Sebastian Lombardi
Secretary

June 16, 2025

VIA ELECTRONIC MAIL

TO: MEMBERS AND ALTERNATES OF THE NEPOOL PARTICIPANTS COMMITTEE

RE: Supplemental Notice of June 24–26, 2025 NEPOOL Participants Committee Summer Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the NEPOOL Participants Committee Summer Meeting will be held on June 24–26, 2025 at The Wequasset in Harwich, MA. Please see the attached meeting agenda, which is also posted with the meeting materials.

As reflected on the meeting agenda:

- ***Tuesday (Jun 24)***: General NEPOOL business will be conducted on Tuesday, with a planned 10:00 a.m. start. Note that Tuesday's agenda includes the annual markets presentation by the ISO's External Market Monitor.
- ***Wednesday (Jun 25)***: As detailed in the attached agenda, Wednesday morning has been set aside for a plenary session with guest speakers (including a panel discussion).
- ***Thursday (Jun 26)***: On Thursday, modified Sector group meetings scheduled to begin at 8:30 a.m., with times set aside for each group to meet separately with ISO Board members, State Officials, and FERC representatives. ***Please note when and where your modified Sector group is scheduled to meet.***

We understand that everyone planning to attend the Summer Meeting in person is registered for the meeting. If you cannot make the meeting in person, the following dial-in number, to be used only by those who otherwise attend NEPOOL meetings and their approved guests, will be available for the plenary sessions on Tuesday, June 24 and Wednesday, June 25: **866-803-2146; Passcode #7169224.** To join webex, click this link and enter the event password **nepool**.

The NEPOOL reservations block at The Wequasset is full. For those staying at The Wequasset, please note that **the cancellation policy is 1 week prior to the first day of your reservation. If any of your arrangements have changed, including the number of people you registered, please contact Jaki as soon as possible.**

Dress for the Summer Meeting is business casual. Additional information regarding the Summer Meeting is available on the Summer Meeting information page.

We very much look forward to seeing you next week.

Respectfully yours,

/s/
Sebastian Lombardi, Secretary

FINAL AGENDA

TUESDAY, JUNE 24, 2025
10:00 a.m.–5:00 p.m. General Session**
(Grand Pavilion)

1. To approve the draft minutes of the Participants Committee meeting held on May 1, 2025. A copy of the draft May 1 meeting minutes are included with this supplemental notice and posted with the meeting materials. Please provide us with any comments on the draft minutes on or before 5:00 p.m., Thursday, June 19, 2025.

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

3. To receive a Chief Executive Officer (CEO) Report by Gordon van Welie, ISO New England. The CEO Report is included with this supplemental notice and posted with the meeting materials.

4. To receive a Chief Operations Officer (COO) Update from Dr. Vamsi Chadalavada, ISO New England. A copy of the June Report, reflecting a full set of May 2025 operations data, is included with this supplemental notice and posted with the meeting materials.

5. To receive a presentation from Dr. Vamsi Chadalavada on ISO New England's Multi-year Roadmap (Review and Discussion of the ISO's longer-term focus for addressing the pace of change and uncertainty facing the power system). Background materials will be circulated and posted in advance of the meeting.

6. To receive a report on the ISO's preliminary 2026 and 2027 Operating and Capital Budgets by Kelly Reyngold, Controller, ISO New England. The 2026 Budget Presentation is included with this supplemental notice and posted with the meeting materials.

7. To consider and take action, as appropriate, on changes to the Financial Assurance Policy (FAP) (including LC issuer eligibility), and to the forms of Standby Letter of Credit (LC), Security Agreement and Blackrock Control Agreement. Background materials and a draft resolution are included with the supplemental notice and posted with the meeting materials.

7A. To consider, and take action, as appropriate, on the request for a waiver of the NEPOOL Generation Information System (GIS) Operating Rules and the GIS Agreement by Plainfield Renewable Energy LLC. Background materials and a draft resolution are included and posted with this supplemental notice.

8. To receive a report on current matters relating to regional wholesale power and transmission arrangements that are pending before the regulators and the courts.

* 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.

****All start and finish times subject to adjustment.**

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

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

10. FERC Staff Introductions.

11. To receive an External Market Monitor Report by Dr. David Patton, President, Potomac Economics. A presentation with highlights of the EMM's 2024 Annual Assessment of the ISO New England Electricity Markets will be circulated and posted following receipt.

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

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****All start and finish times subject to adjustment.**

WEDNESDAY, JUNE 25, 2025
9:30 a.m.–12:00 p.m.**
(Grand Pavilion)

13. To receive morning keynote remarks.

- **Rebecca Tepper**, Secretary of the Executive Office of Energy and Environmental Affairs for the Commonwealth of Massachusetts

14. Panel Discussion – ***Financing the Power Grid: Investment Challenges & Opportunities***

- Moderator: **Catherine Flax**, ISO New England Board Member
- Panelists:
  - **Susan Nickey**, Executive Vice-President and Chief Client Officer, HASI
  - **Nick Violandi**, Senior Director, Power & Infrastructure, Project Finance, John Hancock
  - **Edwin Stone**, Executive Director, US Project Finance & Infrastructure, CIB Capital Markets

Wednesday afternoon has been set aside for separate meetings and organized networking, as desired.

THURSDAY, JUNE 26, 2025
8:30 a.m.–12:45 p.m.**

Thursday, June 26 has been set aside for separate, modified Sector meetings with individual ISO Board Members, State Officials, and FERC Representatives, as detailed in the Sector meeting schedule included with this agenda.

* 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.

****All start and finish times subject to adjustment.**

22nd Annual
Participants Committee Summer Meeting
Harwich, MA
June 26 Schedule

SECTOR/GROUP	8:30–9:45 a.m.	10:00–11:15 a.m.	11:30 a.m.–12:45 p.m.	11:45 a.m.–2:00 p.m.
Generation / Long	FERC Staff (9:15–9:45) ***(Cape Villa 3)***	State Officials Panel 1 ***(Pavilion 4–5)***	ISO Board Panel 2 ***(Pavilion 3)***	Lunch (All) ***Garden Terrace / Twenty-Eight Atlantic***
Transmission	FERC Staff (8:30–9:00) ***(Cape Villa 3)***	State Officials Panel 2 ***(Cape Villa 1–2)***	ISO Board Panel 1 ***(Pavilion 1–2)***	
Supplier / Short (LSE)	State Officials Panel 1 ***(Pavilion 4–5)***	ISO Board Panel 1 ***(Pavilion 1–2)***	FERC Staff (12:15–12:45) ***(Cape Villa 3)***	
Publicly Owned Entity	ISO Board Panel 1 ***(Pavilion 1–2)***	FERC Staff (10:45–11:15) ***(Cape Villa 3)***	State Officials Panel 2 ***(Cape Villa 1–2)***	
AR	ISO Board Panel 2 ***(Pavilion 3)***	FERC Staff (10:00–10:30) ***(Cape Villa 3)***	State Officials Panel 1 ***(Pavilion 4–5)***	
End User	State Officials Panel 2 ***(Cape Villa 1–2)***	ISO Board Panel 2 ***(Pavilion 3)***	FERC Staff (11:30–12:00) ***(Cape Villa 3)***	
ISO Board Panel 1	Publicly Owned Entity ***(Pavilion 1–2)***	Supplier / Short (LSE) ***(Pavilion 1–2)***	Transmission ***(Pavilion 1–2)***	
ISO Board Panel 2	AR ***(Pavilion 3)***	End User ***(Pavilion 3)***	Generation / Long ***(Pavilion 3)***	
State Officials Panel 1	Supplier / Short (LSE) ***(Pavilion 4–5)***	Generation / Long ***(Pavilion 4–5)***	AR ***(Pavilion 4–5)***	
State Officials Panel 2	End User ***(Cape Villa 1–2)***	Transmission ***(Cape Villa 1–2)***	Publicly Owned Entity ***(Cape Villa 1–2)***	
FERC Staff	Transmission (8:30–9:00) Generation/Long (9:15–9:45) ***(Cape Villa 3)***	AR (10:00–10:30) Publicly Owned (10:45–11:15) ***(Cape Villa 3)***	End User (11:30–12:00) Supplier/Short (LSE) (12:15–12:45) ***(Cape Villa 3)***	

ISO Board Panel 1: Caren Anders, Mike Curran, Craig Ivey, Mark Vannoy, and Gordon van Welie

ISO Board Panel 2: Brook Colangelo, Steve Corneli, Catherine Flax, Cheryl LaFleur, and Mel Williams

State Officials Panel 1: ME PUC Commissioner Carolyn Gilbert, ME PUC Staff Michael Haskell, CT DEEP Deputy Commissioner Joseph DeNicola, MA EOEEA Deputy Secretary Jason Marshall, MA DPU Staff Gregg Wade, NH DOE Staff Dan Phelan, VT PUC Staff Mary Jo Krolewski, NESCOE Staff Jeff Bentz, NESCOE Staff Nathan Forster, NESCOE Staff Shannon Beale, and NECPUC Exec. Dir. George Twigg

State Officials Panel 2: ME PUC Chair Phil Bartlett, ME PUC Commissioner Patrick Scully, CT DEEP Staff Bruce Ho, CT DEEP Staff Josh Walters, MA EOEEA Assistant Secretary Weezie Nuara, MA EOEEA Staff Ashley Gagnon, NH DOE Staff Matt Young, VT DPS Commissioner Kerrick Johnson, NESCOE Staff Sheila Keane, and NESCOE Exec. Dir. Heather Hunt

FERC Staff: Scotia Bennett, Pearl Donohoo-Vallett, Zachary Harris, Eric Jacobi, and Aaron Siskind

v. 2025.06.16

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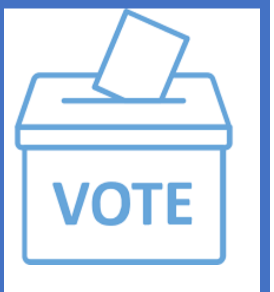
May 1, 2025 Minutes



66.67%

RESOLVED, that the Participants Committee approves the preliminary minutes of the May 1, 2025 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 May 1, 2025 meeting.

PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held beginning at 10:00 a.m. on Thursday, May 1, 2025, at the Renaissance Boston Seaport District in Boston, MA. A quorum, determined in accordance with the Second Restated NEPOOL Agreement, was present and acting throughout the meeting. Attachment 1 identifies the members, alternates and temporary alternates who participated in the meeting, either in person or by telephone/webex.

Ms. Sarah Bresolin, Chair, presided, and Mr. Sebastian Lombardi, Secretary, recorded. Ms. Bresolin welcomed the members, alternates, State officials, and guests who were present. She then informed the Committee that, at the request of Plainfield Renewable Energy, consideration of its GIS-related waiver request would be deferred to a subsequent meeting.

APPROVAL OF APRIL 3, 2025 MEETING MINUTES

Ms. Bresolin referred the Committee to the preliminary minutes of the April 3, 2025 meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of that meeting were unanimously approved as circulated.

CONSENT AGENDA

Ms. Bresolin then referred the Committee to the Consent Agenda that was circulated and posted in advance of the meeting. Following motion duly made and seconded, the Consent Agenda was unanimously approved.

ISO CEO REPORT

In the absence of the ISO Chief Executive Officer, and in light of the fact that there had not been any ISO Board or ISO Board Committee meetings since the April 3 Participants Committee meeting, no CEO report was presented.

ISO CO REPORT

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), began by referring the Committee to his May operations report, which had been circulated and posted in advance of the meeting. Dr. Chadalavada noted that the data in the report was through April 23rd, unless otherwise noted. The May report highlighted: (i) that the Peak Hour for April, with 15,309 MW of Revenue Quality Metered (RQM) Data (including settlement-only generation), occurred on April 8, 2025 during the hour ending 8:00 p.m.; (ii) April averages for Day-Ahead Hub LMP ($43.62/MWh), Real-Time Hub LMP ($41.86/MWh), and natural gas prices ($3.40/MMBtu); (iii) Energy Market value for April 2025 was $331 million, up from $239 million in April 2024 and down from the updated March Energy Market value of $523 million; (iv) Ancillary Services Markets value ($6.6 million) was down from April 2024 ($7.3 million); (v) average Day-Ahead cleared physical energy during the peak hours as a percentage of forecasted load was 99.1% during April (up from 97.2% reported for March 2025); (vi) Daily Net Commitment Period Compensation (NCPC) payments for April totaled $2 million (representing just 0.6% of the monthly Energy Market value), comprised of (a) $1.9 million in First Contingency payments (including $419,000 in Dispatch Lost Opportunity Costs, $156,000 in Rapid Response Pricing Opportunity Costs, and $107,000 paid to resources at external locations), (b) $1,000 in Second Contingency payments, and (c) $129,000 in distribution payments; and (vii) a Forward Capacity Market (FCM) value of $119 million.

Turning to transmission outages, Dr. Chadalavada noted an outage planned for Line 392 (Coopers Mill to Maine Yankee), from April 14, 2025 to May 12, 2025, which was principally related to construction of the New England Clean Energy Connect (NECEC). He said that outage would reduce by 775 MW the transfer capability from New Brunswick to New England and Orrington South by 625 MW. There was also the potential for a month-long outage on Line 398 (Cricket Valley to Long Mountain), related to relay work, scheduled to begin May 6, 2025. Last, he noted an outage on Line 3038 (Buxton to Surowiec South), which was scheduled to be out of service until June 23, 2025. He noted that the Line 3038 would not have any impact on internal interfaces as it would only affect flows going south to north and not north to south.

Dr. Chadalavada then addressed Day-Ahead Ancillary Services (DAAS) market results. He said that daily total Day-Ahead Energy and Ancillary Services Market costs averaged $15 million. Results also included: (i) average daily Gross (pre-closeout) DAAS Credits of $384,000, down from $466,000 in March; (ii) net (post-closeouts) DAAS Credits per MWh Cleared: $229,000; and (iii) $913,000 in Forecast Energy Requirements (FER) credits, which was approximately 6.1% of the total of Day-Ahead Energy and DAAS market value. In addition, the Energy Gap against which the ISO was clearing the energy imbalance reserves was approximately 101 MWh, with an average hourly cleared FER price of $2.97/MWh.

In response to questions on the DAAS data, in particular on FER prices and Energy Imbalance Reserves (EIR) numbers, Dr. Chadalavada noted that the Internal Market Monitor (IMM) would address this topic in more detail at the June Markets Committee meeting. He cautioned members against drawing definitive conclusions too quickly given the availability of just two months' data, though with that caution, he noted the emergence of certain trends that were being more fully explored, and potential explanations for those trends.

Certain members expressed concerns regarding FER and its associated costs. They suggested that FER be monitored to establish whether adjustments were warranted to offset costs. Another member suggested that unobligated offers also needed monitoring. Dr. Chadalavada noted that the report showed offered MW converging between 12,500 – 15,000 GW, which suggested a more constrained actual offer stack.

Other members sought a better understanding of the relationship between Day-Ahead Cleared Physical Demand, Day-Ahead Cleared Load Obligations, ISO forecasts, and actual Real-Time Loads. They felt better explanations and charts of what the basic drivers were, and the changes between the supply and demand relationships relative to the FER charges on a daily and hourly basis could be helpful. Dr. Chadalavada agreed and mentioned that the Internal Market Monitor and Mr. Matthew White, ISO Chief Economist and VP of Market Development and Settlements would be reporting on these topics at future meetings and that additional information would be forthcoming, which several members voiced their appreciation in hearing.

Dr. Chadalavada replied to a member's question that the ISO did conduct an impact assessment on DAAS pricing spanning 2019 through 2021. He explained that as the program was going through the design process, data from those three years were used to develop expectations but that changes on the supply side and on the system are a reflection of what is different currently versus when the impact assessment was done. Dr. Chadalavada informed the Committee that he would follow up at a later date with additional data/information on this issue.

Several members showed their support for the ISO's work on DAAS and thanked Dr. Chadalavada and his the team for their continued reporting efforts. They also encouraged DAAS updates to be more frequent than quarterly or annually. A member added that including the

Revenue Quality Metering Load on the report was extremely informative and requested that the Light Load number also be added to the monthly report.

In response to a suggestion to explore making the Forecast Energy Requirement price a “hedgeable” instrument, Dr. Chadalavada noted the suggestion and said he would follow up internally with the ISO team before circling back. On a separate topic, a member asked if the Pay-for-Performance FAP changes “sandbox” had been made available to Market participants yet and Dr. Chadalavada was able to verify that it was available and open.

CHANGES TO THE AVERAGE BALANCING RATIO (ABR) AND CAPACITY WEIGHTED AVERAGE PERFORMANCE (CWAP) DEFINITIONS

At the request of Mr. Tom Kaslow, the Chair of the Budget & Finance Subcommittee (B&F), Mr. Rosendo Garza, NEPOOL Counsel, summarized the B&F process preceding the ISO’s proposal to update and clarify the Financial Assurance Policy definitions of Average Balancing Ratio (ABP) and Capacity Weighted Average Performance (CWAP), which are used in the determination of FCM Delivery Financial Assurance. Mr. Garza explained that the ISO’s proposed changes removed redundant language and inserted a clarifying clause. He also noted that, although the B&F considered this proposal only once at its April 15, 2025 meeting, the Subcommittee members present agreed that the ISO’s proposal was ready for Participants Committee action.

The following motion was then duly made, seconded and approved unanimously:

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

ORDER 2023 – SECTION 205 RELATED REVISIONS

Mr. Nick Gangi, Transmission Committee (TC) Chair, summarized the stakeholder process for a set of proposed *Order 2023* – Section 205 Related Revisions. He noted that the FERC had issued an order on New England's *Order 2023* Compliance Proposal on April 4, 2025. The Order accepted all dates proposed in the Compliance Proposal including the August 12, 2024 effective date. In order to perform a Transitional Capacity Network Resource ("CNR") Group Study with the 2025 interim reconfiguration auction ("RA") qualification process, and to start other Transitional Studies in the Fall, the ISO has proposed to file narrowly targeted Tariff changes under Section 205 of the Federal Power Act to shift dates associated with the Transitional CNR Group Study and Transitional Cluster Study in 2024 – 2025. ISO indicated that it would request the effective date as the day after the filing. As a result of the expedited stakeholder process required to implement the Transitional CNR Group Study, the TC and Markets Committee ("MC") discussed and voted on the ISO's proposal at one joint TC/MC meeting, held on April 17, 2025. The TC considered revisions through Sections 48, and Schedules 22, 23, and 25 of Section II of the Tariff while the MC considered revisions through Section 3.13 of the Tariff. Before the TC main motion could be voted, an amendment was offered by RENEW Northeast, to shift the late-stage System Impact Study deadline to August 29, 2025 (Amendment). That Amendment passed with 83.3% in favor. The amended main motion was then voted and passed with unanimous support. The ISO's unamended proposal was also voted and passed with only two votes registered in opposition. Separately, the MC unanimously supported minor revisions to Tariff Section 3.13.

Following the April 17 joint TC/MC meeting, the ISO considered the feedback provided and issued a memorandum stating its concerns associated with continuing SISs through August.

The ISO's memo noted at that time that the ISO would include the RENEW Amendment in its filing if approved by NEPOOL. However, at its April 30, 2025 meeting, the Participating Transmission Owners Administrative Committee (PTO-AC) unanimously supported the ISO's unamended proposal but did not support the RENEW Amendment. Because the Participating Transmission Owners share, pursuant to the Transmission Operating Agreement (TOA), certain filing rights with the ISO over portions of the Tariff (including Schedule 22), the PTO-AC's position on the Amendment impacts the ISO's ability to include in a joint Section 205 filing any changes not supported by the PTO-AC.

Ms. Bresolin then requested Mr. Al McBride, ISO-NE VP of System Planning, to comment and answer any questions the Committee might have. Mr. McBride stated that with respect to the RENEW Amendment, the ISO's stance had changed since its earlier memorandum due to the shared filing rights with the PTO-AC and the fact that the PTOs do not support including the Amendment with the filing. Thus, he summarized that the ISO would proceed with its unamended proposal (and without the RENEW Amendment incorporated), and planned to file such proposal with the FERC subsequent to this meeting.

Mr. McBride then turned to clarifying questions. Regarding risks to implementing the compliance filing for *Order 2023* by moving forward with late-stage projects, introducing more interconnection studies in the system would delay ongoing ASO studies. Mr. McBride added that with respect to the RENEW Amendment, there are 10 projects that are in the system impact study phase which is approximately 270 days and that the 10 interconnection customers were part of the original initial filing in May 2024. Mr. McBride further indicated that after ISO's review and based on their experience, it would be unlikely that ongoing studies would finish within the timeframe that is expected. That being said, there are over 12,000 MW of projects that have completed system impact studies which could be ready to move forward to commercial operation and contribute to the regional and capacity transition. He also noted that there would be overlap within the resources that would be working on the SIS studies and ISO personnel resources preparing for *Order 2023* transition.

Responding to a question, Mr. McBride confirmed that the ISO planned to file the next day (May 2) and would be requesting a next-day effective date when they file to permit the ISO to implement the transitional CNR group study.

Several members expressed their frustration and disappointment with the accelerated process and having to vote without having a more advanced notice of the change in circumstances. Others encouraged better real-time communication and increased transparency with respect to future PTO-AC deliberations impacting Tariff proposals before NEPOOL.

Addressing a question posed by a member regarding what the result would be if NEPOOL supported both the amended proposal (with RENEW Amendment included) and the ISO's unamended proposal, Mr. Lombardi explained that consistent with past practice, NEPOOL would likely support both proposals as just and reasonable improvements to the status quo, with any potential of a preference being expressed dependent on the specific vote outcome(s). Mr. Lombardi further clarified that if the Committee affirmatively supports the unamended ISO proposal then he could not see how NEPOOL could protest that proposal in litigation before the FERC.

The motion was then duly made and seconded:

> RESOLVED, that the Participants Committee supports the Section II Revisions, as recommended by the Transmission Committee (including the RENEW Amendment), and as reflected in the materials distributed to the Participants Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair and Vice-Chair of the Transmission Committee.

Further discussion then ensued. Some members expressed sympathy for the difficult situation given implementation timing constraints, remarking that if the unamended proposal is approved by the Committee and filed with FERC, there would at least be some certainty with respect to transitional CNR group study. A representative speaking on behalf of RENEW Northeast addressed some of the concerns members had regarding the RENEW Amendment. She stated that while she understands expressed concerns about the risks, the late-stage system impact study projects have all signed SIS agreements which lay out the obligation of that customer to pay the costs incurred by ISO and the participating transmission owner and that these SIS agreements are not changed by FERC's April 4, 2025 Order. The RENEW representative further explained that the RENEW Amendment was consistent with ISO's underlying *Order 2023* proposal which laid out a transition plan (and which NEPOOL supported). That transition plan said ISO would identify ongoing FERC SIS that they projected could be completed by August 30. 2024 and would continue working on those FERC-jurisdictional studies. She pointed out that if developers who were in late-stage studies were forced to start over that they might protest the filing which if there was a protest, it would put anyone with a project in the queue at risk. RENEW's intention, along with other members with the same view, was to vote in favor of both proposals so that the transition to *Order 2023* process goes smoothly.

The motion to support the TC-recommended proposal (with the RENEW Amendment) was then voted and failed to pass, with oppositions noted by: Avangrid, Eversource, National Grid, RI Energy, Versant, Block Island, Braintree, Chester, Clear River, Danvers Elec, Georgetown Municipal, Groveland Electric, Hingham Municipal, Hudson Light & Power, Littleton (MA) Electric, MBTA, Merrimac, Middleborough, Middleton, North Attleborough Electric, Norwood Municipal, Pascoag Utility, Reading Municipal, Stowe (VT) Electric, Taunton Municipal, Village of Hyde Park, Wallingford, Wellesley Municipal, Westfield Gas & Electric, Garland Manufacturing, Hammond Lumber, Shipyard Brewing, Elektrisola, St. Anselm, Z-TECH, Bath Iron Works, Moore Co., Nylon Corp., and High Liner Foods, and abstentions noted by Nautilus, NextEra, VELCO, BP Energy, Cross-Sound, DTE, Galt Power, Mercuria, Castleton, Constellation, Emera, LIPA, Shell Energy, Vistra, Hydro-Quebec, Ashburnham Municipal, Boylston Municipal, Chicopee Municipal, Groton Electric, Holden Municipal, Holyoke Gas & Electric, Hull Municipal, Ipswich Municipal, Ipswich Municipal, Mansfield Municipal, Marblehead Municipal, Paxton Municipal, Peabody Municipal, Princeton Municipal, Russell Municipal, Shrewsbury's Electric, South Hadley Electric, Sterling Municipal, Templeton Municipal, Wakefield Municipal, West Boylston Municipal, MA Municipal, NH Co-Op, VT Electric Co-Op, Conn. Municipal, MDC, Engie, CT OCC, ME Public Advocacy, MA AGO, MA Dept. Capital Management, and RI DPUC.

Without further discussion, the following separate motion to support the MC-Recommended Section II Revisions was then duly made, seconded, and approved unanimously, with abstentions noted by CPV Towantic, Marble River, Shell Energy, and Vistra:

> RESOLVED, that the Participants Committee supports the ***MC-Recommended Section III Revisions***, as reflected in the materials distributed to the Participants Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

Finally, the following motion to support the ISO's unamended revisions to Sections II and III of the Tariff was duly made, seconded, and approved unanimously with abstentions noted by CPV Towantic and Shell Energy:

> RESOLVED, that the Participants Committee supports the ***ISO-Proposed Revisions to Sections II and III***, as reflected in the materials distributed to the Participants Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair and Vice-Chair of the Transmission Committee.

LITIGATION REPORT

Mr. Lombardi referred the Committee to the April 30, 2025 Litigation Report that had been circulated and posted before the meeting. He highlighted that, in addition to the usual reporting, a new section had been added with summaries of recent Presidential Executive Orders related to energy matters and/or that directly implicate the FERC and its regulations. He briefly identified the four Executive Orders summarized in the April 30 Report. Mr. Lombardi encouraged those with questions on any of those Orders, or on any matter in the Litigation report, to reach out to NEPOOL Counsel.

COMMITTEE REPORTS

Markets Committee (MC). Mr. Ben Griffiths, MC Vice-Chair, reported that the next MC meeting would be held for three full days, May 6-8, 2025, at the DoubleTree Hotel in Milford, MA. The May MC meeting would include continued discussion on a number of Capacity Auction Reforms (CAR)-related project topics and tie benefits. He highlighted a presentation scheduled for Tuesday afternoon by a guest speaker, Mr. Mike DeSocio, formerly of the New York ISO (NYISO), who would provide information regarding NYISO's capacity market design and experience, to be followed by a social gathering of MC members.

Reliability Committee (RC). Mr. Bob Stein, RC Vice-Chair, reported that the next RC meeting would be a virtual meeting on May 13, 2025.

Transmission Committee. Mr. Dave Burnham, TC Vice-Chair, reported that the next TC meeting would be held on May 22, 2025, at the DoubleTree Hotel in Westborough, MA. The main item on the agenda would be a vote on the further changes required in response to the FERC's April 4 order on the region's *Order 2023* compliance filing.

Budget & Finance Subcommittee. Mr. Tom Kaslow, B&F Subcommittee Chair, reported that the next B&F meeting would be held virtually on May 9, 2025. He highlighted plans for continued discussion on changes to the Financial Assurance Policy's form of letter of credit. The Subcommittee was likely to be asked to consider amendments to the ISO's proposal and he encouraged those interested to attend.

Membership Subcommittee. Mr. Brad Swalwell, Membership Subcommittee Chair, reported that the next Membership Subcommittee meeting would be held by Zoom on May 12, 2025 and encouraged all those interested to participate and to reach out to him or NEPOOL Counsel for the Zoom information.

ADMINISTRATIVE MATTERS

Mr. George Twigg, NECPUC Executive Director, reminded the Committee that NECPUC's 2025 Annual Symposium would be held May 18-20, 2025 in Mystic, CT. The Symposium would include a working lunch meeting of the Retail On-Demand Response Working Group and a presentation on retail demand response and access to wholesale markets by the technical assistance partners from the Lawrence Berkeley National Laboratory.

Mr. Lombardi reminded those interested and who had not already done so to register through the NEPOOL website and secure accommodations for the June 24-26, 2025 Participants Committee Summer Meeting to be held at The Wequassett in Harwich, Massachusetts.

Ms. Bresolin noted that, because the ISO Board of Directors did not meet in April, there had not yet been a vote on the slate of Board candidates endorsed by the Participants Committee, but that vote was expected to be taken in May, with the Committee apprised of the outcome of that vote promptly thereafter.

There being no other business, the meeting adjourned at 12:44 p.m.

Respectfully submitted,

____
Sebastian Lombardi, Secretary

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN THE MAY 1, 2025 MEETING

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Acadia Center	End User	Joe LaRusso (tel)		
Advanced Energy United	Assoc. Non-Voting		Alex Lawton	
AR Renewable Gen. (RG) Large Group Seat	AR-RG		Aidan Foley	
Ashburnham Municipal Light Plant	Publicly Owned Entity			Brian Forshaw (tel)
AVANGRID (CMP/UI)	Transmission	Alan Trotta	Jason Rauch	
Bath Iron Works	End User			Bill Short
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
Boylston Municipal Light Department	Publicly Owned Entity			Brian Forshaw (tel)
BP Energy Company (BP)	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
Brookfield Energy Trading and Marketing LLC	Supplier	Aleks Mitreski		Abby Krich (item 6)
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity			Brian Forshaw (tel)
CLEAResult Consulting, Inc.	AR-DG			
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	End User	Phelps Turner (tel)		
Constellation Energy Generation (Constellation)	Supplier	Gretchen Fuhr	Bill Fowler (tel)	
CPV Towantic, LLC (CPV)	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
DTE Energy Trading, Inc. (DTE)	Supplier			José Rotger
Durgin and Crowell Lumber Co.	End User			Bill Short
Earthjustice	End User		Ada Statler (tel)	
ECP Companies Calpine Energy Services, LP New Leaf Energy	Generation	Andy Gillespie (tel)		Bill Fowler (tel)
Elektrisola, Inc.	End User			Bill Short
Emera Energy Services	Supplier			Bill Fowler (tel)
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Eversource Energy	Transmission	Vandan Divatia	Dave Burnham	
Environmental Defense Fund	End User			Phelps Turner (tel)
First Point Power, LLC	Supplier	Peter Schieffelin (tel)	Bryan Amaral (tel)	
FirstLight Power Management, LLC	Generation	Tom Kaslow (tel)		
Gabel Associates, Inc.	Supplier	Sarah Yasutake (tel)		
Galt Power, Inc.	Supplier	José Rotger	Jeff Iafrati (tel)	
Garland Manufacturing Company	End User			Bill Short
Generation Bridge Companies	Generation			Bill Fowler (tel)
Generation Group Member	Generation		Abby Krich	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Groton Electric Light Department	Publicly Owned Entity			Brian Forshaw (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			Bill Short
Harvard Dedicated Energy Limited (Harvard)	End User			Stefan Koester;
High Liner Foods (USA) Inc.	End User		Bill Short	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity			Brian Forshaw (tel)
Holyoke Gas & Electric Department	Publicly Owned Entity			Brian Forshaw (tel)
Hudson Light & Power Department	Publicly Owned Entity			Dave Cavanaugh

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN THE MAY 1, 2025 MEETING

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Hull Municipal Lighting Plant	Publicly Owned Entity			Brian Forshaw (tel)
Icetec Energy Services, Inc.	AR-LR	Doug Hurley		
Ipswich Municipal Light Department	Publicly Owned Entity			Brian Forshaw (tel)
Jericho Power LLC (Jericho)	AR-RG	Ben Griffiths	Nancy Chafetz (tel)	
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	
Littleton (NH) Water & Light Department	Publicly Owned Entity		Craig Kieny (tel)	
Long Island Power Authority (LIPA)	Supplier	Bill Kilgoar (tel)		
Maine Power LLC	Supplier	Jeff Jones (tel)		
Maine Public Advocate's Office	End User	Drew Landry		Stefan Koester
Mansfield Municipal Electric Department	Publicly Owned Entity			Brian Forshaw (tel)
Marble River	Supplier		John Brodbeck (tel)	
Marblehead Municipal Light Department	Publicly Owned Entity			Brian Forshaw (tel)
Mass. Attorney General's Office (MA AG)	End User	Jackie Bihrle	Kelly Caiazzo	Jamie Donovan
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Climate Action Network (MCAN)	End User			Abby Krich
Mass. Dept. Capital Asset Management	End User		Paul Lopes (tel)	Nancy Chafetz (tel)
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity			Brian Forshaw (tel)
MDC – The (CT) Metropolitan District	Publicly Owned Entity		Dave Cavanaugh	
Mercuria Energy America, LLC	Supplier			José Rotger
Merrimac Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Moore Company	End User			Bill Short
Natural Resources Defense Council	End User	Claire Lang-Ree		
Nautilus Power, LLC	Generation		Bill Fowler (tel)	
New England Power (d/b/a National Grid)	Transmission	Tim Brennan (tel)	Tim Martin	
New England Power Gens. Assoc. (NEPGA)	Assoc. Non-Voting			Molly Connors
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 Business Marketing	Supplier		Pete Fuller (tel)	
Nylon Corporation of America	End User			Bill Short
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Pawtucket Power Holding Company	Generation	Dan Allegretti		
Paxton Municipal Light Department	Publicly Owned Entity			Brian Forshaw (tel)
Peabody Municipal Light Department	Publicly Owned Entity			Brian Forshaw (tel)
PowerOptions	End User			Stefan Koester
Princeton Municipal Light Department	Publicly Owned Entity			Brian Forshaw (tel)
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
RENEW Northeast, Inc.	Assoc. Non-Voting	Francis Pullaro		
Rhode Island Division (DPUC)	End User	Linda George		
Rhode Island Energy (Narragansett Electric Co.)	Transmission	Brian Thomson	Robin Lafayette (tel)	
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity			Brian Forshaw (tel)
Saint Anselm College	End User			Bill Short
Shell Energy North America (US) LP	Supplier	Jeff Dannels		
Shipyard Brewing LLC	End User			Bill Short
Shrewsbury Electric & Cable Operations	Publicly Owned Entity			Brian Forshaw (tel)
South Hadley Electric Light Department	Publicly Owned Entity			Brian Forshaw (tel)
Sterling Municipal Electric Light Department	Publicly Owned Entity			Brian Forshaw (tel)

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN THE MAY 1, 2025 MEETING

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
SYSO Inc.	AR-DG	Doug Matheson (tel)		
Tangent Energy	AR-LR	Brad Swalwell (tel)		
Taunton Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity			Brian Forshaw (tel)
The Energy Consortium	End User		Mary Smith (tel)	
Union of Concerned Scientists	End User			Francis Pullaro (tel)
Vermont Electric Company	Transmission	Frank Ettori		
Vermont Electric Cooperative	Publicly Owned Entity	Craig Kieny (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		
Vistra (Dynegy Marketing and Trade, Inc.)	Supplier	Ryan McCarthy		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity			Brian Forshaw (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			Brian Forshaw (tel)
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler (tel)	
ZTECH, LLC	End User			Bill Short

MAY 1, 2025 PARTICIPANTS COMMITTEE MEETING
VOTE ON *ORDER 2023*-RELATED REVISIONS
TC-RECOMMENDED SECTION II REVISIONS (INCLUDING THE RENEW AMENDMENT)

TOTAL

Sector/Group	Vote
GENERATION	16.667
TRANSMISSION	0.000
SUPPLIER	16.667
ALTERNATIVE RESOURCES	16.667
PUBLICLY OWNED ENTITY	1.923
END USER	7.407
% IN FAVOR	**59.331**

GENERATION SECTOR

Participant Name	Vote
CPV Towantic, LLC	F
ECP Companies	F
Generation Bridge Companies	F
Generation Group Member	F
Granite Shore Power Companies	F
Nautilus Power, LLC	A
NextEra Energy Resources, LLC	A
Pawtucket Power Holding Co.	F
IN FAVOR (F)	6
OPPOSED (O)	0
TOTAL VOTES	6
ABSTENTIONS (A)	0

ALTERNATIVE RESOURCES SECTOR

Participant Name	Vote
Renewable Generation Sub-Sector	
ENGIE Energy Marketing NA, Inc.	A
H.Q. Energy Services (U.S.) Inc.	F
Jericho Power LLC	F
Wheelabrator/Macquarie	F
Large RG Group Member	F
Distributed Gen. Sub-Sector	
SYSO Inc.	F
Load Response Sub-Sector	
Icetec Energy Services, Inc.	F
Tangent Energy Solutions, Inc.	F
Vermont Energy Investment Corp.	F
IN FAVOR (F)	8
OPPOSED (O)	0
TOTAL VOTES	8
ABSTENTIONS (A)	1

TRANSMISSION SECTOR

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

SUPPLIER SECTOR

Participant Name	Vote
BP Energy Company	A
Brookfield Renewable Trading & Mktg	F
Constellation Energy Generation	A
Cross-Sound Cable Company	A
DTE Energy Trading, Inc.	A
Emera Energy Companies	A
Gabel Associates, Inc.	F
Galt Power, Inc.	A
LIPA	A
Maine Power, LLC	F
Marble River, LLC	F
Mercuria Energy America, Inc	A
NRG Business Marketing, LLC	F
Shell Energy North America (US) LP	A
Vistra (Dynegy Marketing and Trade, Inc.)	A
IN FAVOR (F)	5
OPPOSED (O)	0
TOTAL VOTES	5
ABSTENTIONS (A)	10

ATTACHMENT 2

MAY 1, 2025 PARTICIPANTS COMMITTEE MEETING
VOTE ON *ORDER 2023*-RELATED REVISIONS
TC-RECOMMENDED SECTION II REVISIONS (INCLUDING THE RENEW AMENDMENT)

END USER SECTOR

Participant Name	Vote
Acadia Center	F
Bath Iron Works	O
Conn. Office of Consumer Counsel	A
Conservation Law Foundation	F
Earthjustice	F
Elektrisola, Inc.	O
Environmental Defense Fund	F
Garland Manufacturing Co.	O
Hammond Lumber Co.	O
Harvard Dedicated Energy Limited	F
High Liner Foods	O
Maine Public Advocate Office	A
Mass. Attorney General's Office	A
Mass. Climate Action Network	F
Mass. Dept. of Capital Asset Management	A
Moore Company	O
Natural Resources Defense Council	F
NH Office of Consumer Advocate	A
Nylon Corporation	O
PowerOptions, Inc.	F
Rhode Island Div. of Public Utilities Carriers	A
St. Anslem	O
Shipyard Brewing Co.	O
The Energy Consortium	F
Union of Concerned Scientists	F
Z-TECH, LLC	O
IN FAVOR (F)	8
OPPOSED (O)	10
TOTAL VOTES	18
ABSTENTIONS (A)	6

PUBLICLY OWNED ENTITY SECTOR

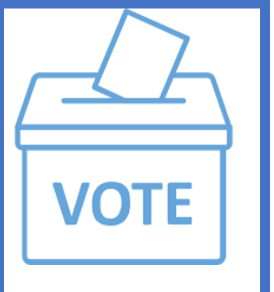
Participant Name	Vote
Ashburnham Municipal Light Plant	A
Belmont Municipal Light Dept.	F
Block Island Utility District	O
Boylston Municipal Light Dept.	A
Braintree Electric Light Dept.	O
Chester Municipal Light Dept.	O
Chicopee Municipal Lighting Plant	A
Concord Municipal Light Plant	F
Conn. Municipal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

PUBLICLY OWNED ENTITY SECTOR (cont.)

