxes, Permits, Licenses & Fees	235.3	193.9	41.4
Total Operating Expense	**195,539.4**	**196,790.3**	**(1,251.0)**
Revenues, Other Income	**(2,055.4)**	**(694.4)**	**(1,361.0)**
Operating Expenses net of Revenue	**193,484.0**	**196,096.0**	**(2,612.0)**
CEO Emerging Work Allowance	-	2,000.0	(2,000.0)
Board Contingency	-	700.0	(700.0)
NPCC/NERC Dues & Expense	7,277.3	7,296.4	(19.1)
Interest Expense	2,834.2	3,137.5	(303.3)
Net Expense Before Depreciation	**203,595.5**	**209,229.9**	(5,634.4)
Depreciation Expense	30,034.2	30,915.3	(881.1)
Gain/Loss on Fixed Asset Disposal	21.5	60.0	(38.5)
Total Depreciation and Debt Services	**30,055.7**	**30,975.3**	**(919.6)**
Total Expense for ACT Recovery	**$ 233,651.2**	**$ 240,205.2**	**(6,553.9)**

2023 (Salaries & Burden)

Description	Actual 2023 Expense	Approved Budget 2023	Incr/(Dec)
Salaries and Wages - Base	$ 85,725.0	$ 85,304.6	$ 420.4
Salaries and Wages - Overtime	3,210.5	2,662.6	547.9
Salaries and Wages - Incentive/Bonus	15,389.0	14,224.8	1,164.2
Employee Benefits - Pension	11,905.2	11,149.2	756.0
Employee Benefits - Post-Ret Benefits	739.2	927.8	(188.6)
Employee Benefits - Health Insurance	8,468.3	8,473.4	(5.1)
Employee Benefits - Dental Insurance	523.6	508.5	15.0
Employee Benefits - 401(K) Match	3,342.4	3,567.0	(224.6)
Salary Burden - Payroll Taxes	7,346.4	7,205.8	140.7
Other Benefit/Burden <$200K	667.9	678.4	(10.6)
Total Salaries & Burden Expense	**$ 137,317.5**	**$ 134,702.1**	**$ 2,615.3**

2023 (Professional Fees)

Department	2023 Actual	2023 Original Budget	Variance Inc/(Dec)
System Operations & Market Admin.	$ 732.2	$ 873.0	$ (140.8)
System Planning	2,530.4	2,120.6	409.8
Market Monitoring	276.1	730.0	(453.9)
Information Technology	7,238.3	8,944.1	(1,705.8)
Market Development & Settlements	2,062.3	2,047.5	14.8
Human Resources	2,354.2	2,093.7	260.5
Finance Operations	1,050.0	702.6	347.4
Internal Audits	1,056.1	1,032.3	23.8
Corp Comm and Public Affairs	726.9	717.2	9.7
Advance Technology Solutions	1,507.9	1,530.0	(22.1)
All Other	209.3	810.0	(600.7)
Total	19,743.7	21,600.9	(1,857.2)
Legal Professional Fees	2,456.7	3,334.5	(877.8)
Total Professional Fees	**$ 22,200.4**	**$ 24,935.4**	**$ (2,735.0)**

2023 Actual vs. Budget variance explanations for items > $1,000,000

- Salaries and Overheads were $2,615,400 higher than the original budget. Significant increases included funding for higher incentive/bonus amounts for retention efforts of employees due to the labor market environment and higher turnover rate experienced in 2023 as well as increased overtime in some departments; these increases were partially offset by higher than forecasted vacancy and lower salary rates for new hires compared to previous incumbents.

- Professional Fees & Consulting were $2,735,000 lower than the original budget. The Information Technology Segment was $1,705,800 lower primarily due to Energy Management System and other Information Technology consultant support that was reallocated for capital development work (nGEM and Day-Ahead Ancillary Services Improvements projects), lower rates for two Information Technology positions, and higher than forecasted vacancy for consulting in Information Technology and Participant Relations.

- Because ISO-NE is a non-profit organization with no equity available there is $2,000,000 of funds (the “CEO Emerging Work Allowance”) built into the budget to cover unknown or unforeseen costs that emerge during the year. Additional funding needs can be created as a result of refined estimates for work, new activities, or changes in accounting estimates. Similarly, to the extent that these changes result in an “under” expenditure, the CEO Emerging Work Allowance is increased. Requests for funds from the Emerging Work Allowance are reviewed by senior management, and require CFO and CEO approval prior to the spending authorization. No actual amounts are charged to this line item as it is only used for budget/forecast purposes.

memo

To: NEPOOL Budget & Finance Subcommittee and Participants Committee

From: Bob Ludlow and Kelly Reyngold

Date: September 23, 2024

Subject: Projected 2025 Revenue Requirement for ISO New England Administrative Cost Tariff Schedules

To help our Participants prepare their 2025 budgets and consistent with information provided in previous years, this memo includes a preliminary indication of ISO-NE's 2025 costs and related tariff schedules. Specifically, the memo includes (1) the estimated 2025 Revenue Requirement, including the final true-up for 2023 and a comparison to the 2024 Revenue Requirement (see Exhibit 1 below), (2) the Draft 2025 Revenue Requirement by activity (see Exhibit 2), and (3) the Draft 2025 Rate Components (see Exhibit 3). Exhibits 2 and 3 are attached and, in their final form, will be part of the ISO's budget filing with FERC. The cost assignment and allocation mechanisms that were utilized in the Draft 2025 tariff schedules were established as part of the settlement that has been in effect for the last twenty-three years.

Overall Change in Revenue Requirement

As shown in Exhibit 1 below, the overall Revenue Requirement has increased by $37.4 million year-over-year, from $273.9M for 2024 to $311.2M for 2025.[1] The change includes a $29.5 million increase in the revenue requirement before taking into account the change in prior year true-ups. Prior year true-ups resulted in an increase of $7.8M. The 2024 tariff included a $3.0M revenue requirement decrease for the final 2022 true-up, while the 2025 tariff will include an increase of $4.8M as a result of the final 2023 true-up.

Draft Exhibit 1

ISO New England
Revenue Requirement By Tariff Schedule
2025 Estimated Amount vs. 2024 Filed Amount

	Sch 1	Sch 2	Sch 3	Total
2025 Revenue Requirement Before Prior Year True Ups	$ 63,699,206	$ 149,150,469	$ 93,555,211	$ 306,404,886
2024 Revenue Requirement Before Prior Year True Ups	57,473,726	134,634,632	84,788,318	276,896,676
$ Increase/(Decrease) from 2024 to 2025	**6,225,480**	**14,515,837**	**8,766,893**	**29,508,210**
% Increase/(Decrease) from 2024 to 2025	**10.8%**	**10.8%**	**10.3%**	**10.7%**
2025 Revenue Requirement Prior Year True Ups-Under/(Over) Collect	$ 2,135,880	$ (1,038,432)	$ 3,746,122	$ 4,843,571
2024 Revenue Requirement Prior Year True Ups-Under/(Over) Collect	421,994	(5,306,720)	1,878,563	(3,006,163)
$ Increase/(Decrease) from 2024 to 2025	**1,713,886**	**4,268,288**	**1,867,559**	**7,849,734**
2025 Revenue Requirement Including Prior Year True-Ups	$ 65,835,086	$ 148,112,037	$ 97,301,333	$ 311,248,456
2024 Revenue Requirement Including Prior Year True-Ups	57,895,721	129,327,912	86,666,881	273,890,513
$ Increase/(Decrease) from 2024 to 2025	**7,939,366**	**18,784,125**	**10,634,452**	**37,357,943**
% Increase/(Decrease) from 2024 to 2025	**13.7%**	**14.5%**	**12.3%**	**13.6%**

[1] Minor variances may appear due to rounding among the various presentations and schedules for the 2025 Budgets.

Change in Revenue Requirement by Schedule

Before true-ups in 2025 and 2024, the 2025 Revenue Requirement reflects an overall increase of $29.5M or 10.7% over the 2024 Revenue Requirement. By tariff schedule, the changes are Schedule 1, a $6.2M or 10.8% *increase*; Schedule 2, a $14.5M or 10.8% *increase*; and Schedule 3, a $8.8M or 10.3% *increase*.

The Tariff Schedule 1 increase of $6.2M is attributable to:

- Increases that impact all three schedules including: Compensation (merit and promotion/equity) increases, employee benefits for medical trend, and for recruitment efforts; Information Technology and Advanced Technology Solutions for personnel and products related to increasing our situational awareness capabilities, cloud computing, cyber security, System Operations and Planning applications, photovoltaic and demand response forecasting tools, and inflationary and vendor increases across our portfolio of products; and employee additions for support in Participant Relations, External Affairs, Human Resources, Legal, Finance, and Market & Credit Risk.
- Transmission Planning support for RFP processing and long-term studies, and for an assessment under NERC Transmission Planning Standard TPL-001 to establish facility out transfer capability for northern New England and NECEC.
- An increase in Depreciation Expense for capital projects that go-live in mid-2025, including Managing Transmission Line Ratings (entirely Schedule 1) and CIP Electronic Security Perimeter Redesign Phase II (allocated across all three tariff schedules).

The Tariff Schedule 2 increase of $14.5M is attributable to:

- Funding for items that impact all three schedules as noted above in the explanation for Schedule 1.
- Funding for items that affect both Schedules 2 and 3, including Market Development design work for flexible response services and Depreciation Expense for the Day-Ahead Ancillary Services Improvements and Day-Ahead Ancillary Services Benchmark Levels projects that have mid-2025 go-live dates.
- Funding for technical writing and instructional design work for broader and deeper training of new market features and initiatives scheduled for 2025 and 2026.
- Depreciation Expense for mid-2025 go-live of nGEM Software Development Part III that is allocated to Schedule 2.

The Tariff Schedule 3 increase of $8.8M is attributable to:

- Funding for items that impact all three schedules as noted above in the explanation for Schedule 1 and items that impact Schedules 2 and 3, as noted above in the explanation for Schedule 2.
- Increases in Northeast Power Coordinating Council (NPCC) and North American Electric Reliability Corporation (NERC) dues.
- Funding for Market Development design work for market overhauls including Capacity Auction Reforms (prompt seasonal capacity market, and resource capacity accreditation), although increases are largely offset by reductions due to the two-year delay of FCA 19 and other non-recurring capacity auction work in 2024.

The ISO 2025 Revenue Requirement will be reviewed and voted on at the October 10, 2024 NPC meeting. Should you have any questions regarding the information provided in this memo, do not hesitate to contact us.

Line	Activity Code		Allocation	Self-Funding Tariff			
No.	No.	Description	Factor (1)	Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Administration-CEO**					
2	12651	Indirect Administrative Support	Total Dir Labor	$ 12,954,210	$ 2,791,632	$ 6,703,804	$ 3,458,774
3	12652	NEPOOL Committee Support	Total Dir Labor	8,925	1,923	4,619	2,383
4	12653	Adm/Finance/HR - Regional Committee Support	Total Dir Labor	225	48	116	60
5	12654	National Committee Support	Total Dir Labor	11,559	2,491	5,982	3,086
6	12657	Indirect Administrative Support for BCC	Total Dir Labor	1,727,506	372,278	893,985	461,244
7		Total		14,702,426	3,168,373	7,608,505	3,925,548
8							
9		**Finance**					
10	11601	Payroll Administration	Total Dir Labor	628,544	135,451	325,272	167,821
11	11701	Accounts Payable	Total Dir Labor	373,939	80,584	193,514	99,842
12	11702	Procurement	Total Dir Labor	513,692	110,701	265,836	137,156
13	11901	Settle for Power Transactions	Total Dir Labor	93,385	20,124	48,327	24,934
14	12001	Budgeting and Forecasting	Total Dir Labor	657,877	141,773	340,452	175,653
15	12005	Credit Administration	Total Dir Labor	2,282,182	491,810	1,181,029	609,343
16	12101	Ledger Closing, Financial Statements and Tax Reporting	Total Dir Labor	607,002	130,809	314,123	162,069
17	12201	Treasury and Cash Management	Total Dir Labor	3,497,770	753,769	1,810,096	933,904
18	25554	Generation Information System	Alloc-Fixed	2,896	1,303	1,303	290
19	92004	Depreciation Expense 2004 Assets	Alloc-Fixed	43,160	8,988	22,535	11,637
20	92005	Depreciation Expense 2005 Assets	Alloc-Fixed	773,169	163,467	402,126	207,577
21	92006	Depreciation Expense 2006 Assets	Total Dir Labor	568,947	122,608	294,430	151,909
22	92007	Depreciation Expense 2007 Assets	Total Dir Labor	156,427	33,710	80,951	41,766
23	92008	Depreciation Expense 2008 Assets	Total Dir Labor	548	118	284	146
24	92009	Depreciation Expense 2009 Assets	Total Dir Labor	1,230	265	637	328
25	92010	Depreciation Expense 2010 Assets	Total Dir Labor	1,785	385	924	477
26	92012	Depreciation Expense 2012 Assets	Total Dir Labor	80,431	17,333	41,623	21,475
27	92013	Depreciation Expense 2013 Assets	Total Dir Labor	827,131	178,247	428,040	220,844
28	92014	Depreciation Expense 2014 Assets	Alloc-Fixed	73,004	15,732	37,780	19,492
29	92015	Depreciation Expense 2015 Assets	Alloc-Fixed	613	132	317	164
30	92016	Depreciation Expense 2016 Assets	Alloc-Fixed	35,260	6,296	21,163	7,801
31	92017	Depreciation Expense 2017 Assets	Alloc-Fixed	352,560	13,222	322,957	16,381
32	92018	Depreciation Expense 2018 Assets	Alloc-Fixed	374,852	1,004	372,605	1,244
33	92019	Depreciation Expense 2019 Assets	Alloc-Fixed	513,198	10,925	488,737	13,536
34	92020	Depreciation Expense 2020 Assets	Alloc-Fixed	1,774,029	71,934	1,642,818	59,277
35	92021	Depreciation Expense 2021 Assets	Alloc-Fixed	5,011,800	421,696	3,876,745	713,358
36	92022	Depreciation Expense 2022 Assets	Alloc-Fixed	8,580,616	996,308	5,428,870	2,155,438
37	92023	Depreciation Expense 2023 Assets	Alloc-Fixed	8,844,626	1,438,266	4,462,589	2,943,772
38	92024	Depreciation Expense 2024 Assets	Alloc-Fixed	6,638,953	1,527,309	3,016,728	2,094,916
39	92025	Depreciation Expense 2025 Assets	Alloc-Fixed	2,223,661	434,610	942,342	846,709
40	99707	Amortization of Land Recovery	Alloc-Fixed	39,300	2,460	24,170	12,670
41	99995	NPCC/NERC Dues	Alloc-Fixed	9,253,473	-	-	9,253,473
42	99996	Operating Contingency	Total Dir Labor	700,000	150,850	362,250	186,900
43	99996	Operating Contingency	Total Dir Labor	3,000,000	646,500	1,552,500	801,000
44	99998	Payroll & Other Accruals	Total Dir Labor	20,565,401	4,431,844	10,642,595	5,490,962
45		Total		79,091,463	12,560,534	38,946,665	27,584,264
46							
47		**Facilities & Security**					
48	12664	Building Maintenance	Total Dir Labor	2,670,768	575,550	1,382,122	713,095
49		Total		2,670,768	575,550	1,382,122	713,095
50							
51		**Strategy, Risk & Operations Compliance**					
52	14806	Employee Development	Alloc-Fixed	15,244	8,468	2,947	3,829
53	14807	NERC RSAW Update and Audit Prep	Alloc-Fixed	1,003,790	501,895	-	501,895
54	14809	ROC - Tariff Compliance	Alloc-Fixed	312,139	93,642	187,283	31,214
55	14816	Support NE Compliance Groups	Total Dir Labor	208,093	44,844	107,688	55,561
56	22704	Record Retention Services	Alloc-Fixed	192,888	64,232	64,232	64,425
57	22705	Corporate Scorecard	Alloc-Fixed	52,024	17,324	17,324	17,376
58	22706	Document Management Services	Alloc-Fixed	91,101	36,440	27,330	27,330
59	22719	Human Performance Improvement	Total Dir Labor	10,424	2,246	5,394	2,783
60	22721	Corp Strategic Risk	Total Dir Labor	696,934	150,189	360,663	186,081
61	23006	Business Continuity Planning	Total Dir Labor	451,436	97,285	233,618	120,534
62	25011	Corrective Action/Preventive Action	Alloc-Fixed	9,447	3,146	3,146	3,155
63		Total		3,043,521	1,019,711	1,009,626	1,014,184
64							
65		**Market & Credit Risk**					
66	22714	FAP Analysis	Alloc-Fixed	386,890	83,375	200,215	103,299
67		Total		386,890	83,375	200,215	103,299
68							
69		**Human Resources**					
70	12661	Employee Affairs (Recreation Committee)	Total Dir Labor	23,873	5,145	12,354	6,374
71	12701	Recruiting/Interviewing	Total Dir Labor	1,469,244	316,622	760,334	392,288
72	12702	Intern Expense	Total Dir Labor	430,075	92,681	222,564	114,830
73	12801	Employee Relations	Total Dir Labor	9,108	1,963	4,714	2,432
74	12901	Benefit Administration	Total Dir Labor	2,376,728	512,185	1,229,957	634,586
75	12951	Compensation	Total Dir Labor	1,446,893	311,805	748,767	386,321
76	12961	HR - General	Total Dir Labor	1,013,969	218,510	524,729	270,730
77	12962	HR - Training	Total Dir Labor	1,086,926	234,233	562,484	290,209
78	13410	Power Training & Development	Total Dir Labor	1,173,822	252,959	607,453	313,411
79	13411	Markets Training & Development	Total Dir Labor	631,732	136,138	326,922	168,673
80	13412	People Training & Development	Total Dir Labor	1,127,389	242,952	583,424	301,013
81	13413	Business Skills Training & Development	Total Dir Labor	731,263	157,587	378,429	195,247
82	13414	Technology Training & Development	Total Dir Labor	999,058	215,297	517,013	266,748
83	13602	Enterprise Learning - Cyber Security Training & Documentation Wor	Total Dir Labor	700	151	362	187
84	22311	Employee Development	Total Dir Labor	10,167	2,191	5,261	2,715
85		Total		12,530,950	2,700,420	6,484,766	3,345,764