Participant Name	Vote
Groveland Electric Light Dept.	O
Hingham Municipal Lighting Plant	O
Holden Municipal Light Dept.	A
Holyoke Gas & Electric Dept.	A
Hudson Light and Power Dept.	O
Hull Municipal Lighting Plant	A
Ipswich Municipal Light Dept.	A
Littleton (MA) Electric Light Dept.	O
Littleton (NH) Water & Light Dept.	A
Mansfield Municipal Electric Dept.	A
Marblehead Municipal Light Dept.	A
Mass. Municipal Wholesale Electric Co.	A
Mass. Bay Transportation Authority	O
MDC – The (CT) Metropolitan District	A
Merrimac Municipal Light Dept.	O
Middleborough Gas and Elec. Dept.	O
Middleton Municipal Electric Dept.	O
New Hampshire Electric Cooperative	A
North Attleborough Electric Dept.	O
Norwood Municipal Light Dept.	O
Pascoag Utility District	O
Paxton Municipal Light Dept.	A
Peabody Municipal Light Plant	O
Princeton Municipal Light Dept.	A
Reading Municipal Light Dept.	A
Rowley Municipal Lighting Plant	F
Russell Municipal Light Dept.	A
Shrewsbury Electric & Cable Operations	A
South Hadley Electric Light Dept.	A
Sterling Municipal Electric Light Dept.	A
Stowe (VT) Electric Dept.	O
Taunton Municipal Lighting Plant	O
Templeton Municipal Lighting Plant	A
Vermont Electric Coop.	A
VT Public Power Supply Authority	A
Village of Hyde Park (VT) Electric Dept.	O
Wakefield Municipal Gas and Light Dept.	A
Wallingford (CT), Town of	O
Wellesley Municipal Light Plant	O
West Boylston Municipal Lighting Plant	A
Westfield Gas & Electric Light Dept.	O
IN FAVOR (F)	3
OPPOSED (O)	23
TOTAL VOTES	26
ABSTENTIONS (A)	27

2

Consent Agenda



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1. GIS Changes (Addition of a Comma-Separated Value Download Via the GIS Transfer Screen Data Pane)
2. Revisions to Tariff Schedules 18 and 24 (*Order 676-K* Compliance Revisions)
3. Revisions to Tariff Section I.2.2 and Schedules 11, 22, 23, and 25 (*Order 2023/2023-A* Further Compliance Revisions)

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

CONSENT AGENDA

Markets Committee (MC)

From the previously-circulated notice of actions of the MC's ***May 6-8, 2025 meeting****, dated May 9, 2025.*[1]

1. **GIS Changes (Addition of a Comma-Separated Value Download Via the GIS Transfer Screen Data Pane)**[2]

   Adopt the changes to the NEPOOL Generation Information System (GIS) related to the addition of the ability to download comma-separated values files from the GIS via the Transfer Screen Data Pane, together with such further non-material 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.

Transmission Committee (TC)

From the previously-circulated notice of actions of the TC's ***May 22, 2025 meeting****, dated May 25, 2024.*[3]

2. **Revisions to Tariff Schedules 18 and 24 (*Order 676-K Compliance* Revisions)**

   Support revisions to Schedules 18 (MTF; MTF Service) and 24 (Incorporation by Reference of NAESB Standards) of Section II of the Transmission, Markets and Services Tariff,[4] in response to the requirements of *Order 676-K*, as recommended by the TC at its May 22, 2025 meeting, together with such further non-material changes as may be approved by the TC Chair and Vice-Chair.

   The motion to recommend Participants Committee support was approved unanimously.

3. **Revisions to Tariff Section I.2.2 and Schedules 11, 22, 23, and 25 (*Order 2023/2023-A Further Compliance Revisions*)**

   Support revisions to Section I.2.2 (Definitions) and Schedules 11, 22 (Large Generator Interconnection Procedures), 23 (Small Generator Interconnection Procedures), and 25 (Elective Transmission Upgrade Interconnection Procedures) of Section II of the Transmission, Markets and Services Tariff, in response to the requirements of the FERC's April 4, 2025 *Order 2023 Compliance Order* (191 FERC ¶ 61,018 (Apr. 4, 2025)), as recommended by the TC at its May 22, 2025 meeting, together with such further non-material changes as may be approved by the TC Chair and Vice-Chair.

   The motion to recommend Participants Committee support was approved unanimously.

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

[2] APX, Inc., the Generation Information System (GIS) Administrator, estimates that implementing this change to the GIS will take 75 development hours. Under Rule 1.3 of the NEPOOL GIS Rules, changes to the GIS that require 50 hours or more of labor must be approved by the NEPOOL Participants Committee.

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

[4] The Further Compliance Revisions also include a non-substantive change to Section III.13.A.2(b) of Market Rule 1 – the inclusion of a clause, reviewed and approved by the Markets Committee at its February 6-7, 2024 meeting, and accepted by the FERC, but inadvertently not included in ISO-NE's base eTariff that otherwise reflected the initial *Order 2023* compliance changes.

3 CEO Report

Jun 24-26, 2025
Summer Meeting

Summary of ISO New England Board and Committee Meetings

June 24, 2025 Participants Committee Meeting

Since the last update, the Audit and Finance Committee, Markets Committee, and the Nominating and Governance Committee met on May 13, and the System Planning and Reliability Committee met on May 14. The Board of Directors met on May 13 and 14. All of the meetings were held in Boston, Massachusetts.

The Audit and Finance Committee reviewed the Company's financial performance against the 2025 budget, and approved the first quarter's unaudited financial statements after management confirmed that all relevant disclosures were included in the financial statements. Next, the Committee discussed the preliminary 2026 operating and capital budgets. The Committee discussed the factors contributing to the increased budgets, including the complexity of various projects. The Committee reviewed a draft of the Company's 2024 tax return on Form 990, and received an update on the Enterprise Resource Planning software upgrade project.

The Markets Committee was provided with a review from both the Internal and External Market Monitors of market performance in winter 2024-2025. Next, the Committee provided final comments on the Internal Market Monitor's draft annual markets report, which assesses the competitiveness of the wholesale markets and reviews market pricing outcomes.

The Nominating and Governance Committee received an update on the conclusion of the Joint Nominating Committee process for 2025 and formally nominated the incumbent directors who are eligible for re-election in 2025 (Catherine Flax, Cheryl LaFleur, and Mel Williams). The Committee also held a preliminary discussion regarding assignments to Board committees and succession planning for board leadership positions, all in advance of the next Board year that begins on October 1, 2025. Next, the Committee drafted a message to the NEPOOL sectors regarding issues that are "top of mind" for the Board, in advance of meetings with the NEPOOL sectors in June. The Committee also discussed ideas to provide to the Compensation and Human Resources Committee to assist with that Committee's planning for a "deep dive" on board culture in September. In executive session, the Committee reviewed the Board and committees' self-evaluation responses.

The System Planning and Reliability Committee was provided with updates on various Orders from the Federal Energy Regulatory Commission related to the status of the Company's compliance efforts with Order No. 2023, Order No. 1920-B, and Order No. 881. The Committee discussed the development of a proposal on Regional Energy Shortfall Threshold metrics and plans for stakeholder review. The Committee also received updates on the Longer-Term Transmission Planning RFP, and discussed the continued exploration of the ISO taking on an Asset Condition Reviewer role.

The Board of Directors received a report from the Chief Executive Officer on current business, and discussed activities related to the Federal Energy Regulatory Commission, federal executive and legislative branches, and the New England states. The Board prepared for the upcoming ISO/RTO Council Conference and NECPUC Symposium, and received reports from the standing committees of the Board. The Board of Directors (acting as the members of the corporation) held its annual meeting of members and elected Mses. Flax and LaFleur and Mr. Williams to the Board of Directors for three-year terms, noting that the slate was previously approved by the NEPOOL Participants Committee at its April 3rd meeting. The meeting then ended with an executive session. The next day, the Board resumed its meeting and conducted an in-depth review of the Company's strategic plan. The Board reviewed detailed reports on a variety of key strategic issues, including diversity, equity and inclusion, and considered initiatives and related resource requirements for 2026. The Board concluded its meeting with an executive session.

4 COO Report – Operations Report Highlights

NEPOOL Participants Committee Report

June 2025

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Regular Operations Report - Highlights

Highlights: May 2025

- **Peak Hour** on May 16
  - 14,633 MW system peak (Revenue Quality Metered/RQM); hour ending 7:00 P.M.
- **Minimum Telemetered Load**
  - 5,451 MW; hour ending 2:00 P.M. on Sunday, May 11
- **Average Pricing**
  - Day Ahead (DA) Hub Locational Marginal Price (LMP): $35.21/MWh
  - Real Time (RT) Hub LMP: $32.77/MWh
  - Natural Gas: $2.55/Mmbtu (MA Natural Gas Avg)
- **Energy Market** value $332M up from $260M in May 2024
  - Ancillary Markets* value $2.6M down from $7M in May 2024
  - Average DA cleared physical energy** during the peak hours as percent of forecasted load was 98.7% during May, down from 98.9% during April
  - Updated April Energy Market value: $400M
- **Net Commitment Period Compensation (NCPC)** total $1.7M
  - Represents 0.5% of monthly Energy Market value
  - First Contingency $1.7M
    - Dispatch Lost Opportunity Cost (DLOC) - $456K; Rapid Response Pricing (RRP) Opportunity Cost - $144K; Posturing - $0; Generator Performance Auditing (GPA) - $0
    - $136K paid to resources at external locations, up $24K from April
      - $104K charged to Day Ahead Load Obligation (DALO) at external locations; $4K to Day Ahead Generation Obligation (DAGO) at external locations; $29K to RT Deviations
  - Distribution $15K ; 2nd Contingency and Voltage were zero
- **Forward Capacity Market (FCM)** market value $119.7M
  - FCM peak for 2025 is currently 19,342 MWh

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

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

Year-to-Date Peak Load* Statistics

- Telemetered System Peak Load: **19,607 MW**
  - hour ending 7:00 P.M. on Wednesday, January 22
- RQM System Peak Load: **19,631 MW**
  - hour ending 7:00 P.M. on Wednesday, January 22
- FCM Peak Load: **19,342 MW**
  - hour ending 6:00 P.M. on Tuesday, January 21
  - At this hour, the capacity zone-level FCM peak loads were 2,761 MW in Northern New England, 1,866 MW in Maine, 7,304 MW in Rest-of-Pool, and 7,411 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.

Day Ahead Ancillary Services (DAAS) Results

- Average daily total DA Energy and Ancillary Services Market value: **$11M**
- DAAS Settlements:
  - Average daily Gross (pre-closeout) DAAS Credits: **$190K**
    - Includes EIR, TMOR, TMNSR, and TMOR
  - Net (post-closeout) DAAS Credits per MWh Cleared: **$0.94/MWh**
  - Net (post-closeout) DAAS Credits as % of total DA E&AS Value: **0.5%**
- FER Credits* as % of total DA Energy and Ancillary Services Market Value: **5.2%**
- Energy Gap:
  - Average hourly cleared EIR MWh: **155 MWh**
  - Average hourly cleared FER Price: **$2.06/MWh**

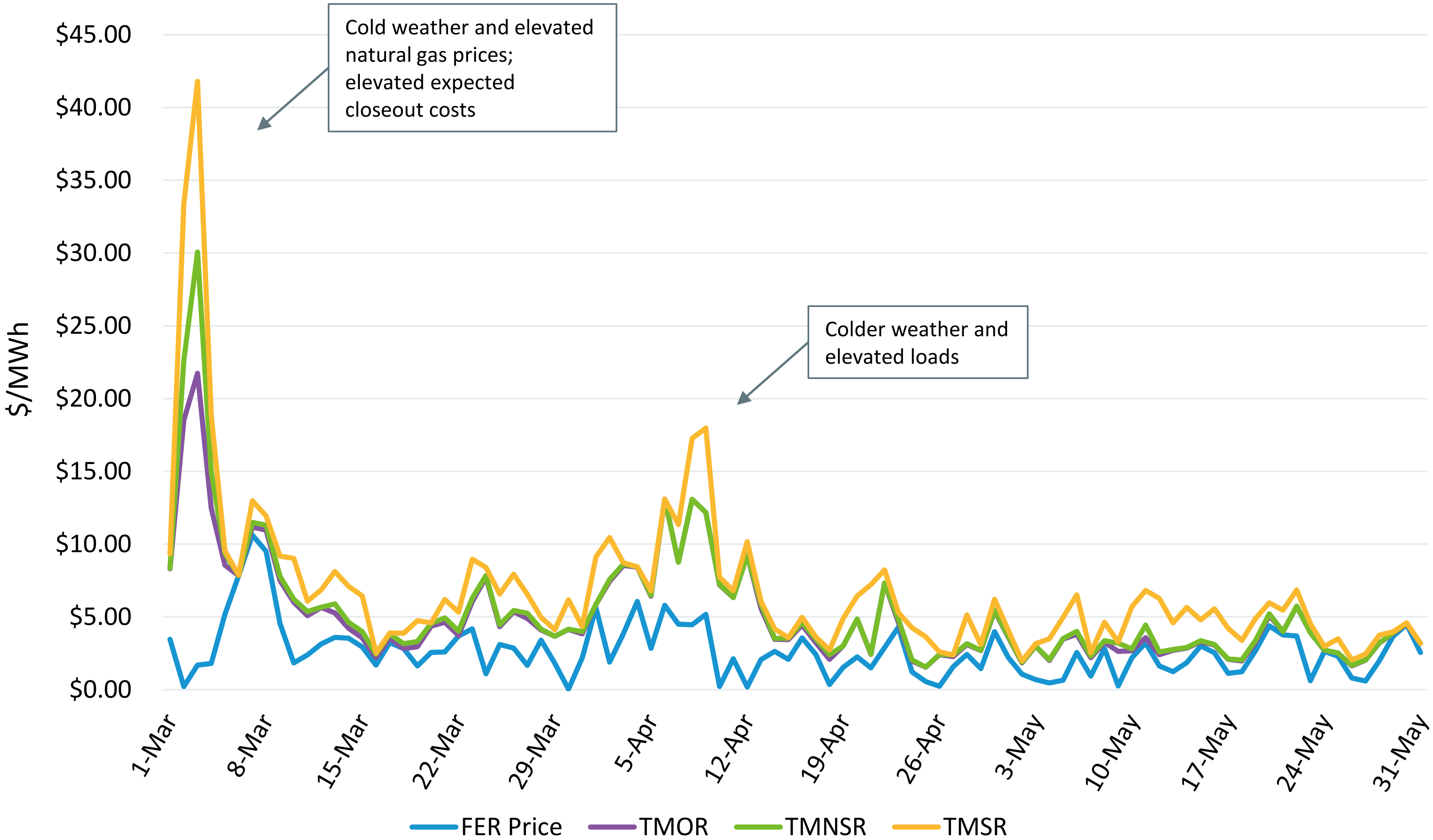
*Forecast Energy Requirements (FER) credits are paid to all DA cleared energy supply from physical resources (Gen, Imports, DRR).
FER credits are allocated to DA Exports and RTLO excluding RTLO associated with RT Exports and Dispatchable Asset Related Demand Resource (DARDs)

Day Ahead Ancillary Services (DAAS) Results

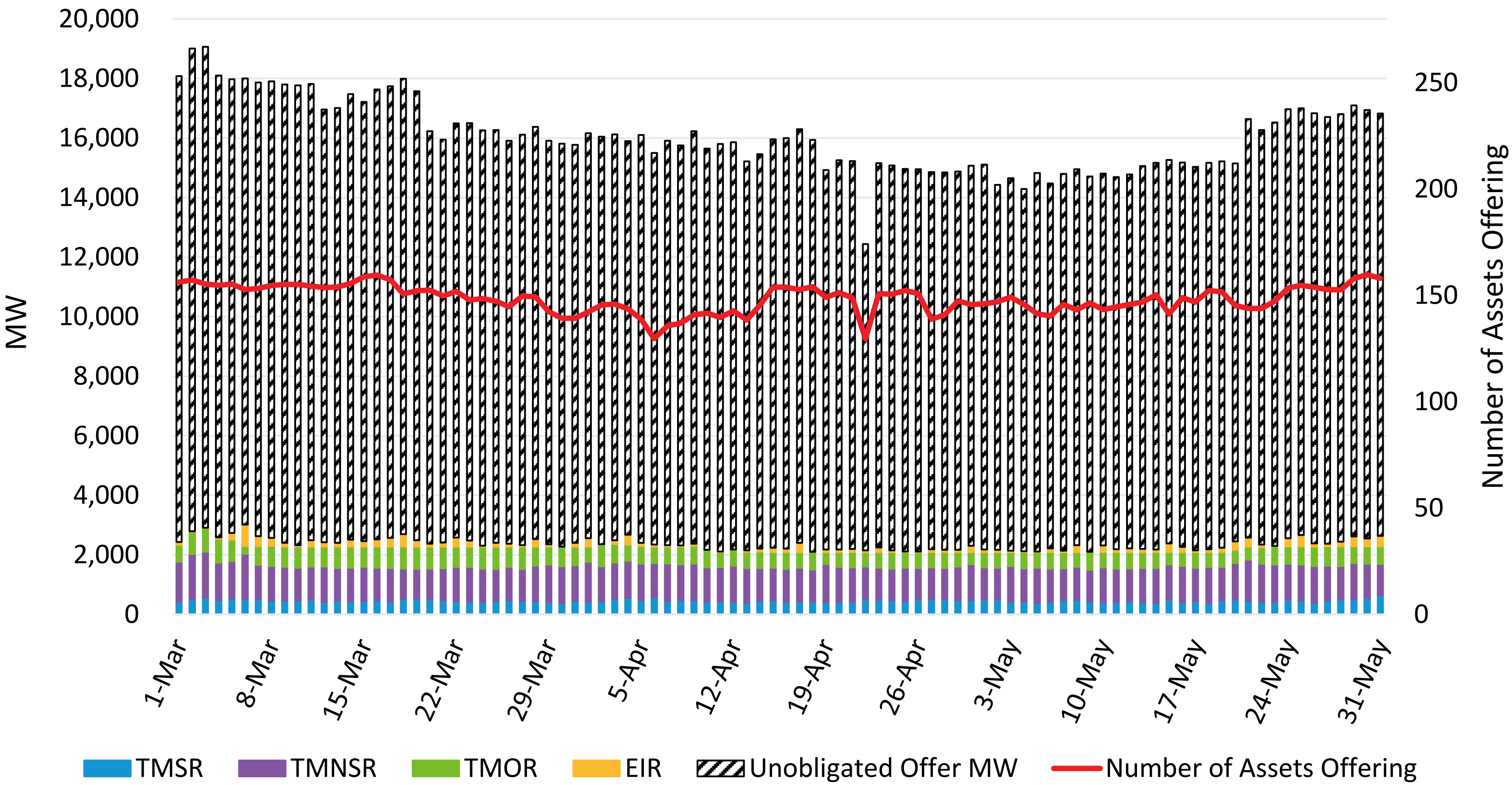
Month	Avg. Daily Total E&AS Credit	Avg. Daily DAAS Credit	DAAS Net Credits (post-closeout)	DAAS Net Credits per MWh Cleared	DAAS Net Credits as % of Total E&AS Credit	FER Credit as % of Total E&AS Credit	Avg. Hourly Cleared EIR Obligation MW	Avg. FER Price
March 25	$17.3M	$466K	$202K	$3.35	1.2%	6.2%	176	$3.26
April 25	$13.9M	$332K	$175K	$3.23	1.3%	5.8%	97	$2.66
May 25	$11.0M	$190K	$52K	$0.94	0.5%	5.2%	155	$2.06

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

Average Hourly Day-Ahead Ancillary Services (DAAS) Prices (March 1st-May 31st)



Average Hourly DAAS Obligated and Unobligated Offer MW*



*Unobligated Offer MW reflect *as-offered* MW that remained unobligated (received no MW reward) and may overstate actual available capacity.

Highlights

- PAC Forum on Grid Enhancing Technologies will take place on June 18 at the Doubletree Westborough
- In response to the April 4, 2025 order on the Order No. 2023 compliance filing, the ISO is targeting narrow date changes that will allow running the Transitional CNR Group Study with the 2025 interim RA qualification process

Forward Capacity Market (FCM) Highlights

- CCP 16 (2025-2026)
  - The third annual reconfiguration auction (ARA3) was held March 3-5 and results were posted on April 1
- CCP 17 (2026-2027)
  - The second annual reconfiguration auction (ARA2) will be held August 1-5 and results will be posted by September 3
- CCP 18 (2027-2028)
  - ICR and related values for the ARAs to be conducted in 2025 were filed with FERC on November 22, 2024; FERC issued an order accepting the results effective January 21
  - The first annual reconfiguration auction (ARA1) will be held June 2-4 and results will be posted by July 3

CCP – Capacity Commitment Period

FCM Highlights, cont.

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

Load Forecast

- A new hourly forecast methodology was implemented as part of CELT 2025, and was discussed at the Load Forecast Committee (LFC)
- Stakeholder discussions related to CELT 2026 will begin in September at the LFC

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (0.8°F) Max: 84°F, Min: 44°F Precipitation: 7.25” - Above Normal Normal: 3.25”	Hartford	Temperature: Above Normal (0.5°F) Max: 85°F, Min: 39°F Precipitation: 8.23” - Above Normal Normal: 3.79”

Peak Load:	14,308 MW	May 16, 2025	20:00 (ending)
Mid-Day Minimum Load:	5,451 MW	May 11, 2025	13:00 (ending)
Mid-Day Minimum Load - Historical:	5,318 MW	April 20, 2025	14:00 (ending)

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

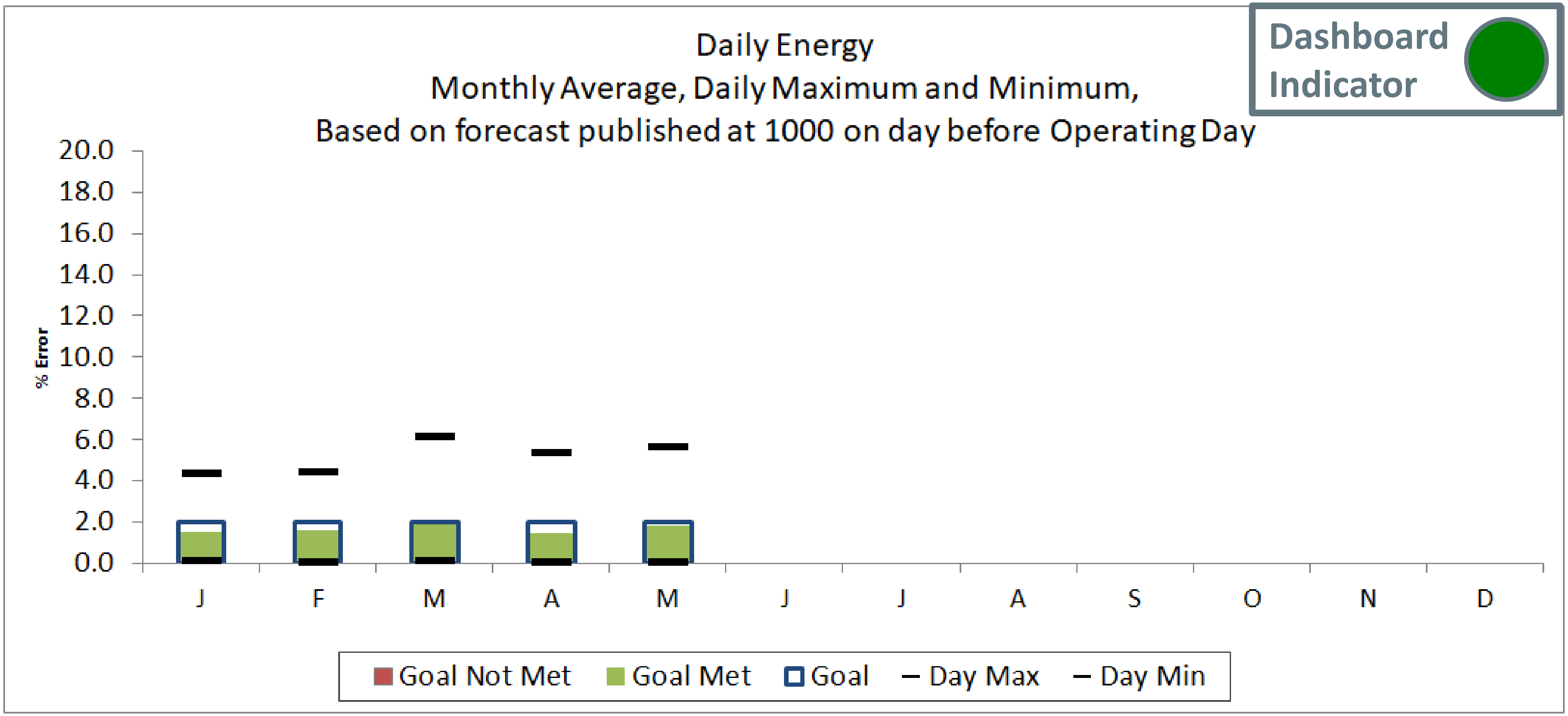
Procedure	Declared	Cancelled	Note
NONE			

System Operations

NPCC Simultaneous Activation of Reserve Events

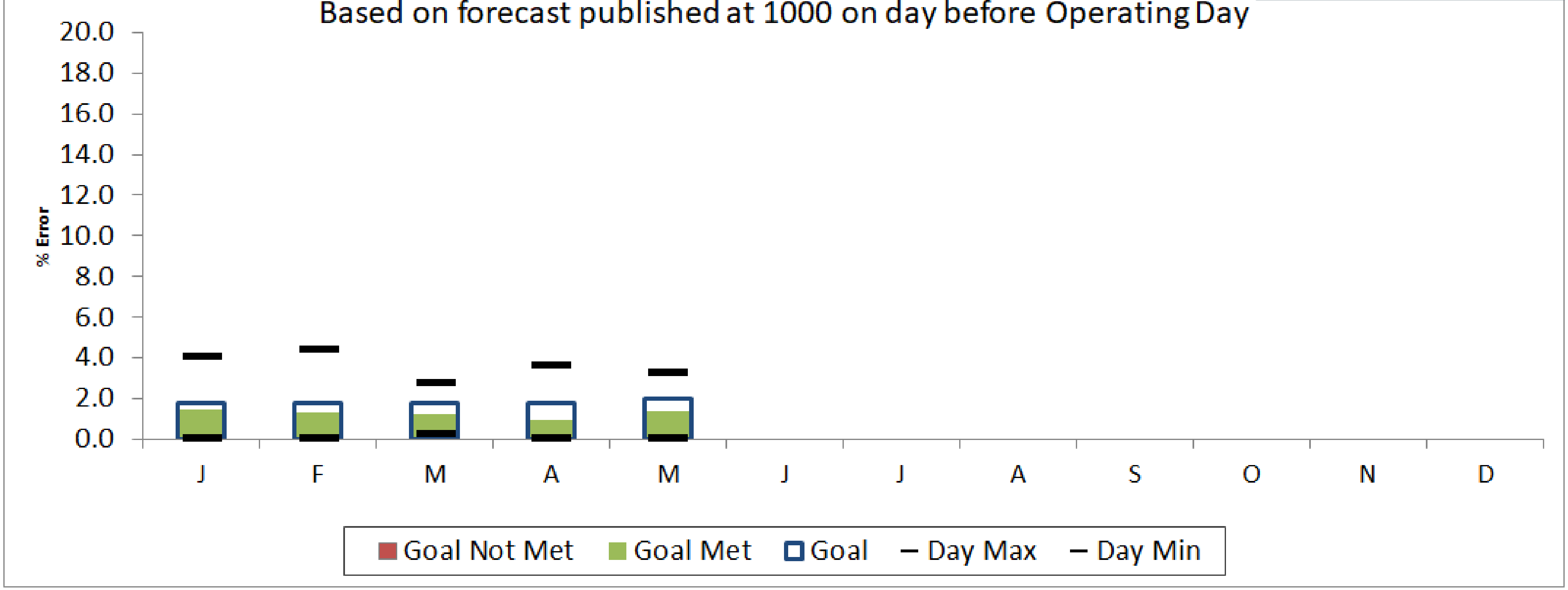
Date	Area	MW Lost
05/12/2025	IESO	1300

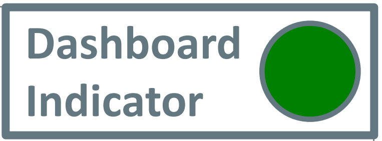
2025 System Operations - Load Forecast Accuracy cont.



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.31	4.44	6.10	5.36	5.61								6.10
Day Min	0.12	0.04	0.12	0.05	0.06								0.04
MAPE	1.54	1.62	1.89	1.45	1.80								1.66
Goal	2.00	2.00	2.00	2.00	2.00								

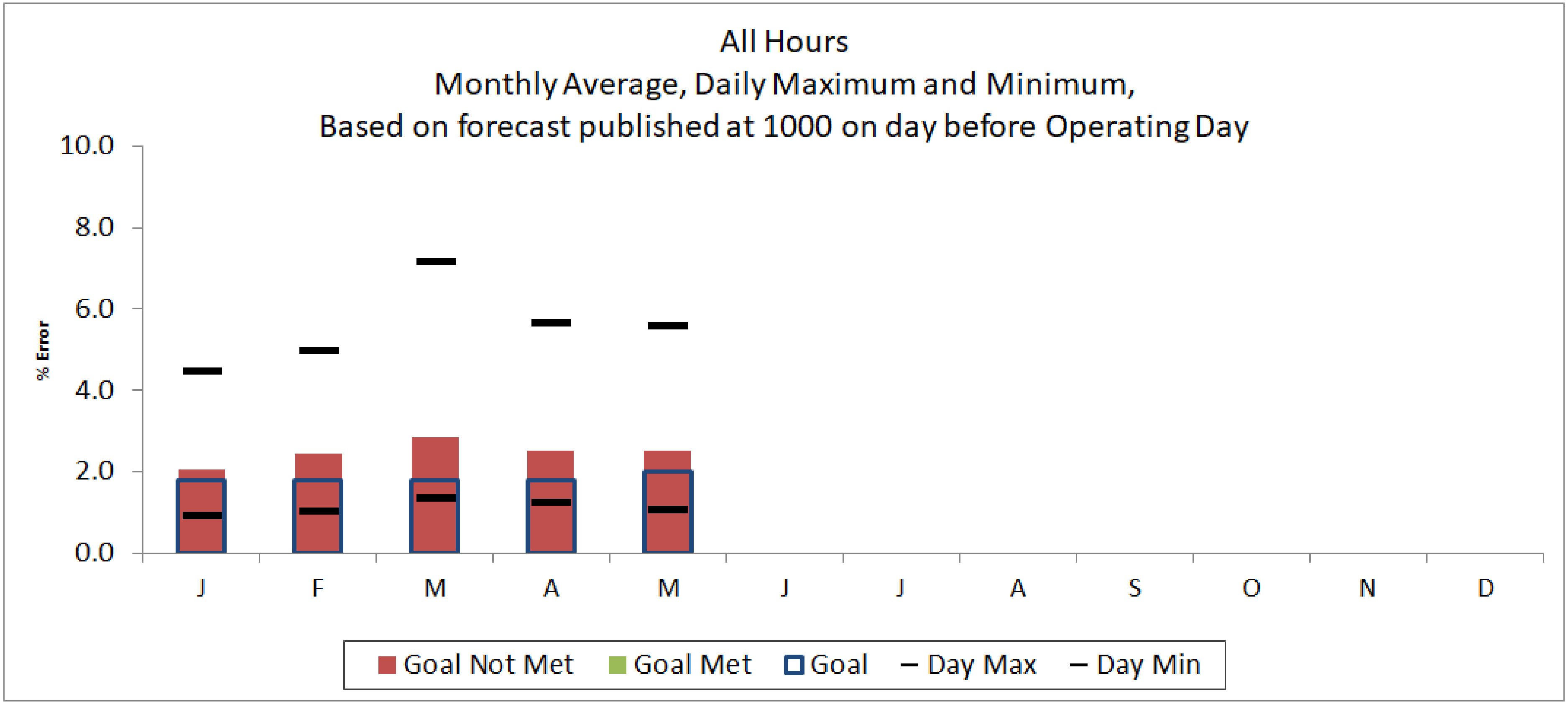
2025 System Operations - Load Forecast Accuracy cont.





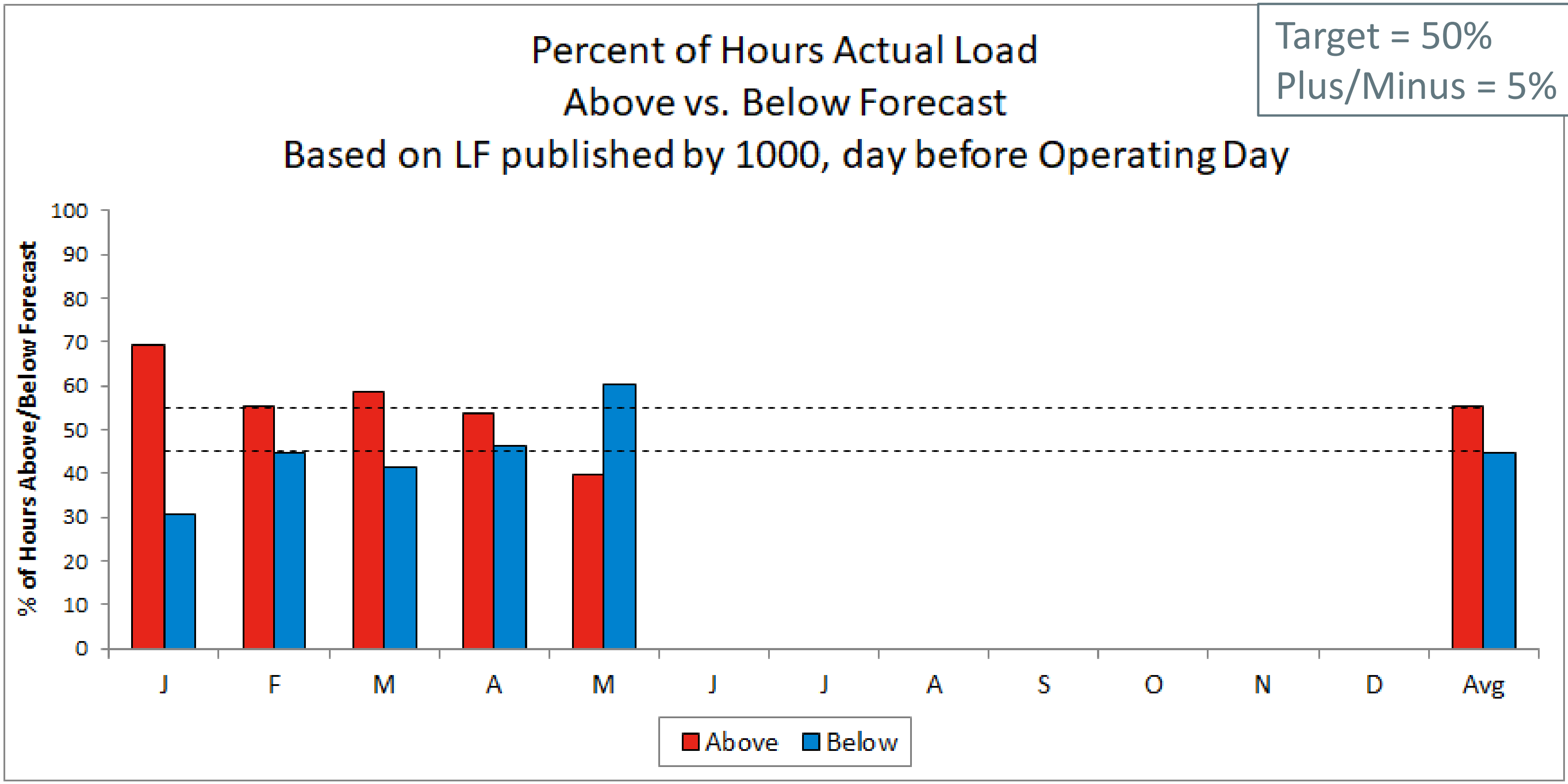
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.04	4.41	2.77	3.63	3.29								4.41
Day Min	0.03	0.06	0.24	0.03	0.06								0.03
MAPE	1.48	1.34	1.29	1.00	1.41								1.30
Goal	1.80	1.80	1.80	1.80	2.00								

2025 System Operations - Load Forecast Accuracy cont.



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.46	4.98	7.13	5.65	5.57								7.13
Day Min	0.90	1.02	1.33	1.23	1.07								0.90
MAPE	2.07	2.47	2.83	2.53	2.53								2.49
Goal	1.80	1.80	1.80	1.80	2.00								

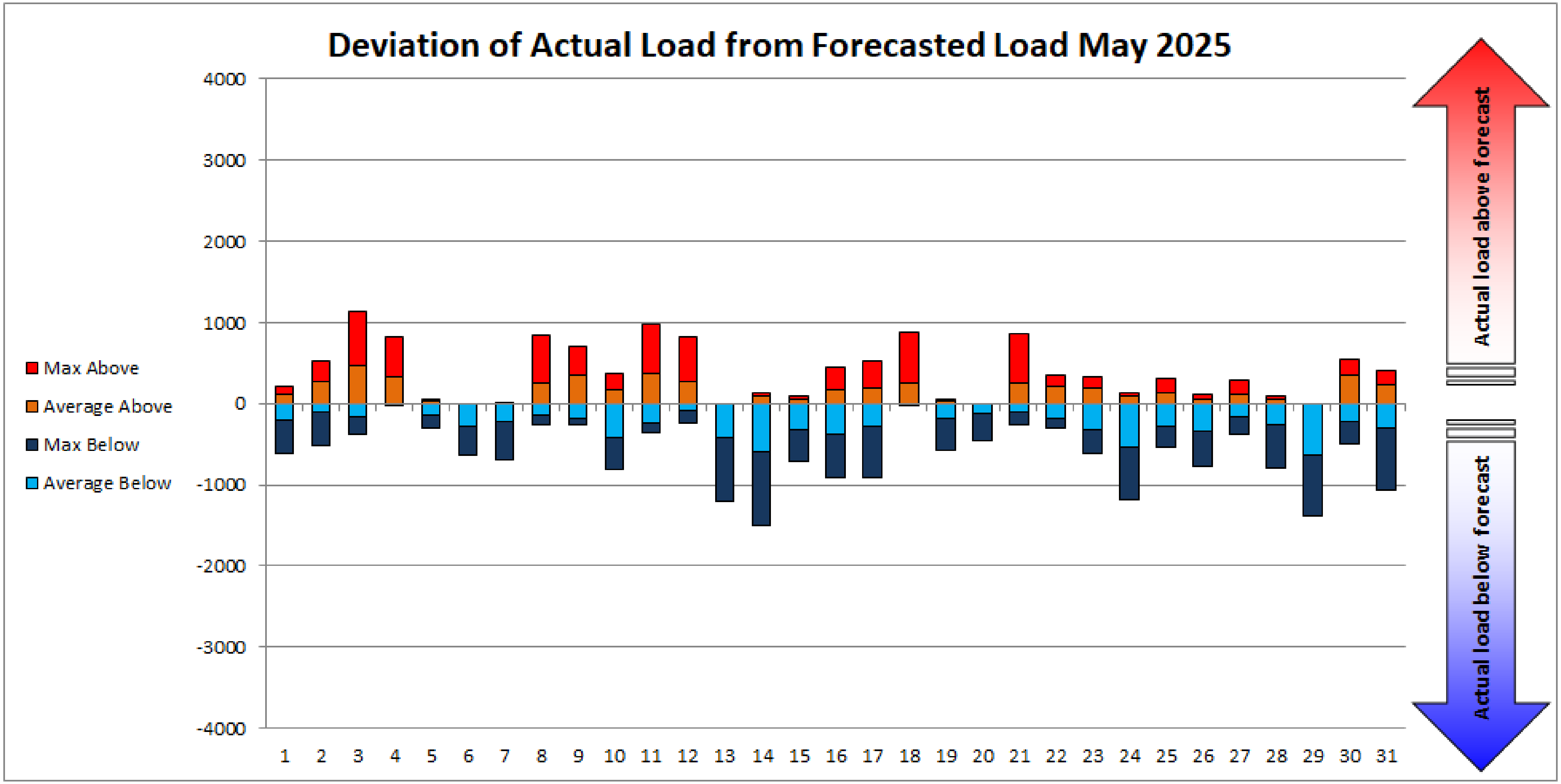
2025 System Operations - Load Forecast Accuracy cont.



Target = 50%
Plus/Minus = 5%

	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	69.2	55.2	58.5	53.5	39.8								55
Below %	30.8	44.8	41.5	46.5	60.2								45
Avg Above	280.5	282.1	246.5	255.8	164.5								282
Avg Below	-178.6	-287.9	-273.2	-190.7	-254.1								-288
Avg All	138	24	12	49	-82								28

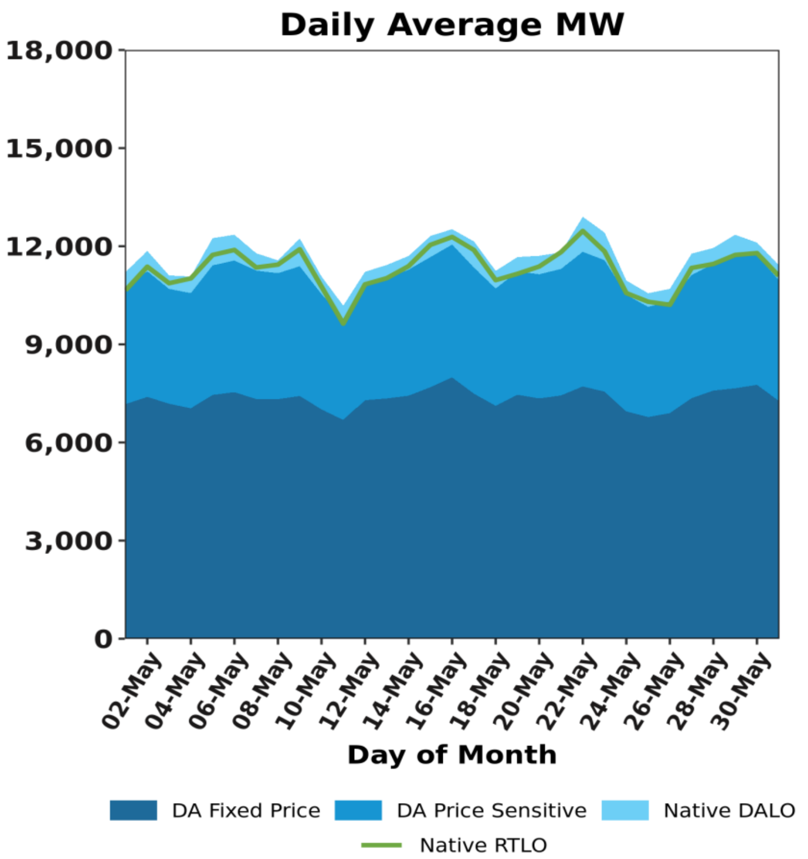
2025 System Operations - Load Forecast Accuracy

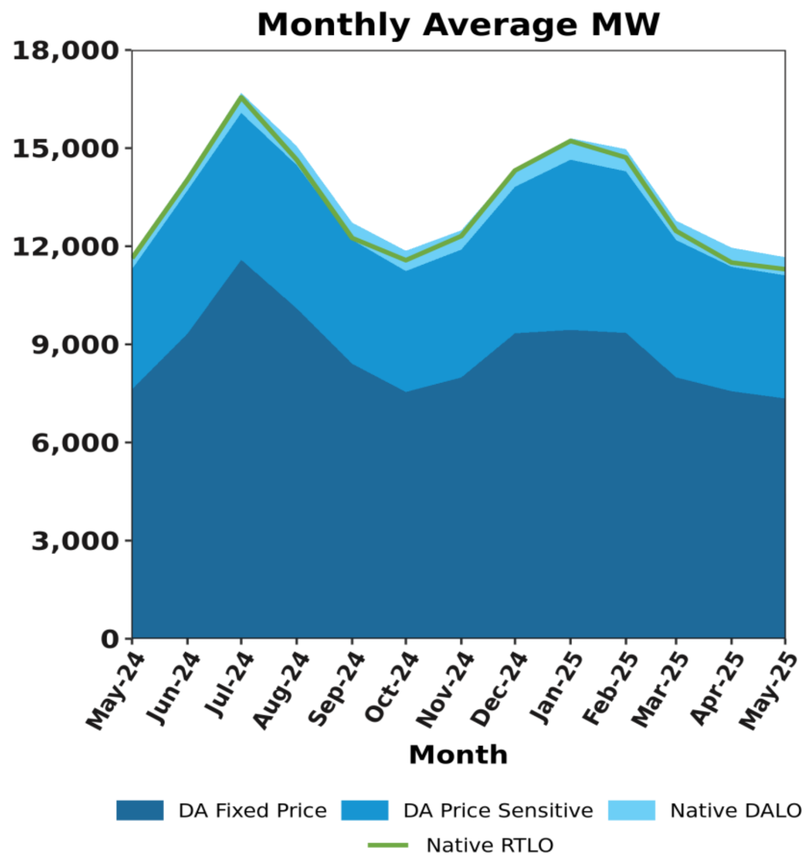


MARKET OPERATIONS

SUPPLY AND DEMAND VOLUMES

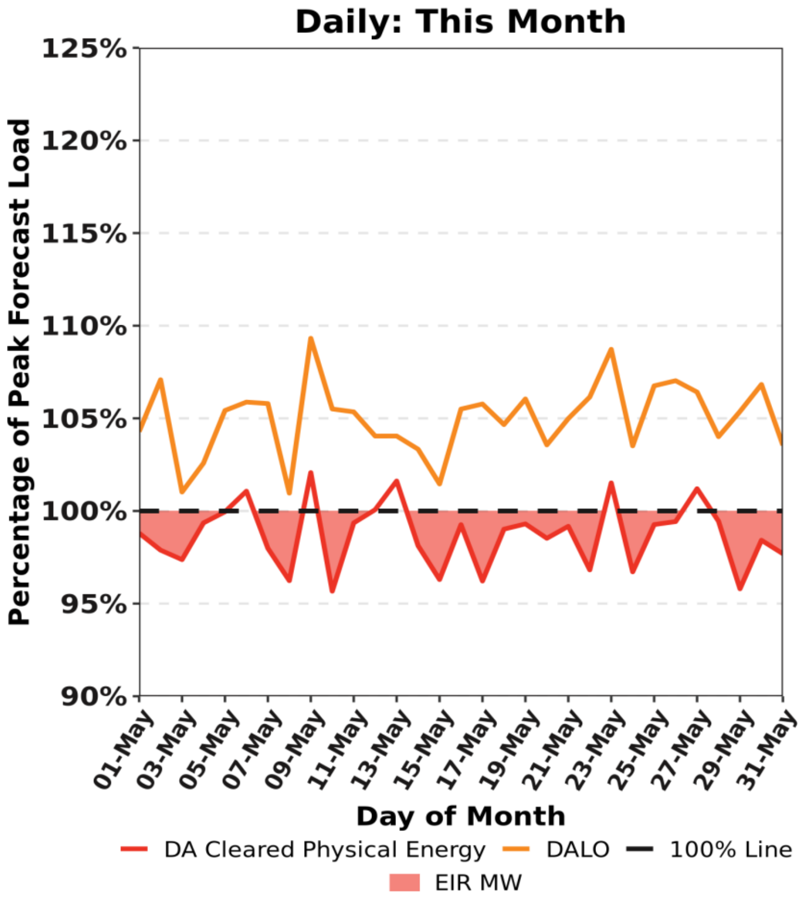
DA Cleared Native Load by Composition Compared to Native RT Load

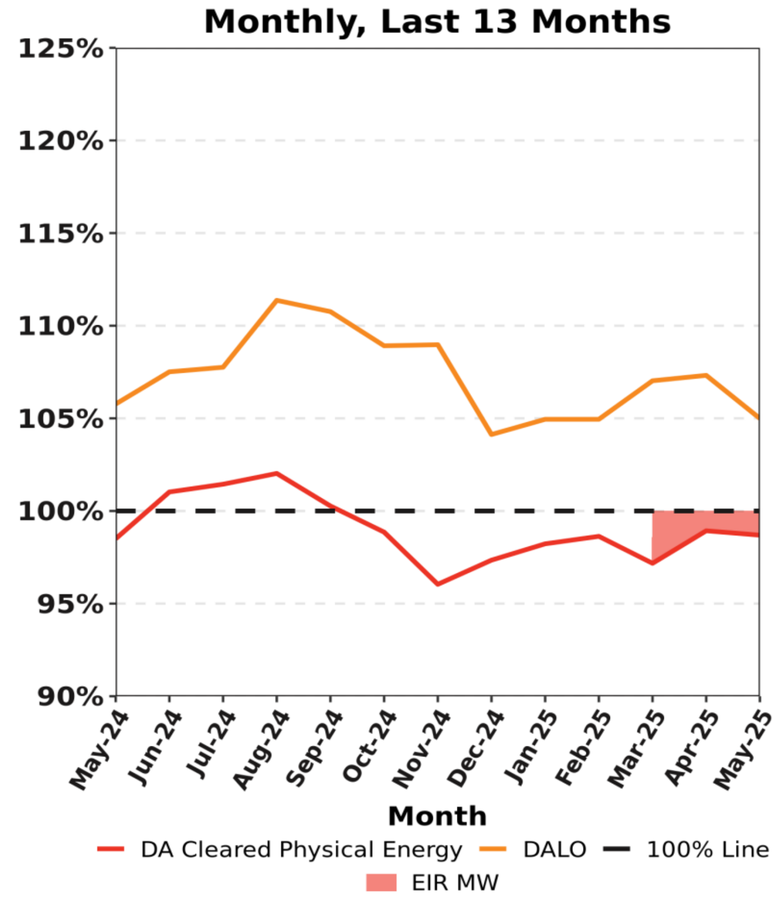




Native Day-Ahead Load Obligation (DALO) is the sum of all internal DA cleared load obligation, including internally cleared decrement bids (DECs). Native Real-Time Load Obligation (RTLO) is the sum of all internal real-time load obligation. Modeled transmission losses and exports are excluded in these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

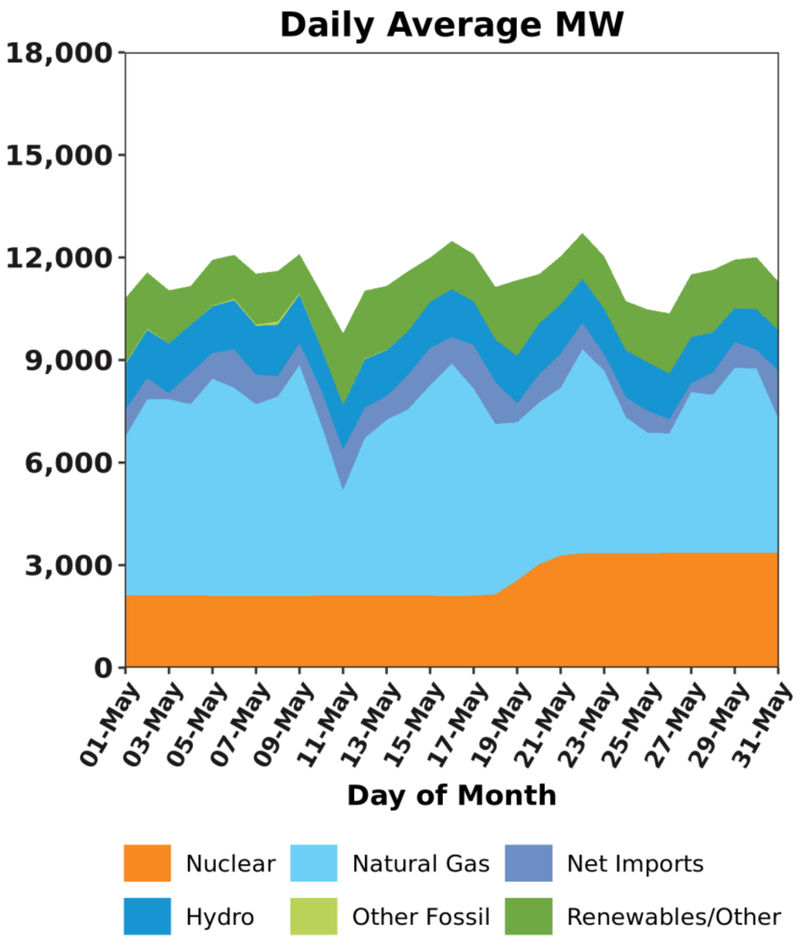
DA Volumes as % of Forecast in Peak Hour

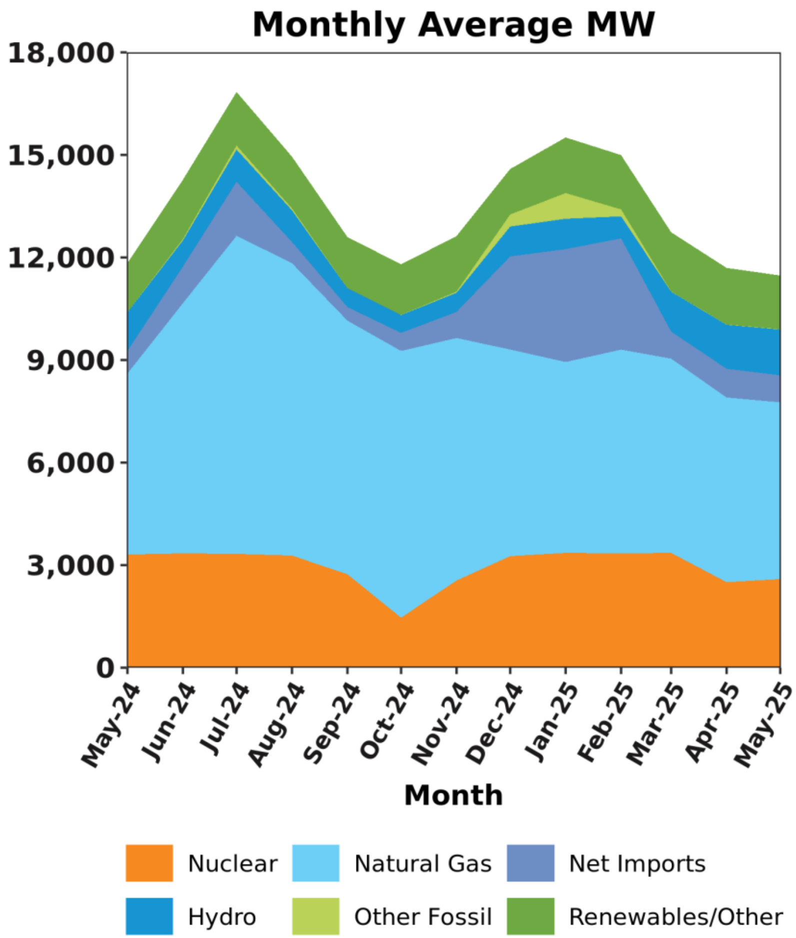




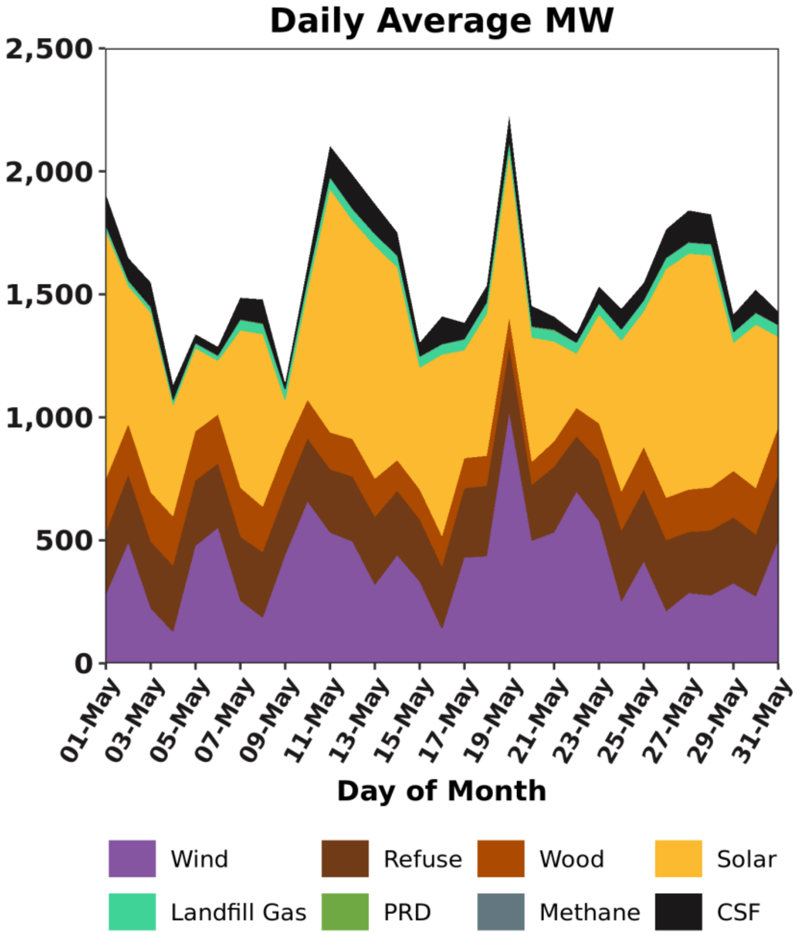
*DA cleared physical energy is the sum of generation, DRR and net imports cleared in the DA Energy Market and does not include EIR MW. Effective March 1, 2025, EIR MW obligations from physical generation and DRR are additionally procured up to (but not exceeding) 100% of the forecasted energy requirement.

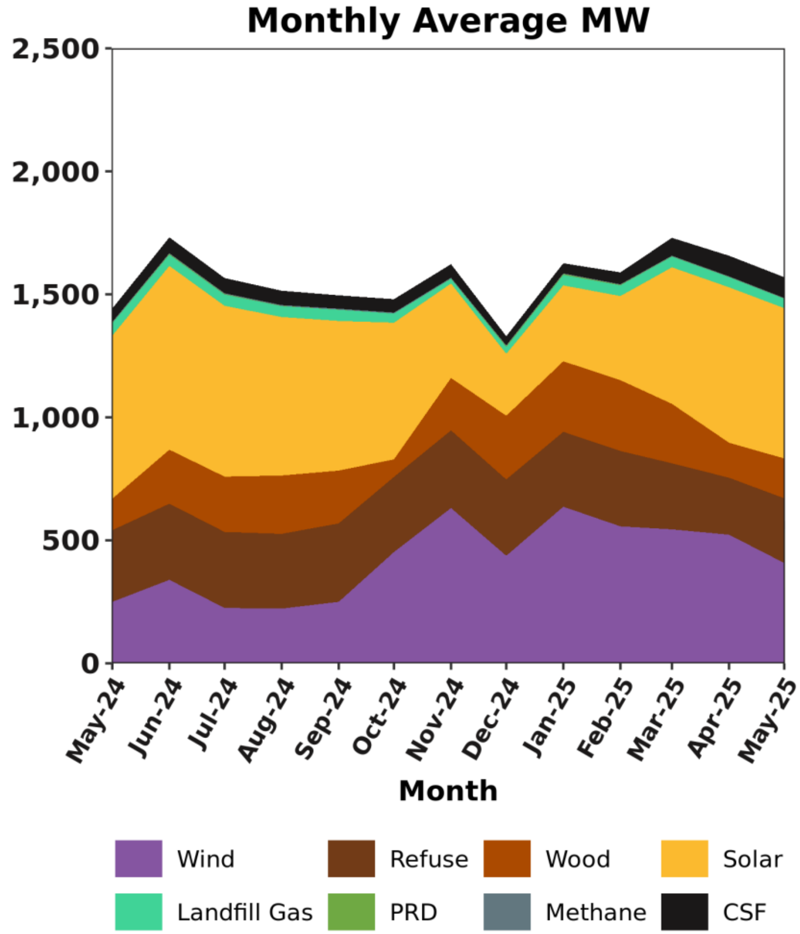
Resource Mix





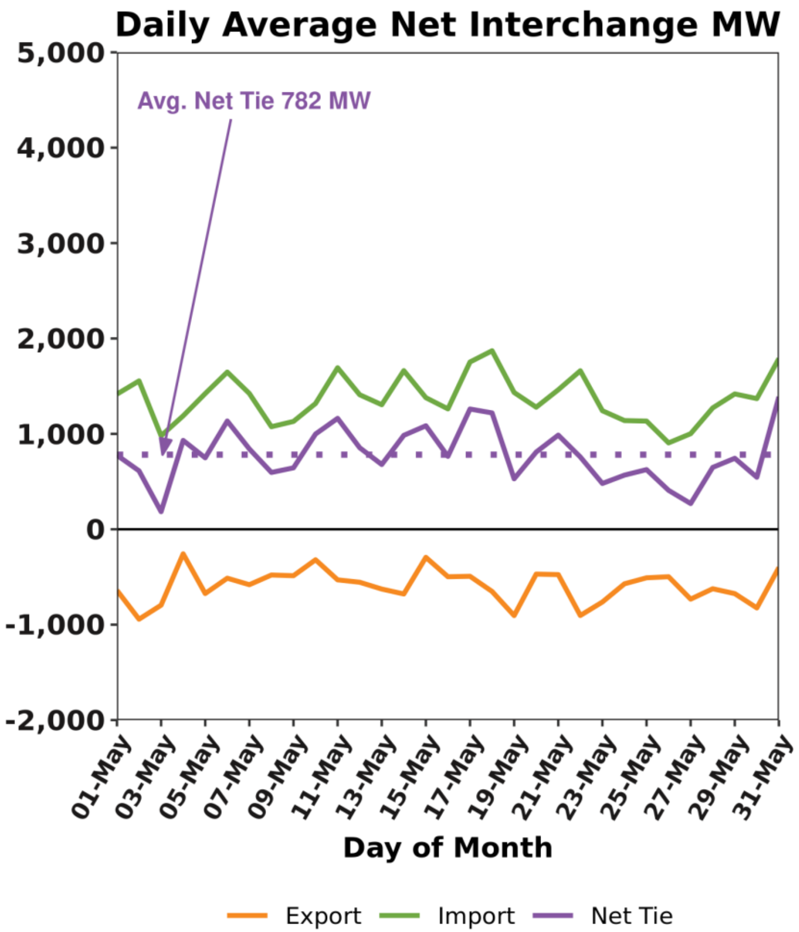
Renewable Generation by Fuel Type

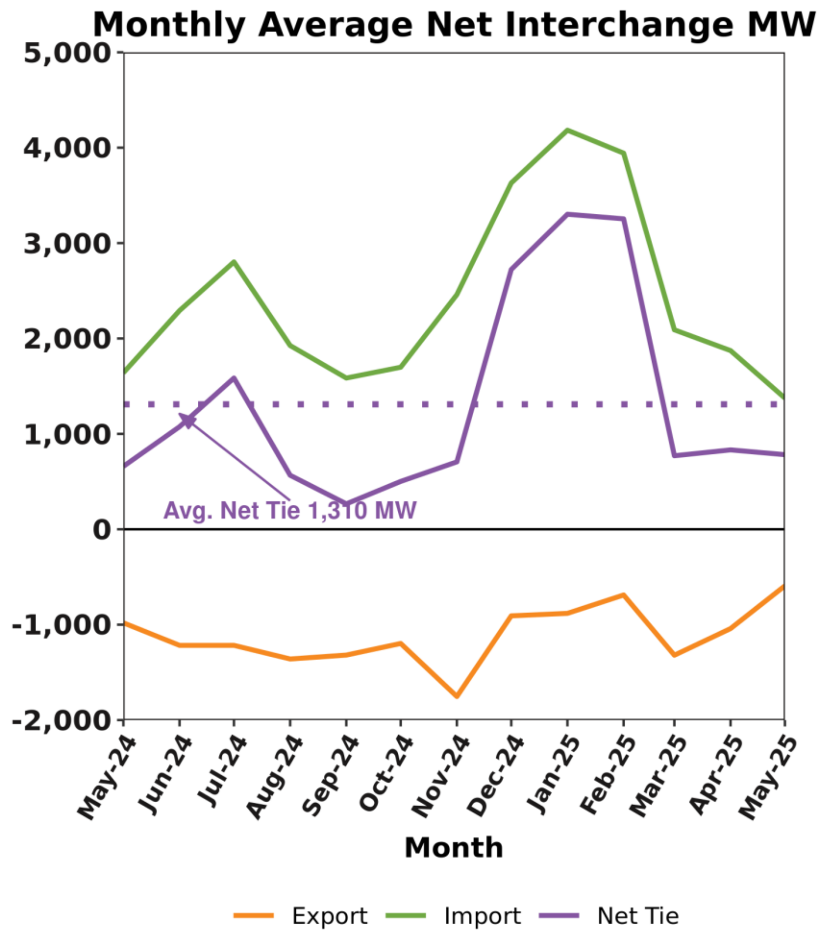




CSF = Continuous Storage Facilities (a.k.a. Batteries)