Line No.	Activity Code No.	Description	Allocation Factor (1)	Self-Funding Tariff Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Legal Department**					
2	12422	Interconnection Queue	Alloc-Fixed	198,018	-	-	198,018
3	12502	Board of Directors	Total Dir Labor	270,352	58,261	139,907	72,184
4	12508	Energy Markets / Complaints / Rule Changes	Alloc-Fixed	1,704,267	-	1,704,267	-
5	12513	Miscellaneous Labor Matters	Total Dir Labor	179,316	38,643	92,796	47,877
6	12514	NEPOOL Participants Committee	Total Dir Labor	211,098	45,492	109,243	56,363
7	12517	Administrative and Clerical Support	Total Dir Labor	742,569	160,024	384,280	198,266
8	12520	GC - Market Monitoring Rules/Regulations	Alloc-Fixed	792,074	-	316,830	475,244
9	12543	Independent Market Advisor	Alloc-Fixed	1,360,000	-	952,000	408,000
10	12559	General Corporate	Total Dir Labor	1,911,304	411,886	989,100	510,318
11	12611	GC - Ancillary Services Markets	Alloc-Fixed	247,523	-	-	247,523
12	12613	GC - CFTC/DOE/NRC/Other Federal Agency	Total Dir Labor	247,523	53,341	128,093	66,089
13	12617	GC - IRC Activities	Total Dir Labor	2,430	524	1,258	649
14	12619	Compliance	Alloc-Fixed	247,523	99,009	99,009	49,505
15	12621	GC - NOPRs and NOIs	Total Dir Labor	99,009	21,336	51,237	26,435
16	12622	Open Access Transmission Tariff	Alloc-Fixed	99,009	99,009	-	-
17	12631	GC - FERC Order 1000 (Legal Only)	Alloc-Fixed	400,087	-	-	400,087
18	12663	Public Information	Total Dir Labor	2,164,880	466,532	1,120,325	578,023
19	12669	Government Affairs	Total Dir Labor	2,830,261	609,921	1,464,660	755,680
20	12675	Web Content Governance Steering Committee	Total Dir Labor	727,704	156,820	376,587	194,297
21		Total		14,434,949	2,220,798	7,929,592	4,284,559
22							
23		**Internal Audit**					
24	15001	Indirect Management Duties	Total Dir Labor	83,664	18,030	43,296	22,338
25	15002	Personnel Management	Total Dir Labor	76,059	16,391	39,361	20,308
26	15003	Budget & Forecasting	Total Dir Labor	30,424	6,556	15,744	8,123
27	15005	Audit & Finance Committee	Total Dir Labor	76,059	16,391	39,361	20,308
28	15006	Internal Audit Business Process Update	Total Dir Labor	15,212	3,278	7,872	4,062
29	15007	Annual Audit Work Plan	Total Dir Labor	479,622	103,359	248,204	128,059
30	15011	Internal Audit Meetings	Total Dir Labor	30,424	6,556	15,744	8,123
31	15013	Indirect Adminstrative Support	Total Dir Labor	3,600	776	1,863	961
32	15014	GRC Tool Admin and Development	Total Dir Labor	239,055	51,516	123,711	63,828
33	15021	Performance Measurements	Total Dir Labor	45,636	9,834	23,616	12,185
34	15040	Audit-Operations	Total Dir Labor	121,695	26,225	62,977	32,493
35	15085	Audit - Information Technology	Total Dir Labor	914,216	197,014	473,107	244,096
36	15133	Satellite Operations Reviews	Total Dir Labor	60,847	13,113	31,489	16,246
37	15137	Satellite IT Reviews	Total Dir Labor	812	175	420	217
38	15161	External Audit- Pension Audit	Total Dir Labor	96,500	20,796	49,939	25,766
39	15162	External Audit- Financial Audit	Total Dir Labor	170,381	36,717	88,172	45,492
40	15165	External Audit - Operations	Total Dir Labor	45,636	9,834	23,616	12,185
41	15166	External Audit -Pricing Module Certification	Alloc-Fixed	17,803	-	17,803	-
42	15176	External Audit - ISO Internet Vulnerability Assessment	Total Dir Labor	15,258	3,288	7,896	4,074
43	15186	External Audit - SSAE 18 Direct Support	Total Dir Labor	45,636	9,834	23,616	12,185
44	25702	External Audit - SSAE 18 Direct Management	Alloc-Fixed	678,705	-	678,705	-
45	28005	Fraud, Waste & Abuse Program	Total Dir Labor	59,774	12,881	30,933	15,960
46	28007	Contractor/Consultant Review	Total Dir Labor	21,082	4,543	10,910	5,629
47	28173	Audit - Identity and Access Management Audit	Total Dir Labor	11,740	3,522	3,522	4,696
48	28176	CIP Oversight, Monitoring, and Reporting Processes Review	Total Dir Labor	82,182	17,710	42,529	21,942
49		Total		3,422,020	588,340	2,104,407	729,273
50							
51		**COO-Adm**					
52	19001	NEPOOL Committee Support	Total OPS Labor	187,368	50,215	89,843	47,310
53	19003	National Committee Support	Total OPS Labor	13,939	3,736	6,684	3,520
54	19005	Indirect Supervision/Clerical Support	Total OPS Labor	1,452,240	389,200	696,349	366,691
55	19009	Renewable Resource Integration	Alloc-Fixed	174,884	-	-	174,884
56		Total		1,828,430	443,151	792,876	592,404
57							
58		**System Operations & Market Administration**					
59	14404	NEPOOL Committee Support	SOA Labor	18,291	6,318	8,490	3,483
60	14405	Indirect Supervision/Clerical Support	SOA Labor	351,916	121,552	163,360	67,005
61	14407	Regional Committee Support	SOA Labor	20,791	7,181	9,651	3,959
62	14408	National Committee Support	SOA Labor	15,000	5,181	6,963	2,856
63	19101	NEPOOL Committee Support	MOA Labor	103,532	-	72,472	31,060
64		Total		509,529	140,232	260,936	108,361

Line No.	Activity Code No.	Activity Code Description	Allocation Factor (1)	Self-Funding Tariff Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Operations**					
2	14001	Generation Dispatch	Alloc-Fixed	3,977,656	-	3,341,231	636,425
3	14002	Transmission Operations	Alloc-Fixed	2,613,888	2,091,110	130,694	392,083
4	14304	Advanced Scheduling and Forecasting	Alloc-Fixed	2,279,144	113,957	1,800,524	364,663
5	14562	Ops - Regional Committee Support	OPS Labor	8,411	2,352	4,657	1,403
6	14563	National Committee Support	OPS Labor	630,393	176,258	348,986	105,150
7	14565	Employee Development	OPS Labor	21,647	6,052	11,984	3,611
8	14582	Ops - Recurring Analysis and Reporting	Total Dir Labor	625,966	134,896	323,937	167,133
9	14586	Ops - Other External Support Meetings	Alloc-Fixed	2,214	-	1,771	443
10	14589	Ops - OPTI Control Performance Monitor	Alloc-Fixed	625,966	625,966	-	-
11		Total		10,785,284	3,150,591	5,963,783	1,670,910
12							
13		**Operational Performance Trng and Integration**					
14	14402	Operations Training	Alloc-Fixed	1,677,286	670,914	670,914	335,457
15	14462	OSS - General Systems Operations Support	TSO Labor	628,179	203,342	300,333	124,505
16	14564	Indirect Supervision/Clerical Support	OPS Labor	1,763,460	493,063	976,251	294,145
17	14574	OPTI Continuing Training	Alloc-Fixed	618,634	247,453	247,453	123,727
18	14575	Ops - OPTI System Operator Initial Training	Alloc-Fixed	580,632	232,253	232,253	116,126
19	14576	Ops - OPTI Internal/External Operations Training	Alloc-Fixed	625,966	250,386	250,386	125,193
20	14577	Ops - OPTI Training Program Administration	Alloc-Fixed	625,966	250,386	250,386	125,193
21	14579	Ops - OPTI TTSE Maintenance	OPS Labor	625,966	250,386	250,386	125,193
22	15501	OA - Operations Analysis	Alloc-Fixed	318,323	47,748	222,826	47,748
23		Total		7,464,410	2,645,933	3,401,189	1,417,288
24							
25		**Operations Support Services**					
26	14453	National Committee Support	TSO Labor	364,929	118,128	174,473	72,329
27	14454	Indirect Supervision/Clerical Support	TSO Labor	668,048	216,247	319,394	132,407
28	14756	OSS - Human Performance Improvement Program	Alloc-Fixed	130,669	-	-	130,669
29	14760	Trans Outage LT (telecommute)	Alloc-Fixed	1,314,024	657,012	328,506	328,506
30	14765	GRIDEX - Grid Exercise	Alloc-Fixed	25,927	12,964	-	12,964
31	18361	Transmission Studies, Operations, OASIS Support	Alloc-Fixed	1,939,563	1,551,650	96,978	290,934
32	18381	Transmission Outage Application - Short Term	Alloc-Fixed	1,314,024	1,051,219	65,701	197,104
33	18382	Transmission Outage Application - Long Term	Alloc-Fixed	1,314,024	-	-	1,314,024
34		Total		7,071,208	3,607,220	985,052	2,478,937
35							
36		**Market Monitoring**					
37	16101	Market Power Monitoring and Mitigation	Alloc-Fixed	5,691,987	-	3,984,391	1,707,596
38	16102	Regulatory Activities	Alloc-Fixed	5,253	-	3,677	1,576
39	16121	FCM Market Monitoring	Alloc-Fixed	89,199	-	-	89,199
40		Total		5,786,439	-	3,988,068	1,798,371
41							
42		**Market Administration & Auctions**					
43	21901	Day Ahead Price Monitoring	Alloc-Fixed	368,196	-	368,196	-
44	21902	Real Time Price Verification	Alloc-Fixed	552,293	-	552,293	-
45	21904	MA - NEPOOL Committee Support	Alloc-Fixed	10,521	-	10,188	332
46	21907	Indirect Supervision/Clerical Support	MA Labor	552,644	-	535,181	17,464
45	21908	Employee Development	MA Labor	230,122	-	222,850	7,272
46	21909	Customer Support	Alloc-Fixed	10,175	-	9,853	322
47	21913	MA - Data Collection/Rpt Writing	Alloc-Fixed	24,550	-	24,550	-
48	21915	FTR/Auction Administration	Alloc-Fixed	355,282	177,641	177,641	-
49	21917	Real Time Price Finalization	Alloc-Fixed	199,098	-	199,098	-
50		Total		2,302,880	177,641	2,099,850	25,389
51							
52		**Market Analysis & Settlements**					
53	1701	Billing Statements - Energy	Alloc-Fixed	172,041	-	172,041	-
54	1702	Billing Statements - Transmission	Alloc-Fixed	123,383	123,383	-	-
55	1713	Billing Statements - ISO Tariff	Total Dir Labor	4,344	936	2,248	1,160
56	1714	Billable Tariff Re-billings	Total Dir Labor	290	290	-	-
57	1717	Inventoried Energy Program	Alloc-Fixed	13,323	-	-	13,323
58	1718	Mystic COS	Alloc-Fixed	131,203	-	-	131,203
59	1719	FCM Daily	Alloc-Fixed	6,372	-	-	6,372
60	2047	Score Card	STLM Labor	6,082	900	2,963	2,220
61	2048	FCM	Alloc-Fixed	374,493	-	-	374,493
62	2049	Product Testing	Alloc-Fixed	1,448	-	1,159	290
63	2005	Customer Service	STLM Labor	19,116	2,827	9,311	6,977
64	2007	Admin support - NEPOOL Committees	STLM Labor	13,033	1,928	6,349	4,757
65	2009	Indirect Supervision/Clerical Support	STLM Labor	962,155	142,303	468,666	351,187
66	2010	Employee Development	STLM Labor	228,939	33,860	111,516	83,563
67	2013	FTR Administration	Alloc-Fixed	31,570	-	31,570	-
68	2014	Billing Statements - NCPC	Alloc-Fixed	494,690	-	247,345	247,345
69	2020	Billing Disputes	Total Dir Labor	3,186	687	1,649	851
70	2021	Analysis & Reporting	Total Dir Labor	741,824	159,863	383,894	198,067
71	2024	ASM Regulation	Alloc-Fixed	22,012	-	-	22,012
72	2025	ASM Locational Forward Reserve	Alloc-Fixed	127,438	-	-	127,438
73	2026	Batch Processing	Total Dir Labor	38,231	8,239	19,785	10,208
74	2032	Billing	STLM Labor	37,652	5,569	18,340	13,743
75	2033	Market Analysis	Alloc-Fixed	42,730	-	42,730	-
76		Total		3,595,556	480,783	1,519,565	1,595,208

Line No.	Activity Code No.	Activity Code Description	Allocation Factor (1)	Self-Funding Tariff Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Market Operations Support Services**					
2	3000	Hourly Settlements Support	Alloc-Fixed	259,364	-	129,682	129,682
3	3002	Monthly Settlements Support	Alloc-Fixed	270,792	135,396	-	135,396
4	3006	Customer Service	Alloc-Fixed	203,721	-	203,721	-
5	3008	Admin Support	Alloc-Fixed	443,453	-	443,453	-
6	3009	Indirect Supervision (Principal Analysts only)	Alloc-Fixed	29,812	-	29,812	-
7	3010	Employee Development	Alloc-Fixed	100,520	-	100,520	-
8	3017	Project MAS (Market Analysis & Settlements)	Alloc-Fixed	290,554	72,638	72,638	145,277
9		Total		1,598,217	208,035	979,827	410,355
10							
11		**Participant Support & Solutions**					
12	16001	Participant/membership support	Alloc-Fixed	14,980	-	7,490	7,490
13	16006	Call Support (Ask ISO)	Alloc-Fixed	2,088,690	543,059	1,378,536	167,095
14	16414	Direct Customer Contact	MS Labor	3,650	-	3,285	365
15	16419	Asset Registration Implemented	Alloc-Fixed	506,269	-	506,269	-
16	16420	Asset Registration Review	Alloc-Fixed	46,024	-	46,024	-
17	16422	Claimed Capability Audits	Alloc-Fixed	552,293	-	552,293	-
17	16432	New Generation Coordination and Registration	Alloc-Fixed	368,196	-	368,196	-
18	16434	QMS/CAPA Process and Procedure Updates	Total Dir Labor	322,171	69,428	166,724	86,020
19		Total		3,902,274	612,487	3,028,816	260,970
20							
21		**Participant Training Services**					
22	16021	Training Development	Alloc-Fixed	1,116,926	-	558,463	558,463
23	16436	Mkt Trng/Cus Serv Indirect Supervision	Total Dir Labor	351,730	-	351,730	-
24		Total		1,468,656	-	910,193	558,463
25							
26		**Planning Services**					
27	17101	Analysis	Alloc-Fixed	264,708	-	185,296	79,412
28	17131	Calculate Objective Capability	Alloc-Fixed	964,824	-	-	964,824
29	17231	PSR Regulatory Filings	Alloc-Fixed	36,932	-	-	36,932
30	17331	NEPOOL Committee Support	Alloc-Fixed	36,937	4,015	1,862	31,060
31	17403	TCA Application Review	Alloc-Fixed	108,398	-	-	108,398
32	17405	Energy Efficiency Forecast	Alloc-Fixed	49,248	-	-	49,248
33	17409	Environmental/Emissions Supp	Total Dir Labor	153,892	-	-	153,892
34	17501	FCA - Evaluate Existing Resource De-list Bids	Alloc-Fixed	115,674	-	-	115,674
35	17503	FCA - New Resource Qualification Support	Alloc-Fixed	1,337,765	-	-	1,337,765
36	17504	FCA - Perform Transmission / Topology Assessments	Alloc-Fixed	102,125	-	-	102,125
37	17505	FCA - Perform Existing Resource Qualification	Alloc-Fixed	25,536	-	-	25,536
38	17507	FCA - Auctions & Filings	Alloc-Fixed	270,322	-	-	270,322
39	17508	FCA - Annual Reconfiguration Auction Support/Reliability Reviews	Alloc-Fixed	510,599	-	-	510,599
40	18101	Develop Load Forecast	Alloc-Fixed	952,457	190,491	190,491	571,474
41	18121	Operations Forecast Support	Alloc-Fixed	246,212	49,242	49,242	147,727
42	18131	Other Load Forecasting Activities	Alloc-Fixed	6,170	1,234	1,234	3,702
43	18133	Solar Load Forecast Development	Alloc-Fixed	246,217	49,243	49,243	147,730
44	18134	Electrification Forecasts	Alloc-Fixed	73,864	14,773	14,773	44,318
45	18135	CELT Rep-Res Outage Analysis	Alloc-Fixed	221,591	-	-	221,591
46		Total		5,723,470	308,999	492,141	4,922,330
47							
48		**System Planning**					
49	18150	Regional Transmission Expansion Plan	Alloc-Fixed	63,175	47,381	15,794	-
50	18152	States Requests	Alloc-Fixed	19,728	9,864	4,932	4,932
51	18402	Transmission Planning/Economic Studies Initiative	Alloc-Fixed	779,874	-	389,937	389,937
52	18531	SP - Indirect Supervision/Clerical Support	Alloc-Fixed	138,630	34,422	24,579	79,629
53	18562	Project Management	Alloc-Fixed	25,161	25,161	-	-
54		Total		1,026,568	116,828	435,242	474,498
55							
56		**Transmission Planning**					
57	21660	Stability Case Building	Alloc-Fixed	51,059	-	-	51,059
58	14715	Non DOE Funded/Unallowable	Alloc-Fixed	162,644	-	-	162,644
59	18201	Transmission System Assessment	Alloc-Fixed	7,033,666	7,033,666	-	-
60	18301	NEPOOL Administrative Support - Schedule 1 Tariff	Alloc-Fixed	207,078	207,078	-	-
61	18333	General SIS/FS	Alloc-Fixed	1,987,413	1,987,413	-	-
62	18334	Indirect Supervision/Clerical Support	Alloc-Fixed	941,259	941,259	-	-
63	18335	Regulatory Activities - NPCC	Alloc-Fixed	345,187	345,187	-	-
64	18336	National Activities	Alloc-Fixed	326,054	326,054	-	-
65	18337	TR - Regulatory Activities	Alloc-Fixed	102,130	102,130	-	-
66	18346	OATT and Oper. Agreement Dev., Adm. and Support	Alloc-Fixed	25,094	25,094	-	-
67	18350	States Future Planning Studies	Alloc-Fixed	168,754	168,754	-	-
68		Total		11,350,337	11,136,634	-	213,704
69							
70		**Program Management**					
71	801	Program Management - Administration	Total Dir Labor	1,089,943	234,883	564,046	291,015
72	1661	ISO Program Management	Alloc-Fixed	473,423	-	331,396	142,027
73	1665	Product and Test Mgmt.	Total Dir Labor	715,188	154,123	370,110	190,955
74	25003	Emerging Work Initiatives	Total Dir Labor	75,283	16,223	38,959	20,101
75		Total		2,353,837	405,229	1,304,511	644,098

Line No.	Activity Code No.	Description	Allocation Factor (1)	Self-Funding Tariff Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Advanced Technology Solutions**					
2	21201	Advanced Technology Solutions	Total Dir Labor	5,266,550	1,134,942	2,725,440	1,406,169
3	21203	Employee Development	Total Dir Labor	63,449	13,673	32,835	16,941
4	21207	ATS - Capacity Auction Reforms	Total Dir Labor	2,458,570	-	-	2,458,570
5		Total		7,788,569	1,148,615	2,758,274	3,881,680
6							
7		**Market Development & Settlements Admin.**					
8	16607	National Committee Support	Total Dir Labor	48,180	10,383	24,933	12,864
9	19104	Indirect Supervision/Clerical Support	MOA Labor	407,001	-	284,901	122,100
10	21001	Market Development	Alloc-Fixed	2,645,527	-	1,322,764	1,322,764
11	21002	Administration	Total Dir Labor	1,063,057	229,089	550,132	283,836
12	21003	Employee Development	Total Dir Labor	94,409	20,345	48,856	25,207
13	21007	Budget/Forecast Support	Total Dir Labor	244,203	52,626	126,375	65,202
14	21010	MD - Day-Ahead Reserve Market	Alloc-Fixed	538	-	511	27
15	21011	Capacity Market	Alloc-Fixed	331,994	-	-	331,994
16	22656	Energy, Reserve, and Regulation Markets	Alloc-Fixed	1,540,524	-	1,155,393	385,131
17	22658	Storage	Alloc-Fixed	292,382	-	233,906	58,476
18	22661	Project: DER Participation	Alloc-Fixed	264,140	-	132,070	132,070
19	22662	Flexible Response Services	Alloc-Fixed	1,312,863	-	656,431	656,431
20	22663	Energy Shortage Pricing	Alloc-Fixed	328,926	-	246,694	82,231
21	22664	Capacity Auction Reforms	Alloc-Fixed	3,398,263	-	-	3,398,263
22		Total		11,972,008	312,442	4,782,967	6,876,598
23							
24		**Participant Relations & Services**					
25	22602	NEPOOL Committee Meetings & Support	Alloc-Fixed	251,354	-	125,677	125,677
26	22607	NEPOOL Committee Administration	Total Dir Labor	1,682,423	362,562	870,654	449,207
27	22613	PR&S Indirect Supervision	Total Dir Labor	88,262	19,020	45,675	23,566
28	22614	PR&S Project Development	Total Dir Labor	154,458	33,286	79,932	41,240
29		Total		2,176,496	414,868	1,121,938	639,690
30							
31		**IT Management**					
32	6517	Employee Development - Hardware/Software	Total Dir Labor	46,834	10,093	24,236	12,505
33	6519	Indirect Supervision and Clerical Support	Total Dir Labor	6,274,339	1,352,120	3,246,971	1,675,249
34	6552	Security	Total Dir Labor	5,713	1,231	2,957	1,525
35	6556	Budget Preparation, Tracking & Forecast	Total Dir Labor	267,734	57,697	138,552	71,485
36	6557	Information Technology Committee	Total Dir Labor	11,151	2,403	5,770	2,977
37	22501	Change Management Support	Alloc-Fixed	138,002	62,101	62,101	13,800
38	22505	Administrative	Alloc-Fixed	444,821	151,239	146,791	146,791
39	22511	IT CM/QA - Professional Training	Alloc-Fixed	8,134	2,765	2,684	2,684
40		Total		7,196,727	1,639,649	3,630,062	1,927,016
41							
42		**IT Infrastructure Services**					
43	6510	Desktop Support - Hardware	Total Dir Labor	1,067,635	230,075	552,501	285,059
44	6511	Desktop Support - Software	Total Dir Labor	970,505	209,144	502,236	259,125
45	6512	Host Computer - Hardware	Alloc-Fixed	4,176,296	-	3,132,222	1,044,074
46	6513	Host Computer - Software	Alloc-Fixed	9,215,291	-	6,911,468	2,303,823
47	6514	Networking - Hardware	Total Dir Labor	1,306,228	281,492	675,973	348,763
48	6516	Communications	Total Dir Labor	4,845,837	1,044,278	2,507,721	1,293,838
49	6619	IT - Infrastructure Coordination	Total Dir Labor	345,831	74,527	178,968	92,337
50	6602	Help Desk Support	Total Dir Labor	208,863	45,010	108,087	55,767
51	6615	Host Computer Monitoring	Alloc-Fixed	1,390,283	-	695,142	695,142
52	6616	Desktop Support	Total Dir Labor	1,035,318	223,111	535,777	276,430
53	6622	CIP & Systems Compliance	Total Dir Labor	2,741,260	590,742	1,418,602	731,916
54	6623	Asset Management	Total Dir Labor	808,189	174,165	418,238	215,786
55	6624	Infrastructure Review & Planning	Total Dir Labor	115,924	24,982	59,991	30,952
56	6625	Infrastructure Patch & Vulnerability Mitigation	Total Dir Labor	56,138	12,098	29,051	14,989
57	6626	IT - Infrastructure Break-fix & Troubleshooting	Total Dir Labor	119,005	25,646	61,585	31,774
58	6627	IT - Infrastructure Support Request	Total Dir Labor	3,099,797	668,006	1,604,145	827,646
59	6628	IT - Infrastructure Cyber Security Support	Total Dir Labor	95,615	20,605	49,481	25,529
60	6629	IT - Infrastructure Refresh/Upgrade	Total Dir Labor	173,088	37,301	89,573	46,215
61	6630	IT - Infrastructure Operation Enhancement Effort	Total Dir Labor	684,873	147,590	354,422	182,861
62		Total		32,455,978	3,808,770	19,885,182	8,762,025
63							
64		**IT Cyber Security**					
65	6539	IT Policy/Procedures Program	Total Dir Labor	205,073	44,193	106,125	54,755
66	6539A	Activation/reactivation work	Total Dir Labor	251,219	54,138	130,006	67,076
67	6540	Security Compliance and Reporting	Total Dir Labor	3,898,761	840,183	2,017,609	1,040,969
68	6540A	Cyber Security Controls Assessment	Total Dir Labor	28,619	6,167	14,810	7,641
69	6540D	Intrusion Monitoring and Response	Total Dir Labor	1,578,904	340,254	817,083	421,567
70	6540E	IT System Compliance, Response and Reporting	Total Dir Labor	28,619	6,167	14,810	7,641
71	6541	Security SW Tools Program	Total Dir Labor	1,943,369	418,796	1,005,694	518,880
72	6543	Critical Infrastructure Protection WG (NERC)	Total Dir Labor	56,485	12,172	29,231	15,081
73	6546	IT Internal Audit Support	Total Dir Labor	23,859	5,142	12,347	6,370
74	6547	Cyber Security Training	Total Dir Labor	124,255	26,777	64,302	33,176
75	6548	CIP Compliance & Monitoring	Total Dir Labor	114,482	24,671	59,245	30,567
76		Total		8,253,646	1,778,661	4,271,262	2,203,724

Line No.	Activity Code No. (a)	Description (b)	Allocation Factor (1) (c)	Self-Funding Tariff Total (2) (d)	Schedule 1 (e)	Schedule 2 (f)	Schedule 3 (g)
1		**IT Architecture & Analytics**					
2	6571	DBA Support - MOPS	Total Dir Labor	3,381,701	728,757	1,750,030	902,914
3	6594	IT Data Analyst	Total Dir Labor	1,495,446	322,269	773,893	399,284
4	6595	IT WEB Application Support	Total Dir Labor	737,778	158,991	381,800	196,987
5	6596	IT Data Governance	Total Dir Labor	542,995	117,015	281,000	144,980
6	21706	Enterprise Software Support	Total Dir Labor	1,956,108	421,541	1,012,286	522,281
7	21801	Software Support - Settlements	Alloc-Fixed	1,562,934	-	1,250,347	312,587
8	21802	Software Support - Publishing	Alloc-Fixed	10,440	-	8,352	2,088
9	21803	Software Support - Finance	Alloc-Fixed	669,551	-	535,641	133,910
10	21804	Software Support - Mitigation	Alloc-Fixed	748,954	-	599,163	149,791
11	21805	Software Support - TSO	Total Dir Labor	851,676	183,536	440,742	227,397
12	21806	Software Support - Enterprise	Total Dir Labor	917,338	197,686	474,723	244,929
13	21807	Software Support - Planning	Alloc-Fixed	1,004,873	-	803,898	200,975
14	21808	Training Delivery to NON-IT	Alloc-Fixed	157,756	-	126,205	31,551
15	21811	Single Sign On Support	Alloc-Fixed	361,255	-	289,004	72,251
16	21812	GADS Support	Alloc-Fixed	198,921	-	159,136	39,784
17	21814	IT - Manual Database Edit	Total Dir Labor	18,035	3,887	9,333	4,815
18	21816	CMS Support	Total Dir Labor	83,488	17,992	43,205	22,291
19	21818	Discoverer Support	Total Dir Labor	62,286	13,423	32,233	16,630
20	21824	FCTS Support	Alloc-Fixed	1,249,885	-	-	1,249,885
21	21825	eTariff Support	Alloc-Fixed	37,569	-	30,055	7,514
22	21830	Annual Software Maintenance for Enterpirse Wide Software	Total Dir Labor	309,539	66,706	160,186	82,647
23	21832	GDMA/Gateway Support	Alloc-Fixed	53,722	-	42,977	10,744
24	21834	Federated SSO support	Total Dir Labor	17,845	3,846	9,235	4,765
25		Total		16,430,094	2,235,648	9,213,446	4,981,000
26							
27		**IT Energy Management Systems**					
28	21602	Applications Support	Total Dir Labor	295,675	63,718	153,012	78,945
29	21603	EMS Power System Applications Support	Total Dir Labor	957,563	206,355	495,539	255,669
30	21604	Dispatcher Training Simulatory Support	Alloc-Fixed	2,951,298	2,361,039	590,260	-
31	21605	DAM FTR/ARR Support	Alloc-Fixed	2,544,332	508,866	1,526,599	508,866
32	21606	Real-time Market Support	Alloc-Fixed	3,549,302	709,860	2,129,581	709,860
33	21607	Forecast Support	Alloc-Fixed	620,167	124,033	372,100	124,033
34		Total		10,918,338	3,973,872	5,267,091	1,677,375
35							
36		**IT Enterprise Applications Development**					
37	6518	Employee Development - Software	Total Dir Labor	25,197	5,430	13,040	6,728
38	21701	IT Settlement Application Support	Alloc-Fixed	10,708	-	8,566	2,142
39	21702	IT Corporate Application Support	Alloc-Fixed	12,492	-	9,994	2,498
40	21707	Application Analysis and Conceptual Design	Alloc-Fixed	542,401	-	433,921	108,480
41	21708	Application Design Evaluation and Selection	Alloc-Fixed	869,613	-	695,691	173,923
42	21709	Technology Evaluation and Selection	Alloc-Fixed	2,254,287	-	1,803,430	450,857
43	21710	Indirect Supervision and Administration	Alloc-Fixed	1,596,148	-	1,276,918	319,230
44	21711	EWR and CAPA Analysis	Alloc-Fixed	147,978	-	118,383	29,596
45		Total		5,458,825	5,430	4,359,942	1,093,453
46							
47		**IT Power System Modeling Management**					
48	21650	Indirect Supervision and Administration	Total Dir Labor	241,165	51,971	124,803	64,391
49	21651	Power System Modeling	Alloc-Fixed	2,636,873	1,054,749	1,054,749	527,375
50	21652	System Application Support	Alloc-Fixed	63,064	25,226	25,226	12,613
51	21653	PSMM-TTSE Support	Alloc-Fixed	76,068	60,854	15,214	-
52	21654	NX9 Administration	Alloc-Fixed	472,776	189,110	189,110	94,555
53	21655	ICCP Support	Alloc-Fixed	1,470,966	588,386	588,386	294,193
54	21656	Transmission Project Management	Alloc-Fixed	42,040	33,632	8,408	-
55	21657	Model On Demand Admin	Alloc-Fixed	1,294,468	-	-	1,294,468
56	21658	PSMM- Model on Demand Case Requests	Alloc-Fixed	104,617	-	-	104,617
57	21659	Synchrophasor Applications	Alloc-Fixed	176,397	26,459	26,459	123,478
58	21661	MAS Software Dev and Support	Alloc-Fixed	125,690	-	-	125,690
59		Total		6,704,123	2,030,388	2,032,355	2,641,379
60							
62		**Total ISO**		$ 306,404,886	$ 63,699,206	$ 149,150,469	$ 93,555,211

Exhibit 3

Draft 2025 Rate Components (1)

Tariff Schedule	Jan. 1, 2025
Schedule 1	
Network Load (per kW-hour)	$0.00041
Schedule 2	
TU Bids (Virtual Inc/Dec)	
Submitted	$0.00500
Cleared	$0.06000
FTR Bids	
Submitted	$3.26750
Cleared	$5.32383
TU's	
Block 1 - 1st 12,500	$0.81457
Block 2 - Next 27,000	$0.74051
Block 3 - Over 39,500	$0.66646
Volumetric	
Block 1 - 1st 250,000	$0.56227
Block 2 - Next 1,250,000	$0.51116
Block 3 - Over 1,500,000	$0.46004
Schedule 3	
R-T NCP Load Obligation	$0.37690
Export Rate	$0.82000

(1) From Exh 3, RCL-7, Sch. 3

September 11, 2024

Cheryl LaFleur
Chair
Board of Directors
ISO New England
One Sullivan Road
Holyoke, MA 01040

RE: Comments on Proposed 2025 ISO New England Operating & Capital Budgets

Dear Chair LaFleur:

On behalf of the undersigned New England state agencies, we submit our comments regarding the ISO New England (ISO-NE) proposed 2025 Operating and Capital Budgets.

As a preliminary matter, we appreciate ISO-NE's ongoing commitment to the budget review process that has been in place since 2013 and offers the New England state agencies an opportunity to ask questions and provide input on the proposed budgets for ISO-NE. In particular, we appreciate the comprehensive and detailed budgetary information provided and the thorough responses to our questions. As ISO-NE's budgets grow as its tasks increase in amount, complexity, and import, it is incumbent upon ISO-NE and those who oversee it to ensure that budgeted amounts are appropriate for the responsibilities involved and the work required, and that the amounts are efficiently and effectively spent.

Starting with the 2023 budget, this year's proposal marks the third year of double-digit increases to ISO-NE's operating budget. Even so, we observe that the increases to date and this year's proposal are necessary reflections of the added amount and complexity of the tasks required of ISO-NE as it guides, assists, and manages the transition to a cleaner energy system. While we are concerned about the size of the proposed budget increase, it is important that the transition be done right. Mistakes made in the how, when, and towards-what-end of system transition would be extremely costly. A well-run, well-designed market needs to be in place throughout the transition. We note that the proposal as of August 2024 is $300,000 more than what was proposed back in June 2024 when presented to NECPUC, for an overall $25.1 million or 10.3% increase from the 2024 operating budget (before depreciation). ISO-NE is also proposing an increase to its capital budget of 21.4%. For the proposed 2025 operating budget, the increase is primarily driven by increases in personnel and technology investments. We request that ISO-NE examine cost-savings opportunities, such as expanding remote work policies similar to other RTOs and maximizing use of the Windsor facility before considering an expansion of the Holyoke campus. The other significant driver of the increase is inflationary pressure on operating costs. Despite the increases involved, we support ISO-NE taking a proactive approach in preparing for anticipated changes to the system, including changes to the number and dispatchability of system resources and changes to the variability of load and supply. We stress the importance of ISO-NE anticipating and resolving problems that may arise in its ability to manage reliability, and to ensure efficient and competitive markets.

Due to expectations that significant amounts of generation and transmission will need to be added over the foreseeable future, it is important that ISO-NE work to ensure that these additions occur efficiently and appropriately. For this reason, we applaud ISO-NE's focus on the wholesale electricity market and its efforts to improve that market, including by identifying and eliminating flaws in the valuing of resources, incentives for market participants, the information available to market participants and to ISO-NE, and in enhancing the tools and options available for managing the market. Without taking away from ISO-NE's efforts in the electricity market, we also stress the need for ISO-NE to place a similar priority on the transmission system and its transition and expansion. While ISO-NE has made appropriate changes in its approach to transmission system planning – including enhancing its ability to assist state plans in this area, to forecast and identify future transmission needs, and to process interconnection requests – there is not a proactive and ongoing assessment of transmission system costs, procedures, and opportunities to incorporate environmental justice principles. In addition, ISO-NE currently has little to no role in the processes by which asset condition projects are identified, vetted, and priced. Many of the mechanisms necessary to ensure an efficient wholesale electricity market, such as independent monitoring and competitive processes, should also be utilized to ensure an efficient transmission system. We note that ISO-NE can do more in monitoring and helping to discipline costs as the transmission system expands.

CONCLUSION

We find the proposed 2025 budget proposal to be appropriate given the increased amount and complexity of the tasks required of ISO-NE as the New England power system transitions to clean energy. We ask that the Board carefully consider how ISO-NE can be more proactive and instrumental in planning, guiding, and improving transmission system expansion.

Respectfully submitted,

Massachusetts Department of Public Utilities
James M. Van Nostrand, Chair
Cecile M. Fraser, Commissioner
Staci Rubin, Commissioner
1 South Station, 3rd Floor
Boston, MA 02110

Vermont Department of Public Service
June E. Tierney, Commissioner
112 State Street
Montpelier, VT 05620

Connecticut Public Utilities Regulatory Authority
Marissa P. Gillett, Chairman
10 Franklin Square
New Britain, CT 06051

Vermont Public Utility Commission
Edward McNamara, Chair
Margaret Cheney, Commissioner
Riley Allen, Commissioner
112 State Street
Montpelier, VT 05620

Maine Public Utilities Commission
Philip L. Bartlett II, Chairman
Patrick Scully, Commissioner
Carolyn Gilbert, Commissioner
18 State House Station
Augusta, ME 04333

Cheryl A. LaFleur
Chair, Board of Directors

September 19, 2024

Via Electronic Mail

Marissa P. Gillett, Chairman, Connecticut Public Utilities Regulatory Authority
James M. Van Nostrand, Chair, Massachusetts Department of Public Utilities
Cecile M. Fraser, Commissioner, Massachusetts Department of Public Utilities
Staci Rubin, Commissioner, Massachusetts Department of Public Utilities
Philip L. Bartlett II, Chairman, Maine Public Utilities Commission
Patrick Scully, Commissioner, Maine Public Utilities Commission
Carolyn Gilbert, Commissioner, Maine Public Utilities Commission
June E. Tierney, Commissioner, Vermont Department of Public Service
Edward McNamara, Chair, Vermont Public Utility Commission
Margaret Cheney, Commissioner, Vermont Public Utility Commission
Riley Allen, Commissioner, Vermont Public Utility Commission

Dear State Officials:

Thank you for your letter of September 11 regarding ISO New England's 2025 operating and capital budgets. We are grateful for your support of the budget, and your recognition of the increased number and complexity of the tasks required of ISO-NE resulting from the transition to clean energy.