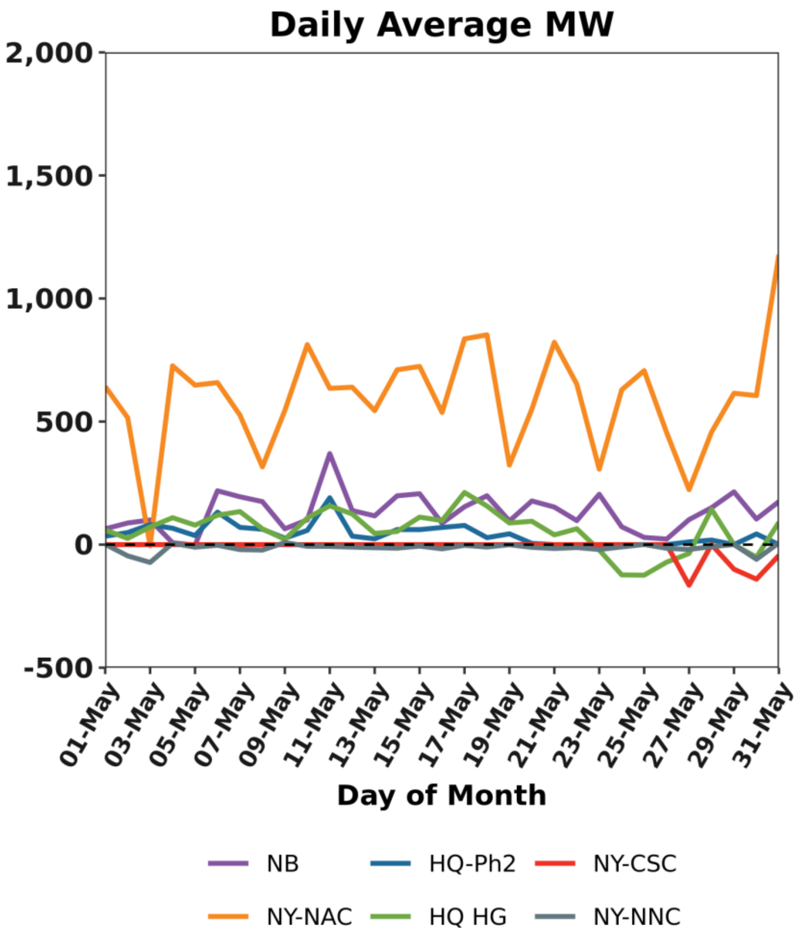
RT Net Interchange

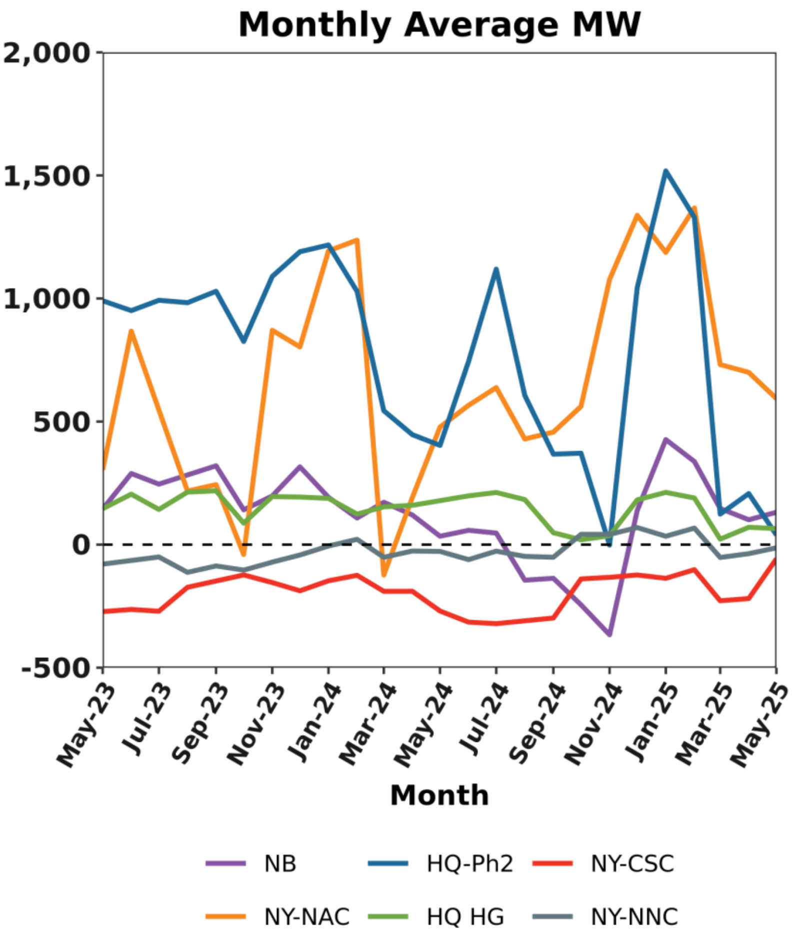




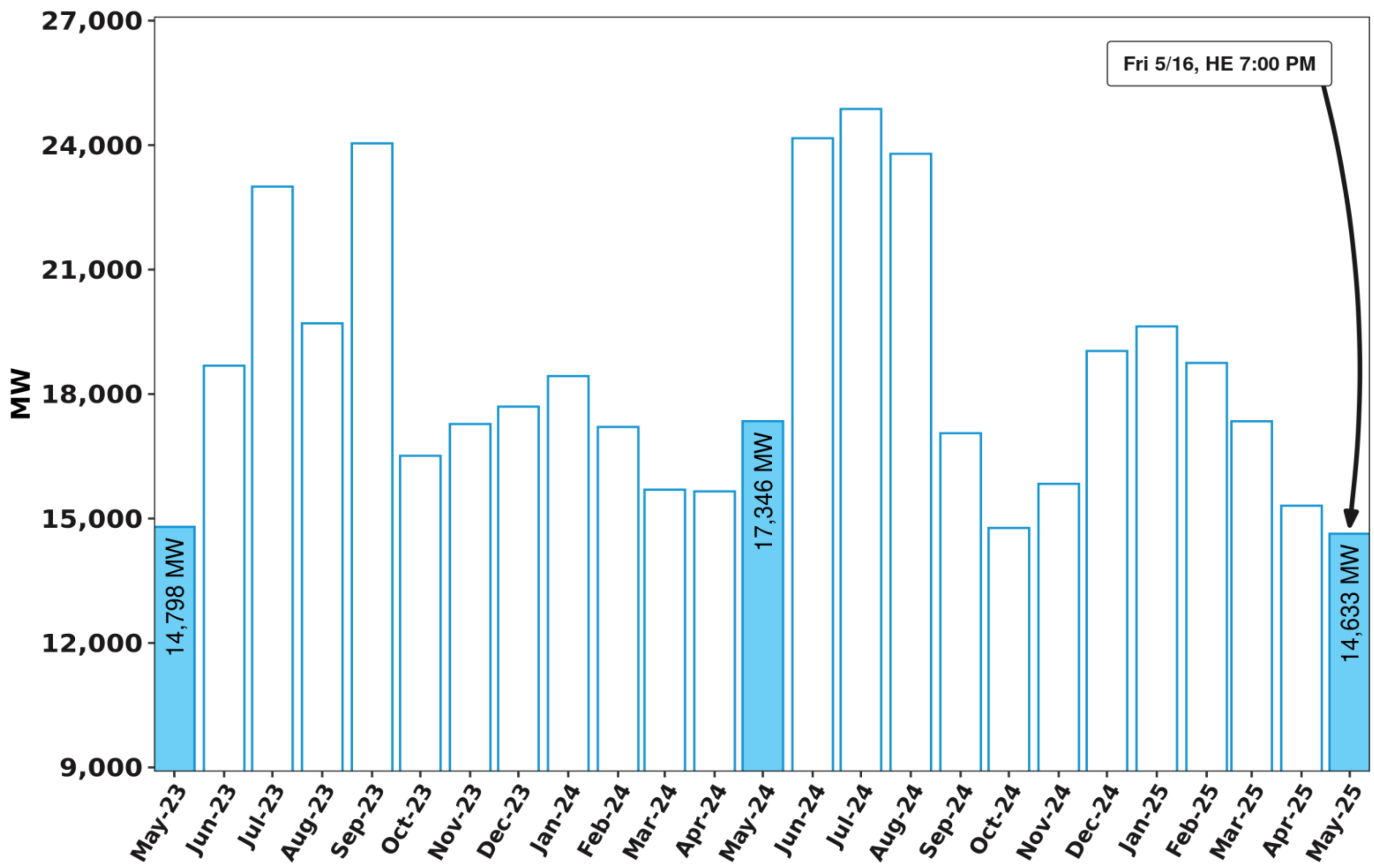
Net Interchange is the net of Participant scheduled imports (+) and exports (-). Inadvertent flows are not reflected

RT Net Interchange by External Interface



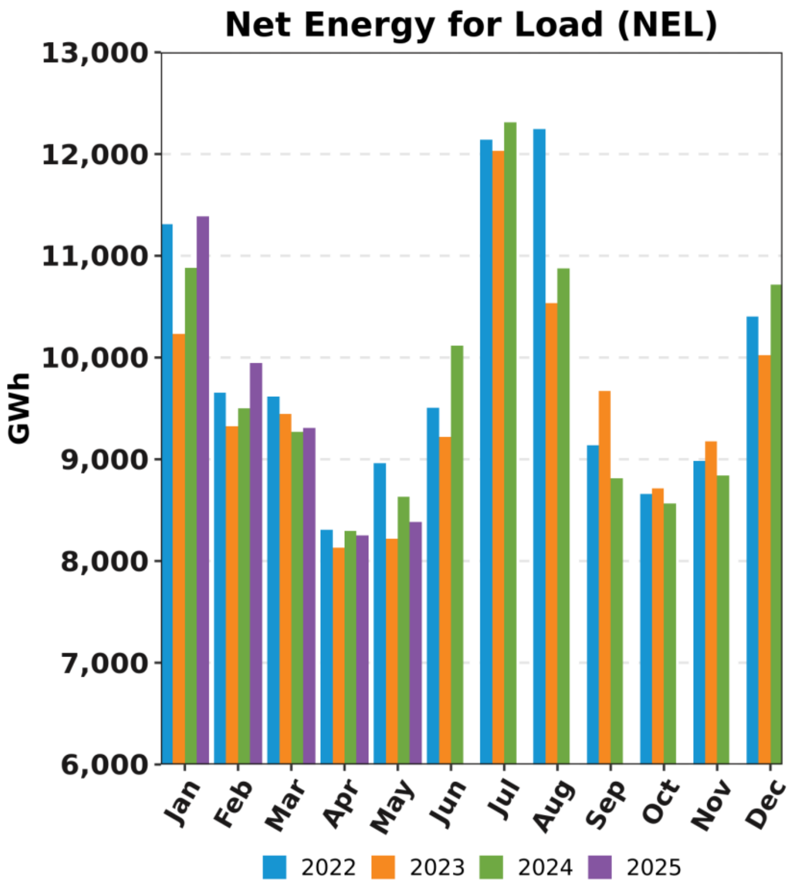


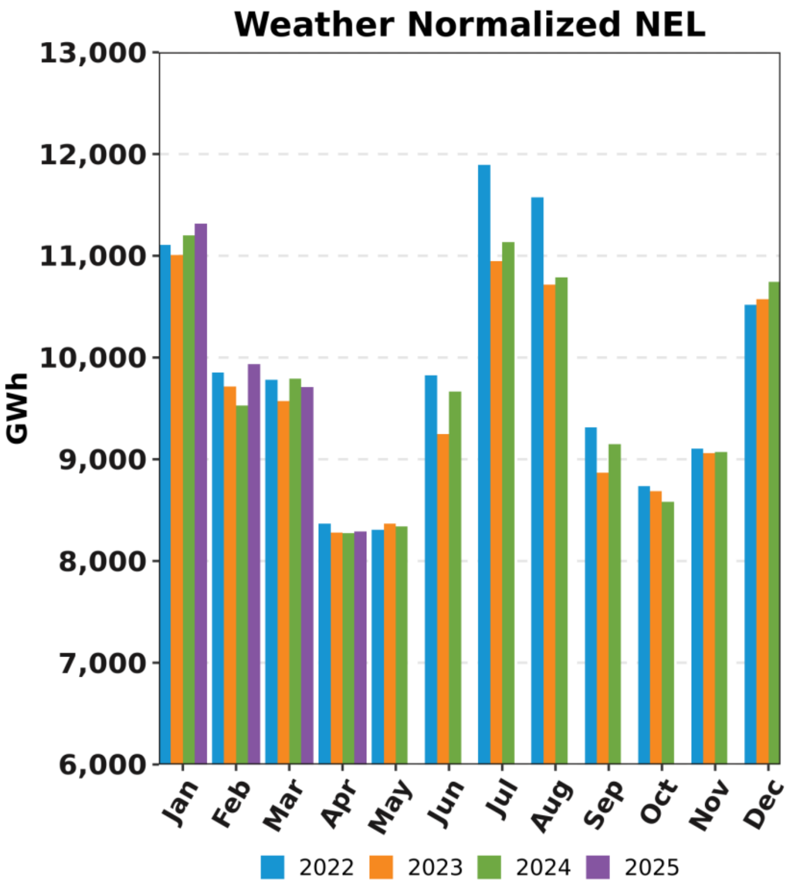
RQM System Peak Load MW by Month



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

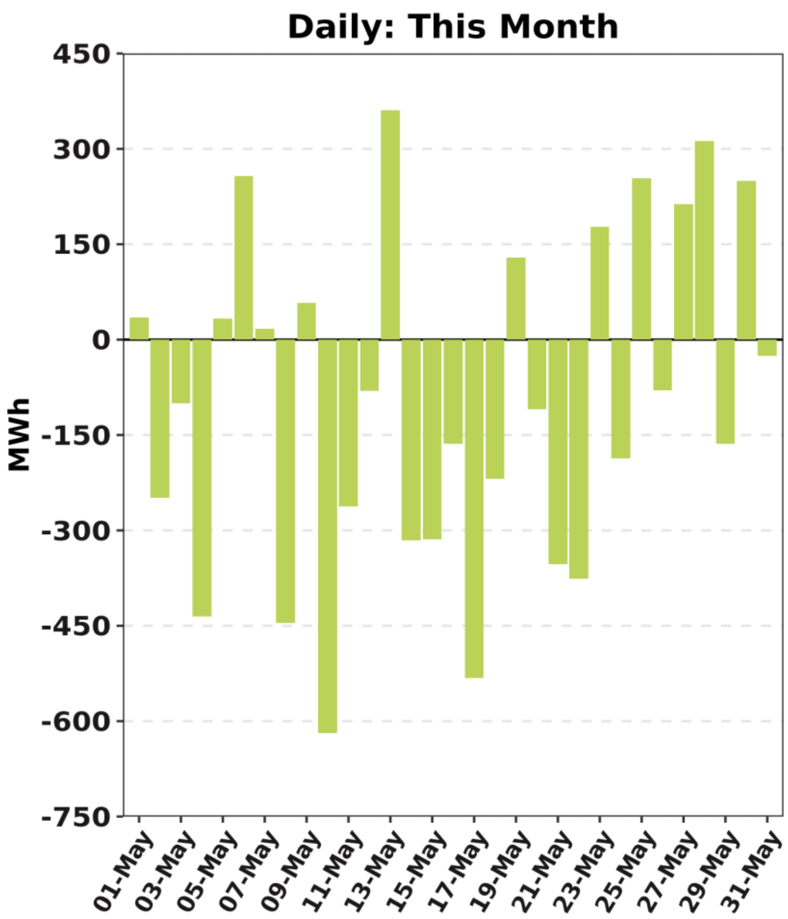
Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL

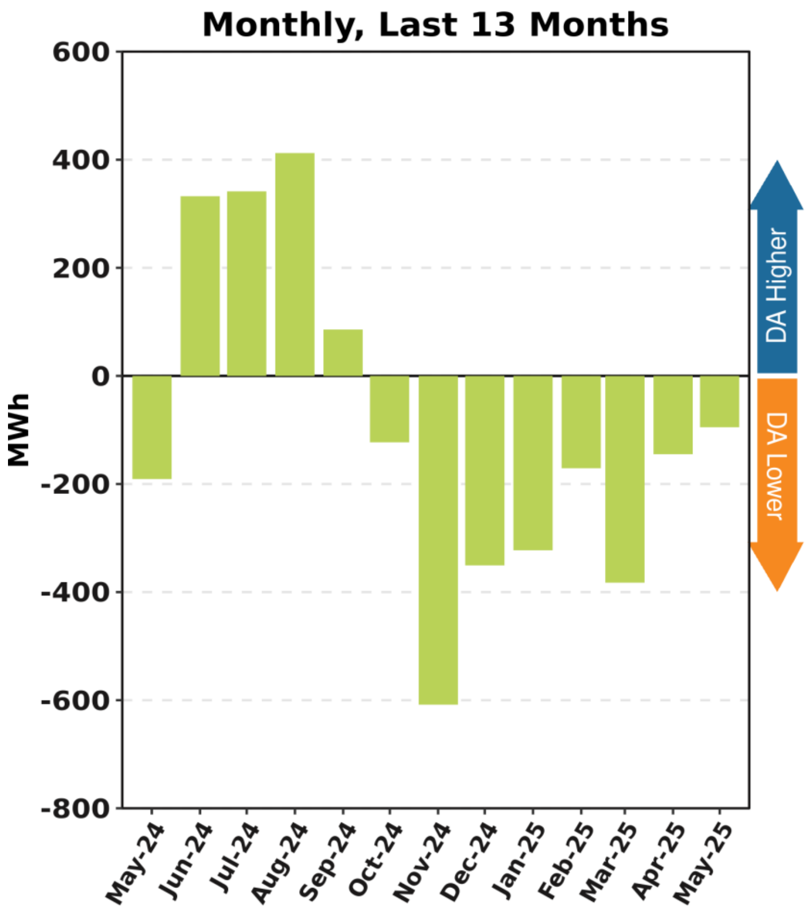




NEPOOL NEL is the total net revenue quality metered energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation + Demand Response Resource output - pumping load + net interchange where imports are positively signed. Current month's data may be preliminary. Weather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

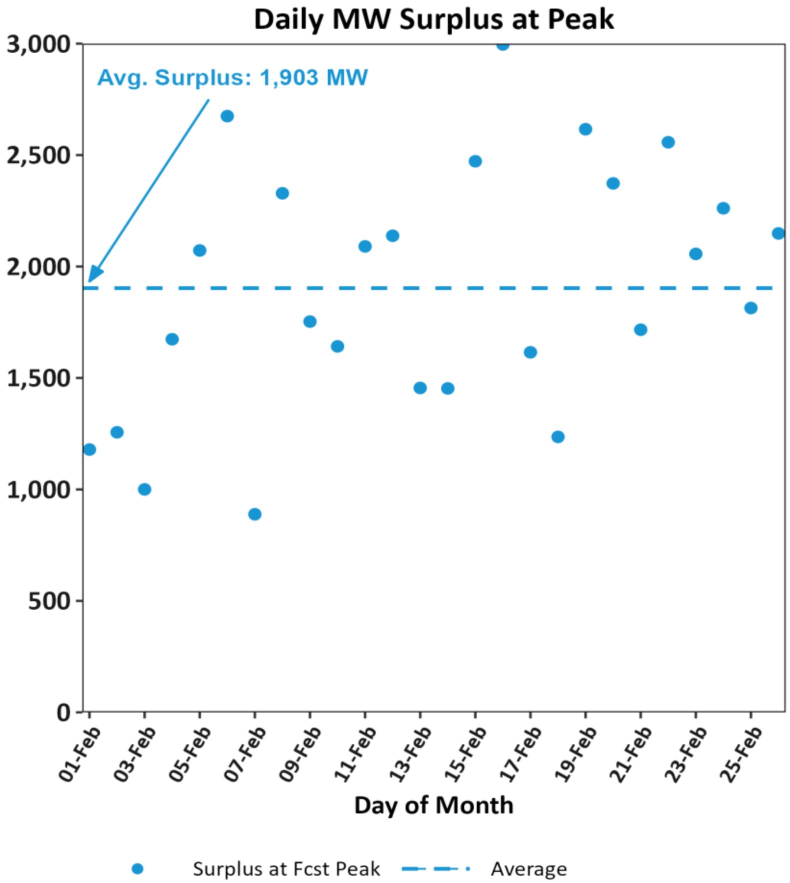
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour

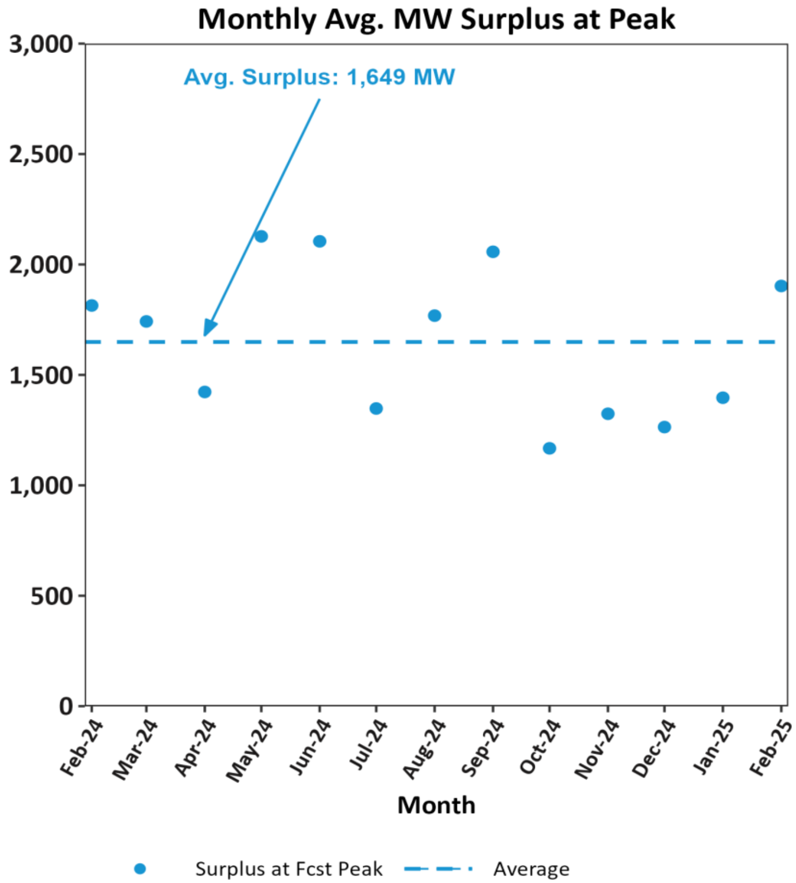




Negative values indicate DA Cleared Physical Energy value below its RT counterpart. EIR MW are not included in DA Physical Energy.

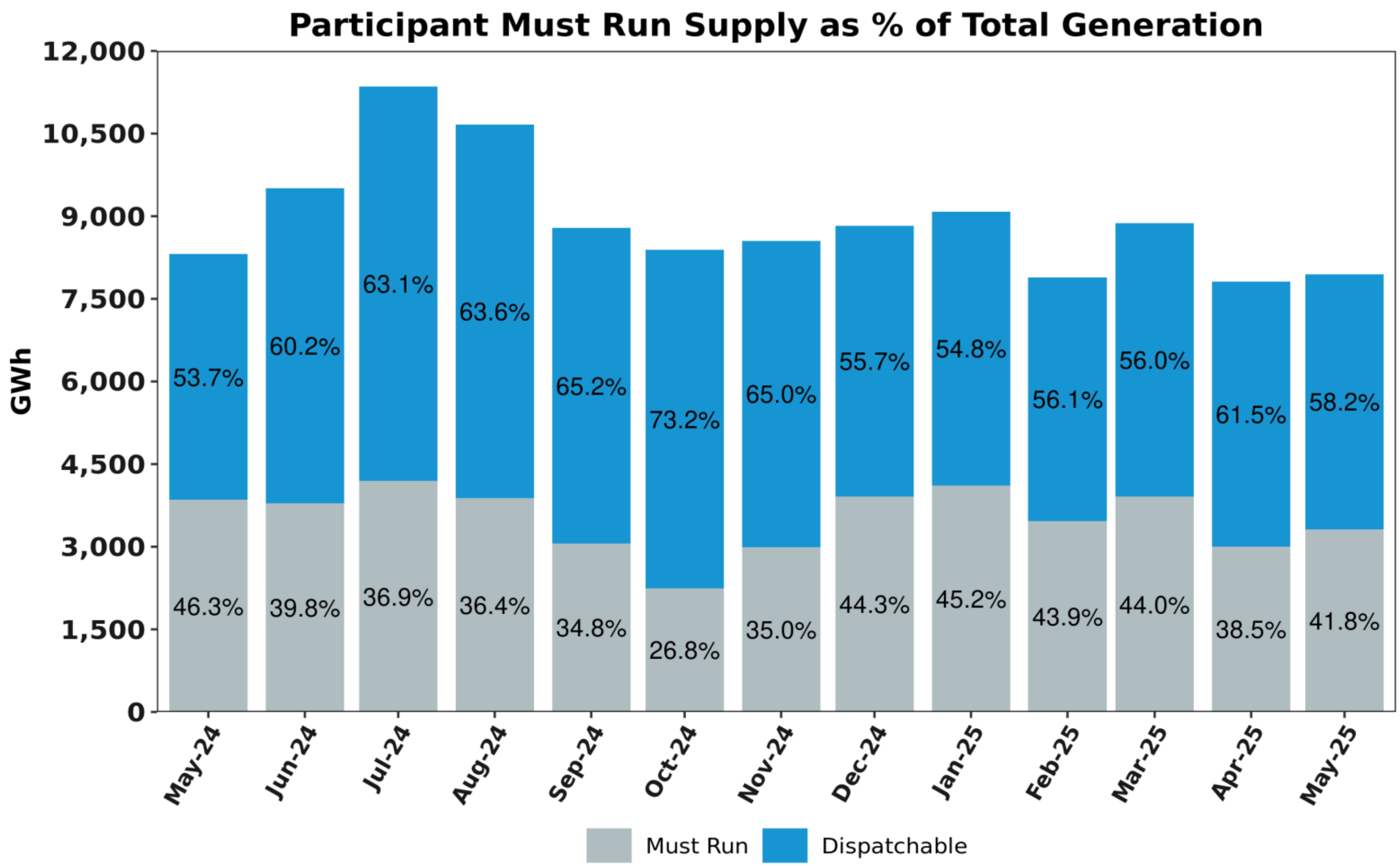
Native Capacity Surplus* Cleared in the DA Market Relative to Forecasted Peak-Hour Requirements





*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. It does not reflect additional available imports up to the TTC, if any.

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

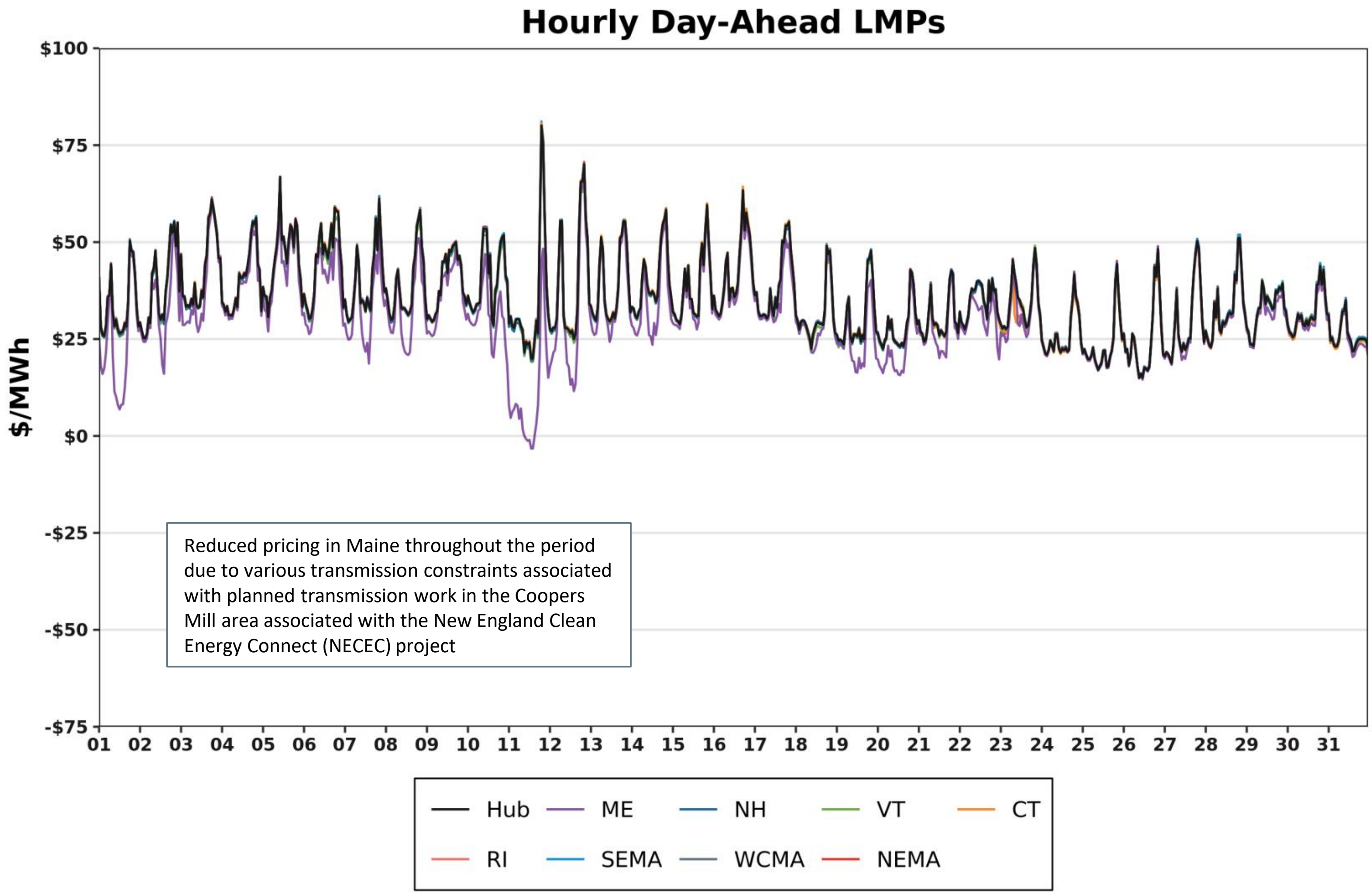
DA vs. RT LMPs ($/MWh)

Arithmetic Average

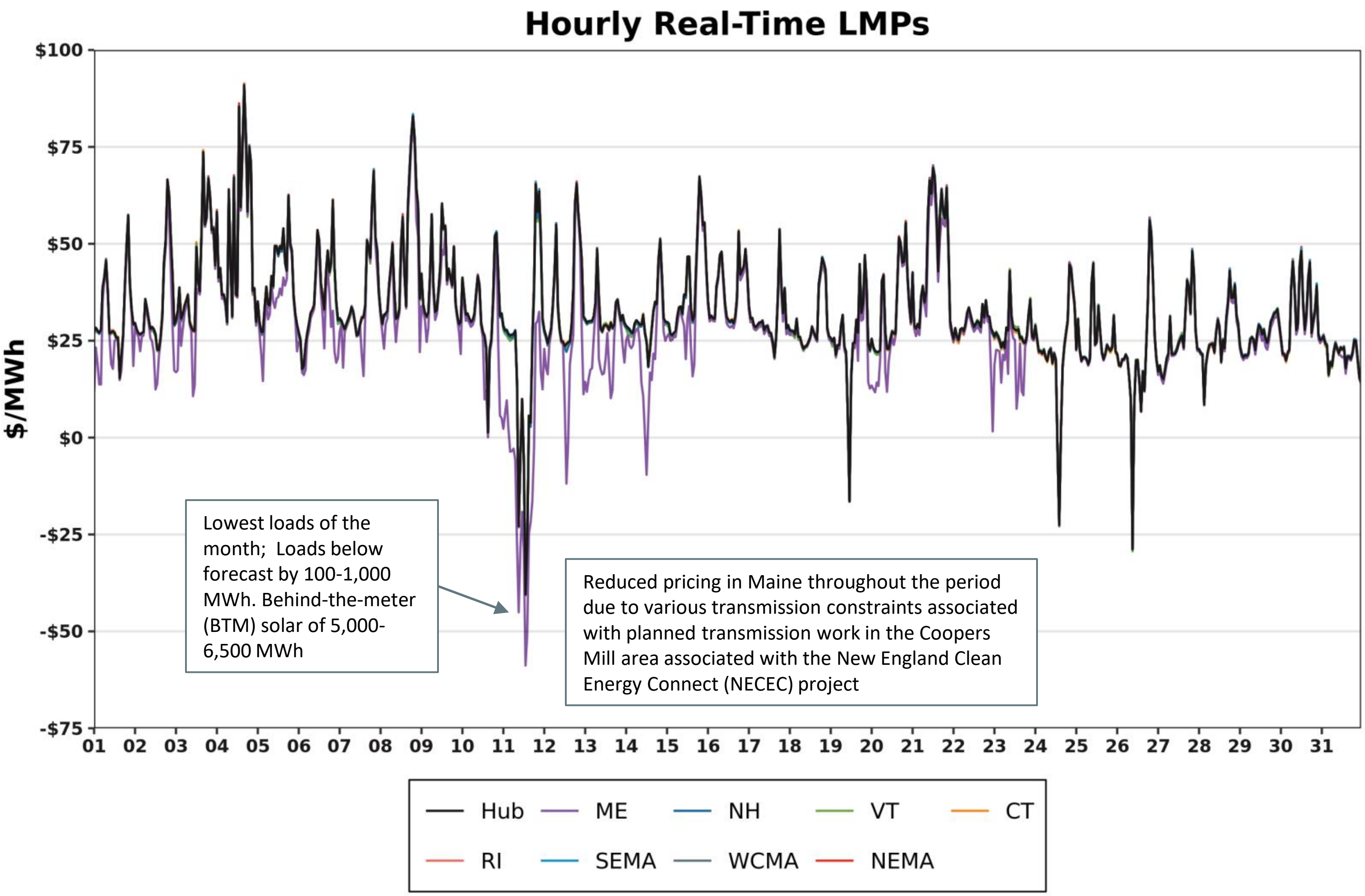
Year 2023	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$37.04	$36.59	$37.22	$36.78	$36.25	$36.89	$37.34	$37.07	$37.35
Real-Time	$35.91	$35.36	$36.05	$35.55	$35.26	$35.71	$36.17	$35.92	$36.21
RT Delta %	-3.05%	-3.36%	-3.14%	-3.34%	-2.73%	-3.20%	-3.13%	-3.10%	-3.05%
Year 2024	Hub	ME	NH	VT	CT	RI	SEMA	WCMA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