We agree that the budget review process established in 2013 has contributed to a robust assessment of the budget, and are committed to continuing our collaborative efforts to balance costs with concerns about ratepayer impacts. With regard to these concerns, which we share, we agree with your suggestion that ISO-NE continue to examine cost-saving opportunities. You specifically propose approaches to possible future costs for hosting our workforce. At this time, we remain committed to our hybrid work posture, as we believe that in-person collaboration (at least part of the time) is a critical component of our success. That said, we will consider all of our options, including, as you suggest, continuing use of the Windsor facility.

We appreciate your recognition of the ISO team's work to prepare for changes to the system, including changes to the system resources and load, and our focus on the wholesale electricity market. We also agree that we will need to continue to place equivalent priority on the transmission system.

We have made significant strides in the area of transmission, particularly regarding interconnection in response to the Federal Energy Regulatory Commission's Order No. 2023, and long-term public policy planning in conjunction with you. Regarding the latter, we were excited to receive a positive order from the Commission and are preparing our workforce in anticipation of potential Requests for Proposals that will lead to much-needed transmission development. We also hope that the team has been helpful in working with the states to secure federal funds.

Going forward, we are ready to work with you to incorporate transmission owners' improvements to the asset condition process, and then to establish a method for right-sizing these projects. We agree with you that the region can benefit from increased monitoring of these projects and transmission costs in general, and would support your advocacy for a narrowly-focused independent transmission monitor that reports to the states or to the Federal Energy Regulatory Commission.

Thank you again for your support of the 2025 budgets. The Board of Directors appreciates your input and will consider the issues you have raised carefully.

Sincerely,

Cheryl A. LaFleur
Chair, Board of Directors

STATE OF CONNECTICUT
OFFICE OF CONSUMER COUNSEL

TEN FRANKLIN SQUARE
NEW BRITAIN, CONNECTICUT 06051

TELEPHONE
(860 827-2900
VOICE AND TDD
WWW.CT.GOV/OCC

James M. Talbert-Slagle
Direct Dial: (860) 827-2918
Email: james.talbert-slagle@ct.gov

September 10, 2023

Cheryl LaFleur, Chair
Board of Directors
ISO-New England
One Sullivan Road
Holyoke, MA 01040

Re: Comments on ISO-NE 2025 Budget

Dear Ms. LaFleur:

The Connecticut Office of Consumer Counsel ("OCC") respectfully submits these Comments regarding the ISO-New England budget for 2025.

The proposed budget for 2025 that ISO-NE presented to state officials on August 9, 2024, reflects an increase in the revenue requirement after true-up of $7.8 million, or 13.6 percent in a year over year basis. *See* Slide 28, ISO New England Proposed 2025 Operating and Capital Budgets (August 9, 2024). According to ISO-NE, this significant increase in the budget stems from needed additions to personnel as well as upgrades to IT infrastructure. *Id.* at Slide 30. According to ISO-NE's calculations, the overall revenue requirement for the entity has grown more than $100 million since 2021, ballooning from $205.1 million in 2021 to a projected $311.2 million in 2025. *Id*. at Slide 42. As a result,the average consumer is projected to pay 25 cents more per month for ISO-NE in 2025 that that consumer paid in 2024 and 67 cents more than the average consumer paid per month in 2021. *Id*. (reflecting average monthly costs of $1.71 in 2025, $1.46 in 2024, and $1.04 in 2021). While OCC understands that the transition to clean energy requires more of ISO-NE, the significant growth in ISO-NE over the past five years, which ISO-NE noted in the data that it presented to stakeholders last month, reflects a 51.7% increase over a five-year period. If this level of growth continues unchecked over the next five years, in 2030 ISO-NE's revenue requirement would be $472.1 million dollars and rate payers would be paying an estimated $2.80 per month for the services of ISO-NE, which represents a 64% increase over the 2025 estimated costs.

Along the same lines as OCC noted in its comments on the 2024 budget, finding the most capable and skilled workforce to carry out its important implementation goals obviously costs ISO-NE money, just like it does any other employer. But OCC implores ISO-NE to remain mindful of the costs that it passes on to ratepayers in New England, who already pay some of the highest bills for electricity in the nation. Adding millions of dollars in administrative costs for more employees, IT infrastructure and new capital improvements at the ISO-NE campuses are all understandable investments for ISO-NE to make as the entity takes on more responsibilities, but consumers do not have bottomless wallets, and this level of spending at the regional level cannot continue, unabated, in perpetuity. An ever-growing ISO-NE budget in parallel with very expensive asset condition projects from transmission owners and region-wide infrastructure expansion under the Phase 2 long-term planning process will create a massive regional electric bill spread across a finite number of consumers.

OCC suggests that ISO-NE attempt in future budgets to operate within its current allocation of revenue. Just as consumers cannot expect a 13 percent increase in income year over year and must find a way to make ends meet when money is short, going forward ISO-NE needs to plan better to enable it to work within its current budget to achieve its desired outcomes. Seeking annual increases each year of this magnitude will quickly become unsustainable, especially given other increases that customers are seeing at the local and state levels in this time of extraordinary change in the energy sector.

Respectfully submitted,

STATE OF CONNECTICUT
OFFICE OF CONSUMER COUNSEL

CLAIRE E. COLEMAN
CONSUMER COUNSEL

By: ***/s/ James Talbert-Slagle***
James Talbert-Slagle, Esq.
Staff Attorney
Richard Sobolweski
Supervisor of Utility Financial Analysis

cc: Service List

ISO new england

Cheryl A. LaFleur
Chair | Board of Directors

September 19, 2024

Via Electronic Mail (claire.e.coleman@ct.gov)

Claire E. Coleman
State of Connecticut
Office of Consumer Counsel
10 Franklin Square
New Britain, Connecticut 06051

Dear Ms. Coleman:

Thank you for your letter of September 10 regarding ISO New England's 2025 operating and capital budgets. We appreciate your acknowledgement that our increased costs are "understandable investments" as our responsibilities expand. These expenses, as you note, include paying for our capable and skilled workforce.

In your letter, you urge us to remain mindful of the costs that are paid by ratepayers in New England, and suggest that ISO-NE attempt in future budgets to operate within its current allocation of revenue. I want to assure you that ISO-NE's independent Board of Directors, which is responsible for overseeing the fiscal prudency of the ISO's budget, shares your concerns about budget impacts on ratepayers. We scrutinize information about those impacts and consider how to balance them against the very real challenges we face. These challenges include maintaining reliability during the power system's transformation, which is being driven in large part by the states' clean energy goals.

Going forward, we will continue to rely on our robust budget development process, which includes a number of opportunities for participation by states and stakeholders. We have found this process, and your participation, to be valuable components of our budget oversight.

The Board of Directors appreciates your input and will consider the issues you have raised carefully as it considers the 2025 and future budgets.

Sincerely,

Cheryl A. LaFleur

Cheryl A. LaFleur
Chair, Board of Directors

State of Maine
Office of the Public Advocate
112 State House Station, Augusta, Maine 04333-0112
(207) 624-3687 (voice) 711 (TTY)
www.Maine.gov/meopa

Janet T. Mills
GOVERNOR

William S. Harwood
PUBLIC ADVOCATE

September 13, 2024

Cheryl LaFleur
Chair, Board of Directors
ISO New England
One Sullivan Road
Holyoke, MA 01040

RE: Comments on Proposed 2024 ISO New England Operating & Capital Budgets

Dear Chair LaFleur:

The Maine Office of the Public Advocate offers the following comments regarding the 2025 Operating and Capital Budgets proposed by ISO New England.

As we did with respect to the 2024 Budget, we write to express our concern with the size of the budget increases. This year, ISO New England is proposing an overall $25.1 million, or 10.3%, increase over the 2024 operating budget, and an increase to the capital budget of 21.4%. We understand that these increases are primarily driven by increases in personnel expense and by technology investments. Our concern is that these increases place an unnecessary burden on regional ratepayers struggling with rising transmission, distribution, and commodity costs, as well as the cost to support climate policy initiatives.

We appreciate your response to our 2024 letter regarding the ISO budgets. In that letter, you assured us that the ISO has a robust budget development process that allows the ISO to align its budget with key priorities while identifying efficiencies, and that provides multiple opportunities for the Board of Directors and stakeholders to provide input regarding priorities and cost impacts. These are useful and important opportunities. However, as we did last year, before granting final approval the 2025 budgets, we urge the Board of Directors of ISO New England to carefully reexamine the proposed budgets, to reduce spending wherever possible, and to direct ISO New England management to give greater priority to consideration of adverse ratepayer impacts when developing future budgets.

Thank you for your consideration of our concerns.

Sincerely,

William S. Harwood

William S. Harwood
Public Advocate

Andrew Landry
Deputy Public Advocate

Cc: Maria Gulluni, Corporate Secretary, ISO NE

Cheryl A. LaFleur
Chair, Board of Directors

September 19, 2024

Via Electronic Mail (william.harwood@maine.gov; andrew.landry@maine.gov)

William S. Harwood, Public Advocate
Andrew Landry, Deputy Public Advocate
State of Maine
Office of the Public Advocate
112 State House Station
August, Maine 04333

Dear Messrs. Harwood and Landry:

Thank you for your letter of September 13 regarding ISO New England's 2025 operating and capital budgets. We understand your concerns about the proposed budget increases, and the related burden on ratepayers.

As you indicate, we have, in previous correspondence, described our robust budget development process, which includes a number of opportunities for participation by states and stakeholders, as well as significant oversight by the Board and its committees. In your letter, you urge us to continue this process by reexamining the budgets, reducing spending where possible, and directing management to "give greater priority to consideration of adverse ratepayer impacts when developing future budgets."

Please know that, during the budget development process, when we consider the spending necessary to maintain reliability as we transition to the states' envisioned clean grid, we also carefully consider data regarding the impacts of those costs on New England's ratepayers. We will continue to seek a balance between our concerns about ratepayer costs and our responsibility to ensure that reliable electricity is provided to those same ratepayers. We look forward to continuing to work with you to achieve that balance.

The Board of Directors appreciates your input and will consider the issues you have raised carefully as it considers the 2025 and future budgets.

Sincerely,

Cheryl A. LaFleur
Chair, Board of Directors

5b 2025 NESCOE Budget

VOTE

66.67%

To consider, and take action, as appropriate, on the 2025 NESCOE Budget as presented at this meeting.

RESOLVED, that the Participants Committee supports the Year 2025 NESCOE budget, as presented at this meeting.

New England States
Committee on Electricity

2025 Budget Presentation

NEPOOL Budget & Finance Subcommittee

August 9, 2024

REVISED October 2024 PC
Change only to p. 12 to reflect final Network Load factor

Background: Budget Review

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

- ✓ Proposed 2025 budget conforms to:
  - Boundaries of 5-year pro forma (2023-2027) reviewed by Budget & Finance
  - NESCOE commitment not to seek an increase over pro forma budget of more than 10% in any 1 year: 2025 proposed budget is less than 2025 5-year pro forma budget
- ✓ Following calendar year 2023, independent auditor concluded NESCOE books conform to generally accepted accounting principles

Background: Policy Priorities

Term Sheet Provision Governing Identification of Policy Priorities:

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

Consistent with Term Sheet, 2023 *Report to the New England Governors*:

- ✓ Reviewed work in 2023
- ✓ Projected policy priorities
- ✓ Provided spending from prior year
- ✓ Projected budget information for upcoming two years

Projected Policy Priorities

- ✓ NESCOE provided to the Governors the ***2023 Annual Report to New England Governors***
- ✓ Report simultaneously released to NEPOOL & ISO-NE & circulated to the Participants Committee
- ✓ NESCOE identified forward looking policy priorities at Section V, pages 13

Report in "Resource Center"

www.nescoe.com

Projected Policy Priorities

- ✓ **Transmission has a strong presence in forward-looking priorities.** This includes, but is not limited to:
  - ✓ Asset Condition Project process changes
  - ✓ Operationalizing long-term transmission analysis; moving as expeditiously as possible toward ISO-NE's first competitive solicitation under FERC-approved procedures
  - ✓ Continued engagement in FERC's efforts to reform transmission planning, generator interconnection, and cost allocation processes
  - ✓ Continued work to improve transmission cost oversight, estimation, and controls
- ✓ **Wholesale Market Reforms**. Continued engagement on means to modernize wholesale electricity markets to support achievement of clean energy laws and other state law objectives while maintaining system reliability, and participate in the design of associated market rules and governance, including for example:
  - ✓ resource capacity accreditation
  - ✓ retirement reforms
  - ✓ capacity market timing changes, as well as those to support energy storage and distributed generation.

NESCOE Organization & Misc.

Employees

- ✓ Retain and attract diversity in academic training, skills; blend of private & public sector experience
- ✓ Assume return to NESCOE's prior steady state employee level of six
  - ✓ Seeking transmission technical expertise/engineer

Office Space

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

Other Organization Matters

Technical Consultants

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

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

- ✓ Wilson Energy Economics
- ✓ Oxford Power
- ✓ Apex Analytics
- ✓ Supplement with other expertise as needed, such as Daymark

Legal Counsel

Litigation is not the primary means by which NESCOE seeks to accomplish its objectives & thus, greater resource and focus has historically, and thus far in 2024, been on technical consulting. Further, while NESCOE produces most legal pleadings and analysis internally, the frequency and type of litigation brought by others influences the extent to which NESCOE engages outside counsel.

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

5-Year Pro Forma

Proposed 2025 budget conforms to 2025 budget in 5-year Pro Forma Framework

✓ 2025 Projected Budget in 5-Year Pro Forma:	$2,942,090
✓ 2025 Proposed Budget:	$2,707,893
✓ 2024 Budget, for reference:	$2,596,015

The 2025 Proposed Budget reflects:

- ✓ Assumed return to prior steady state of six employees
- ✓ Continued inflationary pressures
- ✓ No office rent or utilities
- ✓ More travel for meetings

5-Year Pro Forma, for reference

NESCOE
PRO FORMA BUDGET 2023-2027*

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

*Projected 5% salaries and wages annual adjustment, and projected 3% annual adjustment on all other items. Line items and categories subject to increase greater than, or decrease from, amounts projected.
Any such changes will be subject to review, input, and recommendations by the NEPOOL Participants Committee (and/or its designees).
**At no time during this 5-year period will NESCOE seek a budget increase of more than 10% in any 1 year of more than 30% on a cumulative basis.

2025 Proposed Budget

	2025
Salaries and Wages	
Salaries	1,219,758
Payroll Taxes	121,976
Health and Other Benefits	140,000
Retirement §401(k)	48,790
Total, Salaries and Wages	**1,530,524**
Direct Expenses - Consulting	
Technical Analysis	527,634
Legal (FERC)	200,000
Total, Direct Expenses, Consulting	**727,634**
General and Administrative	
Rent	-
Utilities	-
Office and Administrative Expenses	51,938
Professional Services	48,925
Travel/Lodging/Meetings	92,700
Total General and Administrative	**193,563**
Capital Expend. & Contingencies	
Computer Equipment	10,000
Contingencies	246,172
Capital Expend. & Contingencies	**256,172**
TOTAL EXPENSES	**2,707,893**

2023 & 2024 Spending & Implications for 2025

Unspent funds in any year credited toward future year

2023 Total Spending:	$1,490,069*
2024 Spending to end of June:	$760,663
2024 Projected Year End:	$2,158,180*

Second half of 2024 spending projected to exceed first half due to work on transmission matters and interest in returning to prior staff size with addition of transmission technical expertise/engineer.

*Cumulative prior years' true up, including 2022, was reflected in the 2024 revenue requirement and rates. The 2023 true up will be reflected in the 2025 revenue requirement and rates (see next slide). Any 2024 true up will be reflected in the 2026 revenue requirements and rates.

2025 Projected Billing Rate

With thanks to ISO-NE for calculations -

2025 Budget:	$2,707,893
Less 2023 True Up:	($1,115, 346)
Total Revenue Recovery:	$1,592,547
Divided by Total Network Load:	~~214,795,375~~ 222,552,617

~~(total network load from 2024 ISO-NE tariff; no escalation or reduction used in calculation)~~

~~2025 Schedule 5 Estimated Rate $0.00741 per kW-month~~

Updated 2025 Schedule 5 *Actual* Rate $0.00716 per kW-month

(Actual Rate based on now finalized 2025 Network Load factor): $1,592,547 (revenue requirement) ÷ 222,552,617 (2025 Network Load) = $0.00716

Thank you.

Questions?

NESCOE

6 Litigation Report

October 10, 2024
Meeting

NEPOOL
NEW ENGLAND POWER POOL
Participants Committee

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of October 8, 2024

The following activity, as more fully described in the attached Litigation Report, has occurred since the report dated September 3, 2024 ("last Report") was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

I. Complaints/Section 206 Proceedings

	Page	Matter	Date	Activity
	1	206 Proceeding: *TO Initial Funding Show Cause Order* (EL24-83)	Sep 11	ISO-NE submits NE Response; comments due on or before ***Oct 10, 2024***
			Sep 26	FERC issues "Allegheny Order", dismissing Indicated Utilities' Reh'g Request
			Sep 30	Clean Energy Associations request 14-day extension of time, to and including Oct 24, 2024, to comment on ISO/RTO Responses
			Oct 8	FERC grants an extension of time for interested parties to file comments; comment deadline now ***Oct 25, 2024***

II. Rate, ICR, FCA, Cost Recovery Filings

	Page	Matter	Date	Activity
	4	MOPA Formal Challenge to TO's Annual (2023-24) Transmission Rate Update/Info Filing (ER20-2054-000)	Sep 5	MOPA challenges National Grid statement and renews request that the FERC direct Identified TOs to answer MOPA's questions
			Sep 6	VTransco submits responses
	5	**Mystic 8/9 COSA (ER18-1639)**		
	5	(-027) Second CapEx Info Filing Settlement Proceedings	Oct 2	Judge French issues 5th status report recommending that settlement proceedings continue
	6	Mystic COSA Protocols Waiver Request (ER24-3054)	Sep 13	Mystic requests second waiver of the deadlines in Sections II.6.A and II.4.F of the Protocols
			Sep 19	ISO-NE intervenes

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

	Page	Matter	Date	Activity
	8	Waiver Request: Late Stage SIS Process (GDQ ESS) (ER24-2926)	Sep 6	ISO-NE protests GDQ ESS' waiver request
			Sep 9, 18	Calpine, NEPOOL intervene
	8	DASI Conforming Changes (ER24-2883)	Sep 9-18	National Grid, NEPGA, MA DPU intervene
	9	Waiver Request: Withdrawal from IEP and Return of IEP Net Revenues Received (Canal Marketing/Canal 3) (ER24-1407)	Sep 20	Judge Hurt issues 1st settlement report recommending that settlement procedures continue
			Sep 23	1st settlement conference held
			Oct 8	Canal IEP Settlement Agreement filed (ER25-56)
	11	New England's *Order 2222* Compliance Filings: Metering Data Submission Revisions (ER22-983-008)	Sep 5	FERC accepts Metering Data Submission Revisions, eff. *Nov 1, 2026*

IV. OATT Amendments / TOAs / Coordination Agreements

	Page	Matter	Date	Activity
*	12	VELCO Att. F App. D Depreciation Rate Changes (ER24-3019)	Sep 11	VTransco files changes to incorporate revised depreciation rates used to calculate VTransco's annual transmission revenue requirements

	12	Fitchburg Att. F App. D Depreciation Rate Changes (ER24-2766)	Sep 26	FERC accepts changes to App. D to Tariff Att. F to reflect updated FG&E depreciation rates as approved by the MPUC, eff. *Jul 1, 2024*
	12	*Order 2023* Compliance Changes (ER24-2009)	Sep 30	Allco intervenes out-of-time and protests filing
	13	*Order 2023* Related Changes (ER24-2007)	Sep 30	Allco intervenes out-of-time and protests filing
	14	LTTP Phase 2 Tariff Changes Compliance Filing (ER24-1978)	Sep 30	FERC accepts corrections to Section I.1.2 that were not yet intended to be in effect but had been included with the LTTP Phase 2 Changes in error

V. Financial Assurance/Billing Policy Amendments

*	14	FAP Revisions to Mitigate Risk of PFP Penalty Payment Defaults (ER24-3071)	Sep 19-Oct 8	Calpine, Dominion, ENE, HQ US, NEPGA, MA DPU, Public Citizen intervene
*	15	Updates to Non-Commercial Capacity FA Amount Multiplier (ER24-3040)	Sep 13 Sep 16-26	ISO-NE and NEPOOL jointly file updates to the Non-Commercial Capacity FA Amount Multiplier Calpine, National Grid, Public Citizen intervene

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

*	15	LGIA – ISO-NE/CMP/Andro Hydro (ER24-2970)	Sep 4	ISO-NE and CMP file executed, non-conforming LGIA with Andro Hydro (the Interconnection Customer) under Schedule 22

VII. NEPOOL Agreement/Participants Agreement Amendments

	17	135th Agreement; PA13 (Unused Provisional Member Voting Share Allocation Changes) (ER24-2636)	Sep 24	FERC accepts Changes, eff. *Aug 1, 2024*

VIII. Regional Reports

	17	Capital Projects Report – 2024/Q2 (ER24-2769)	Sep 6	FERC accepts Q2 2024 Capital Projects Report, eff. *Jul 1, 2024*

IX. Membership Filings

*	19	Oct 2024 Membership Filing (ER24-3139)	Sep 30	***New Members:*** Castleton Commodities Energy Services; Castleton Commodities Energy Trading; Alan Sliski; and Stony Creek Energy; and ***Termination of Participant status:*** Gas Recovery Systems; comment deadline ***Oct 21, 2024***
	19	Aug 2024 Membership Filing (ER24-2623)	Sep 24	FERC accepts the membership of Twig Redwood Inc. and the termination of the Participant status of MFT Energy US 1 LLC
*	19	Suspension Notices (not docketed)	Sep 11	ISO-NE files notice of Sep 9, 2024 suspension from the New England Markets of: Excelsior Billerica, Bondsville and Lexington; Hudson Energy Services; and Wolverine Holdings

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

XI. Misc. - of Regional Interest

	21	203 Application: Carlyle Group (Nautilus)/Q-Generation (Trafigura) (EC24-114)	Sep 13 Sep 23 Sep 30	Public Citizen, ODEC submit comments Applicants answer ODEC comments PJM (out-of-time) intervenes
	21	203 Application: Berkshire Power/Gate City Power (EC24-104)	Sep 13 Oct 1	FERC authorizes Gate City Power's acquisition of Berkshire Power Berkshire Power Co. submits notice of *Sep 30, 2024* consummation of transaction
	22	203 Application: GIP/BlackRock (EC24-58)	Sep 6	FERC authorizes BlackRock's acquisition of 100% of the LLC interests in GIP and thus an indirect controlling interest in the GIM public utility subsidiaries, including, among others, Clearway Power Marketing and GenConn Energy
*	22	D&E Agreement: NSTAR / Vicinity Energy Boston (ER25-49)	Oct 7	NSTAR files D&E Agreement; comment deadline ***Oct 28, 2024***
*	22	Wholesale Distribution Tariff – NSTAR (ER24-3154)	Sep 30 Oct 3	NSTAR files new Wholesale Distribution Tariff to facilitate ESS resources' participation in the wholesale markets via distribution facilities owned by NSTAR; comment deadline ***Oct 21, 2024*** MA DPU intervenes
*	22	Wholesale Distribution Tariff – CL&P (ER24-3153)	Sep 30	CL&P files new Wholesale Distribution Tariff to facilitate ESS resources' participation in the wholesale markets via distribution facilities owned by CL&P; comment deadline ***Oct 21, 2024***
*	22	LGIA - Versant / Eagle Point Energy Center (ER24-2982)	Sep 6	Versant Power submits a fully executed, non-conforming LGIA by and among Versant and Eagle Point Energy Center, LLC
	23	Wholesale Distribution Tariff – UI (ER24-2939)	Sep 20 Sep 6-17	Alliance for Climate Transition, Elevate Renewable F7 file comments Agilitas, Eversource, New Leaf intervene
	23	Wholesale Distribution Tariffs – National Grid (ER24-2796 (MECO); ER24-2795 (Nantucket))	Sep 6 Sep 23 Oct 4	MA AG and Northeast Clean Energy Council file protests National Grid answers the Sep 6 protests Alliance for Climate Transition (f/k/a the Northeast Clean Energy Council) responds to National Grid's Sep 23 answer
	24	LGIA: ISO-NE/CL&P/Brookfield Husky Solar (ER24-2740)	Sep 26	FERC accepts non-conforming LGIA covering the interconnection of Brookfield's ~50 MW solar facility located in Sterling, CT, eff. *Aug 10, 2024*
	24	D&E Agreement Cancellation: NSTAR/Hingham (ER24-2695)	Sep 9	FERC accepts notice of cancellation of NSTAR/Hingham D&E Agreement, eff. *Aug 5, 2024*
	24	E&P Agreement, 3d Amendment: Seabrook / NECEC Transmission (ER24-2588)	Sep 20	FERC accepts third amendment to the E&P Agreement, eff. *Jul 3, 2024*
	24	CMP ESF Service Rate (ER24-1177)	Sep 19 Sep 20	3rd settlement conference held 4th settlement conference scheduled for ***Dec 10-11, 2024***
	25	IA Cancellation Versant / PERC (ER24-965)	Sep 9	Versant asks the FERC to "un-pause" action on its Jan 22, 2024 notice of cancellation of the IA between itself and PERC

XII. Misc. - Administrative & Rulemaking Proceedings

25	Large Loads Co-Located at Generating Facilities (AD24-11)	Sep 10	FERC issues 2nd supplemental notice of ***Nov 1, 2024*** tech. conf.
26	Innovations & Efficiencies in Generator Interconnection (AD24-9)	Sep 10-11 Sep 12	FERC holds workshop FERC invites post-workshop comments; comments due (following an extension of time) on or before ***Nov 14, 2024***

	26	Joint Federal-State Current Issues Collaborative (AD24-7)	Sep 17	FERC issues notice of the first public meeting of the Collaborative to be held ***Nov 12, 2024*** in Anaheim, California
	26	ANOPR: Implementation of Dynamic Line Ratings (RM24-6)	Sep 16, 23	Topolonet Corporation, Laki Power submit comments

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

*	30	Big Rivers Electric Corporation Stipulation and Consent Agreement (IN24-9)	Sep 5	FERC approves Agreement that resolves OE's investigation into whether BREC violated the MISO Tariff and FERC regulations through false and misleading communications with MISO and the MISO IMM and by submitting bids to MISO at full availability when BREC knew or was reckless in not knowing that its plant could not run at full availability; BREC agrees to ***disgorge $308,341***, pay a ***$336,870 civil penalty***, and provide compliance training & monitoring
	30	Ketchup Caddy / Phillip Mango (MISO DR Program Violations) (IN23-14)	Sep 4	FERC Secretary issues notice that Respondents were served with a copy of the *Ketchup Caddy Show Cause Order* on Jul 26, 2024 (to which they did not respond)

Gas-Related Enforcement Actions

	32	Total Gas & Power North America, Inc. et al. (IN12-17)	Sep 19	In light of the Supreme Court's decision in *Jarkesy*, the FERC terminated the hearing procedures established in the *Hearing Order*. The FERC stated that "will not impose penalties against [TGPNA] for the conduct alleged in the *Show Cause Order* on the basis of an administrative enforcement proceeding before a FERC ALJ." This proceeding will be held in abeyance until a further FERC order is issued.

XIV. Natural Gas Proceedings

No Activity to Report

XV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XVI. Federal Courts

	34	*TO Initial Funding Show Cause Order* (8th Circuit - 24-2714)	Oct 3	Court issues order holding briefing schedule in abeyance for 90 days (until ***Jan 1, 2025***)
	35	*Order 2222* Compliance Orders (23-1167, 23-1168, 23-1169, 23-1170, 23-1335)(consolidated)	Sep 30	FERC files status report stating that the FERC has not yet issued a final order in ER22-983, and these consolidated appeals should remain in abeyance
	36	Seabrook Dispute Order (23-1094, 23-1215) (consolidated)	Oct 4	Court issues 2-1 opinion denying Seabrook's Petition for Review

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Pat Gerity, Teresa Chen NEPOOL Counsel

DATE: October 8, 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 October 8, 2024. If you have questions, please contact us.

I. Complaints/Section 206 Proceedings[2]

- **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).[3] 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.[4] 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.[5] 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.[6] The refund effective date for this proceeding is June 24, 2024.[7] 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] Reporting on Base ROE Complaints I-IV: (EL11-66, EL13-33; EL14-86; EL16-64) has been suspended and will be continued if and when there is new activity to report.

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

[4] *Id.* at P 1.

[5] *Id.*

[6] *Id.* at P 2.

[7] 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:[8] 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.

NE Response to Show Cause Order (Attaching Substantive Response by NETOs). On September 11, 2024, ISO-NE submitted a response ("NE Response") explaining that, because the rules identified in the *TO Initial Funding Show Cause Order*[9] fall within the exclusive purview of, and are implemented by, the Participating Transmission Owners ("PTOs") under the Transmission Operating Agreement ("TOA") between ISO-NE and the PTOs, it had requested that the PTOs respond to the *TO Initial Funding Show Cause Order* and attached the response of Indicated New England Transmission Owners ("NETOS")[10] to the NE Response. NETOs' response identified several reasons why the FERC's proposal is in their view beyond the FERC's authority and power.

Responses to the September NE Response are currently due on or before ***October 25, 2024***.[11] Responses may address: (i) whether the OATT remains just and reasonable and not unduly discriminatory or preferential; (ii) if not, what changes to the OATT should be implemented as a replacement rate; and (iii) and respond to any of the questions in Appendix A to the *TO Initial Funding Show Cause Order*.[12]

Order Dismissing Indicated Utilities[13] Request for Rehearing (-001). As previously reported, Indicated Utilities requested rehearing, asking the FERC rescind its *TO Initial Funding Show Cause Order*. On August 15, 2024, the FERC issued an "Allegheny Notice",[14] noting that Indicated Utilities request for rehearing may be deemed to have been denied by operation of law, but noting that Indicated Utilities' request would be addressed

[8] 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).

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

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

[11] On Oct. 8, 2024, the FERC, in response to a September 30, 2024 request by Clean Energy Associations (AEU, ACPA, SEIA) for an additional 14 days to submit responses to the ISO/RTO filings, granted an extension of time, to and including October 25, 2024, for interested parties to file comments.

[12] *TO Initial Funding Show Cause Order* at Ordering Paragraph (E).

[13] "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").

[14] 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") 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.

in a future order.[15] On September 26, 2024, the FERC issued that order, dismissing Indicated Utilities' Request for Rehearing.[16] In dismissing the Request for Rehearing, the FERC explained that, because its action was not final, is to succeeded by further Commission action and is therefore not yet a final FERC action, "it is premature to address Indicated Utilities' arguments" and "a request for rehearing may be dismissed."[17]

Federal Court Appeals. On August 30, 2024, certain parties[18] filed a petition for review of the FERC's orders in this proceeding in the 8th Circuit. Developments on the federal court appeals will be reported in Section XVI below. In the meantime, if you have questions on this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

- **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.[19] 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,[20] and became effective as of *December 12, 2023*. On January 29, 2024, ISO-NE requested that this proceeding continue to be held in abeyance,[21] through August 30, 2024, "pending completion of the stakeholder process through which further revisions to [the Tariff] are being proposed and vetted.[22] 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). Those changes are pending before the FERC. 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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[15] *Midcontinent Indep. Sys. Op. et al.*, 188 FERC ¶ 62,084 (Aug. 15, 2024) ("*TO Initial Funding Show Cause Allegheny Notice*").

[16] *Midcontinent Indep. Sys. Op. et al.*, 188 FERC ¶ 61,211 (Sep. 26, 2024) ("*TO Initial Funding Show Cause Allegheny Order*").

[17] Citing*, e.g.*, *Westlands Transmission, LLC*, 177 FERC ¶ 61,175, at P 4 (2021); *Red Horse Wind 2, LLC*, 172 FERC ¶ 61,147, at P 3 (2020); *BridgeTex Pipeline Co., LLC*, 164 FERC ¶ 61,111, at PP 10-12 (2018); *Pac. Gas & Elec. Co.*, 162 FERC ¶ 61,246, at PP 6-7 (2018); *Talen Energy Mktg., LLC*, 158 FERC ¶ 61,077, at PP 3-4 (2017).

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

[19] *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.

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

[21] 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.

[22] 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,[23] 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, ACPA, 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.

On July 16, 2024, RENEW submitted 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. On August 9, 2024, RENEW replied to the PTO AC's July 31 protest. 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).

II. Rate, ICR, FCA, Cost Recovery Filings

- **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.[24] MOPA asserted that, (i) with respect to the cost of asset condition projects placed into service in 2022, Identified TOs[25] 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

[23] 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.

[24] 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.

[25] "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").

or before February 21, 2024 and were filed by Consumer Advocates[26] (who supported MOPA's attempt to discover the information requested in its September 15, 2023 requests and agreed that policies, processes, and procedures related to ACP costs are discoverable pursuant to the Protocols) and Identified TOs (who urged the FERC to reject the MOPA Formal Challenge as baseless and misguided). On March 4, 2024, MOPA answered Identified TOs' comments. Identified TOs answered MOPA's March 4 answer on March 15 (as corrected on March 18, 2024).

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

The MOPA Formal Challenge is pending before the FERC. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

***(-018) Second CapEx Info Filing*.** On December 5, 2023, the FERC issued an order[27] on the formal challenges to Mystic's September 15, 2022 "Second CapEx Info Filing".[28] As previously reported, formal challenges to the Second CapEx Info Filing were submitted by NESCOE and ENECOS[29] (with ENECOS challenges supported separately by MMWEC/NHEC). Several rounds of answers, described in previous reports, followed. 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).[30]

(-027) Second CapEx Info Filing Settlement Proceedings. As previously reported, while the FERC set several aspects of ENECOS Formal Challenges to Mystic's September 15, 2022 "Second CapEx Info Filing" for a

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

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

[28] 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").

[29] ENECOS Formal Challenges included asserted 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.

[30] As noted in previous reports and as summarized in Section XVI below, this matter has been appealed to, and is pending (though being held in abeyance) before, the DC Circuit.

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, has been holding the hearing in abeyance pending the completion of settlement judge procedures. Judge Patricia M. French is the appointed settlement judge in this proceeding. Judge French has convened seven settlement conferences.[31] Judge French submitted her 5th status report on October 2, 2024, reporting that a settlement in principle has been reached, and noting Mystic's most recent request for a waiver of certain deadlines required by Schedule 3A of the Mystic COSA (*see* ER24-3054 below), which states the anticipated agreement will "resolve[ ] all outstanding issues related to the Mystic Agreement, including matters set for hearing in Docket No. ER18-1639-027, and all issues that would have been in scope of Mystic's 2024 and 2025 Informational Filing processes." Judge French recommended that settlement procedures continue. The settlement process continues.

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*,[32] 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 ROE Settlement Agreement (ER24-2804). On August 14, 2024, Mystic filed an unopposed Settlement Agreement to establish a settled ROE of 9.0%[33] for the Mystic COSA ("*Mystic ROE Settlement Agreement*") that would, if approved, moot all of the ROE appeals currently pending before the DC Circuit related to that ROE[34] and a pending Revised ROE (Sixth) Compliance Filing pending in ER18-1639-014.[35] Mystic requested

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[31] 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; the sixth, June 18, 2024; and the most recent and seventh settlement conference, Aug. 29, 2024.

[32] *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).

[33] The ROE to be used in the Methodology for both Everett and Mystic would be 9.0% for the entirety of the Term (or June 1, 2022 – May 31, 2024) ("Settled Mystic ROE"), a reduction from the currently-on-file ROE of 9.19%. Recall that, on July 15, 2021, the FERC set the base ROE for the Mystic COSA at 9.33%. (*Constellation Mystic Power, LLC*, 176 FERC ¶ 61,019 (July 15, 2021) ("*Mystic ROE Order*")) Subsequently, in response to challenges, the FERC on rehearing lowered the base ROE to 9.19%. (*Constellation Mystic Power*, LLC, 178 FERC ¶ 61,116 (Feb. 18, 2022) ("*Mystic ROE Second Allegheny Order*")).

[34] The *Mystic ROE Order* and the *Mystic ROE Second Allegheny Order* were appealed to the DC Circuit and are being held in abeyance. *See* Section XVI of this Report, Mystic II (ROE & True-Up) (21-1198 *et al.*)

[35] As long reported, Mystic filed a revised ROE (Sixth) compliance filing (docketed as ER18-1639-014) in response to the requirements of the *Mystic ROE Allegheny Order*. The sixth compliance filing revised (i) the Cost of Common Equity figures from 9.33% to 9.19%, for both Mystic 8&9 and Everett Marine Terminal ("Everett"), and (ii) the stated Annual Fixed Revenue Requirements for both the 2022/23 and 2023/24 Capacity Commitment Periods.

a November 1, 2024 effective date for the Settlement Agreement. Comments on the *Settlement Agreement* were due on or before September 4, 2024; none were filed. ISO-NE, National Grid, MMWEC, NHEC, and CT PURA intervened. The *Mystic ROE Settlement Agreement* is pending before the FERC.