May-24	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$27.23	$26.56	$27.30	$27.22	$26.66	$27.00	$27.36	$27.23	$27.47
Real-Time	$26.25	$25.32	$26.33	$26.22	$25.78	$25.99	$26.35	$26.23	$26.48
RT Delta %	-3.60%	-4.67%	-3.55%	-3.67%	-3.30%	-3.74%	-3.69%	-3.67%	-3.60%
May-25	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$35.21	$31.12	$34.94	$34.71	$34.90	$34.96	$35.39	$35.21	$35.46
Real-Time	$32.77	$28.78	$32.54	$32.33	$32.45	$32.47	$32.85	$32.76	$32.97
RT Delta %	-6.93%	-7.52%	-6.87%	-6.86%	-7.02%	-7.12%	-7.18%	-6.96%	-7.02%
Annual Diff.	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Yr over Yr DA	29.31%	17.17%	27.99%	27.52%	30.91%	29.48%	29.35%	29.31%	29.09%
Yr over Yr RT	24.84%	13.67%	23.59%	23.30%	25.87%	24.93%	24.67%	24.90%	24.51%

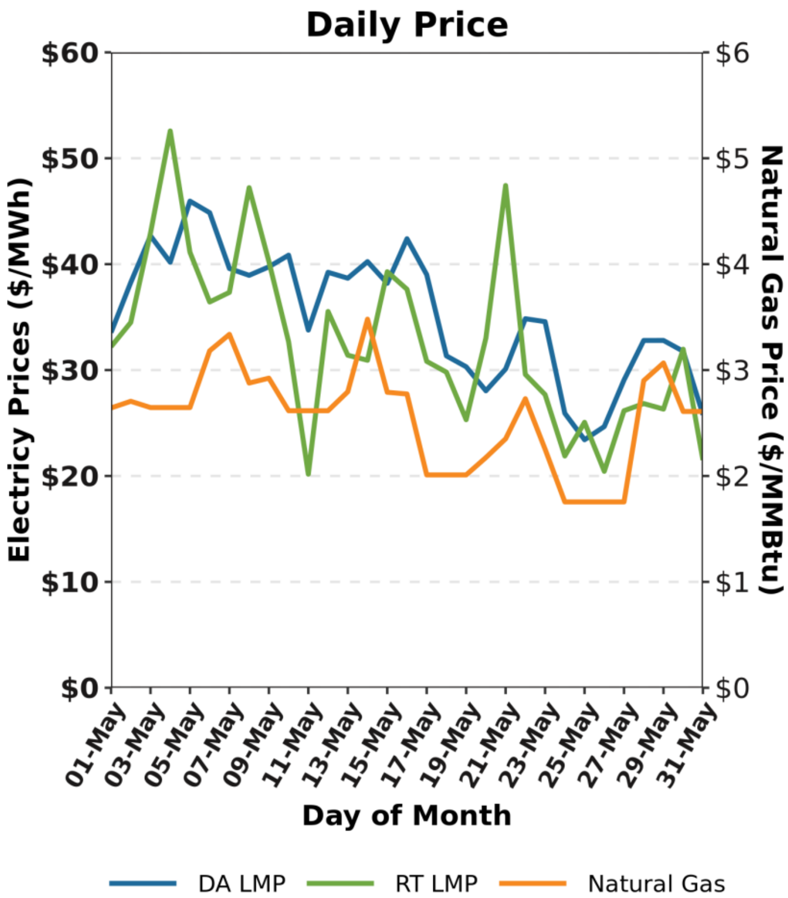
Hourly DA LMPs, May 1-31, 2025

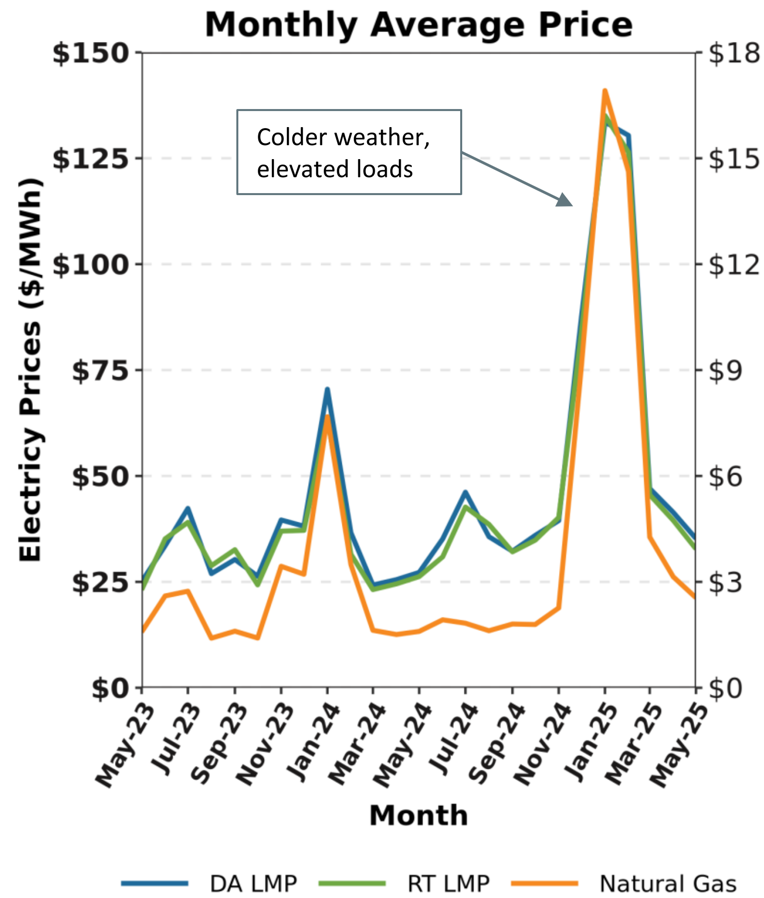


Hourly RT LMPs, May 1-31, 2025



Wholesale Electricity vs Natural Gas Price by Month

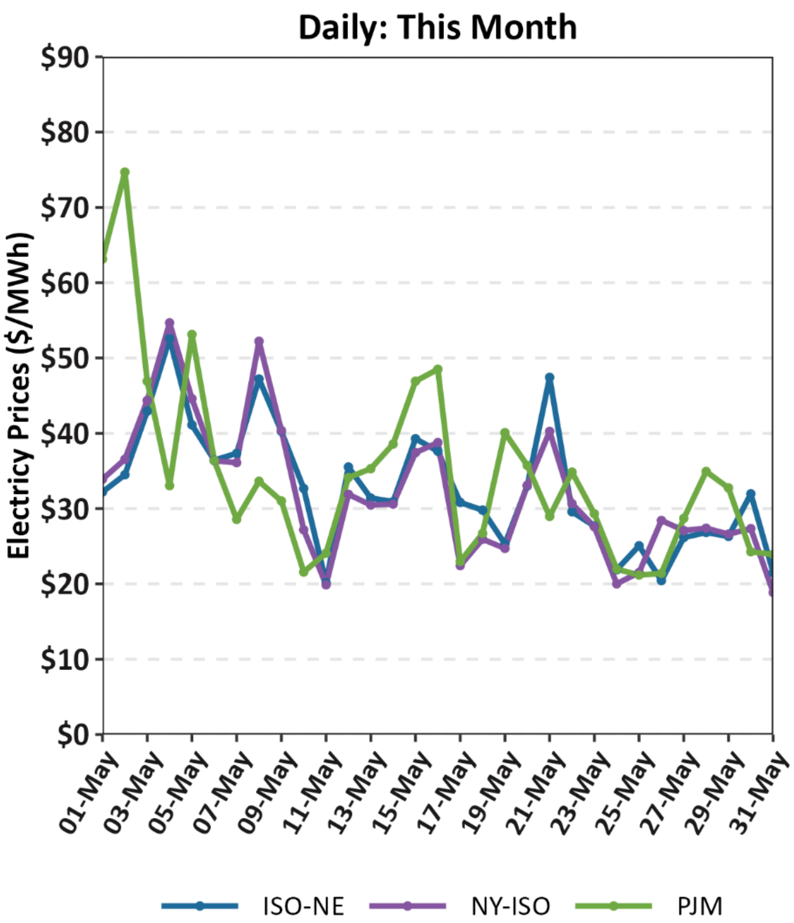


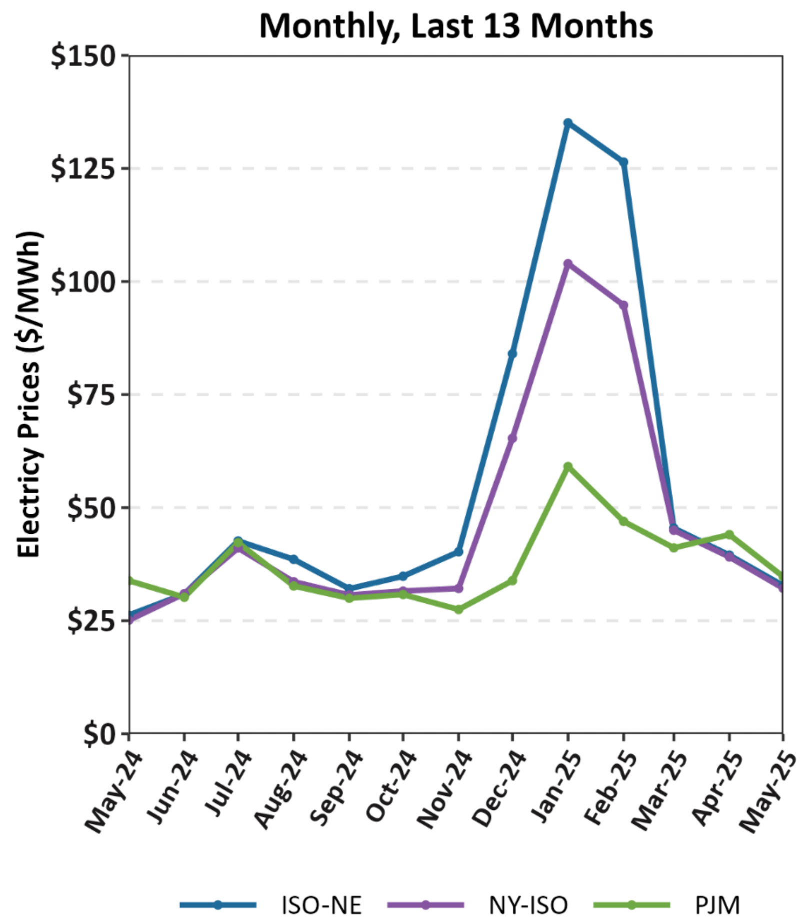


Underlying natural gas data furnished by: ICE Global markets in clear view

Gas price is average of Massachusetts delivery points

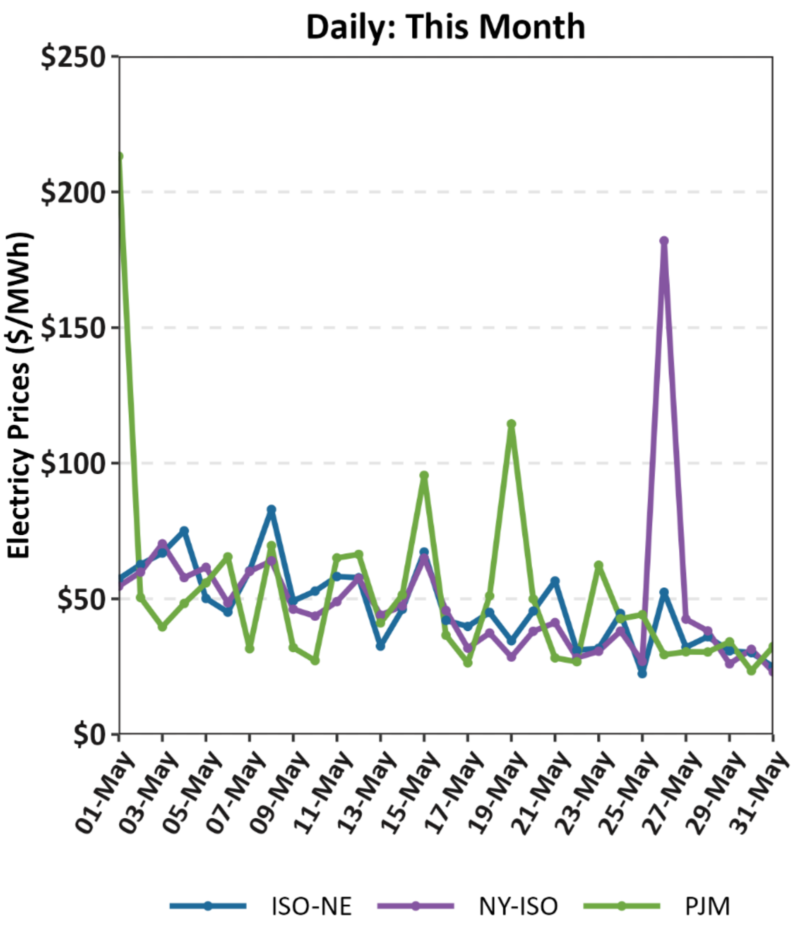
New England, NY, and PJM Hourly Average RT Prices by Month

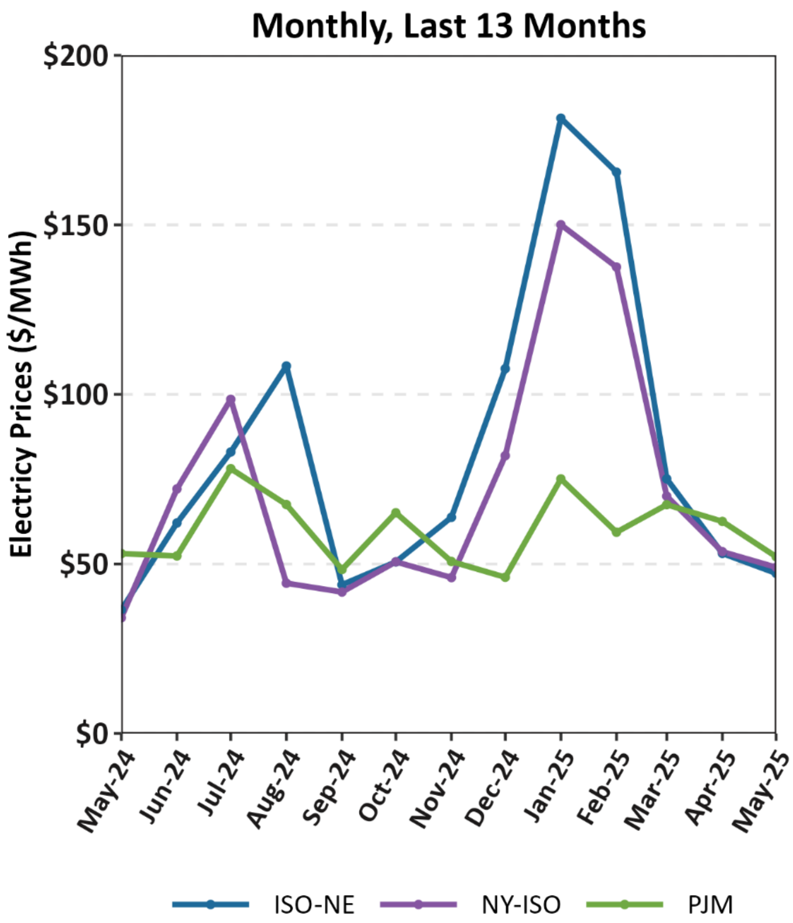




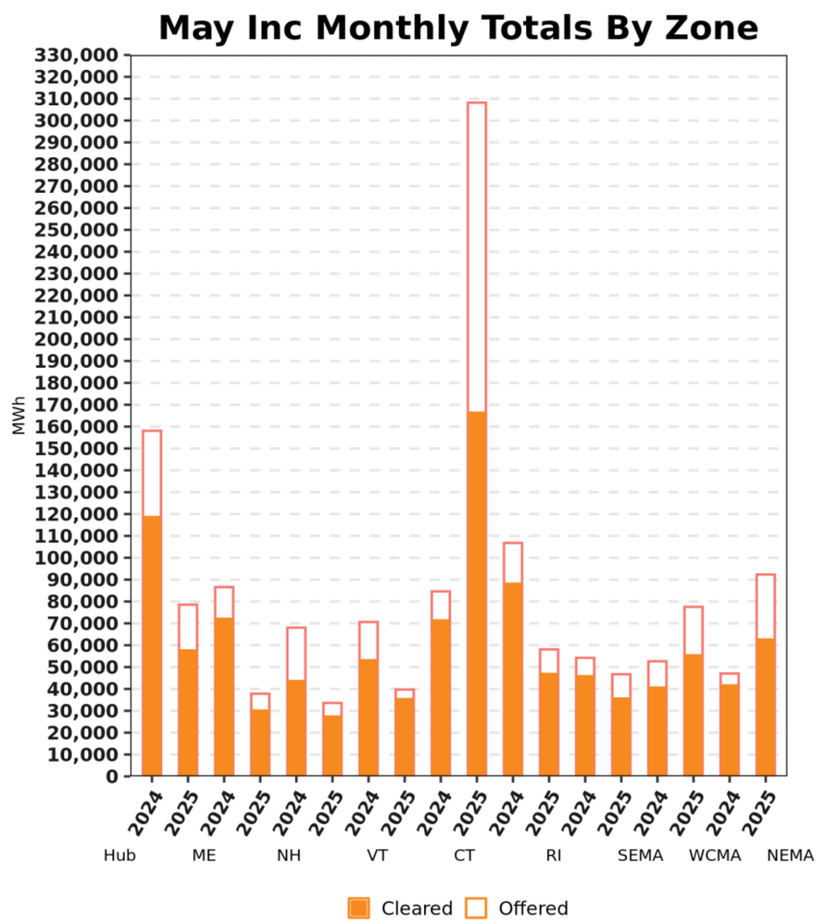
Hourly average prices are shown

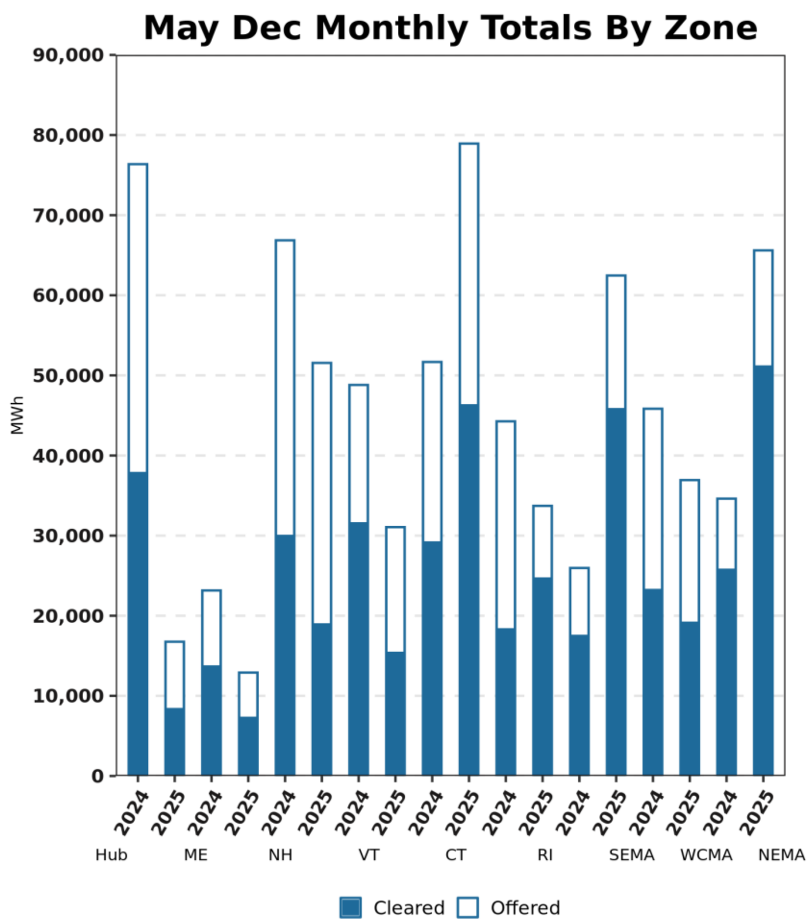
New England, NY, and PJM RT Pricing during New England's Forecasted Daily Peak Hours





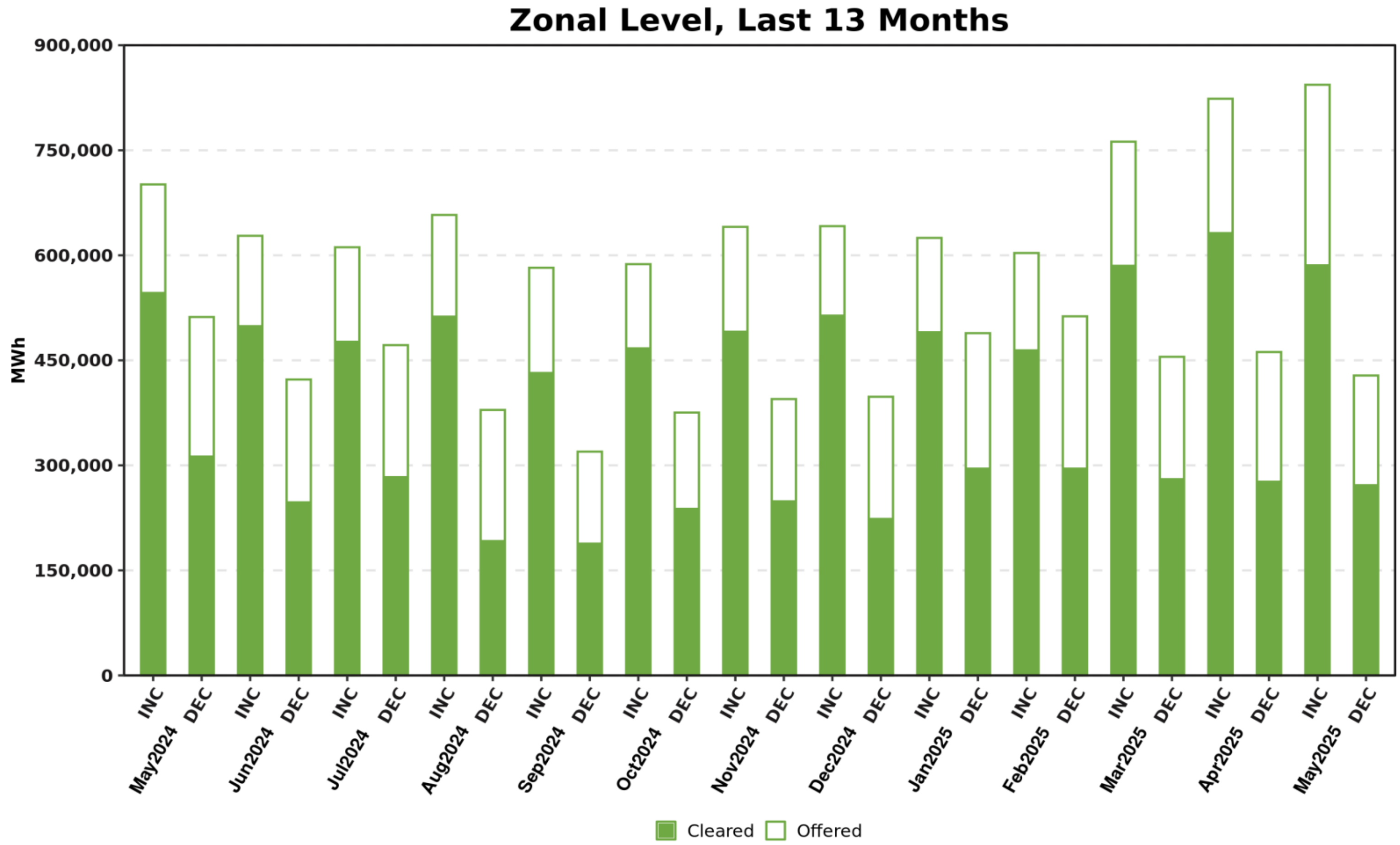
Zonal Increment Offers and Decrement Bid Amounts





Includes nodal activity within the zone; excludes external nodes

Total Increment Offers and Decrement Bids

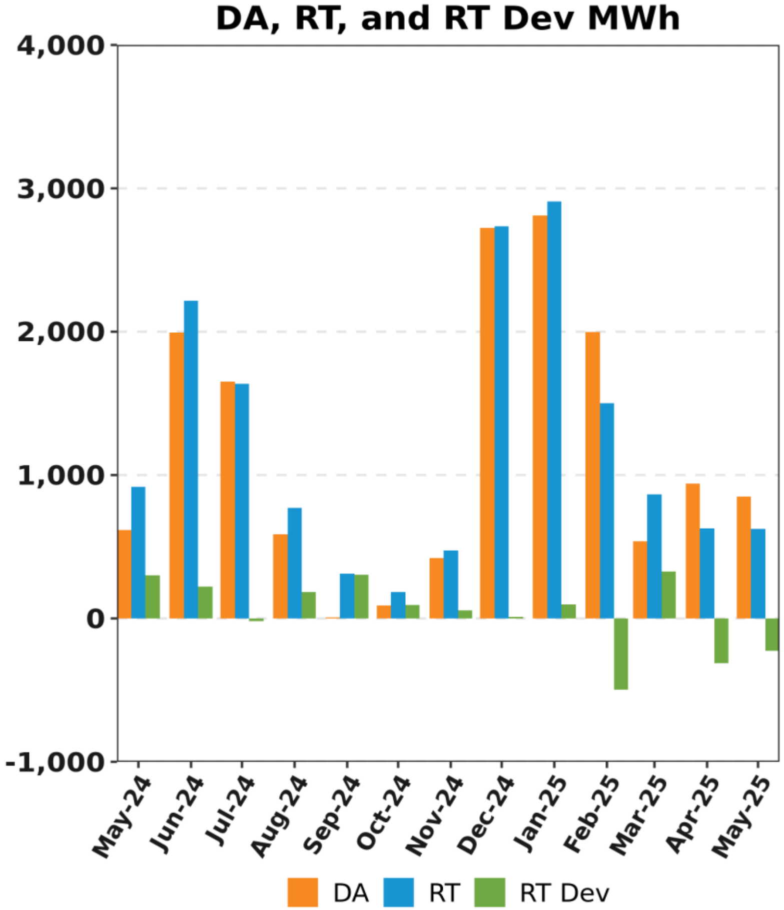


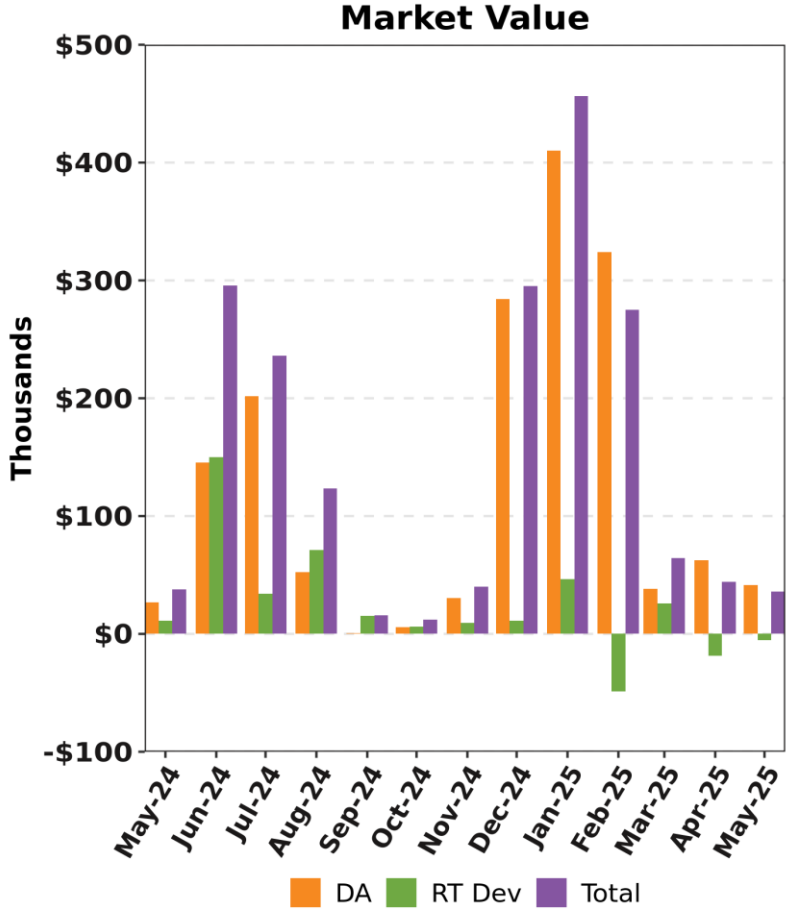
Includes nodal activity within the zone; excludes external nodes

BACK-UP DETAIL

DEMAND RESPONSE

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

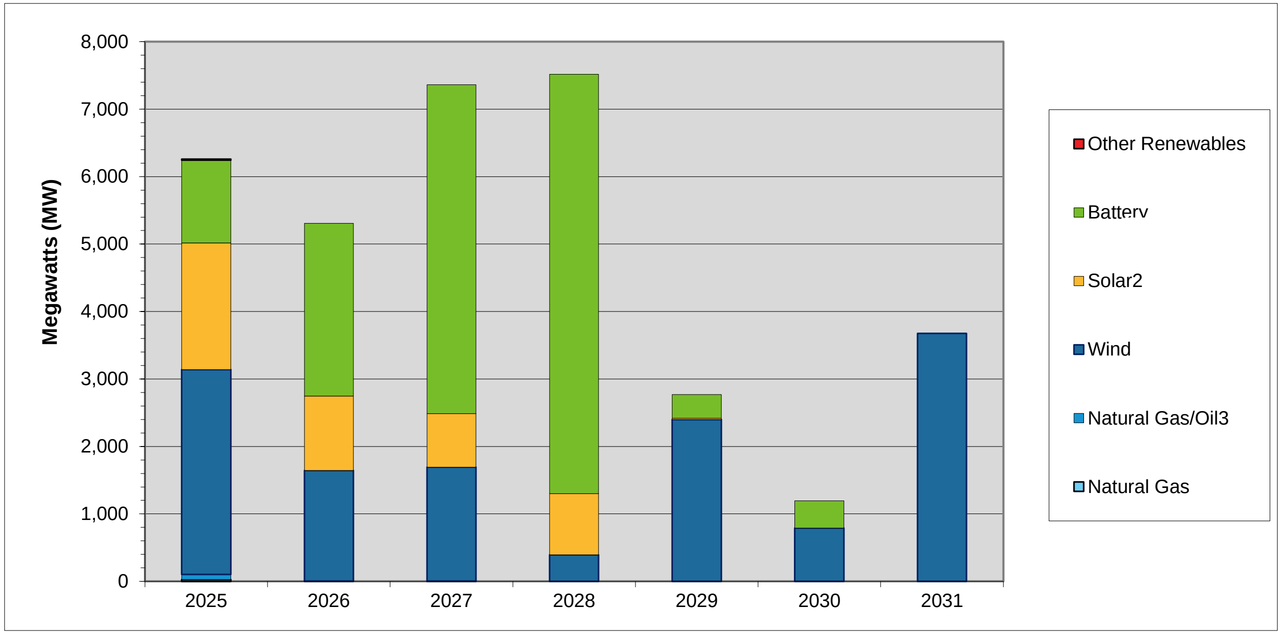
New Generation Update

Based on Queue as of 06/01/25

- No new projects were added to the interconnection queue since the last update
  - Any new ISO Interconnection Requests seeking to successfully enter the Order No. 2023 Transitional Cluster Study process were required to be submitted by June 13, 2024 at 23:59
    - Thereafter, the creation of new ISO Interconnection Requests is now suspended until the next Cluster Entry Window opens
- In total, 375 generation projects are currently being tracked by the ISO, totaling approximately 37,684 MW

Projected Annual Capacity Additions

By Supply Fuel Type



	2025	2026	2027	2028	2029	2030	2031	Total MW	% of Total[1]
Other Renewables	12	0	0	0	0	0	0	12	0.0
Battery	1,228	2,561	4,874	6,220	353	404	0	15,640	45.9
Solar[2]	1,879	1,103	796	905	17	0	0	4,700	13.8
Wind	3,038	1,640	1,687	394	2,400	791	3,675	13,625	40.0
Natural Gas/Oil[3]	73	0	0	0	0	0	0	73	0.2
Natural Gas	26	4	4	0	0	0	0	34	0.1
Totals	6,256	5,308	7,361	7,519	2,770	1,195	3,675	34,084	100.0

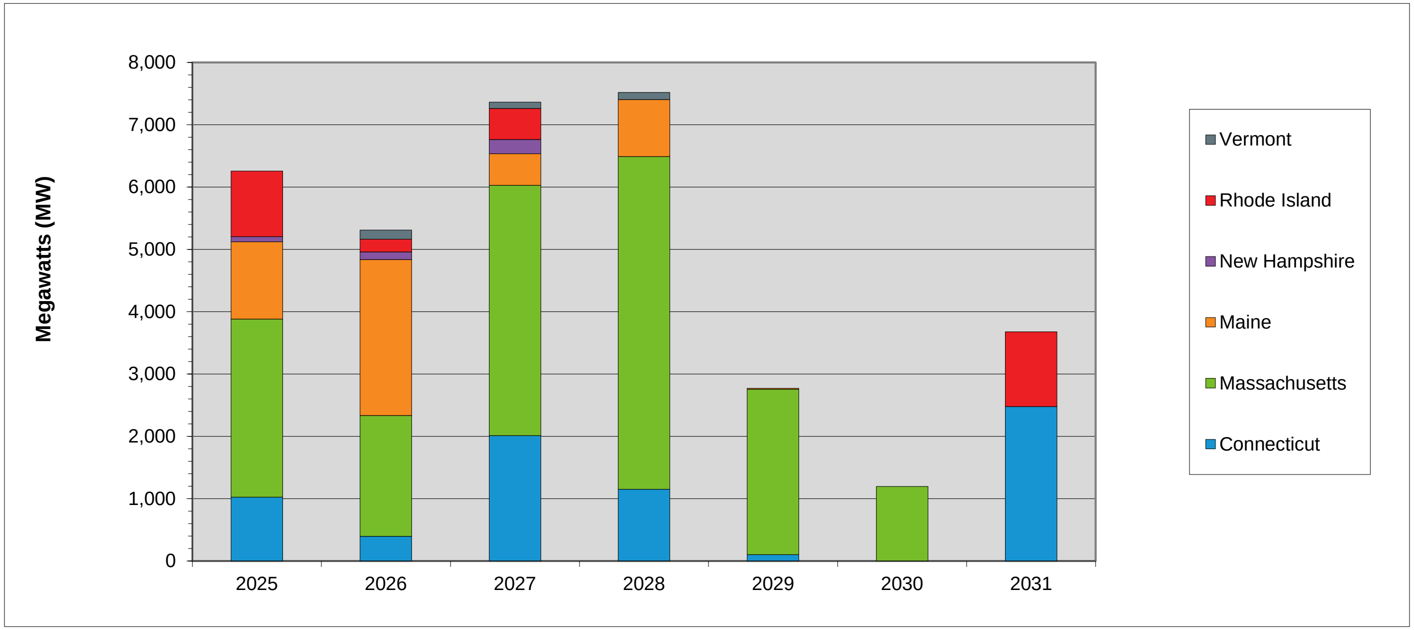
[1] Sum may not equal 100% due to rounding