Mystic COSA Protocols Waiver Request (ER24-3054). On September 13, 2024, Mystic requested another waiver[36] 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 Filing (and subsequent related deadlines, including billings and re-billings) can be further delayed to provide time for the drafting and filing of, and action on, a settlement agreement that will resolve all remaining matters pertaining to the Mystic COSA. Mystic reported that Mystic and Active Intervenors in ER18-1639-027,[37] have reached (or are not opposed to) a settlement in principle in that proceeding that will resolve all outstanding issues related to the COSA. Comments on Mystic's waiver request were due on or before September 20, 2024; none were filed. This waiver request is pending before the FERC.

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[38] 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).

[36] As previously reported, the FERC granted a waiver to extend the original deadline of Mystic's Fourth Informational Filing from Sep. 15, 2024 to Oct. 15, 2024 to provide parties additional time to negotiate a global settlement agreement. *Constellation Mystic Power, LLC*, 188 FERC ¶ 61,121 (Aug. 12, 2024).

[37] "Active Intervenors" are: ISO-NE; NEPOOL; NESCOE; CT PURA; CT DEEP; CT OCC; MA AG; MMWEC; National Grid; and Belmont, Block Island Utility District, Braintree, Concord, Georgetown, Groveland, Hingham, Littleton (NH), Merrimac, Middleborough, Middleton, North Attleborough, Norwood, Pascoag, Reading, Taunton, Wallingford, Wellesley, and Westfield.

[38] 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.

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

- **Waiver Request: Late Stage SIS Process (GDQ ESS) (ER24-2926)**

On August 29, 2024, GDQ ESS LLC ("GDQ ESS") requested a limited waiver of pending *Order 2023* compliance Tariff revisions[39] to allow it to accept, after August 30, 2024, the SIS results for its facility[40] and thus to enable its LGIA to benefit from the proposed Late-Stage SIS Process and for it to be refunded its deposits associated with participation in the Transitional Cluster Study.[41] On September 6, ISO-NE protested the waiver request asserting that GDQ ESS does not meet the FERC's standard for granting waivers. NEPOOL and Calpine intervened. The GDQ ESS waiver request is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **DASI Conforming Tariff Changes (ER24-2883)**

On August 27, 2024, ISO-NE and NEPOOL jointly filed Tariff changes necessary to fully implement the Day-Ahead Ancillary Services Initiative ("DASI") in the spring of 2025 ("DASI Conforming Changes"). Specifically, the DASI Conforming Changes: (i) revise the Day-Ahead Net Commitment Period Compensation ("NCPC") framework to incorporate the new DASI costs and revenues introduced by the DASI Rules; (ii) revise certain "special case" NCPC rules to include the Forecast Energy Requirement ("FER") Price, which was also introduced by the DASI Rules and incorporated into Day-Ahead Prices; (iii) update the Day-Ahead excess energy condition rules to account for the new co-optimized Day-Ahead Market created as part of DASI; (iv) incorporate average avoided peak distribution losses into Day-Ahead Ancillary Services obligations for Demand Response Resources; and (v) propose a methodology to capture and allocate administrative costs related to DASI in Section IV.A of the Tariff. In addition to the DASI Conforming Changes, the filing also proposes Tariff clarifications related to Day-Ahead Self-Scheduled External Transactions ("Self-Scheduled External Transactions Changes"). Two effective dates were requested -- October 27, 2024 for the Self-Scheduled External Transactions Changes and March 1, 2025 for the DASI Conforming Changes. The Participants Committee supported the DASI Conforming Changes, as well as the Self-Scheduled External Transactions Changes, by way of the Summer Meeting Consent Agenda (Consent Agenda Items 1-3). Comments on the changes were due on or before September 17, 2024; none were filed. Calpine, National Grid, NEPGA, MA DPU, and Public Citizen intervened. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **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 ("Fuel Price Adjustments"). 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 filing were due on or before August 14, 2024. The ISO-NE IMM, NEPGA and Vistra filed comments generally supporting the Fuel Price Adjustments. Calpine, National Grid, MA DPU, EPSA, and Public Citizen filed doc-less interventions. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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[39] Revisions to Section 5.1.1.2 of the LGIP, pending in the *Order 2023* Compliance Changes proceeding (ER24-2009), provide that "if the Interconnection Customer accepts the results of its system impact study on or before August 30, 2024, the System Operator shall not include the Interconnection Request in the Transitional Cluster Study and instead tender a Large Generator Interconnection Agreement pursuant to Section 11 of this LGIP, and refund any deposits associated with participation in the Transitional Cluster Study" (the "Late-Stage SIS Process").

[40] GDQ is the project company for a 203 MW battery energy storage project located in North Kingstown, Rhode Island (Queue Position "QP1163") (the "ESS Facility"). The ESS Facility will interconnect to the RI Energy transmission system.

[41] GDQ states that it is in potential jeopardy of missing the August 30, 2024 deadline under Section 5.1.1.2 to enter into a LGIA because a previously queued project upon which its queue position is dependent was unlikely to complete its System Impact Study ahead of GDQ's.

- **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")[42] 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.[43] 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 IEP and, if determined to be warranted by the FERC, net of Program charges. NEPOOL (out-of-time) and National Grid intervened doc-lessly.

Settlement Judge Proceedings. On August 12, 2024, the FERC issued an order establishing settlement judge procedures to address the issue of whether and how CM should return revenues or net revenues, with applicable interest, to ISO-NE.[44] On August 21, 2024, the Chief ALJ designated ALJ Patricia E. Hurt as the settlement judge in this proceeding. Judge Hurt submitted her 1st status report on September 20, 2024, recommending that the settlement process continue. A formal settlement conference was held on September 23, 2024, at which time the parties reported that a settlement in principle between Canal and ISO-NE had already been reached.

Settlement Agreement (ER25-56). An *unopposed* settlement agreement, which will resolve all of the issues raised in this proceeding ("Canal IEP Settlement Agreement") was submitted on October 8, 2024 (ER25-56). The Settlement Agreement provides that CM will refund and repay to ISO-NE the net revenues that it received on behalf of Canal 3 for participating in the IEP for the Winter 2023-2024 period, plus interest. The settlement amount ("Settlement Amount") will consist of a lump sum of $1,968,156.08 and an amount of interest to be calculated in accordance with FERC regulations. The time period for calculating that interest will be from January 15, 2024, the midpoint of the IEP 2023-2024 Winter period, until the day that the parties receive notice of approval of the Agreement by the FERC. Canal Marketing will have 10 Business Days from the date that the FERC approves the Settlement Agreement to pay the Settlement Amount to ISO-NE. ISO-NE will have 60 days to distribute the Settlement Amount as appropriate to the average Real-Time Load Obligation for the IEP Winter 2023-2024 period. Details regarding the distribution to IEP Participants will be provided by ISO-NE in a notice and included in the applicable monthly settlement's job aid. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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[42] 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.

[43] 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.

[44] *Canal Marketing LLC*, 188 FERC ¶ 61,122 (Aug. 12, 2024).

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

In a lengthy compliance Order[45] issued March 1, 2023, the FERC approved in part, and rejected in part, the *Order 2222* compliance filing[46] ("*Order 2222 Compliance Order*") filed jointly by ISO-NE, NEPOOL and the PTO AC ("Filing Parties").[47] 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.[48] In the order conditionally accepting the 60-day compliance filing,[49] 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.[50] 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*.[51] 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.[52]

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[45] 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."

[46] 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.

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

[48] *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).

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

[50] 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.

[51] 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.

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

(-006) Order 2222 60-Day Compliance Filing Order Allegheny Order.[53] 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,[54] 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").[55] The FERC found that, under its rule of reason,[56] 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").[57] 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 ("ATTR Submetering Tariff Revisions") (*see* sub-docket -009 below).

(-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.[58] In the *Further Order 2222 Compliance Filing Order*, the FERC found that ISO-NE complied with *Order 2222 60-Day Compliance Filing Order*'s 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".[59] Accordingly, the FERC directed ISO-NE "to submit … Tariff revisions that include the meter data submission deadline in its Tariff"[60] (the "Metering Data Submission Revisions").

***(-008) Metering Data Submission Revisions*.** On September 5, 2024, the FERC accepted the Metering Data Submission Revisions,[61] effective as of *November 1, 2026*, as requested. The September 5 order was not challenged and is final and unappealable.

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[53] 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.

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

[55] *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").

[56] "[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.

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

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

[59] *Id.* at P 13.

[60] *Id.*

[61] *ISO New England Inc.*, Docket No. ER22-983-008 (Sep. 5, 2024) (unpublished letter order).

(-009) ATTR Submetering Tariff Revisions. The ATTR Submetering Revisions required by the *Order 2222 60-Day Compliance Filing Order Allegheny Order*[62] 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 supported the ATTR Submetering Revisions at its August 1, 2024 meeting (Consent Agenda Item No. 1). Comments on ISO-NE's July 22 compliance filing were due on or before *August 12, 2024*. NEPOOL filed comments reporting on the Participants Committee's August 1 action and supporting the revisions. No other comments or interventions were filed. The July 22 compliance filing is pending before the FERC.

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

- **VTransco Attachment F App. D Depreciation Rate Changes (ER24-3019)**

On September 11, 2024, VTransco file changes to its Appendix D to Attachment F of the ISO-NE OATT to reflect updated depreciation rates in VTransco's Regional and Local Service formula rate calculations. VTransco stated that implementation of the updated depreciation rates produces a reduction in VTransco's annual revenue requirement by reducing annual depreciation expense by approximately $877,044. Comments on the VTransco depreciation rate changes were due on or before October 7, 2024; none were filed. Thia matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **FG&E Attachment F App. D Depreciation Rate Changes (ER24-2766)**

On September 26, 2024, the FERC accepted the changes to Fitchburg Gas & Electric Company's ("FG&E") Appendix D to Attachment F of the ISO-NE OATT to reflect updated depreciation rates in FG&E's Regional and Local Service formula rate calculations.[63] As previously reported, the changes were recommended in a depreciation study based on 2022 data and approved by the MPUC as part of FG&E's retail rate filing. The proposed updates to depreciation rates submitted will result in an estimated annual decrease of $28,067 to depreciation expense. FG&E said that the revised depreciation rates will have a *de minimus* effect on the transmission rates of Regional and Local Service customers. Unless the September 26 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 Changes (ER24-2009)**

On May 14, 2024 (as corrected May 31, 2024), ISO-NE, NEPOOL and the PTO AC filed proposed Tariff revisions in 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)).

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

[63] *ISO New England Inc.*, Docket No. ER24-2766-000 (Sep. 26, 2024) (unpublished letter order).

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 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,[64] 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 July 5 answers. Since the last Report, on August 5, Longroad Energy answered ISO-NE's July 19 answer (again advocating for why ISO-NE should be required to accept surety bonds for CETU Participation Deposits, as it asserts is required for all commercial readiness deposits per *Order 2023*) ("Additional Answer"). ISO-NE answered Longroad's August 5 Additional Answer on August 7.

Since the last Report, Allco Finance Limited ("Allco") intervened out-of-time and protested this filing (asserting that the new proposed ISO-NE practices "will strike a crushing blow to small distributed solar between 1 MW and 5 MW" by "imposing knee-buckling interconnection fees and costs and a crushing interconnection process"). This matter is still pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617- 345-4735; ekrunge@daypitney.com).

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

Also on May 14, 2024, ISO-NE, NEPOOL and the PTO AC ("Filing Parties") 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. The Filing Parties requested, contingently, that the *Order 2023 Related Changes* become effective on the same date as the *Order 2023 Revisions* (i.e. August 12, 2024) and that the FERC issue an order for the *Order 2023 Related Changes* concurrently with its order on the *Order 2023 Revisions*. 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. On July 19, ISO-NE answered Glenvale's and Longroad Energy's further answers. On August 5, Longroad Energy answered ISO-NE's July 19 answer (again advocating for why ISO-NE should be required to accept surety bonds for CETU Participation Deposits, as it asserts is required for all commercial readiness deposits per *Order 2023*) ("Additional Answer"). ISO-NE answered Longroad's August 5 Additional Answer on August 7.

Since the last Report, Allco Finance Limited ("Allco") intervened out-of-time and protested this filing (asserting that the new proposed ISO-NE practices "will strike a crushing blow to small distributed solar between 1 MW and 5 MW" by "imposing knee-buckling interconnection fees and costs and a crushing

[64] "Clean Energy Associations" are, collectively, AEU, ACPA, Natural Resources Defense Council ("NRDC"), and SEIA.

interconnection process"). This matter is still pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617- 345-4735; ekrunge@daypitney.com).

- **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").[65] 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 ("ROFR"), 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 unreasonable or unduly discriminatory or preferential."[66] The LTTP Phase 2 Changes were accepted effective *July 9, 2024*, as requested. The *LTTP Phase 2 Changes Order* was not challenged as is final and unappealable.

Compliance Filing Accepted. In addition, the FERC accepted, on September 30, 2024, ISO-NE's proposed corrections (filed on July 27, 2024, after the *LTTP Phase 2 Changes Order*) to 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 were not yet intended to be in effect but had been included with the LTTP Phase 2 Changes in error (ER24-1978-001).[67] Unless the September 30 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Eric Runge (617- 345-4735; ekrunge@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

- **FAP Revisions to Mitigate Risk of PFP Penalty Payment Defaults (ER24-3071)**

On September 18, 2024, ISO-NE proposed Financial Assurance Policy ("FAP") revisions for participants that are determined not to have adequate corporate liquidity relative to potential obligations that may be incurred under the pay for performance ("PFP") construct of the Forward Capacity Market ("FCM"). Beginning with the 2025 – 2026 Capacity Commitment Period ("CCP"), ISO-NE will perform a corporate liquidity assessment on each FCM participant holding a Capacity Supply Obligation ("CSO") (or its guarantor, if such guarantor is guaranteeing the payment of PFP penalties), to determine its ability to pay potential penalty payment obligations associated with its CSO within the applicable Capacity CCP, over a forward-looking rolling six months. "Low risk" participants will continue to be subject to the current FCM Delivery Financial Assurance methodology; "medium and high risk" participants will be subject to higher collateral requirements (risk adders). ISO-NE proposed a February 1, 2025, effective date for these changes. The changes were considered, but were not supported, by the Participants Committee at its September 5, 2024 meeting (Agenda Item #5). Comments on these changes are due on or before October 9, 2024. Thus far, NEPOOL submitted comments summarizing consideration of the changes in the stakeholder process. Interventions have been filed by: Calpine, Dominnion, HQ US, NEPGA, MA DPU, and Public

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

[66] *Id.* at P 40.

[67] *ISO New England Inc.*, Docket No. ER24-1978-001 (Sep. 30, 2024) (unpublished letter order).

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

- **Updates to Non-Commercial Capacity FA Amount Multiplier (ER24-3040)**

On September 13, 2024, ISO-NE and NEPOOL jointly filed FAP revisions to: (i) ensure that the post-auction Non-Commercial Capacity Financial Assurance ("NCCFA") Multiplier continues to increase annually during the three-year delay of the next FCA; (ii) ensure that the formula for calculating the NCCFA Amount directly before an FCA ("pre-auction NCCFA Amount") remains generally consistent with the formula for calculating NCCFA required upon completion of an FCA ("post-auction NCCFA Amount"), and (iii) eliminate an NCCFA provision which is no longer relevant due to the passage of time ("ministerial revision"). ISO-NE proposed a November 13, 2024 effective date for these changes. The changes were supported by the Participants Committee at its August 1, 2024 meeting (Agenda Item #2A). Comments on these changes were due on or before October 4, 2024; none were filed. Calpine, National Grid and Public Citizen intervened. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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

- **Schedule 22: ISO-NE/CMP/Andro Hydro LGIA (ER24-2970)**

On September 4, 2024, ISO-NE and CMP filed a revised LGIA with Andro Hydro to clarify the relationship between Andro Hydro (Interconnection Customer) and JGT2 Redevelopment LLC ("JGT2"), the owner of a closed paper mill located on Andro Hydro's side of the interconnection, and the status of the Interconnection Facilities governed by the LGIA. While the LGIA is based on the Schedule 22 *pro forma* LGIA, it contains limited revisions that are necessary given the Large Generating Facility's unique interconnection to the system, , including the interconnection of its facility through shared facilities co-owned, and used by, JGT2 Redevelopment LLC to serve its own load,[68] thus making it non-conforming and requiring it to be filed with the FERC. The Parties requested an August 8, 2024 effective date (the date on which all of the parties to the LGIA executed the agreement). Comments on the LGIA filing were due on or before September 25, 2024; none were filed. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **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.[69] 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).

[68] The original non-conforming LGIA was filed in Docket No. ER24-1477. Reporting on that docket has concluded as the Filing Parties indicated that filing will be withdrawn upon action on this instant filing. Details concerning Docket No. ER24-1477 can be found in the last Report.

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

- **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").[70] 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[71] to the extent necessary to permit a requested October 21, 2022 effective date. The LSA was filed separately given that requested effective date.

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.[72] 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").[73] 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.[74] On August 29, 2023, Versant 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).

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

71 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.

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

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

74 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.

- **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 September 24, 2024, the FERC accepted 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").[75] As previously reported, the Changes modify the allocation of any unused Provisional Member Group Seat voting share to all six Sectors. The Changes were accepted effective August 1, 2024, as requested. Unless the September 24 order is challenged, this proceeding will be concluded. If you have any questions concerning the Changes, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VIII. Regional Reports[76]

- **Capital Projects Report – 2024/Q2 (ER24-2769)**

On September 6, 2024, the FERC accepted, effective July 1, 2024, ISO-NE's Capital Projects Report and Unamortized Cost Schedule covering the second quarter ("Q2") of calendar year 2024 (the "Report").[77] As previously reported, Q2 2024 Report highlights included:

- One new project -- Automatic Ring Down Circuit Continuity Modernization and Reliability Enhancements ($897,200).
- Two projects with significant changes: (i) Energy Management System Short-Term Load Forecast Replacement (increased in 2024 by $327,300); and (ii) IT Asset Workflow Integration and Updates (2024 budget increased by $116,400); and
- Three projects completed in Q2: (i) Settlement Technology Improvements; (ii) Control Room Voice Recorder Update; and (iii) On Call Notification Systems. Each cost less than planned.

Unless the September 6 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

[75] *ISO New England Inc.*, Docket No. ER24-2636-000 (Sep. 24, 2024) (unpublished letter order).

[76] 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.