[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



	2025	2026	2027	2028	2029	2030	2031	Total MW	% of Total[1]
Vermont	0	144	101	115	0	0	0	360	1.1
Rhode Island	1,052	205	499	0	0	0	1,200	2,956	8.7
New Hampshire	82	122	226	0	0	0	0	430	1.3
Maine	1,240	2,501	507	916	17	0	0	5,181	15.2
Massachusetts	2,859	1,942	4,017	5,336	2,650	1,195	0	17,999	52.8
Connecticut	1,023	394	2,011	1,152	103	0	2,475	7,158	21.0
Totals	**6,256**	**5,308**	**7,361**	**7,519**	**2,770**	**1,195**	**3,675**	**34,084**	**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	117	15,640	2	425	115	15,215
Fuel Cell	2	12	0	0	2	12
Hydro	0	0	0	0	0	0
Natural Gas	5	34	0	0	5	34
Natural Gas/Oil	1	73	0	0	1	73
Nuclear	0	0	0	0	0	0
Solar	224	4,700	15	241	209	4,459
Wind	26	17,225	3	985	23	16,240
Total	375	37,684	20	1,651	355	36,033

- 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	4	25	0	0	4	25
Intermediate	1	73	0	0	1	73
Peaker	344	20,361	17	666	327	19,695
Wind Turbine	26	17,225	3	985	23	16,240
Total	375	37,684	20	1,651	355	36,033

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

New Generation Projection

By Operating Type and Fuel Type

	Total		Baseload		Intermediate		Peaker		Wind Turbine	
Unit Type	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0	0	0	0	0
Battery Storage	117	15,640	0	0	0	0	117	15,640	0	0
Fuel Cell	2	12	2	12	0	0	0	0	0	0
Hydro	0	0	0	0	0	0	0	0	0	0
Natural Gas	5	34	2	13	0	0	3	21	0	0
Natural Gas/Oil	1	73	0	0	1	73	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0
Solar	224	4,700	0	0	0	0	224	4,700	0	0
Wind	26	17,225	0	0	0	0	0	0	26	17,225
Total	375	37,684	4	25	1	73	344	20,361	26	17,225

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 15

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	677.673	673.401	-4.272	579.692	-93.709	461.416	-118.276
Demand	*Passive Demand*	3,212.865	3,211.403	-1.462	3,134.652	-76.751	3,113.332	-21.32
Demand Total		**3,890.538**	**3,884.804**	**-5.734**	**3,714.344**	**-170.460**	**3,574.748**	**-139.596**
Generator	*Non-Intermittent*	28,154.203	27,714.778	-439.425	27,081.653	-633.125	27,132.413	50.76
Generator	*Intermittent*	1,089.265	1,073.794	-15.471	1,056.601	-17.193	865.694	-190.907
Generator Total		**29,243.468**	**28,788.572**	**-454.896**	**28,138.254**	**-650.318**	**27,998.107**	**-140.147**
Import Total		**1,487.059**	**1297.132**	**-189.927**	**1,249.545**	**-47.587**	**1,193.583**	**-55.962**
Grand Total*		**34,621.065**	**33,970.508**	**-650.557**	**33,102.143**	**-868.365**	**32,766.438**	**-335.705**
Net ICR (NICR)		**33,270**	**31,775**	**-1,495**	**31,545**	**-230**	**31,380**	**-165**

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2024-2028 CCP Month Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 16

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	765.35	589.882	-175.468	504.466	-85.416	437.780	-66.686
	Passive Demand	2,557.256	2,579.120	21.864	2,574.367	-4.753	2,568.703	-5.664
Demand Total		**3,322.606**	**3,169.002**	**-153.604**	**3,078.833**	**-90.169**	**3,006.483**	**-72.350**
Generator	*Non-Intermittent*	26,805.003	26,643.379	-161.624	26,503.730	-139.649	26,049.059	-454.671
	Intermittent	1,178.933	1,146.783	-32.15	989.265	-157.518	912.376	-76.889
Generator Total		**27,983.936**	**27,790.162**	**-193.774**	**27,492.995**	**-297.167**	**26,961.435**	**-531.560**
Import Total		**1,503.842**	**1,247.601**	**-256.241**	**1,244.601**	**-3.000**	**1,234.800**	**-9.801**
Grand Total*		**32,810.384**	**32,206.765**	**-603.619**	**31,816.429**	**-390.336**	**31,202.718**	**-613.711**
Net ICR (NICR)		**31,645**	**30,585**	**-1,060**	**30,775**	**190**	**30,300**	**-475**

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2024-2028 CCP Month Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 17

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	622.854	584.913	-37.941				
	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 2024-2028 CCP Month Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 18

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	543.580						
	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

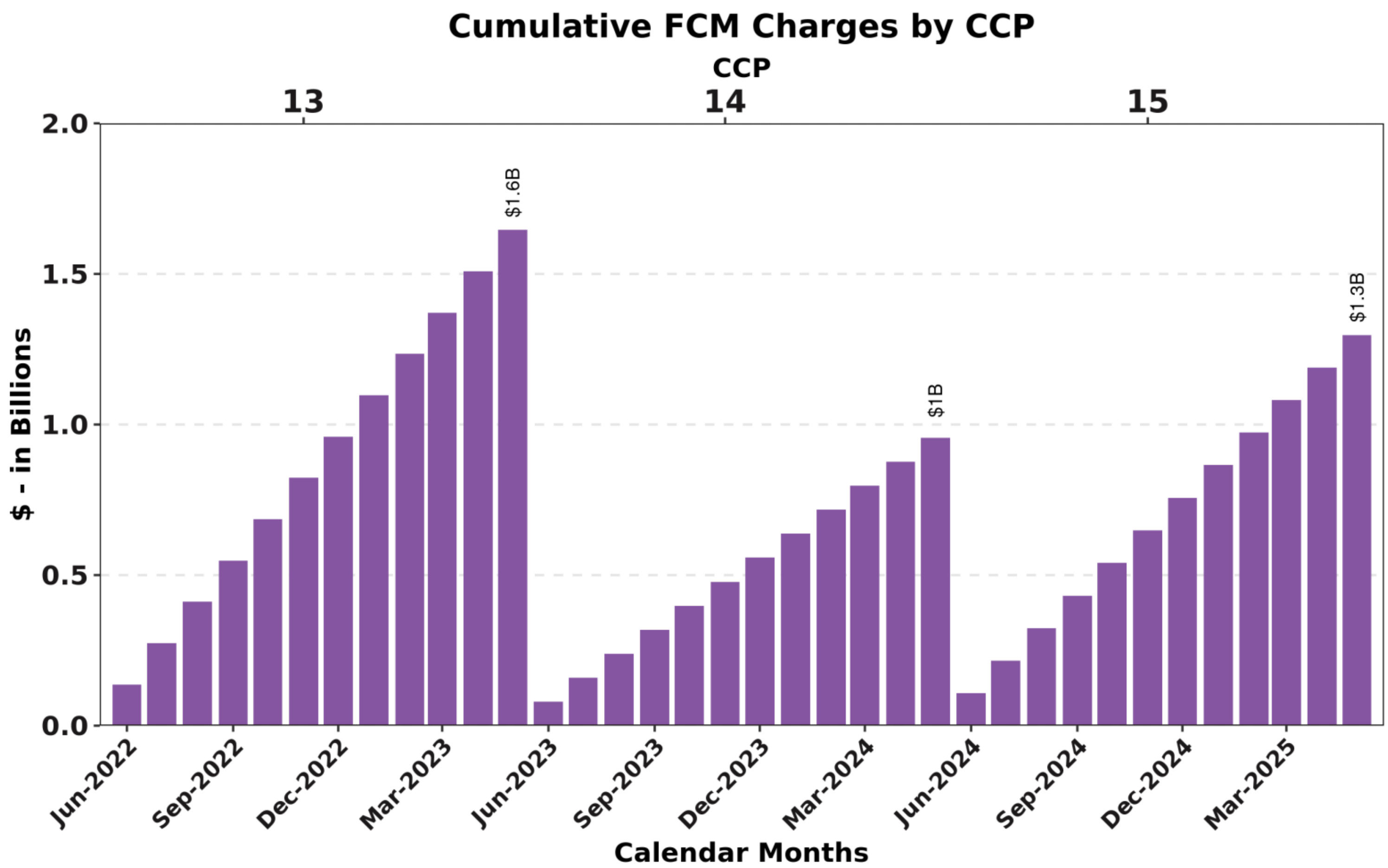
Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2024-2028 CCP Month Capacity Supply Obligation Changes report on the ISO New England website.

Active/Passive Demand Response

CSO Totals by Commitment Period

Commitment Period	Active/Passive	Existing	New	Grand Total
2021-22	Active	480.941	143.504	624.445
	Passive	2,604.79	370.568	2,975.36
	Grand Total	**3,085.734**	**514.072**	**3,599.806**
2022-23	Active	598.376	87.178	685.554
	Passive	2,788.33	566.363	3,354.69
	Grand Total	**3,386.703**	**653.541**	**4,040.244**
2023-24	Active	560.55	31.493	592.043
	Passive	3,035.51	291.565	3,327.07
	Grand Total	**3,596.056**	**323.058**	**3,919.114**
2024-25	Active	674.153	3.520	677.673
	Passive	3,046.064	166.801	3,212.865
	Grand Total	**3,720.217**	**170.321**	**3,890.538**
2025-26	Active	664.01	101.34	765.35
	Passive	2,428.638	128.618	2557.256
	Grand Total	**3,092.648**	**229.958**	**3,322.606**
2026-27	Active	615.369	7.485	622.854
	Passive	2,194.172	122.643	2,316.815
	Grand Total	**2,809.541**	**130.128**	**2,939.669**
2027-28	Active	543.58	0.0	543.58
	Passive	1,965.515	104.983	2070.498
	Grand Total	**2,509.095**	**104.983**	**2,614.498**

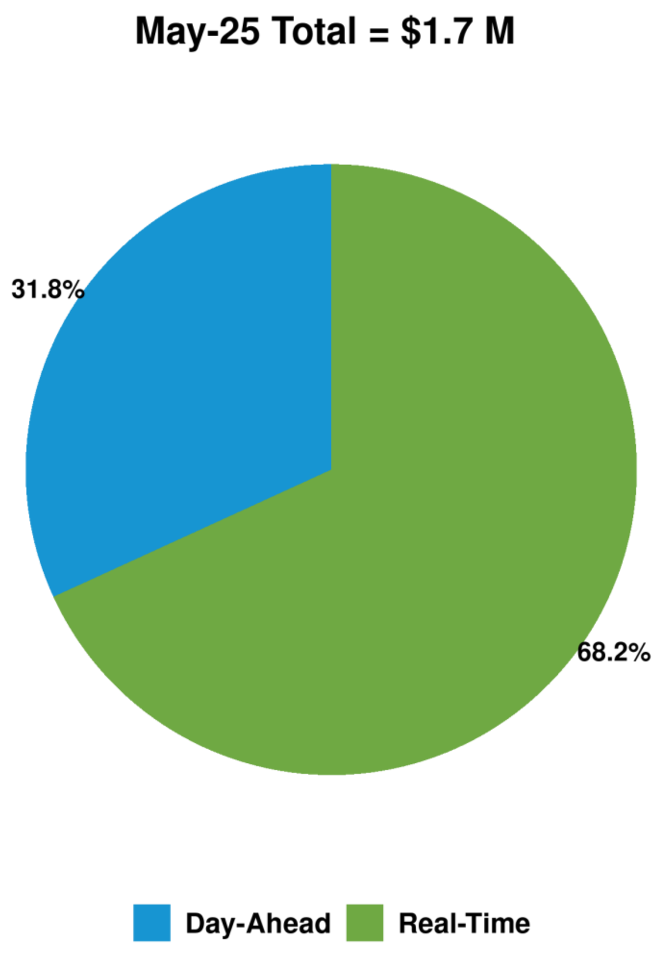
Forward Capacity Market Auctions

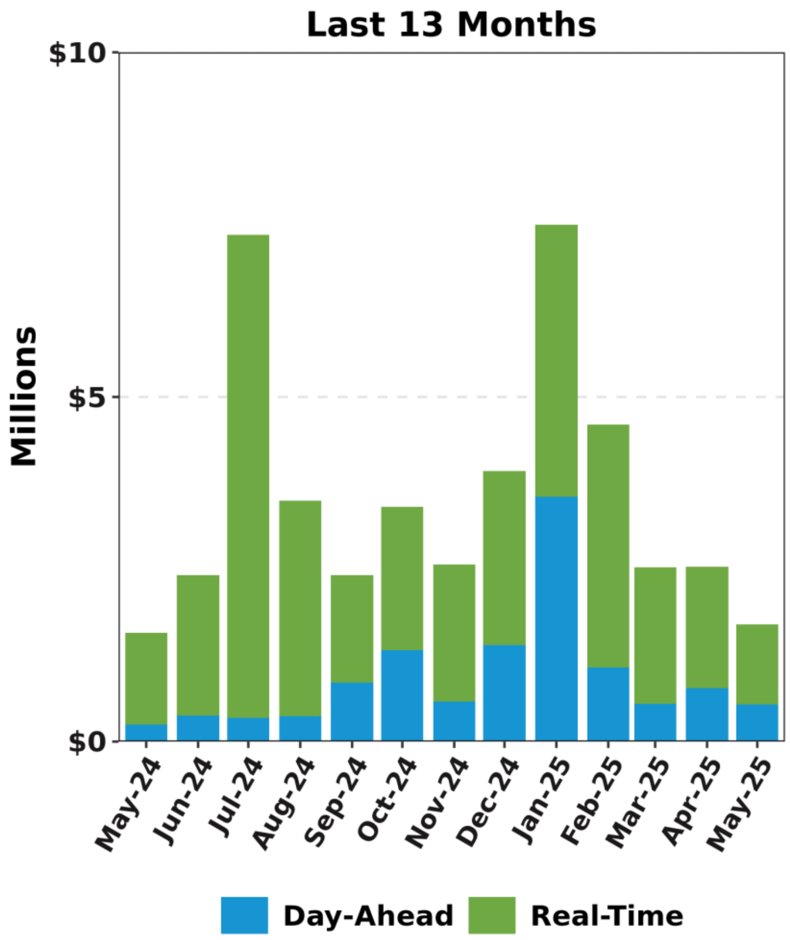


The items in the graph shaded in a lighter color represent the forecast for future months in the Capacity Commitment Period (CCP)

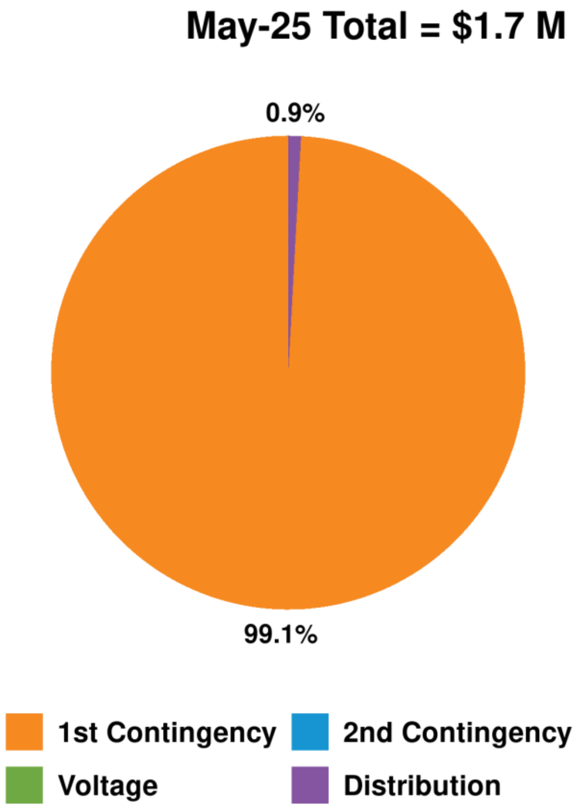
NET COMMITMENT PERIOD COMPENSATION

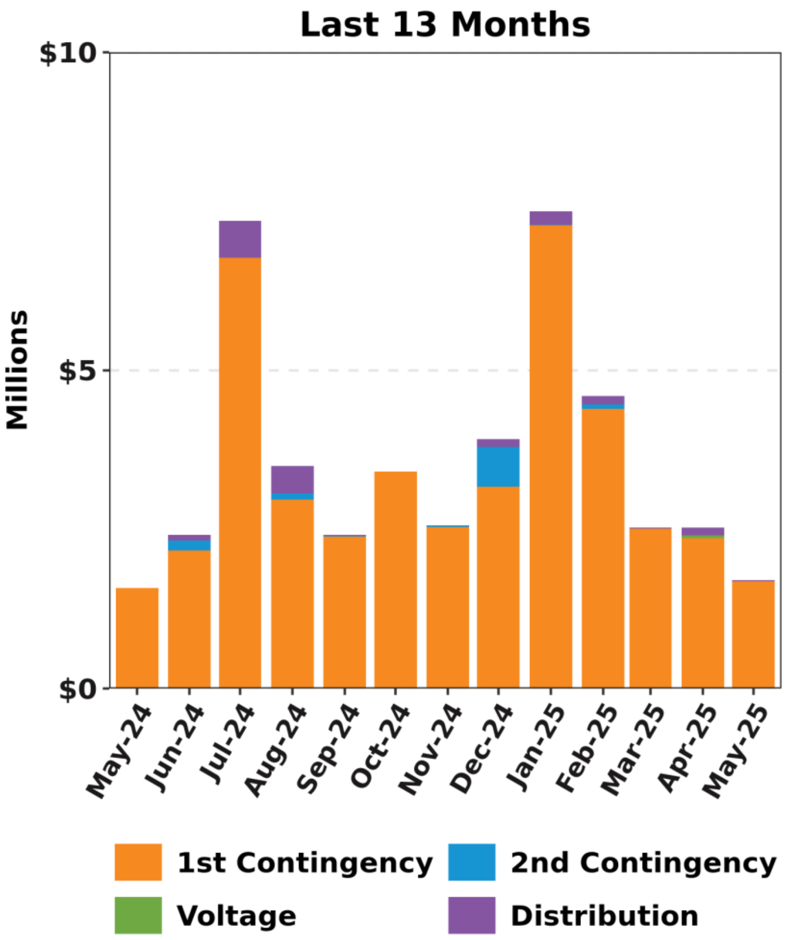
DA and RT NCPC Charges



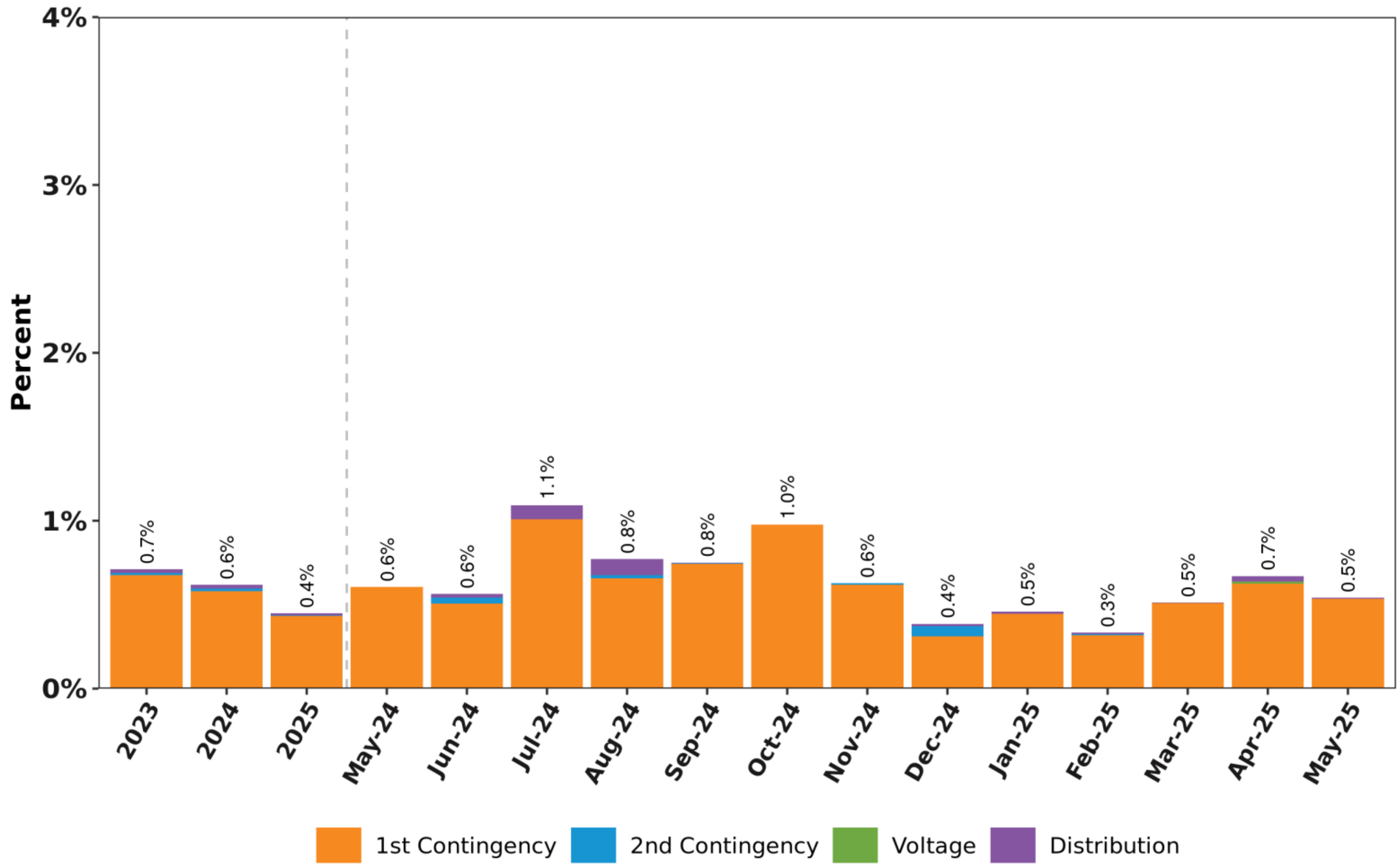


NCPC Charges by Type

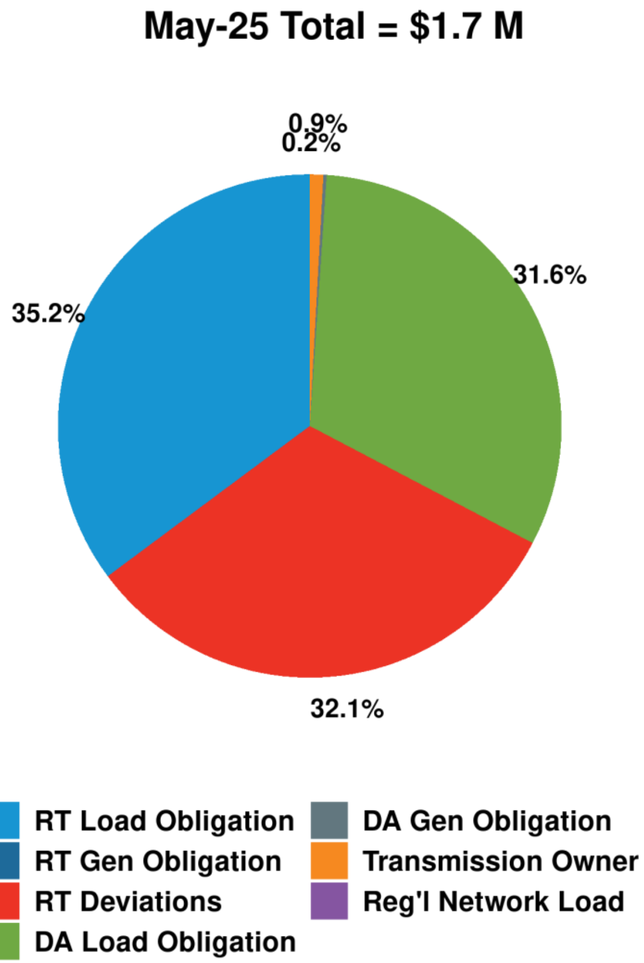


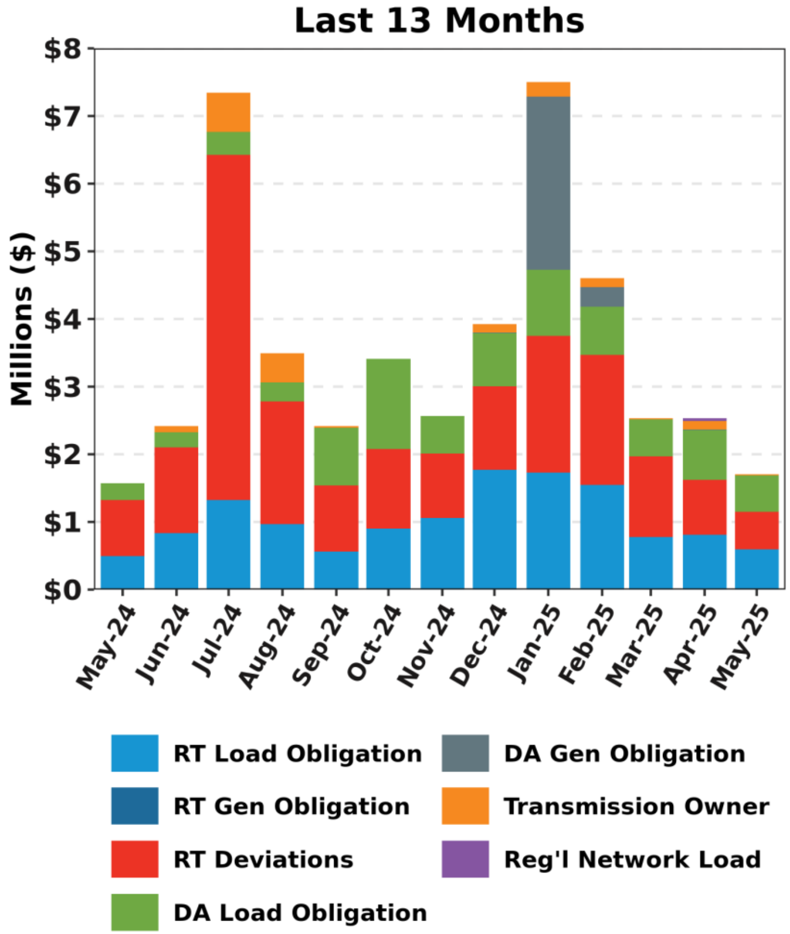


NCPC Charges by Type as Percent of Energy Market Value

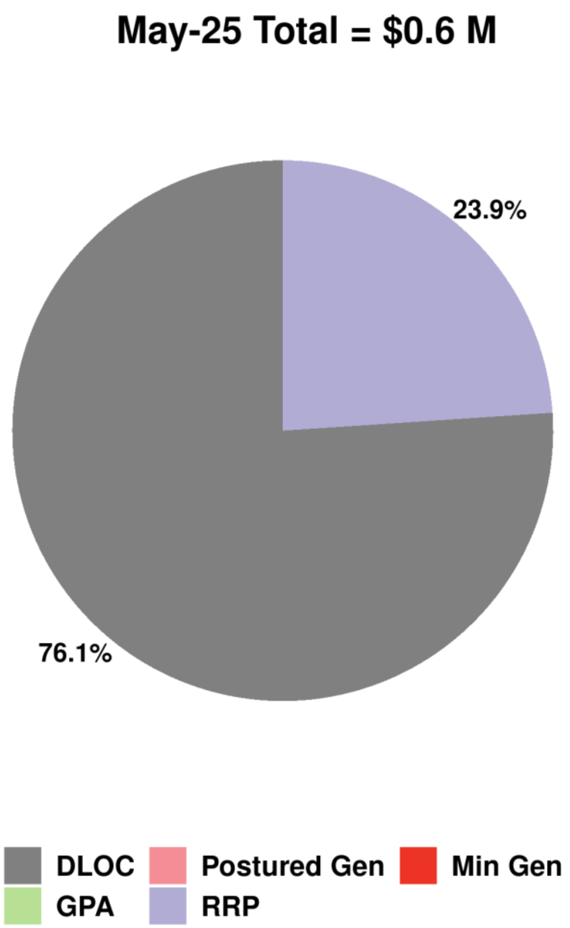


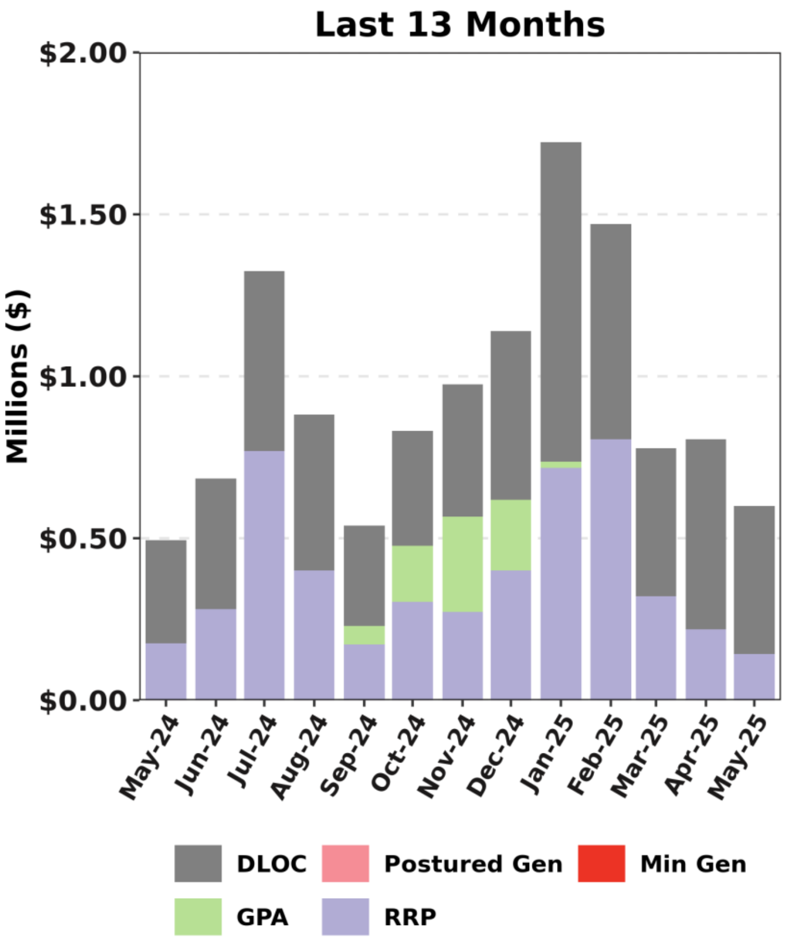
NCPC Charge Allocations





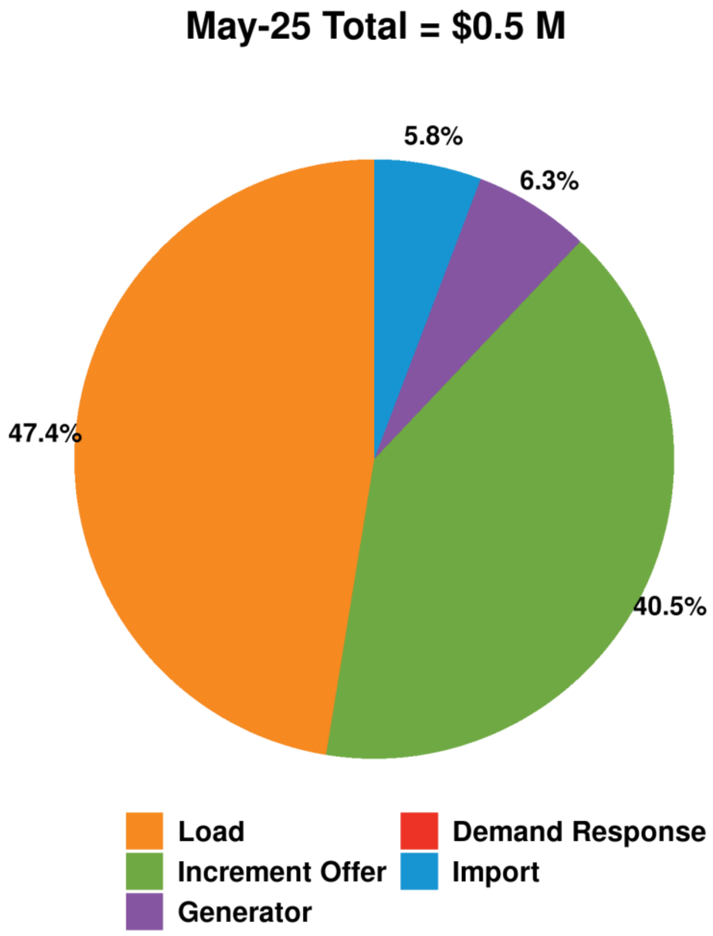
RT First Contingency NCPC Paid to Units and Allocated to RTLO and/or RTGO

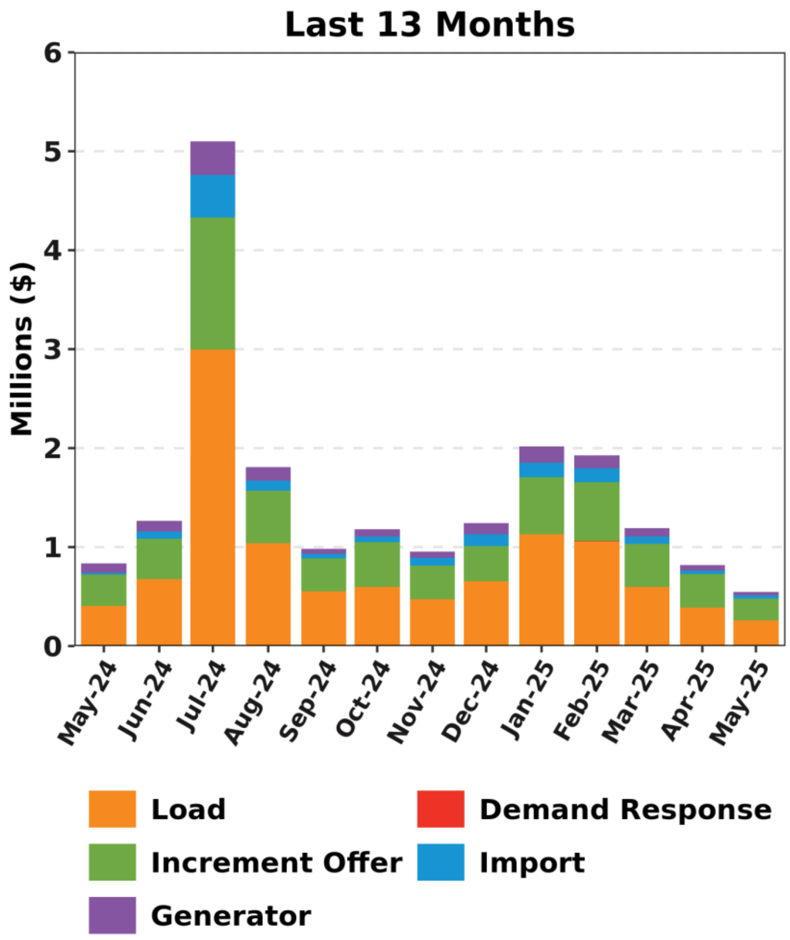




The categories shown above are a subset of those reflected in First Contingency NCPC throughout this report. The above categories are allocated to RTLO, except for Min Gen Emergency credits, which are allocated to RTGO.

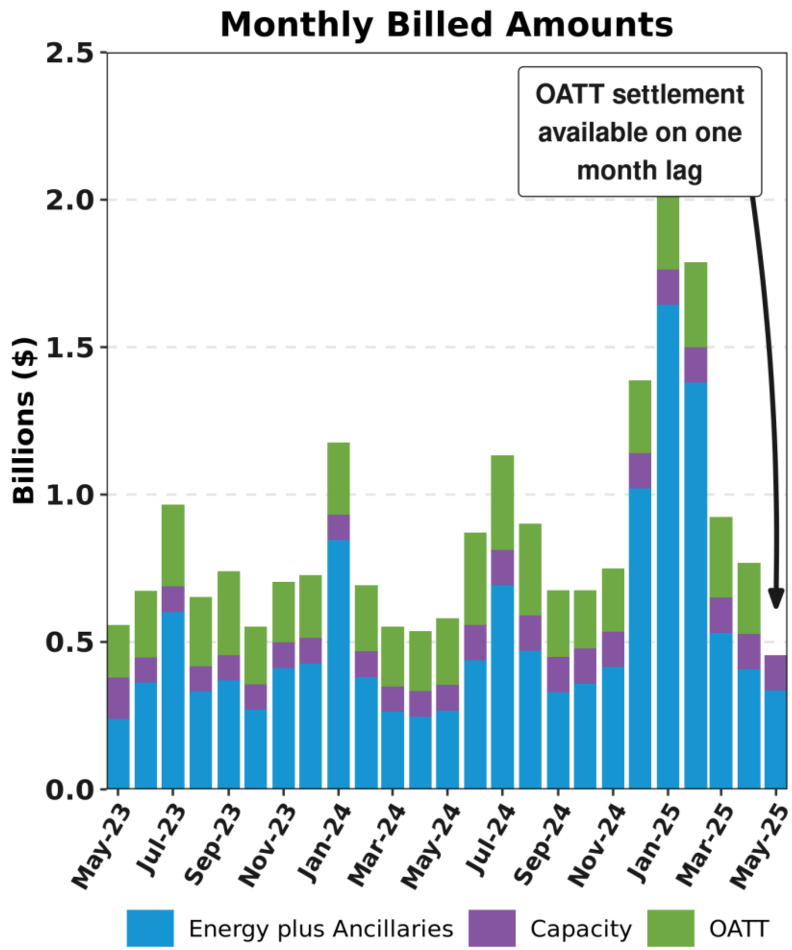
RT First Contingency Charges by Deviation Type

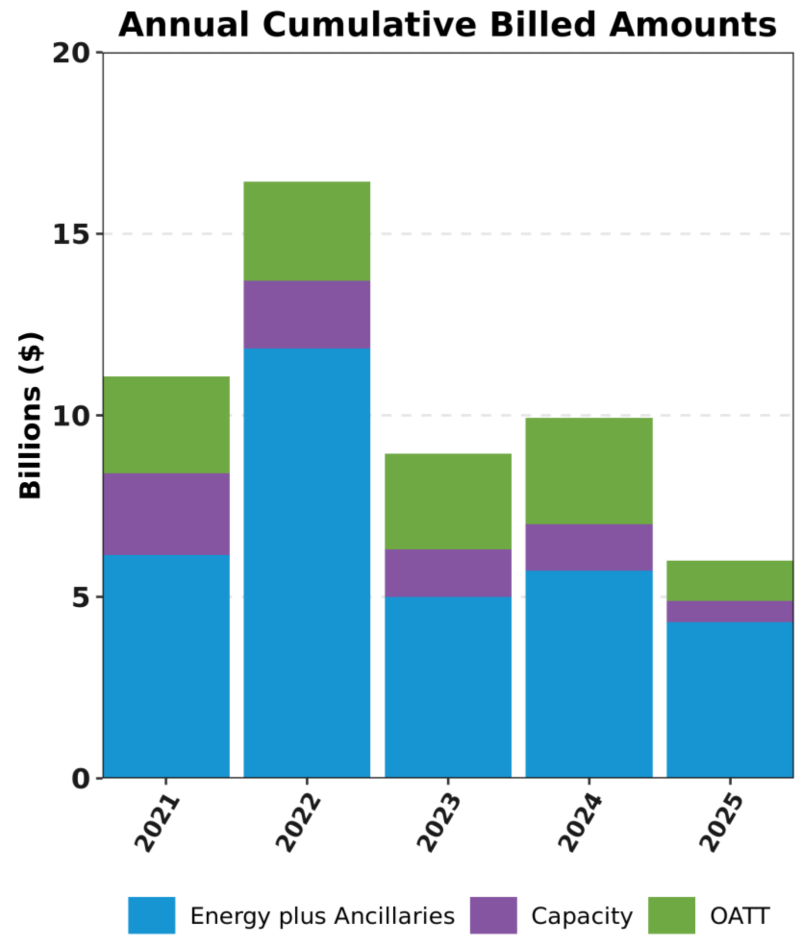




ISO BILLINGS

Total ISO Billings





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

REGIONAL SYSTEM PLAN (RSP)

Planning Advisory Committee (PAC)

- June 16 PAC Meeting Agenda Topics*
  - Asset Condition Projects
    - New Hampshire Line Asset Condition Structure Replacement – Lines 373, 385, 391 (Eversource)
    - Orchard Substation – 115 kV Circuit Breaker Asset Condition Replacement (Eversource)
    - A-179 Asset Condition Refurbishment Project (National Grid)
  - CT 2034 Needs Assessment Update
  - RSP Project List and Asset Condition List June 2025 Update
- June 18 PAC Forum on Grid Enhancing Technologies

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

2025 Longer-Term Transmission Planning RFP

- NESCOE provided a letter on 10/16/24 discussing potential transmission needs for a Longer-term Transmission Planning (LTTP) RFP, which was discussed at the 10/23/24 PAC meeting
- On 12/13/24, NESCOE provided its LTTP request describing the needs to be addressed by 2035:*
  - Increase the Maine-New Hampshire interface capacity to at least 3,000 MW
  - Increase the Surowiec-South interface capacity to at least 3,200 MW
  - Develop new infrastructure (e.g., substation) at Pittsfield, Maine that can accommodate the interconnection of at least 1,200 MW (nameplate) of onshore wind**
- NESCOE's LTTP request was discussed at the 12/18/24 PAC meeting
- Further discussion on details of the RFP, led by the ISO, occurred at the 1/23/25 PAC meeting, and additional discussion occurred at the 2/26/25 PAC meeting
- QTPS training on the use of Responsive occurred on 2/20/25
- The ISO issued the LTTP RFP on 3/31/25, with proposals due by 9/30/25

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

Economic Studies: 2024 Study

- The 2024 Economic Study
  - This study is the first use of new Economic Study Process Tariff language
    - The study was initiated at the January 2024 PAC meeting and will be completed this year unless a Request for Proposal is triggered
  - The Benchmark Scenario has been completed and the Policy and Stakeholder-Requested Scenarios are being analyzed between now and Q2 2025
    - Final results for the Policy scenario, some sensitivities, and preliminary stakeholder-requested results have been presented. Some additional results will be presented in July. The System Efficiency Needs Scenario will be studied in Q3-Q4 2025, following acceptance of the Tariff changes by FERC
    - As part of the Economic Study Process Phase 2 Tariff changes, “Market Efficiency” is being renamed to “System Efficiency;” Economic Study Phase 2 Tariff changes were filed with FERC on 4/23/25

RSP Project Stage Descriptions

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

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

Greater Boston Projects

Status as of 5/27/2025

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

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

Greater Boston Projects, cont.

Status as of 5/27/2025

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1330	Separate X-24 and E-157W DCT	Dec-18	4
1363	Separate Q-169 and F-158N DCT	Dec-15	4
1637, 1640	Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap	May-17	4
1516	Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook	Sep-20	4
965	Install third 115 kV line from West Walpole to Holbrook	Sep-20	4
1558	Install new 345 kV breaker in series with the 104 breaker at Stoughton	May-16	4
1199	Install new 230/115 kV autotransformer at Sudbury and loop the 282-602 230 kV line in and out of the new 230 kV switchyard at Sudbury	Dec-17	4
1335, 1672*	Install a new 115 kV line from Sudbury to Hudson	Dec-24, Sep-25*	4, 3

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

Greater Boston Projects, cont.

Status as of 5/27/2025

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

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

Greater Boston Projects, cont.

Status as of 5/27/2025

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

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

Greater Boston Projects, cont.

Status as of 5/27/2025

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

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

SEMA/RI Reliability Projects

Status as of 5/27/2025

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

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

SEMA/RI Reliability Projects, cont.

Status as of 5/27/2025

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1718	Add 115 kV circuit breaker at Robinson Ave substation and re-terminate the Q10 line	Mar-22	4
1719	Install 45.0 MVAR capacitor bank at Berry Street substation	Cancelled*	N/A
1720	Separate the N12/M13 DCT and reconductor the N12 and M13 between Somerset and Bell Rock substations	Mar-27	2
1721	Reconfigure Bell Rock to breaker-and-a-half station, split the M13 line at Bell Rock substation, and terminate 114 line at Bell Rock; install a new breaker in series with N12/D21 tie breaker, upgrade D21 line switch, and install a 37.5 MVAR capacitor	Aug-23	4
1722	Extend the Line 114 from the Dartmouth town line (Eversource-National Grid border) to Bell Rock substation	Dec-26	2
1723	Reconductor L14 and M13 lines from Bell Rock substation to Bates Tap	Cancelled*	N/A

*Cancelled per ISO-NE PAC presentation on August 27, 2020

SEMA/RI Reliability Projects, cont.

Status as of 5/27/2025

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1725	Build a new 115 kV line from Bourne to West Barnstable substations which includes associated terminal work	May-24	4
1726	Separate the 135/122 DCT from West Barnstable to Barnstable substations	Dec-21	4
1727	Retire the Barnstable SPS	Nov-21	4
1728	Build a new 115 kV line from Carver to Kingston substations and add a new Carver terminal	Aug-23	4
1729	Install a new bay position at Kingston substation to accommodate new 115 kV line	Aug-23	4
1730	Extend the 114 line from the Eversource/National Grid border to the Industrial Park Tap	Dec-26	2

SEMA/RI Reliability Projects, cont.

Status as of 5/27/2025

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1731	Install 35.3 MVAR capacitors at High Hill and Wing Lane substations	Dec-21	4
1732	Loop the 201-502 line into the Medway substation to form the 201-502N and 201-502S lines	Dec-25	3
1733	Separate the 325/344 DCT lines from West Medway to West Walpole substations	Cancelled**	N/A
1734	Reconductor and upgrade the 112 Line from the Tremont substation to the Industrial Tap	Jun-18	4
1736	Reconductor the 108 line from Bourne substation to Horse Pond Tap*	Oct-18	4
1737	Replace disconnect switches on 323 line at West Medway substation and replace 8 line structures	Aug-20	4

* Does not include the reconductoring work over the Cape Cod canal

** Cancelled per ISO-NE PAC presentation on August 27, 2020

SEMA/RI Reliability Projects, cont.

Status as of 5/27/2025

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

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

New Hampshire Solution Projects

Status as of 5/27/2025

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	Oct-24	4
1880	Install a +127/-50 MVAR synchronous condenser at Amherst 345 kV Substation with two 345 kV breakers	Dec 24	4
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 5/27/2025

Project Benefit: Addresses system needs in the Upper Maine area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1882	Rebuild 21.7 miles of the existing 115 kV line Section 80 Highland-Coopers Mills 115 kV line	Aug-24	4
1883	Convert the Highland 115 kV substation to an eight breaker, breaker-and-a-half configuration with a bus connected 115/34.5 kV transformer	Jul-28	1
1884	Install a 15 MVAR capacitor at Belfast 115 kV substation	Jul-28	1
1885	Install a +50/-25 MVAR synchronous condenser at Highland 115 kV substation	Jul-28	1
1886	Install +50/-25 MVAR synchronous condenser at Boggy Brook 115 kV substation, and install a new 115 kV breaker to separate Line 67 from the proposed solution elements	Aug-25	3

Upper Maine Solution Projects, cont.

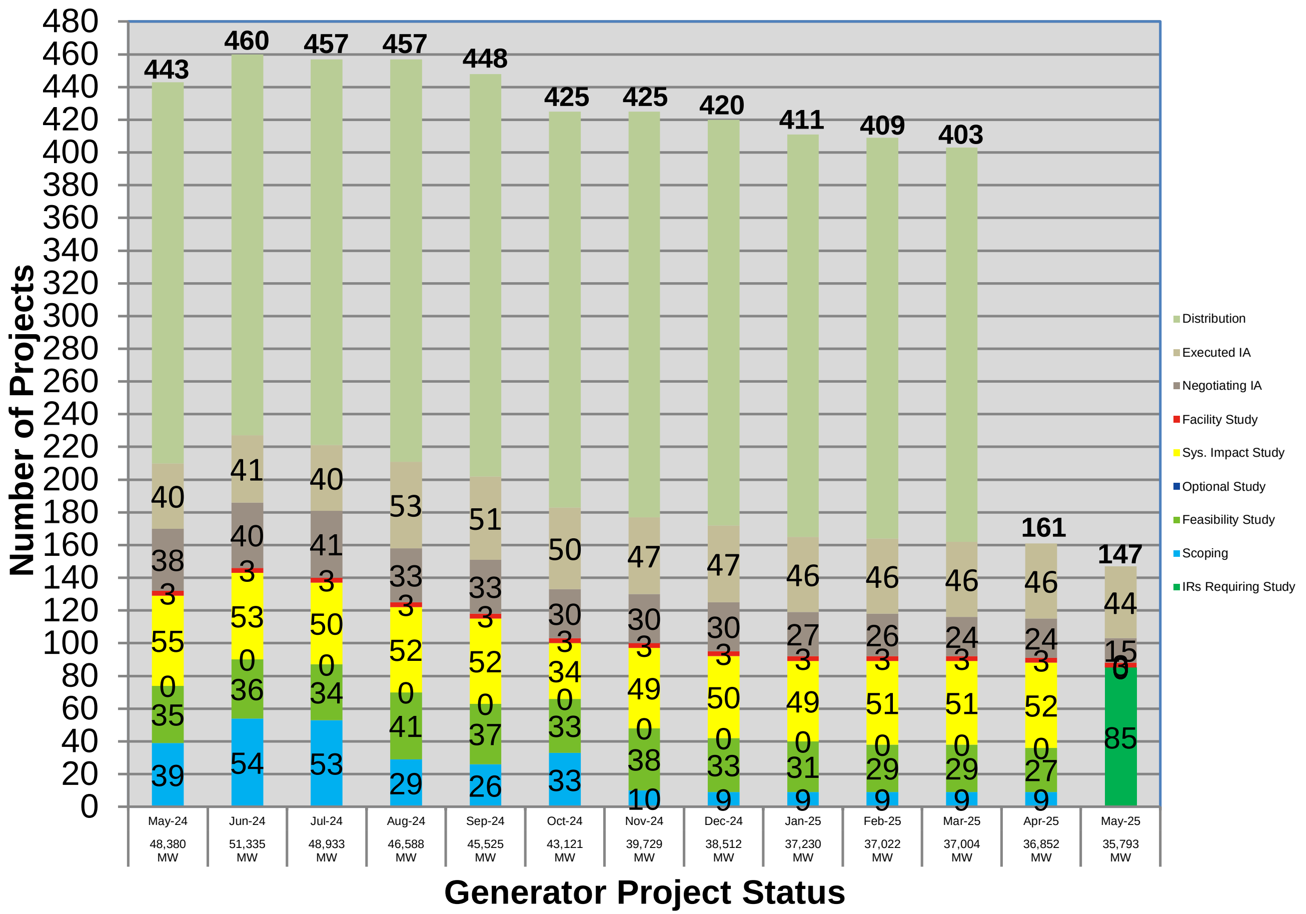
Status as of 5/27/2025

Project Benefit: Addresses system needs in the Upper Maine area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1887	Install 25 MVAR reactor at Boggy Brook 115 kV substation	Nov-24	4
1888	Install 10 MVAR reactor at Keene Road 115 kV substation	Jul-24	4
1889	Install three remotely monitored and controlled switches to split the existing Orrington reactors between the two Orrington 345/115 kV autotransformers	Cancelled *	N/A
1914	Install a new 80 MVAR reactor, reconfigure the existing two reactors at the 345 kV Orrington substation	Jun-26	2

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

Status of Tariff Studies as of May 29, 2025



ETUs: 7 with IRs Requiring Study, 0 in OIS, 0 in FAC, 0 Negotiating IA, and 4 with Executed IA
Transmission Service Requests needing study: 0
https://irtt.iso-ne.com/external.aspx

Note: As of April 2025, the ISO is no longer tracking Distribution Projects in its interconnection queue. Also, the values starting in May 2025 reflect that, as a result of the Order No. 2023 response from FERC, the ISO is no longer performing serial interconnection studies.

Note on Air Emissions Slides

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

OPERABLE CAPACITY ANALYSIS

Summer 2025 Analysis

Summer 2025 Operable Capacity Analysis

50/50 Load Forecast (Reference)	June - 2025[2] CSO (MW)	June - 2025[2] SCC (MW)
Operable Capacity MW [1]	25,989	27,054
Active Demand Capacity Resource (+) [5]	373	400
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,235	1,235
Non Commercial Capacity (+)	267	267
Non Gas-fired Planned Outage MW (-)	229	920
Gas Generator Outages MW (-)	166	192
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)	24,669	25,044
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	24,803	24,803
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	26,928	26,928
Operable Capacity Margin	-2,259	-1,884

[1] Operable Capacity is based on data as of **May 27, 2025** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **May 27, 2025.**

[2] Load forecast that is based on the 2025 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **June 14, 2025.**

[3] Total of (Gas at Risk MW) – (Gas Gen Outages MW).

[4] Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.

[5] Active Demand Capacity Resources (ADCRs) can participate in the Forward Capacity Market (FCM), have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.

Summer 2025 Operable Capacity Analysis

90/10 Load Forecast	June - 2025[2] CSO (MW)	June - 2025[2] SCC (MW)
Operable Capacity MW [1]	25,989	27,054
Active Demand Capacity Resource (+) [5]	373	400
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,235	1,235
Non Commercial Capacity (+)	267	267
Non Gas-fired Planned Outage MW (-)	229	920
Gas Generator Outages MW (-)	166	192
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)	24,669	25,044
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	25,886	25,886
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	28,011	28,011
Operable Capacity Margin	-3,342	-2,967

[1]Operable Capacity is based on data as of **May 27, 2025** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **May 27, 2025.**

[2] Load forecast that is based on the 2025 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **June 14, 2025.**

[3] Total of (Gas at Risk MW) – (Gas Gen Outages MW).

[4] Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.

[5] Active Demand Capacity Resources (ADCRs) can participate in the Forward Capacity Market (FCM), have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.

Summer 2025 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

May 27, 2025 - 50-50 FORECAST using CSO MW

This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week in June through mid September.

Report created: 5/27/2025

Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 50-50PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 50-50PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
6/14/2025	25989	373	1235	267	229	166	2800	0	24669	24803	2125	26928	-2259	Y	Summer 2025
6/21/2025	25989	373	1235	267	201	166	2800	0	24697	24803	2125	26928	-2231	N	Summer 2025
6/28/2025	25989	373	1235	267	188	166	2800	0	24710	24803	2125	26928	-2218	N	Summer 2025
7/5/2025	26072	404	1235	457	188	10	2100	0	25870	24803	2125	26928	-1058	N	Summer 2025
7/12/2025	26072	404	1235	457	201	10	2100	0	25857	24803	2125	26928	-1071	N	Summer 2025
7/19/2025	26072	404	1235	457	201	10	2100	0	25857	24803	2125	26928	-1071	N	Summer 2025
7/26/2025	26072	404	1235	457	83	0	2100	0	25985	24803	2125	26928	-943	N	Summer 2025
8/2/2025	26072	404	1235	469	81	0	2100	0	25999	24803	2125	26928	-929	N	Summer 2025
8/9/2025	26072	404	1235	469	67	0	2100	0	26013	24803	2125	26928	-915	N	Summer 2025
8/16/2025	26072	404	1235	469	67	0	2100	0	26013	24803	2125	26928	-915	N	Summer 2025
8/23/2025	26072	404	1235	469	67	0	2100	0	26013	24803	2125	26928	-915	N	Summer 2025
8/30/2025	26072	404	1235	469	115	0	2100	0	25965	24803	2125	26928	-963	N	Summer 2025
9/6/2025	26072	404	1235	469	115	0	2100	0	25965	24803	2125	26928	-963	N	Summer 2025
9/13/2025	26072	404	1235	469	149	0	2100	0	25931	24803	2125	26928	-997	N	Summer 2025

Column Definitions

1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.
5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 2025 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

Summer 2025 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

May 27, 2025 - 90/10 FORECAST using CSO MW

This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week in June through mid September.

Report created: 5/27/2025

Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 90-10PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 90-10PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
6/14/2025	25989	373	1235	267	229	166	2800	0	24669	25886	2125	28011	-3342	Y	Summer 2025
6/21/2025	25989	373	1235	267	201	166	2800	0	24697	25886	2125	28011	-3314	N	Summer 2025
6/28/2025	25989	373	1235	267	188	166	2800	0	24710	25886	2125	28011	-3301	N	Summer 2025
7/5/2025	26072	404	1235	457	188	10	2100	0	25870	25886	2125	28011	-2141	N	Summer 2025
7/12/2025	26072	404	1235	457	201	10	2100	0	25857	25886	2125	28011	-2154	N	Summer 2025
7/19/2025	26072	404	1235	457	201	10	2100	0	25857	25886	2125	28011	-2154	N	Summer 2025
7/26/2025	26072	404	1235	457	83	0	2100	0	25985	25886	2125	28011	-2026	N	Summer 2025
8/2/2025	26072	404	1235	469	81	0	2100	0	25999	25886	2125	28011	-2012	N	Summer 2025
8/9/2025	26072	404	1235	469	67	0	2100	0	26013	25886	2125	28011	-1998	N	Summer 2025
8/16/2025	26072	404	1235	469	67	0	2100	0	26013	25886	2125	28011	-1998	N	Summer 2025
8/23/2025	26072	404	1235	469	67	0	2100	0	26013	25886	2125	28011	-1998	N	Summer 2025
8/30/2025	26072	404	1235	469	115	0	2100	0	25965	25886	2125	28011	-2046	N	Summer 2025
9/6/2025	26072	404	1235	469	115	0	2100	0	25965	25886	2125	28011	-2046	N	Summer 2025
9/13/2025	26072	404	1235	469	149	0	2100	0	25931	25886	2125	28011	-2080	N	Summer 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.
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5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 2025 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

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

Possible Relief Under OP4: Appendix A

OP 4 Action Number	Page 1 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
1	Implement Power Caution and advise Resources with a CSO to prepare to provide capacity and notify "Settlement Only" generators with a CSO to monitor reserve pricing to meet those obligations. Begin to allow the depletion of 30-minute reserve.	0 [1] 600
2	Declare Energy Emergency Alert (EEA) Level 1[4]	0
3	Voluntary Load Curtailment of Market Participants' facilities.	40 [2]
4	Implement Power Watch	0
5	Schedule Emergency Energy Transactions and arrange to purchase Control Area-to-Control Area Emergency	1,000
6	Voltage Reduction requiring > 10 minutes	125 [3]

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

Possible Relief Under OP4: Appendix A

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

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

5 ISO New England's Multi-year Roadmap

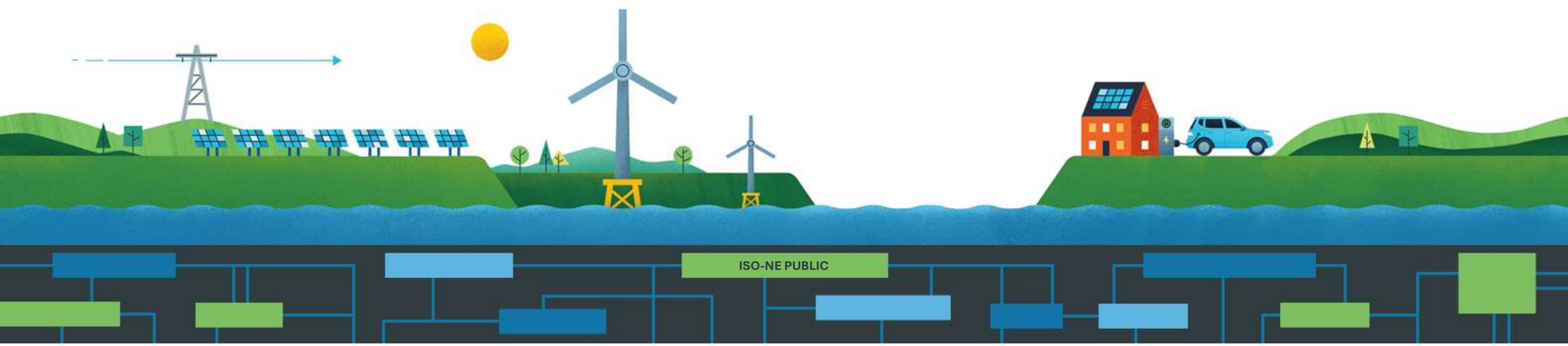
Review and Discussion of the ISO's longer-term focus for addressing the pace of change and uncertainty facing the power system

Multi-Year Roadmap

Key Future Focus Areas for 2027-2030 to advance a reliable, clean-energy transition

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER



Roadmap Aligns with the Four Pillars

- Through continuous observation and evaluation of current and changing system conditions, the ISO identifies potential enhancements needed to support the four pillars critical to achieving a reliable, clean-energy transition

Clean Energy
to power the economy with a greener grid

Balancing Resources
that can supply electricity, reduce demand, or provide other services to maintain power system equilibrium

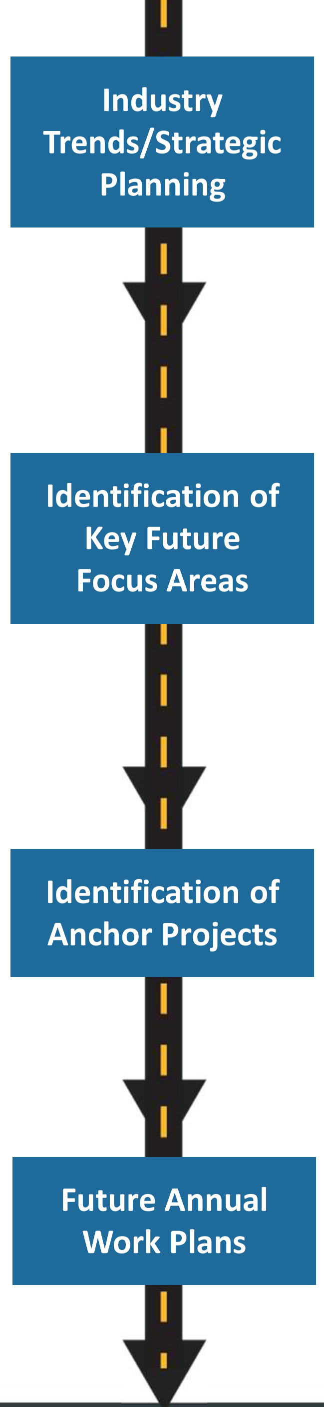
Energy Adequacy
requires a dependable energy supply chain and/or a robust energy reserve to manage through periods of stress on the grid

Robust Transmission
to integrate renewable resources and move clean energy to consumers across New England

- The *Multi-Year Roadmap* commences execution of the ISO's longer-term strategic planning by identifying **Key Future Focus Areas**
  - Resulting initiatives are anticipated to become **Anchor Projects**, or the ISO's highest priority efforts, in future Annual Work Plans

About this Roadmap

- The Roadmap reflects the ISO's current perspective of upcoming issues, though Key Future Focus Areas may change or resolve over time
  - Increased or expanded stakeholder requests, regional policy directives, and Federal Energy Regulatory Commission rulemaking, can also shift priorities and affect plans
- The Roadmap does not reflect the full volume of future project development work, implementation work, or work representing the extensive day-to-day operations related to running the grid, markets, IT infrastructure, and organization
- This Roadmap outlines the **Key Future Focus Areas** likely to yield **Anchor Projects** in **2026/2027-2029**
  - Development and implementation of the 2025 Anchor Projects are expected to extend into 2026/2027 due to their breadth and complexity



2025 Anchor Projects Summary

For Development and Implementation in ***2025-2026/2027***

- **Capacity Auction Reforms (CAR):** Designing and implementing a set of distinct, highly complex initiatives that restructure the capacity market and resource accreditation models in step with grid transformation
- **Regional Energy Shortfall Threshold (REST):** Innovating ways to identify and address reliability risks from extreme weather events as grid supply and demand trends change
- **Longer-Term Transmission Planning (LTTP) and Generator Interconnection Compliance, Implementations, and Enhancements:** Executing the first LTTP competitive solicitation to help meet state clean-energy goals; continuing compliance with and implementation of FERC Order Nos. 1920 and 2023 and other related, ongoing enhancements
- **nGEM Real-Time Market Clearing Engine:** Developing and implementing a replacement of the 20+ year old Market Management System with a platform that is foundational to managing an exponentially complex future grid

See the 2025 Annual Work Plan and 2025 Annual Work Plan Update

KEY FUTURE FOCUS AREAS

System Operations Key Future Focus Area

Reliably Manage Increased Operational Uncertainty

- **Issue.** Changes in demand and energy supply technologies are creating greater operational uncertainties hour-to-hour and day-to-day
  - These uncertainties result from the variable, or dynamic, nature of: weather-dependent renewable energy supply, limited-energy storage resources, and load-side behaviors from behind-the-meter photovoltaic (PV) and from heating- and transportation-sector electrification
- Managing operational uncertainty will require the ISO to improve its ability to perform the following functions:
  - Forecast load, solar PV, wind, and energy availability of limited energy resources
  - Maintain real-time situational awareness of deviations from forecasts and respond to significant deviations reliably and efficiently
  - Monitor and respond (as needed) to non-traditional system behaviors at the transmission and distribution interface
- **Key Focus Area.** Developing high-performing tools and systems to manage uncertainty and to enhance reliable and efficient operations of a dynamic power system

System Operations Focus Area Example Initiative

Probabilistic Forecasting of Load, Solar PV, and Wind

- In a system with high levels of uncertainty, there is increased value in quantifying that uncertainty using probabilistic forecasting methodologies
  - ISO's existing short-term forecasts are primarily deterministic, meaning they produce a single value (*e.g.*, the load forecast for the peak hour tomorrow is X MW)
- Probabilistic forecasting is a complex process that provides a range of forecasted values along with a probability of occurrence for each (*e.g.*, the load forecast is between X and Y for peak hour at Z% confidence)
  - As a key input to operational risk assessments, probabilistic forecasts could better inform real-time (and near-real time) decision-making, facilitating more reliable, efficient operating plans
- Research on probabilistic forecasting methodologies and tools is underway

Markets Key Future Focus Area

Real-Time Pricing Improvements for a Dynamic Power System

- **Issue.** Real-time systems must be able to "see" far enough ahead to efficiently optimize and price energy and ancillary services over the balance of the day
- The clean energy transition will require new, forward-looking intra-day market clearing and pricing systems that can co-optimize over multiple time periods during the operating day, in order to:
  - Price the costs of managing steep, multi-hour load ramps (up and down) with the development of significant solar PV resources
  - Incorporate time-varying probabilistic forecasts of renewable energy production into dynamic reserve requirements or new flexibility services
  - Optimize storage technologies' limited energy and flexibility more efficiently with an increasingly storage-dependent system
- **Key Focus Area.** Developing dynamic pricing systems that balance these operating characteristics and address uncertainties in the evolving system

Markets Focus Area Example Initiative

Multi-Interval Pricing with Operational Uncertainty

- To cost-effectively address operational uncertainties in a dynamic power system, costs will need to be incurred *now* to position the system with sufficient flexibility *later*
- This will require new real-time "multi-interval" optimization and pricing algorithms incorporating probabilistic forecasts
- Research is currently underway; due to the foundational system changes involved, the ISO may recommend a sequence of phased and inter-dependent market enhancements over the course of this initiative

System Planning Key Future Focus Area

Comprehensive Planning Framework for Grid Efficiency

- **Issue:** The continuing clean-energy transition will require consolidated planning for a growing range of system uncertainty
- The ISO uses an increasing variety of studies, models, and processes to support its planning decisions and recommendations
- Further cohesion and capability of those studies, models, and processes will be critical to fine-tuning the accuracy of resulting decisions and recommendations, such as for:
  - Quantifying reliability risks (e.g., Expected Unserved Energy)
  - Evaluating various “what if” scenarios (e.g., longer-term transmission planning)
  - Assessing system impacts of new system components (e.g., inverter-based resources)
- **Key Focus Area:** Developing a platform to enable further advancement and alignment of planning tools and technologies to address uncertainty in a dynamic power system

System Planning Focus Area Example Initiative

Innovating Inverter-Based Resource (IBR) Modeling

- NERC has analyzed instances of widespread IBR output reductions on the bulk power system that were unexpected largely because generator interconnection study models or other system studies did not adequately reflect the dynamic performance characteristics of IBRs
- This IBR performance uncertainty will require the ISO to enhance its generation interconnection studies to more accurately and efficiently model:
  - Increasing system complexity (e.g., IBRs are changing the behavior of the system)
  - Larger data volumes and computational capabilities (e.g. interconnection data volume due to IBR growth)
- The ISO has begun to take steps to develop an electromagnetic transient (EMT) model management system
  - EMT simulation is computationally challenging and requires complex models that describe fast transient phenomena, such as controls and protections of IBRs
  - Will enable more efficient and reliable integration of IBRs and transmission solutions to meet clean-energy goals, among many other benefits