[77] *ISO New England Inc.*, Docket No. ER24-2769-000 (Sep. 6, 2024) (unpublished letter order).

- **Interconnection Study Metrics Processing Time Exceedance Report 2024 Q2 (ER19-1951)**

On August 14, 2024, ISO-NE filed, as required,[78] public and confidential[79] versions of its Interconnection Study Metrics Processing Time Exceedance Report (the "Exceedance Report") for the Second Quarter of 2024 ("2024 Q2"). ISO-NE reported that with respect to:

- ♦ **Interconnection Feasibility Study ("IFS") Reports**
  - One IFS Report was delivered to an Interconnection Customer in 2024 Q2 and was delivered later than the best efforts completion timeline of 90 days.
  - 32 IFSs that are not yet completed have already exceeded the 90-day completion expectation.
  - The average time from ISO-NE's receipt of the executed IFS Agreement to delivery of the completed IFS Report to the Interconnection Customer was 307 days (which is approximately 134 days longer than the previous quarter).

- ♦ System Impact Study ("SIS") Reports
  - 4 SIS Reports were delivered to Interconnection Customers in 2024 Q2. 3 of those 4 SIS Reports were delivered later than the best efforts completion timeline of 270 days.
  - 31 SISs that are not yet completed have already exceeded the 270-day completion expectation.
  - The average time from ISO-NE's receipt of the executed SIS Agreement to delivery of the completed SIS report to the Interconnection Customer was 416 days (a decrease of approximately 120 days from 2024 Q1's average).

- ♦ Facility Study Reports
  - No Facility Study Reports were delivered to Interconnection Customers in 2024 Q2.
  - 3 Facility Studies in process have exceeded the 90-day completion expectations for a 20% level of cost estimate.

Section 4 of the Exceedance Report identified steps ISO-NE has identified to remedy issues and prevent future delays, including mitigating the impact of backlogs and initiating clustering, moving to earlier in the process certain Interconnection Customer data reviews, and enhanced information sharing and coordination efforts with Interconnecting TOs. On September 13, 2024, ISO-NE corrected the Exceedance Report to remove QP1121 from the list of project dependencies for Queue Position No. 1320 ("Correction"). Neither the Exceedance Report nor the Correction were noticed for public comment.

- **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. The Spring 2024 Report was reviewed with the Markets Committee at the Markets Committee's September 10, 2024 meeting. These filings are not noticed for public comment by the FERC.

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

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

- **ISO-NE FERC Form 3Q (2024/Q2) (not docketed)**

On August 23, 2024, ISO-NE submitted its 2024/Q2 FERC Form 3Q (quarterly financial report of electric utilities, licensees, and natural gas companies). FERC Form 3-Q is a quarterly regulatory requirement which supplements the annual FERC Form 1 financial reporting requirement. Form 3-Q filings are not noticed for public comment.

IX. Membership Filings

- **October 2024 Membership Filing (ER24-3139)**

On September 30, 2024, NEPOOL requested that the FERC accept: (i) the following Applicant's membership in NEPOOL as of October 1, 2024: Castleton Commodities Energy Services LLC and Castleton Commodities Energy Trading LLC [Related Persons to Castleton Commodities Merchant Trading (Supplier Sector)]; Alan Sliski (End User Sector, Governance Only Member); and Stony Creek Energy LLC [Related Person to Invenergy Energy Management (Supplier Sector)]; and (ii) the termination of the Participant status of Gas Recovery Systems. Comments on this filing are due on or before ***October 21, 2024***.

- **September 2024 Membership Filing (ER24-2925)**

On July 30, 2024, NEPOOL requested that the FERC accept: (i) the following Applicant's membership in NEPOOL as of September 1, 2024: Elyctra LLC (Supplier Sector) and Halia Energy LLC (Supplier Sector); and (ii) the termination of the Participant status of the Town on Hanover, New Hampshire. Comments on this filing were due on or before September 20, 2024; none were filed. This matter is pending before the FERC.

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

On September 24, 2024, the FERC accepted the membership in NEPOOL as of August 1, 2024 of Twig Redwood Inc. and the termination of the Participant status of MFT Energy US 1 LLC.[80] Unless the September 24 order is challenged, this proceeding will be concluded.

- **Suspension Notices (not docketed)**

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

Date of Suspension/ FERC Notice	***Participant Name***	***Default Type***	***Date Reinstated***
Sep 9/11, 2024	Excelsior Billerica, LLC	Financial Assurance	--
Sep 9/11, 2024	Excelsior Bondsville, LLC	Financial Assurance	--
Sep 9/11, 2024	Excelsior Lexington, LLC	Financial Assurance	--
Sep 9/11, 2024	Hudson Energy Services, LLC	Financial Assurance	--
Sep 9/11, 2024	Wolverine Holdings, L.P.	Financial Assurance	--

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

[80] *New England Power Pool Participants Comm.*, Docket No. ER24-2623-000 (Sep. 24, 2024) (unpublished letter order).

X. Misc. - ERO Rules, Filings; Reliability Standards[81]

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

- **Revised Reliability Standards: 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,[82] as well as 18 new or revised definitions for inclusion in NERC's Glossary,[83] to facilitate the full implementation of virtualization and to address the risks associated with virtualized environments. The proposed CIP Reliability Standards would permit Responsible Entities with more "traditional" architecture to continue with their current configurations. As of the date of this Report, the FERC still has not notice a proposed rulemaking proceeding or otherwise invited public comment.

- **2025 NERC/NPCC Business Plans and Budgets (RR24-5)**

On August 23, 2024, NERC submitted its proposed Business Plan and Budget, as well as the Business Plans and Budgets for the Regional Entities, including NPCC, for 2025. FERC regulations[84] require NERC to file its proposed annual budget for statutory and non-statutory activities 130 days before the beginning of its fiscal year (January 1), as well as the annual budget of each Regional Entity for their statutory and non-statutory activities, including complete business plans, organization charts, and explanations of the proposed collection of all dues, fees and charges and the proposed expenditure of funds collected. NERC reports that its proposed 2025 funding requirement represents an overall increase of approximately 8.2% over NERC's 2024 funding requirement. The NPCC U.S. allocation of NERC's net funding requirement is $13.12 million. NPCC has requested $25.69 million in statutory funding (a U.S. assessment per kWh (2023 NEL) of $0.000023) and $1.22 million for non-statutory functions. Comments on this filing were due on or before September 13, 2024; none were filed. This matter is pending before the FERC.

- **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,[85] including NPCC. The Report includes comparisons of actual funding received and costs incurred, with explanations of significant actual cost-to-budget variances, audited financial statements, and tables showing metrics concerning NERC and Regional Entity administrative costs in their 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.

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[81] 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.*).

[82] 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).

[83] 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").

[84] 18 CFR § 39.4(b) (2014).

[85] 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").

- **IBR ROP Compliance Filing (RR24-2)**

On August 26, 2024, in response to the requirements of the *IBR ROP Order*,[86] NERC submitted a compliance filing clarifying that the term "generating resources" as used in the ROP Appendices 2 and 5B definitions of Generator Operator ("GOP") and Generator Owner ("GO") includes those inverter-based resources ("IBRs") that provide energy for load, including resources that are battery energy storage systems ("BESS") or fuel cells. Comments on the compliance filing were due on or before September 16, 2024; none were filed. This matter is pending before the FERC.

XI. Misc. - of Regional Interest

- **203 Application: Carlyle Group (Nautilus)/Q-Generation (Trafigura) (EC24-114)**

On August 23, 2024, Applicants, including Nautilus Power, Bridgeport Energy LLC; Essential Power Massachusetts, LLC; Essential Power Newington, LLC; Rumford Power LLC; and Tiverton Power LLC (collectively, the "ISO-NE Companies") requested authorization for Q-Generation Partner's acquisition of 100% of the interests of CPP II Master Holdco, LLC ("CPP II"), a company indirectly owned by investment fund vehicles managed/advised by The Carlyle Group. Following consummation of the proposed transaction, the ISO-NE Companies will no longer be Related Persons to The Carlyle Group and will become Related Persons to Trafigura Trading LLC (whose upstream parent will own or control more than 10% of the equity interests in Q-Generation Partners). Comments on this application were due on or before September 13, 2024 and were filed by Old Dominion Electric Cooperative ("ODEC") and Public Citizen. Applicants answered the ODEC comments on September 23, 2024. On September 30, 2024, PJM intervened (out-of-time). 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: Berkshire Power/Gate City Power (EC24-104)**

On September 13, 2024, the FERC authorized Gate City Power – NE Generation LLC's ("Gate City Power") acquisition of 100% of the membership interests in Berkshire Power's parent, Tenaska Hampden Partners, LLC ("Tenaska Hampden"), from Tenaska Energy, Inc. ("Tenaska Energy") and Tenaska Energy Holdings, LLC ("Tenaska Holdings").[87] Gate City Power filed a notice of the *September 30, 2024* consummation of the transaction. Berkshire Power is no longer a Related Person to Tenaska Power Services *et al*. and instead is a Related Person to Millennium Power Company, a member of the Generation Sector Group Seat. This concludes reporting on this proceeding. 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").[88] Upon consummation, GIP Whale will hold: (i) Eversource Investment's 50% interest in North East Offshore and will thereby also indirectly hold a 50% interest in Revolution Wind; and (ii) Eversource Investment's 50% 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).

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[86] *N. Am. Elec. Reliability Corp.*, 187 FERC ¶ 61,196 at P 43 (June 27, 2024) ("*IBR ROP Order*").

[87] *Berkshire Power Co., LLC*, 188 FERC ¶ 62,137 (Sep. 13, 2024).

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

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

On September 6, 2024, the FERC authorized BlackRock Funding Inc.'s acquisition of 100% of the LLC interests in Global Infrastructure Management, LLC ("GIM") d/b/a Global Infrastructure Partners, thereby creating an indirect controlling interest in the GIM public utility subsidiaries, including, among others, Clearway Power Marketing and GenConn Energy.[89] 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).

- **D&E Agreement: NSTAR / Vicinity Energy Boston (ER25-49)**

On October 7, 2024, NSTAR filed a Design and Engineering Agreement ("D&E Agreement") between itself and Vicinity Energy Boston, Inc. ("Vicinity") to initiate the D&E process required to develop a non-binding cost estimate for the development of Kneeland Substation, which will incorporate Vicinity's proposed 100 MW electrode boiler load into the overall design, at Vicinity's expense. Comments on the D&E Agreement are due on or before ***October 28, 2024***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Wholesale Distribution Tariff – NSTAR (ER24-3154)**

On September 30, 2024, NSTAR filed a new Wholesale Distribution Tariff ("WDT") to provide for NSTAR's recovery of costs associated with the provision of Wholesale Distribution Service ("WDS") to customers who own electric energy storage systems ("ESS") connected to NSTAR's distribution system. The WDT allows such customers to utilize NSTAR's distribution system when charging their ESS for the purpose of participating in the wholesale (New England) market. A December 1, 2024 effective date was requested. Comments on the NSTAR WDT are due on or before ***October 21, 2024***. Thus far, MA DPU has filed an intervention. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Wholesale Distribution Tariff – CL&P (ER24-3153)**

Also on September 30, 2024, CL&P filed a new WDT to provide for CL&P's recovery of costs associated with the provision of WDS to customers who own ESS connected to CL&P's distribution system. The WDT allows such customers to utilize CL&P's distribution system when charging their ESS for the purpose of participating in the wholesale (New England) market. A December 1, 2024 effective date was requested. Comments on the CL&P WDT are due on or before ***October 21, 2024***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Construction Services Agreement Cancellation: NEP/WMECO (ER24-3056)**

On September 16, 2024, NEP filed a notice of cancellation of a Construction Services Agreement ("CSA") with Western Massachusetts Electric Company ("WMECO") pursuant to which NEP performed work to facilitate the interconnection of a 15 MW facility to WMECO's distribution system. The CSA is no longer required because all work pursuant to the CSA is complete and all invoices for that work paid. A November 16, 2024 effective date was requested for the cancellation notice. Comments on the CSA cancellation were due on or before October 7, 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).

- **LGIA - Versant / Eagle Point Energy Center (ER24-2982)**

On September 6, 2024, Versant Power filed a fully executed, non-conforming LGIA by and among Versant Power and Eagle Point Energy Center, LLC.[90] The Eagle Point Facility LGIA is based fundamentally on the PERC LGIA

[89] *Global Infrastructure Management, LLC and BlackRock, Inc.*, 188 FERC ¶ 61,166 (Sep. 6, 2024).

[90] Eagle Point is the owner and operator of a solid waste-fired generating facility (the "Eagle Point Facility") with a maximum nameplate capability of 25.3 MW. The Eagle Point Facility is directly interconnected with Versant Power's 115 kV Line 247—an approximately 4 mile radial transmission line that interconnects the Eagle Point Facility with Versant Power's Orrington Substation, which is

originally executed by Versant Power and PERC. An August 8, 2024 effective date was requested. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Wholesale Distribution Tariff – UI (ER24-2939)**

On August 30, 2024, UI filed a new Wholesale Distribution Tariff to provide for UI's recovery of costs associated with the provision of Wholesale Distribution Service ("WDS") to customers who own front-of-the-meter ("FTM"), distribution-connected battery energy storage systems ("BESS") connected to UI's distribution systems and participate in the ISO-NE markets. The proposed Wholesale Distribution Tariff will enable UI to provide the WDS necessary to facilitate BESS resources' participation in the ISO-NE markets via distribution facilities owned by UI, consistent with FERC *Orders 841* and *2222* and Connecticut's ESS Program.[91] An October 30, 2024 effective date was requested. Comments on the UI Wholesale Distribution Tariff were due on or before September 20, 2024*.* Supportive comments and were filed by Alliance for Climate Transition (but requesting clarifications, supporting data, and additional information as to how UI proposes to measure and bill for demand-related charges when a BESS is providing ancillary services in response to ISO-NE dispatch instructions) and Elevate Renewable F7, LLC (but offering proposed clarifications to improve customer understanding). Interventions were filed by Agilitas, Eversource, and New Leaf. 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).

- **Cost Reimbursement Agreement Cancellation: NEP/Holden (ER24-2852)**

On August 23, 2024, National Grid filed a notice of cancellation of its Cost Reimbursement Agreement ("CRA") with Holden Municipal Light Department ("Holden") pursuant to which NEP performed work to support Holden's plan to rebuild its Chaffins Substation. The CRA is no longer required because all work pursuant to the CRA is complete and all invoices for that work paid. An October 23, 2024 effective date was requested for the cancellation notice. Comments on the CRA cancellation were due on or before September 13, 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).

- **Wholesale Distribution Tariffs – National Grid (ER24-2796; ER24-2795)**

On August 16, 2024, National Grid filed two new Wholesale Distribution Tariffs (one for Massachusetts Electric Company (ER24-2796); the other for Nantucket Electric Company (ER24-2795)) to provide for National Grid's recovery of costs associated with the provision of Wholesale Distribution Service ("WDS") to customers who own qualifying standalone electric energy storage systems ("ESS") connected to National Grid's distribution system and who charge those resources via deliveries over National Grid's distribution system for purposes of making wholesale sales through the ISO-NE markets. The proposed Wholesale Distribution Tariffs will enable National Grid to provide the WDS necessary to facilitate ESS resources' participation in the ISO-NE markets via distribution facilities owned by National Grid, consistent with FERC *Order 841* and the Massachusetts Clean Energy Act. A March 1, 2025 effective date was requested. Comments on these Tariffs were due on or before September 6, 2024. Protests and comments were filed by the MA AG and the Alliance for Climate Transition ("ACT") (formerly known as the Northeast Clean Energy Council). Agilitas, BlueWave, Engie, Eversource, New Leaf, MA DPU, and MA DOER intervened. On September 23, 2024, National Grid answered the ACT and MA AG comments. On October 4, 2024, ACT answered National Grid's September 23 answer. 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).

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a point of interconnection between Versant Power's non-PTF assets and the PTF grid administered by ISO-NE. The Eagle Point Facility is the only generating facility or load directly interconnected with Line 247.

[91] The ESS Program provides incentives for residential and commercial customers to install energy storage systems at their homes or businesses. *See* State of Conn. Pub. Utils. Regul. Auth., PURA Investigation into Distrib. Sys. Plan. of the Elec. Distrib. Cos. – Elec. Storage, Decision, CT PURA Docket No. 17-12-03RE03 at 5, 50 (July 28, 2021), https://portal.ct.gov/-/media/pura/electric/final-decision-17-12-03re03.pdf.

- **LGIA: ISO-NE/CL&P/Brookfield Husky Solar (ER24-2740)**

On September 26, 2024, the FERC accepted a non-conforming LGIA covering the interconnection of Brookfield's ~50 MW solar facility located in Sterling, CT (non-conforming only in that it was unexecuted), effective *August 10, 2024*, as requested.[92] Unless the September 26 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement Cancellation: NSTAR/Hingham (ER24-2695)**

On September 9, 2024, the FERC accepted the notice of cancellation of the Design & Engineering Agreement ("D&E Agreement") between NSTAR and Hingham Municipal Lighting Plant ("Hingham").[93] As previously reported, NSTAR stated that it had completed all work pursuant to the Agreement and reconciliation of billings was complete. The notice of cancellation was accepted effective as of *August 5, 2024*. Unless the September 9 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On September 20, 2024, the FERC accepted a third amendment to the Engineering and Procurement ("E&P") Agreement between NextEra Energy Seabrook, LLC ("Seabrook") and NECEC Transmission LLC ("NECEC") (the "A&R E&P Agreement"), effective *July 3, 2024*, as requested.[94] As previously reported, 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". Unless the September 20 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)**

Versant Power's MPD OATT Order 2023 Compliance filing remains pending. As previously reported, 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* in a May 16, 2024 filing. 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 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. As noted, this matter remains 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").[95] 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*

[92] *ISO New England Inc.*, Docket No. ER24-2740-000 (Sep. 26, 2024) (unpublished letter order).

[93] *NSTAR Electric Co.*, Docket No. ER24-2695-000 (Sep. 9, 2024) (unpublished letter order).

[94] *NextEra Energy Seabrook, LLC*, Docket No. ER24-2588-000 (Sep. 20, 2024) (unpublished letter order).

[95] *Central Maine Power Co.,* 187 FERC ¶ 61,002 (Apr. 1, 2024) ("*CMP ESF Rate 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.[96] 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.[97] 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.

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.[98] There have been three settlement conferences (May 3, July 17, and September 19, 2024); a fourth settlement conference is scheduled to take place over two days from ***December 10-11, 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)**

On September 9, 2024, Versant asked that the FERC "un-pause" action on its January 22, 2024 notice of cancellation of an Interconnection Agreement ("IA") between itself and Penobscot Energy Recovery Company ("PERC"). As previously reported, Versant had 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 to agree to a course of action. Versant reported that it filed a LGIA between itself and the new owner of the PERC Facility, Eagle Point Energy Center, LLC (*see* ER24-2982 above). Versant asked that the cancellation be accepted effective as of November 20, 2023, as originally requested. This matter is again pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

XII. Misc. - Administrative & Rulemaking Proceedings[99]

- **Large Loads Co-Located at Generating Facilities (AD24-11)**

On ***November 1, 2024***, the FERC will hold a Commissioner-led technical conference to explore whether co-located loads require the provision of wholesale transmission or ancillary services, related cost allocation issues, and potential resource adequacy, reliability, affordability, market, and customer impacts. In a second supplemental notice issued on September 10, 2024, the FERC invited individuals interested in participating as panelists to submit a self-nomination email by September 19, 2024. Speakers will be asked to provide pre-conference background materials and a written opening statement to facilitate the discussion during the technical conference. The preliminary agenda identifies 3 panels: Overview of Large Co-Located Load Issues (Panel 1); Exploration of Issues Presented by Large Co-Located Loads (Panel 2); and Roundtable with State Representatives (Panel 3). The list of panelists will be included in a further supplemental notice. The technical conference will be open to the public. Advance registration is not required, and there is no fee for attendance. Information will also be posted on the Calendar of Events on the FERC's website prior to the event.

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[96] *Id.* at P 29.

[97] *Id.*

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

[99] 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).

- **Annual Reliability Technical Conference (AD24-10)**

On ***October 16, 2024***, the FERC will convene its annual Commissioner-led Reliability Technical Conference to discuss policy issues related to the reliability and security of the Bulk-Power System. In a second supplemental notice issued on October 7, 2024, the FERC attached an agenda, including expected panelists on the following two topics: Managing Reliability Risks and Challenges (Panel 1); and Resource Adequacy and Expected Load Growth (Panel 2). The technical conference will be open to the public. Advance registration is not required, and there is no fee for attendance. Information will also be posted on the Calendar of Events on the FERC's website prior to the event.

- **Innovations and Efficiencies in Generator Interconnection (AD24-9)**

On September 10-11, 2024, the FERC held a workshop for the presentation and discussion of opportunities for further innovation and increased efficiency in the generator interconnection process. The three September 10 panels addressed: Integrated Transmission Planning and Generator Interconnection, Exploring Different Approaches to Processing and Studying Generator Interconnection Requests, and Prioritizing Certain Generator Interconnection Requests. The three September 11 panels addressed: Further Efficiencies in the Generator Interconnection Process, Automation and Advanced Computing Technologies, and Post-Generator Interconnection Agreement Construction Phase. Panelists materials are posted in the FERC's eLibrary.

Interested parties are now invited to submit post-technical conference comments, on or before ***November 14, 2024***, on the questions presented in the workshop agenda or on issues raised during the workshop that they believe would benefit from further discussion. Commenters were urged to organize their comments by panel topic and question presented at the workshop, to be brief, and when possible, to provide examples and quantitative data in support of their answers.

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

On September 17, 2024, the FERC issued a notice announcing that the first public meeting of the Federal and State Current Issues Collaborative ("Collaborative")[100] will be held on ***November 12, 2024***, from approximately 2:30 pm—5:00 pm PST, at the Anaheim Marriott in Anaheim, California. The meeting will be open to the public for listening and observing and on the record. There is no fee for attendance and registration is not required. The public may also attend via Webcast.

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

On June 27, 2024, the FERC issued an advanced notice of proposed rulemaking ("ANOPR")[101] seeking comments on both the need for a dynamic line ratings ("DLRs")[102] 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

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

[101] *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.

[102] 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.

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***.[103] 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, comments were submitted by Topolonet Corporation and Laki Power.

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

On October 19, 2023, the FERC issued a NOPR[104] 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.

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

On May 16, 2024, the FERC issued *Order 1977*[105] 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*.[106] 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.[107] 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.[108] 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).

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

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

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

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

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

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

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

On March 21, 2024, the FERC issued a NOPR[109] 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 the provision of reactive power within the standard power factor range or "deadband."[110] The proposed change may affect revenues received by reactive power resources in New England.[111] 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.[112]

Initial comments on the *Reactive Power NOPR* were due May 28, 2024; reply comments were due June 26, 2024.[113] 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*,[114] 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

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

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

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

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

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

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

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

(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,*[115] 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 took effect on *August 12, 2024.*[116] 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.[117]

Petitions for Federal Court Review. *Order 1920* has been challenged in several federal circuits, including the DC, First, Fourth, Fifth, Sixth, Ninth, Tenth, and Eleventh Circuits. Further developments on the federal court appeals will be reported in Section XVI below.

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

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

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

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

- **Big Rivers Electric Corporation Stipulation and Consent Agreement (IN24-9)**

On August 6, 2024, the FERC approved a Stipulation and Consent Agreement with Big Rivers Electric Corporation ("BREC")[118] to resolve OE's investigation following a MISO IMM referral of whether BREC violated FERC regulations and/or the MISO Tariff through false and misleading communications with MISO and the MISO IMM[119] and by submitting bids to MISO at full availability when BREC knew or was reckless in not knowing that the plant could not run at full availability.[120] Under the Stipulation and Consent Agreement, BREC agreed to ***disgorge $308,341*** to MISO, to pay a ***civil penalty of $336,870*** to the United States Treasury, and to provide compliance training to its personnel about the MISO Tariff and the FERC's Anti-Manipulation Rule, to review its compliance procedures for potential improvements, and to provide compliance monitoring. 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.[121] 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."[122]

On September 4, 2024, the FERC Secretary issued a notice that Respondents were served with a copy of the *Ketchup Caddy Show Cause Order* on July 26, 2024. Respondents have not, as of the date of this Report,

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[118] BREC is a member-owned, not-for-profit, electric generation and transmission cooperative headquartered in Owensboro, Kentucky. BREC is a member of MISO and provides services under the terms of the MISO Tariff.

[119] To avoid penalties, BREC falsely told MISO that a planned outage ended on June 29, 2023 and that its outages from that date until July 6, 2023 were forced, when in fact the outages from June 29 to July 6, 2023 were a continuation of the planned outage. BREC also submitted false and misleading information to the MISO IMM about its expectations for its unit running at full availability.

[120] *Big Rivers Electric Cop.*, 188 FERC ¶ 61,155 (Sep. 5, 2024). On 33 days during Summer 2022 ("Relevant Period"), Vista submitted inaccurate/low expected Initial State of Charge values as part of its Regulation Down bids when the Vista Battery actual State of Charge was otherwise much higher based on Regulation Up awards in the final hour of the day before. Because VES submitted low Initial State of Charge values, VES obtained Bid Cost Recovery payments and Regulation Down awards it would not have otherwise obtained.

[121] *Ketchup Caddy, LLC and Philip Mango*, 186 FERC ¶ 61,132 (Feb. 21, 2024) ("*Ketchup Caddy Show Cause Order*").

[122] *Id.* at P 3.

responded to the *Ketchup Caddy Show Cause Order.* 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,[123] 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,[124] 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[125] 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,[126] 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;[127] (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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[123] 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.

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

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

[126] *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*").

[127] 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.[128] 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[129] 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.[130]

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.[131] 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.[132]

On June 14, 2023, the FERC issued an Order on Presiding Officer Reassignment,[133] 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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[128] *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.

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

[130] 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.

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

[132] *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).

[133] *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, 2023, Judge Patricia M. French was substituted as Presiding Judge (relieving Judge Krolikowski of all of her duties with respect to this proceeding).

Order Terminating Hearing and Holding Proceeding in Abeyance. On September 19, 2024, in light of the Supreme Court's decision in *Jarkesy*,[134] the FERC terminated the hearing procedures established in the *Hearing Order*. The FERC stated that "will not impose penalties against [TGPNA] for the conduct alleged in the *Show Cause Order* on the basis of an administrative enforcement proceeding before a FERC ALJ." This proceeding will be held in abeyance until a further FERC order is issued.

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.[135] 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

[134] *Jarkesy* was decided by the Supreme Court on June 27, 2024. *Jarkesy* held that the Seventh Amendment to the U.S. Constitution entitles a respondent in an administrative enforcement proceeding to a jury trial in a federal court organized under Article III of the Constitution when the SEC seeks civil penalties for securities fraud. Because the SEC's civil penalties for securities fraud are "designed to punish and deter, not to compensate" they are the "type of remedy at common law that could only be enforced in courts of law" with Seventh Amendment protections. In short, SEC civil penalty actions regarding fraud are "a common law suit in all but name" and therefore the *Jarkesy* respondents were "entitled to a jury trial in an Article III court." The FERC is examining *Jarkesy*'s impact on the FERC's existing enforcement procedures and expects to further address its approach to enforcement cases in light of *Jarkesy*. The FERC expects that it will issue a further order regarding the status of this proceeding.

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

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.

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).

- ***TO Initial Funding Show Cause Order* (8th Circuit - 24-2714)**
  Case Title: Ameren Services Company, et al v. FERC
  Underlying FERC Proceeding: EL24-80 et al.[136]
  Status: Being Held In Abeyance

On August 23, 2024, Petitioners[137] filed a Petition for Review of the FERC's *TO Initial Funding Show Cause Order and TO Initial Funding Show Cause Allegheny Notice*. Pursuant to an order of the Court issued on October 3, 2024, the Briefing Schedule in this proceeding is being held in abeyance for an initial period of 90 days (until ***January 1, 2025***).

- ***Order 1920*: Transmission Planning Reforms (4th Circuit – 24-1650)**
  Case Title: Appalachian Voices v. FERC
  Underlying FERC Proceeding: RM21-17[138]
  Status: Being Held in Abeyance

As previously reported, on July 18, 2024, AEU/ACPA/SEIA and Invenergy petitioned the DC Circuit Court of Appeals for review of the FERC's *Order 1920*.[139] Petitions were also filed in the First, Second, Fourth, Fifth, Sixth, Seventh, Ninth, and Eleventh Circuits. The Judicial Panel on Multidistrict Litigation randomly selected the Fourth Circuit as the Circuit in which to consolidate the petitions for review. The DC Circuit ordered that its cases be transferred to the 4th Circuit. The 4th Circuit lead case no. is 24-1650. On August 26, 2024, the 4th Circuit granted the FERC's motion to hold the petitions for review in abeyance, with motions to govern due ***January 6, 2025***, all filing deadlines— including filing of the agency record—are deferred until the abeyance period expires. The FERC

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[136] *Midcontinent Indep. Sys. Op. et al.,* 187 FERC ¶ 61,170 (June 13, 2024) ("*TO Initial Funding Show Cause Order*"); *Midcontinent Indep. Sys. Op. et al., 188 FERC ¶ 62,084 (Aug. 15, 2024) ("TO Initial Funding Show Cause Allegheny Notice"); Midcontinent Indep. Sys. Op. et al., 188 FERC ¶ 61,211 (Sep. 26, 2024) ("TO Initial Funding Show Cause Allegheny Order").*

[137] Petitioners are: Ameren Services Co.; Ameren Illinois Co.; Union Electric Co., d/b/a Ameren Missouri; Ameren Transmission Co. of Illinois; American Transmission Co. LLC; Duke Energy Corp.; Duke Energy Business Services, LLC; Duke Energy Ohio, Inc.; Duke Energy Kentucky, Inc.; Duke Energy Indiana, LLC; Northern Indiana Public Service Co. LLC; Xcel Energy Services Inc.; Northern States Power Co. - Minnesota; Northern States Power Co. - Wisconsin; Southwestern Public Service Co.; Exelon Corp.; Atlantic City Electric Co.; Baltimore Gas and Electric Co.; Commonwealth Edison Co.; Delmarva Power & Light Co.; PECO Energy Co.; Potomac Electric Power Co.

[138] *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*").

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

suggested that abeyance will afford the FERC time to respond to the approximately 50 applications for rehearing of *Order 1920*.

- **Mystic Second CapEx Info Filing (24-1077)**
  Case Title: Constellation Mystic Power, LLC v. FERC
  Underlying FERC Proceeding: ER18-1639-028[140]
  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 on Mystic's Second CapEx Info Filing. 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.[141]

In response to a motion by the FERC, the Court ordered that this case be held in abeyance pending further order of the court. Subsequently, in response to a July 16, 2024 unopposed motion by Mystic, the court ordered that the case remain in abeyance pending further order of the Court, with the parties directed to file motions to govern future proceedings in this case by ***December 4, 2024***.

- ***Orders 2023 and 2023-A* (23-1282 et al.) (consolidated)**
  Case Title: Advanced Energy United, et al v. FERC
  Underlying FERC Proceeding: RM22-14[142]
  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. On August 5, 2024, the Court ordered the following briefing schedule: Initial Submissions and Certified Index to the Record (August 21, 2024); Joint Petitioners' Briefs (***October 30, 2024***); Petitioner-Intervenor Brief(s) (November 13, 2024); Respondent's Brief (February 5, 2025); Intervenors for Respondent's Brief (February 19, 2025); Petitioners' Reply Briefs (March 19, 2025); Petitioner-Intervenor Reply Brief(s) (March 19, 2025), Deferred Joint Appendix (April 2, 2025); and Final Briefs (April 16, 2025). The parties will be informed later of the date of oral argument and the composition of the merits panel. The next expected submission will be Joint Petitioners' Briefs.

- ***Order 2222* Compliance Orders (23-1167, 23-1168, 23-1169, 23-1170, 23-1335) (consolidated)**
  Case Title: Eversource Energy Service Company v. FERC
  Underlying FERC Proceeding: ER22-983[143]
  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*.[144] On July 3, 2023, the Court consolidated the cases, with Case No. 23-1667 as the lead case.

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[140] *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*").

[141] Braintree, Concord, Georgetown, Hingham, Littleton (NH), Middleborough, Middleton, Norwood, Pascoag, Reading, Taunton, Wellesley, and Westfield (collectively, the "Eastern New England Consumer-Owned Systems").

[142] *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).

[143] *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*").

[144] 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,

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 had until August 5, 2024 to file motions to govern future proceedings in these consolidated appeals. However, 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". On July 31, 2024, the Court issued an order that these consolidated cases remain in abeyance pending further order of the court. The parties were directed to file motions to govern future proceedings within 90 days of the FERC's issuance of a final order in the ER22-983 proceeding. The FERC was also directed to file status reports at 60-day intervals beginning September 30, 2024. The FERC filed a status report on September 30, 2024 stating that the FERC has not yet issued a final order in ER22-983, and these consolidated appeals should remain in abeyance.

- ***Seabrook* Dispute Order (23-1094, 23-1215) (consolidated)**
  Case Title: NextEra Energy Resources, LLC, et al v. FERC
  Underlying FERC Proceeding: EL21-6, EL 23-3[145]
  Petitioner: NextEra Energy Resources, LLC and NextEra Energy Seabrook, LLC
  Status: Petition for Review Denied; Issuance of Mandate Withheld

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.[146] NextEra subsequently petitioned the Court for review of the June 15, 2023 *Seabrook Dispute Allegheny Order*, which was consolidated with Case No. 23-1094. Oral argument was heard on February 6, 2024 by Judges Millett, Katsas and Rao. On October 4, 2024, in a 2-1 Decision, the Court denied Seabrook's Petition for review,

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.

[145] *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*").

[146] 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.

finding that the "FERC did not exceed its statutory jurisdiction, correctly interpreted the governing tariff and LGIA, and permissibly denied Seabrook compensation for any indirect costs".

- **Mystic II (ROE & *True*-Up) (21-1198 *et al.*) (consolidated)**
  Case Title: Constellation Mystic Power, LLC v. FERC
  Underlying FERC Proceeding: ER18-1639-010, -011,[147] -013[148] -017[149]
  Petitioners: Mystic (21-1198 (lead), 22-1008, 22-1026), CT Parties,[150] (21-1222, 22-1001) MA AG (21-1223), ENECOS (21-1224)
  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 Decisions 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 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***. Since the last Report, Mystic filed an opposed Settlement Agreement that would set the ROE at 9.0% and moot these appeals; Mystic asked for a November 1, 2024 effective date for that Agreement. (*see* Section II, Mystic COSA ROE Settlement Agreement (ER24-2804). On August 14, 2024, Mystic filed an unopposed Settlement Agreement to establish a settled ROE of 9.0% for the Mystic COSA ("Mystic ROE Settlement Agreement") that would, if approved, moot all of the ROE appeals currently pending before the DC Circuit related to that ROE. Mystic requested a November 1, 2024 effective date for the Settlement Agreement).

- ***CASPR* (20-1333, 21-1031) (consolidated)****
  Case Title: Sierra Club, et al v. FERC
  Underlying FERC Proceeding: ER18-619[151]
  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

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[147] *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).

[148] *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).

[149] *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*).

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

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

subsequent *CASPR Allegheny Order*. Appearances, docketing statements, a statement of issues to be raised, and a statement of intent to utilize deferred joint appendix were filed. A motion by the FERC to dismiss the case was dismissed as moot by the Court, referred to the merits panel (Judges Pillard, Katsas and Walker), and is to be addressed by the parties in their briefs.

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

- ***Opinion 531-A*** **Compliance Filing Undo (20-1329)**
  Case Title: Central Maine Power Company, et al v. FERC
  Underlying FERC Proceeding: ER15-414[152]
  Petitioners: TOs (CMP et al.)
  Status: Being Held in Abeyance

On August 28, 2020, the TOs[153] 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*[154] decision. On September 22, 2020, the FERC submitted an unopposed motion to hold this proceeding in abeyance for four months to allow for the Commission to "a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the Commission." On October 2, 2020, the Court granted the FERC's motion, and directed the parties to file motions to govern future proceedings in this case by February 2, 2021. On January 25, 2021, the FERC requested that the Court continue to hold this petition for review in abeyance for an additional three months, with parties to file motions to govern future proceedings at the end of that period. The FERC requested continued abeyance because of its intention to issue a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the FERC. Petitioners consented to the requested abeyance. On February 11, 2021, the Court issued an order that that this case remain in abeyance pending further order of the court. On April 21, 2021, the FERC filed an unopposed motion for continued abeyance of this case *because* the Commission intends to issue a future order on Petitioners' request for rehearing of the challenged *Order Rejecting Compliance Filing*, and because the remand proceeding in which the challenged order was issued remains ongoing.

On May 4, 2021, the Court ordered that this case remain in abeyance pending further order of the Court, directing the FERC to file a status 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.

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

[153] 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.

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

- ***Chevron Doctrine* (US Supreme Ct 20-1329)**[155]
  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*.[156] *Chevron*, a landmark and often-cited 1984 decision, required courts to defer to a federal agency's reasonable interpretation of ambiguity in a statute.[157] 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.

[155] *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)).

[156] *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)).

[157] 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."

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