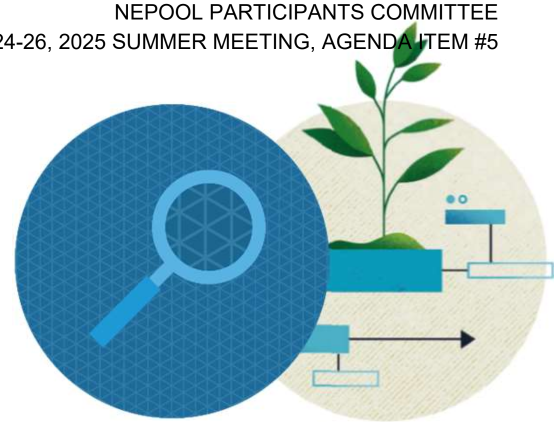
Resource Adequacy Key Future Focus Area

Engage on Emerging Resource Adequacy Policy Developments

- **Issue.** Resource adequacy has become an emerging topic at the federal level, as evidenced by the March 25, 2025, congressional hearing on the state of grid reliability, and the June 4-5, 2025, FERC Technical Conference on Meeting the Challenge of Resource Adequacy in RTO/ISO Regions
  - The ISO's 2025 AWP Anchor Projects and the Multi-Year Roadmap Key Future Focus Areas lay the necessary groundwork to maintain resource adequacy
  - Over the next 3-5 years, the ISO is heavily invested in developing the Capacity Auction Reforms (CAR-prompt, -seasonal, -accreditation, -mitigation) and the follow-on enhancements (CAR roadmap), that adapt to shifting resource mixes and regional conditions
    - New England needs to be prepared for the various uncertainties pertaining to resource adequacy in the 2030s
- Federal developments may result in added or modified efforts for ISOs/RTOs
- **Key Focus Area.** Actively engaging with stakeholders as and when resource adequacy needs/policies become more actionable

Technology and Security Focus Areas

Continued investment in critical IT priorities to support a dynamic future system



- **Cloud Computing**
  - Transitioning to a cloud environment continues to be a major effort over the next several years to minimize technology infrastructure maintenance costs, speed deployment of software, increase scalability and flexibility, and enable faster computing performance
- **Artificial Intelligence**
  - Artificial Intelligence has become a transformative technology, and the ISO is preparing for its proliferation; policies have been updated, governance processes are established, and multiple initiatives are underway providing experience to both business and IT teams
- **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

APPENDIX

Anchor Project Details from 2025 Annual Work Plan Update

Anchor Projects on Track

Schedules on track from 2025 AWP publication

- **Day-Ahead Ancillary Services Initiative**
  - Implemented February 28, 2025
  - On April 10, 2025, the ISO is offering another session for Participants looking for further support and information on the market mechanics; additionally, the Internal Market Monitor plans to discuss its initial market outcomes and findings with stakeholders, in conjunction with its market reports, starting as early as Q2 2025
- **Capacity Auction Reforms (CAR)**
  - Stakeholder discussions are moving forward on target; *see* the schedule on slides 50-51 of the March 11, 2025, Markets Committee materials
- **First Competitive Solicitation for Longer-Term Transmission Planning (LTTP) Solution**
  - The 2025 Longer-Term Transmission Planning RFP was issued March 31, 2025, after a brief Planning Advisory Committee (PAC) comment period; *see* the schedule on slides 38 and 43 of the February 26, 2025, PAC materials
- **nGEM Real-Time Market Clearing Engine**
  - To implement Q2 2026

Anchor Projects on Track, cont'd

- **Regional Energy Shortfall Threshold (REST)**
  - Discussions are continuing on 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 Probabilistic Energy Adequacy Tool (PEAT)
  - Starting with winter 2025/2026, the ISO plans to use the PEAT to begin performing seasonal assessments of energy adequacy risk against the REST criteria
  - The ISO also plans to annually perform PEAT/REST assessments with longer look-ahead horizons (to be defined) to inform risk trends over time
    - Forewarning of when system stresses may be expected will be essential as load profiles change, the resource mix evolves, and climate projections are refined
  - Risk-trend data from the assessments will guide the timing and nature of the **next phase:** evaluating whether the possibility of exceeding the REST requires development of specific regional solutions to mitigate risks and, if so, when to begin to develop solutions
    - Note that initial PEAT study results concluded that winter energy shortfall impacts appear manageable using existing tools through 2032, allowing time to develop solutions to mitigate future risk as needed

Updated Anchor Projects

Schedules adjusted since 2025 AWP publication

- **FERC Order No. 2023 Continued Compliance and Implementation**
  - On April 4, 2025, FERC issued an order on the ISO's compliance filing; the ISO is reviewing the order and working on next steps, which it will discuss with stakeholders at the April 2025 Transmission Committee meeting
- **FERC Order No. 1920 and 1920-A Compliance**
  - On February 10, 2025, FERC accepted the ISO's two-year extension request, with regional and interregional compliance now due June 2027, effective four months after FERC acceptance; stakeholder discussions are targeted to begin in Q3 2026 (from Q3 2024 in the AWP)

Updated Anchor Projects, cont'd

- **Further Inclusion of Grid Enhancing Technologies (GETs) Into Transmission Planning**
  - With the extension on Order No. 1920, stakeholder discussions are expected to begin in Q2 2025 (from Q4 2024 in the AWP) on establishing guidelines for *how* to apply GETs in assessments; tariff rules for *when* to consider GETs will be considered as part of the Order No. 1920 compliance discussions
- **Transmission Sizing for the Clean Energy Transition**
  - Discussions to establish "right-sizing" guidelines are expected to begin after the states and Transmission Owners complete their asset condition process improvements initiative
- **Longer-Term Transmission Planning Phase 3**
  - Stakeholder discussions are targeted to begin after experience has been gained from completing the First Competitive Solicitation for LTTP Solution and after the Order No. 1920 compliance filing

<table>
<tr><th>2025 AWP Update</th><th>Q2</th><th>Q3</th><th>Q4</th><th>Spans Into 2026</th></tr>
<tr><td rowspan="2">Markets</td><td colspan="3">Capacity Auction Reforms</td><td>CAR-SA</td></tr>
<tr><td colspan="2"></td><td colspan="2">Flexible Response</td></tr>
<tr><td rowspan="6">Operations & Planning</td><td colspan="3">Regional Energy Shortfall Threshold</td><td>REST Solutions</td></tr>
<tr><td colspan="4">Order No. 2023 Continued Compliance and Implementation</td></tr>
<tr><td colspan="4">First Competitive Solicitation for LTTP Solution</td></tr>
<tr><td>GETs</td><td colspan="2">Transmission Sizing for Energy Transition</td><td>Order No. 1920</td></tr>
<tr><td colspan="3">Single Source Contingency Limit Assessment</td><td></td></tr>
<tr><td colspan="3">Tie Benefits Winter Modeling Evaluation</td><td></td></tr>
<tr><td rowspan="4">Capital Priorities</td><td colspan="4">nGEM Market Clearing Engine</td></tr>
<tr><td colspan="4">Inverter-Based Resource Modeling, Synchrophasor, IMS</td></tr>
<tr><td colspan="4">Cloud Computing & Cyber Security</td></tr>
<tr><td colspan="4">Order No. 881: Managing Transmission Line Ratings</td></tr>
</table>

Approximate Stakeholder Discussion Timing

6 Preliminary ISO 2026 and 2027 Operating and Capital Budgets

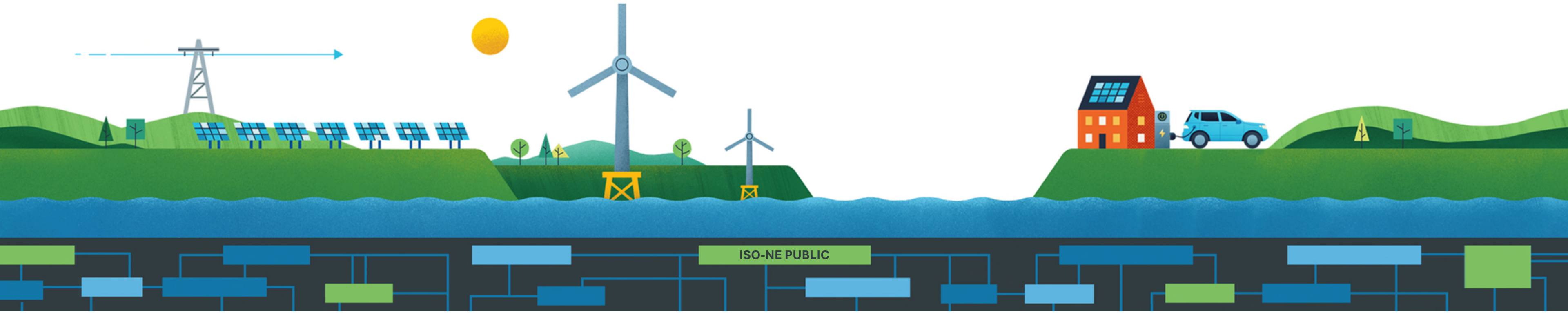
To receive a report on the ISO's preliminary 2026 and 2027 Operating and Capital Budgets by Kelly Reyngold, Controller, ISO New England.

ISO New England 2026 and 2027 Preliminary Operating and Capital Budgets

NEPOOL Participants Committee 2025 Summer Meeting

Robert Ludlow
CHIEF FINANCIAL OFFICER

Kelly Reyngold
DIRECTOR, ACCOUNTING



Contents of Presentation

EXECUTIVE SUMMARY

Introduction

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

2026 Budget Inputs and 2040 Scenario Outlook

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

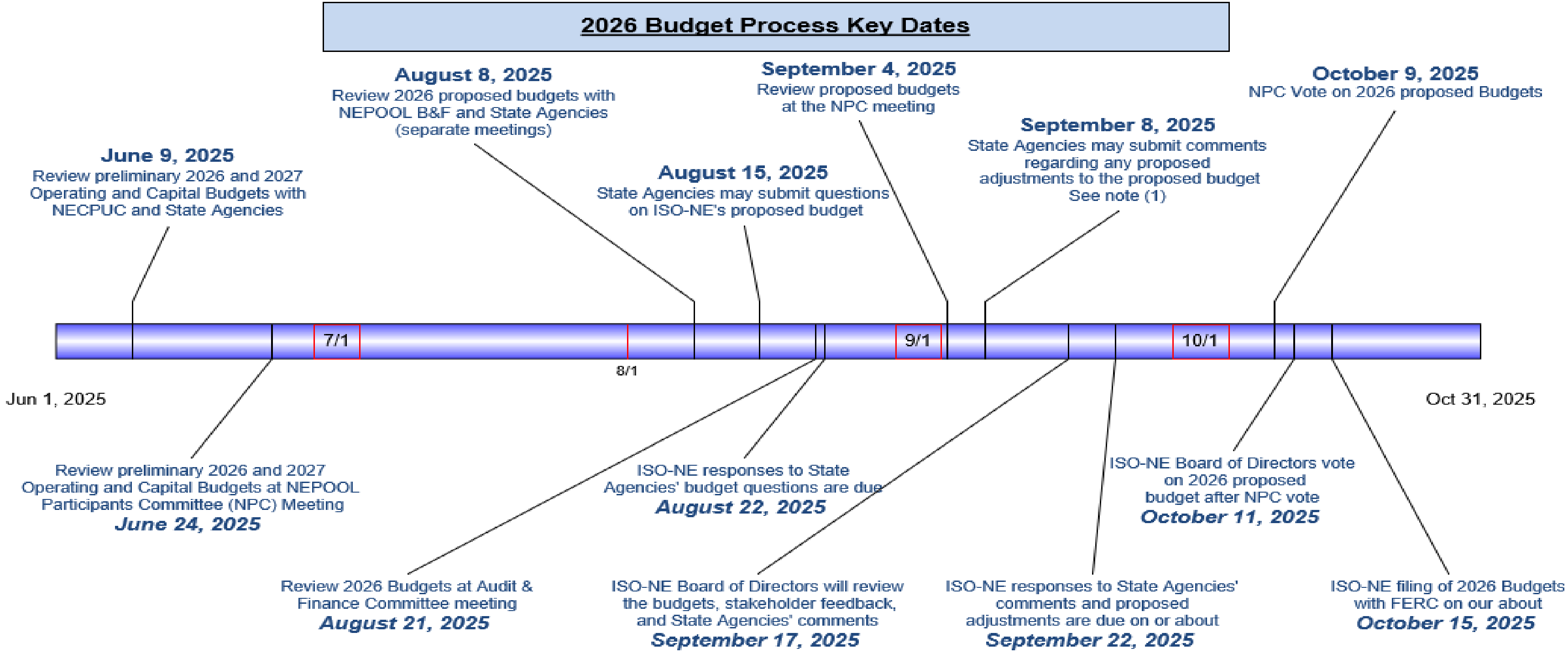
Executive Summary

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

Executive Summary *(cont.)*

- This top-down Preliminary 2026 budget, provided for stakeholder feedback, reflects a decrease relative to what was initially projected for 2026 at this time last year (during the 2025 and 2026 Preliminary Budgets):
  - Reducing the number of FTE additions in 2026, to 24 from the initial projection of 30 (onboarding of the 24 positions is prorated over 2026)
    - 2026 contains full funding for 2025 positions that had prorated onboarding that year
  - Technology costs that were not as steep as originally estimated
  - The rapid energy transition and increasing requirements by FERC and the states, require continued investment to achieve and maintain our strategic objectives (in many areas we are still catching up with changes that have already occurred, or complying with past FERC orders)

2026 Budget Process – Key Dates



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

STRATEGIC PLANNING PROCESS OVERVIEW

ISO-NE's integrated business and strategic planning framework

Annual Process – Business and Strategic Planning

ISO-NE is guided by a purposeful and integrated business planning approach that drives focus towards a common target that 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 support the states' policy goals to achieve a reliable transition to clean energy, utilizing competitive markets and transmission planning

Vision Statement:

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

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

Our Responsibility to the Region: ISO's Mission

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

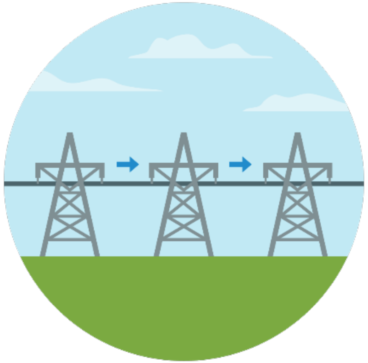
Mission Statement:

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

Core Functions Within ISO Jurisdiction

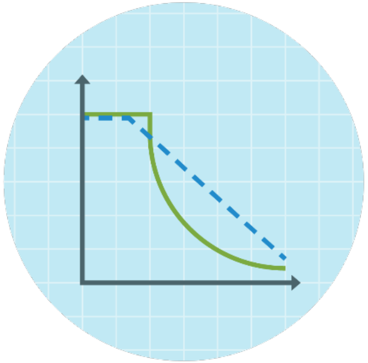
Grid Operation

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



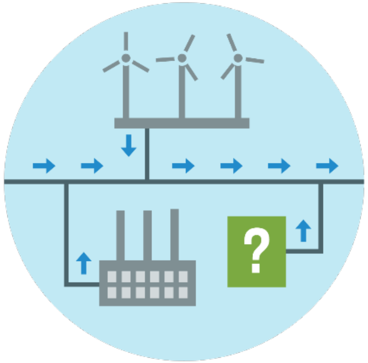
Market Administration

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



Transmission System Planning

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



Functions Outside of ISO Jurisdiction

The ISO does not...

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

GRID TRANSITION AND ISO-NE'S BUDGET

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

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

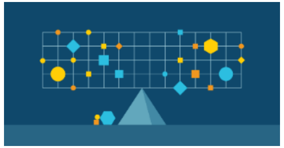
- The operationalizing of market, transmission, and emerging technology initiatives put in place through 2025 and 2026 requires ongoing support through increased headcount to service new tools and the needed technology stack associated with them
- The resource mix and customer use patterns in New England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

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

- Continue capacity market reforms to better ensure power system reliability and cost-efficiency as New England's resource mix evolves
- Advance long-term transmission planning to support clean energy integration and address evolving system needs
- Collaborate with stakeholders to address potential risks of exceeding Regional Energy Shortfall Threshold (REST)
- Enhance collaboration with NEPOOL, state agencies, and other stakeholders to ensure inclusive and transparent decision-making
- Inform policymakers about the role of retail market designs in mitigating price volatility and promoting resource development
- Invest in advanced technologies and analytics to improve system operations and planning capabilities to improve forecasting and situational awareness around changing resource mix
- Strengthen cybersecurity measures and infrastructure to safeguard grid reliability
- Consider Asset Condition Reviewer role

Key Trends Informing Our Budget

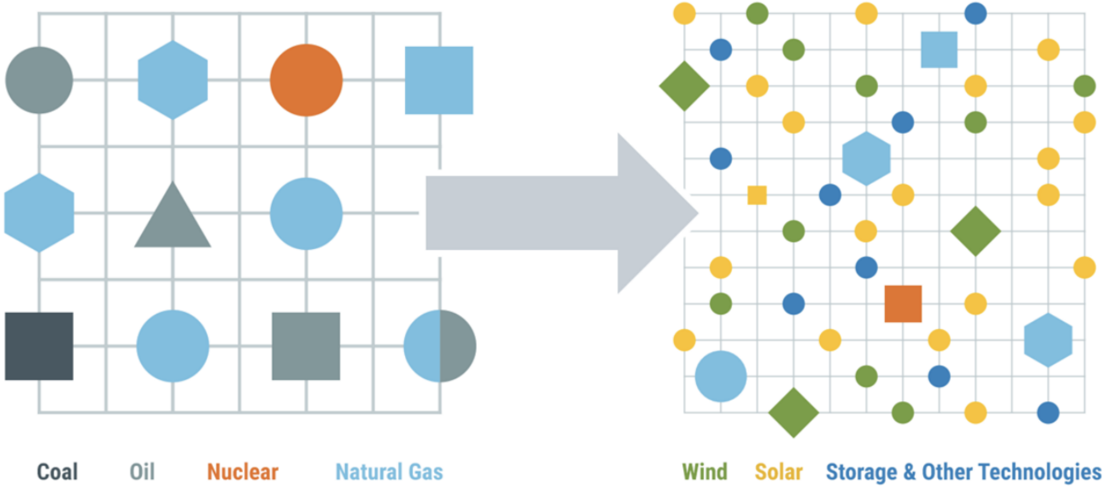
More renewable energy and storage on the New England grid by 2030



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

New England's seasonal operating risks

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

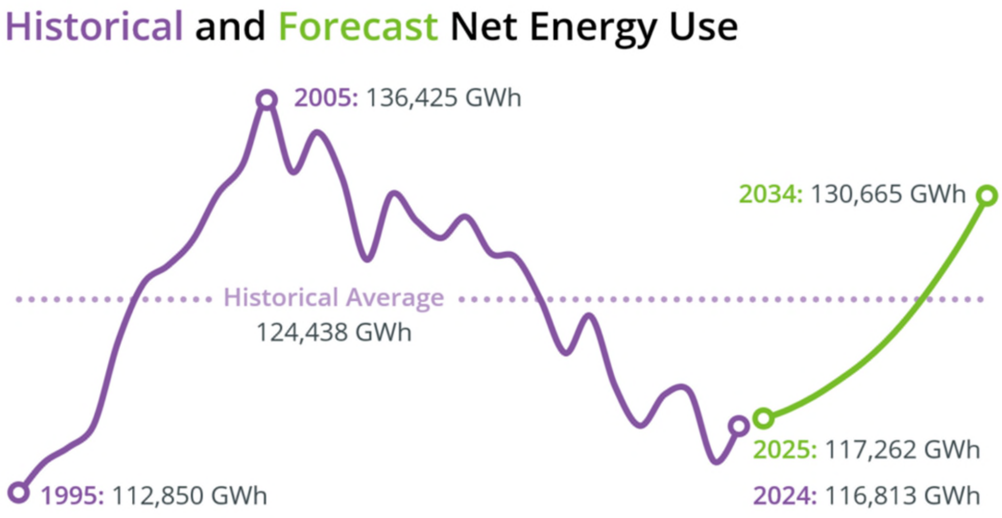


1. A shift from centrally dispatched generation to distributed resources

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

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

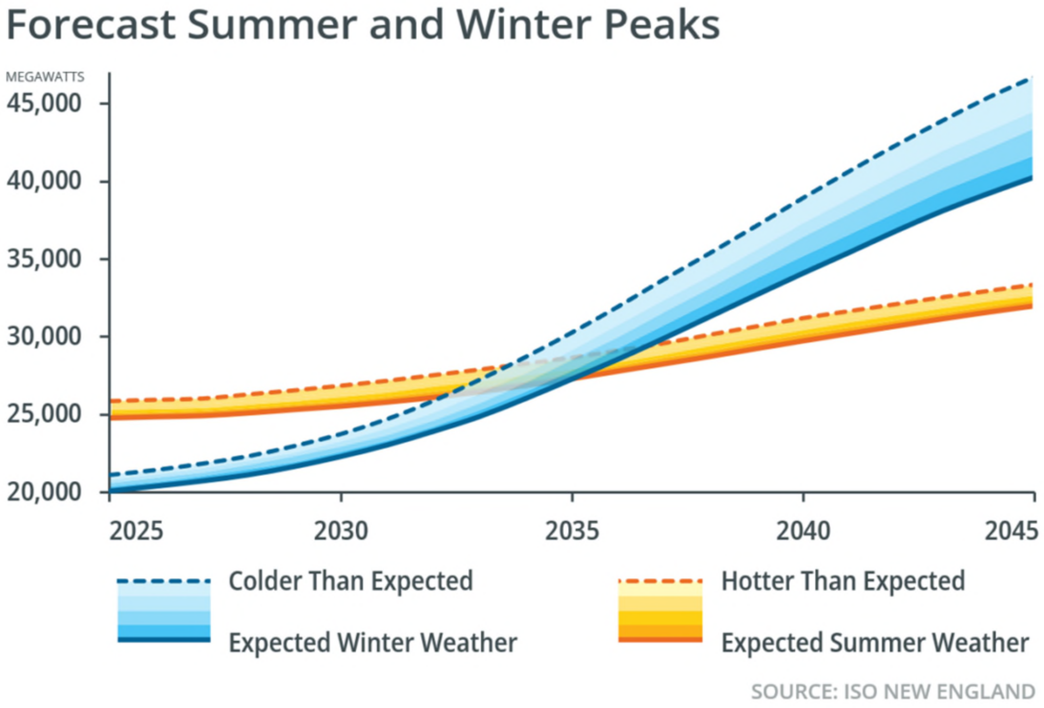
Following two decades of decreased net energy use as a result of state policies incentivizing solar PV and energy efficiency



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

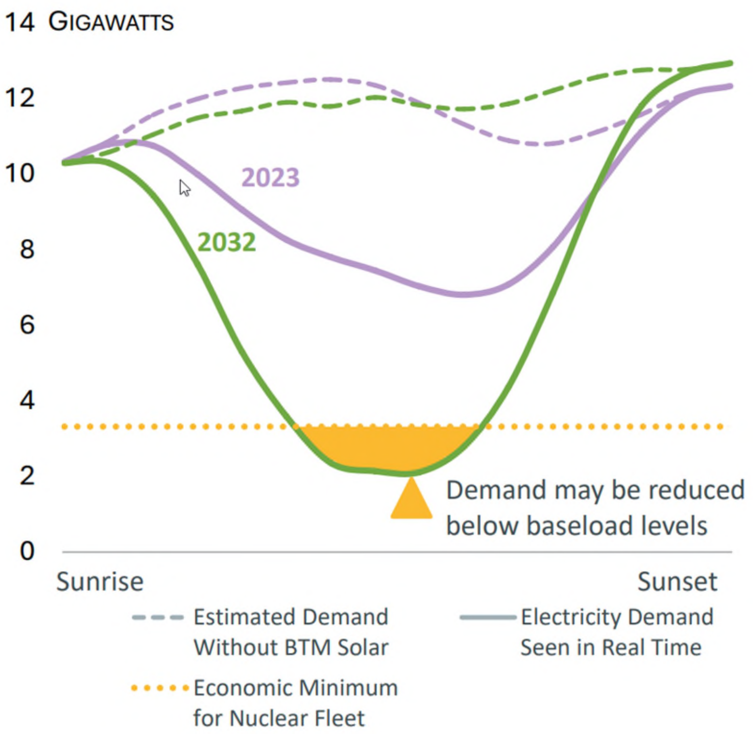
Source: ISO New England 2024-2033 Forecast Report of Capacity, Energy, Loads, and Transmission (2025 CELT Report) (May 2025)

Changes in Timing of Daily Peaks has Necessitated Advanced Modeling Methodologies



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

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



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

SUPPORTING THE FOUR PILLARS

ISO Initiatives to bolster the four pillars

Four Pillars of Supporting a Successful Energy Transition

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

1

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

2

Balancing resources that keep electricity supply and demand in equilibrium

3

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

4

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

Clean Energy Pillar – ISO Initiatives

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

2025

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

2026

- Explore enhancing probabilistic forecasting to improve evaluating BTMPV
  - Along with other weather dependent resources
- Implement FERC Order 2222 to promote participation of aggregated distributed resources in wholesale electric markets

Balancing Resources Pillar – ISO Initiatives

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

2025

- Implement Day-Ahead Ancillary Services Initiative (DASI) to create pricing incentives for specific energy and reserve capabilities needed for reliability as regional supply and demand transform
- Complete design of prompt and retirements for CAR
- Complete assessment of capacity accreditation for CAR
- CAR implementation – 2028

2026

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

Energy Adequacy Pillar – ISO Initiatives

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

2025

- Defining an acceptable REST with stakeholders
- Developing capacity accreditation reforms so that resources are appropriately compensated for available capacity
- Implementing DASI and begin assessing further market reforms to support flexible reserves for those resources that can respond to operational uncertainty and higher ramp rates
- Evaluate Potential Tie Benefits Winter Modeling Improvements
  - Report to stakeholders in Q3/Q4 2025, in alignment with CAR stakeholder schedule on seasonal tie benefits

2026

- Complete design of Seasonal Accreditation
- Continue to assess market reforms to support flexible reserves
- Explore using Probabilistic Energy Adequacy Tool (PEAT) analyses to support outage coordination management

Transmission Pillar – ISO Initiatives

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

2025

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

2026

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

2026 AND 2027 PRELIMINARY BUDGET OVERVIEW

Drivers of 2026 Budget Increases

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

2026 Preliminary Budget Overview

- The net revenue requirement with prior year true-ups is an increase of $4.0M or 1.3% year-over-year
  - The proposed 2026 revenue requirement, before true-up is $330.8M, an increase of 8.0% over 2025, which is $6.2M or 1.8% lower than the amount initially projected for 2026 in the budget presentation given last year
    - Included in the above amounts is a $1M “placeholder” funding for Asset Condition Review work that will only be used for this purpose, and if not needed will not be reallocated for other uses

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

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

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

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

Factor	% Increase	$ Amount	$KWh Rate	Average Monthly Consumer Cost Impact *
Changing Resource Mix/Customer Use Patterns	4.8 %	$15,018,100	$ 0.00012	$ 0.09
Attract/Retain Staff and Operational Increases	3.0%	$ 9,381,200	$ 0.00008	$ 0.06
Net Change in Rev Req True-Up	(6.5)%	$(20,445,300)	$(0.00017)	$(0.13)
Total Change in Revenue Req for 2026:	**1.3 %**	**$3,954,000**	**$0.00003**	**$0.02**

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

2026 Preliminary Capital Budget Overview

The 2026 Capital Budget is also presented in summary form

- The 2026 Capital Budget is consistent with the 2025 Capital Budget at $42.5M
  - Capital budget increases over the past several years have been driven by three primary drivers as explained in further detail in Appendix 3
  - Capital budget spending is expected to increase in the foreseeable future
    - In addition, ISO is considering additional expansion of building space which would be funded by tax-exempt bonds, if approved (See Appendix 7 for additional information)
  - The increased capital spending will result in higher interest expense costs and depreciation expense in future years as capital projects go into service and are included in operating budgets and rates
- The 2026 proposed capital budget of $42.5M is provided with a list of projects by strategic goal that are currently chartered and on-going or in planning/conceptual design (See Appendix 4)
- Detailed project descriptions will be presented in August once the final resource requirements are determined

2027 Preliminary Budget Overview

2027 Budget Assumptions include:

- The addition of 28 FTEs, primarily to address the changing resource mix and customer use patterns as well as operational needs, in the areas of System Planning, System Operations & Market Administration, Information and Cyber Security Services, Advanced Technology Solutions, Participant Relations and Services, Market Development and other support areas
- Merit and promotional/equity annual increases consistent with 2026 percentage increases noted on slide 40
- Estimated increases based on market or historical trends related to: employee benefits (primarily for health insurance); Computer Services; and Insurance Expense
- Inflationary increases in other lines based on consumer price index indicator

2026 and 2027 Operating Budget Risks

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

APPENDIX 1: 2026 Detailed Budget Changes by Strategic Goal

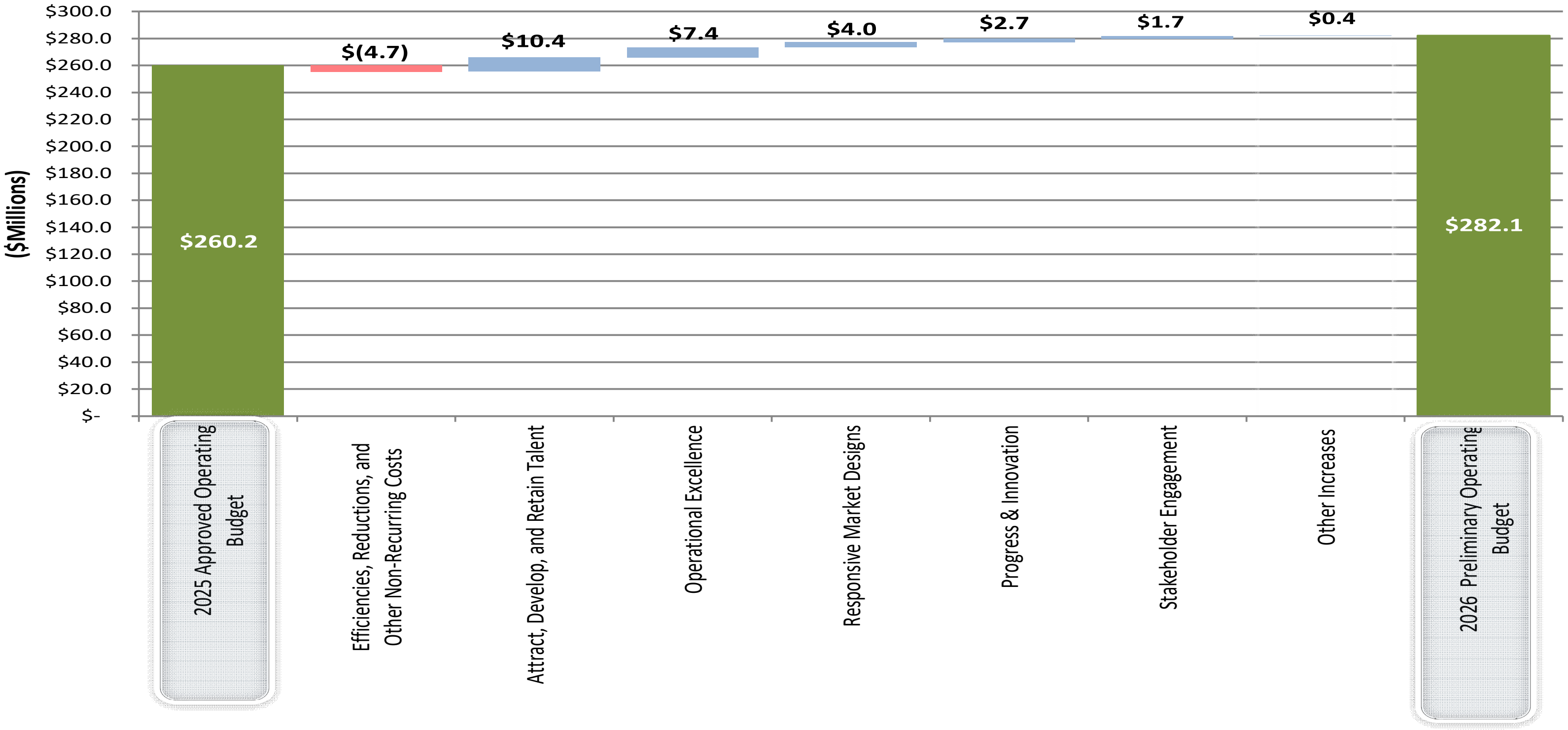
2026 ISO-NE Strategic Goals

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

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

2026 Preliminary Budget

Changes in budget by Strategic Goal



2026 Preliminary Budget Details

Efficiencies, Reductions, and Other Non-Recurring Costs

Reductions include: ($4.7M)

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

2026 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2026 Initiatives

Changes in budget for Attract, Develop, and Retain Talent: $10.4M

- Merit and Promotion increases: for annual merit (4.0%) and for standard and targeted promotion/adjustments (1.5%) ($6.5M)
- Increases in employee benefit costs, primarily for medical trend, and increased number of employees in Defined Contribution Benefit Plan ($2.4M)
- An increase for the reduction of employee vacancy from 6% to 5.5% based on projected hiring ($0.7M)
- Employees fees related to the relocation of approximately 90 employees to the Windsor campus ($0.2M)
- Funding for Human Resource (HR) membership for business advice on priorities across the HR function ($0.2M)
- Board of Director search fees to recruit for position scheduled for turnover ($0.2M)
- Funding for 0.5 of an FTE related to this goal for Corporate Counsel to support employee related matters ($0.1M)
- Increase in Board of Director retainer fees ($0.1M)

2026 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2026 Initiatives

Changes in budget for Operational Excellence: $7.4M

- Computer service and leasing increases for: cyber security (security log management, network detection and response tool, zero trust access and protection, and cloud monitoring); network collaboration software; leasing of servers as part of data center refresh; computing and storage capacity application; licensing for System Planning and Operations applications; and inflationary and vendor increases across our portfolio of computer service products ($3.8M)
- Funding for 16.0 FTEs for System Operations and System Planning to address technical challenges and perform system assessments and studies with the continued installation of Inverter Based Resources and for NERC/NPCC requirement responsibilities; for Information and Cyber Security for Cloud Computing transition including architecture, service delivery, and IT forecasting tool support; for project management support due to increased number and sophistication of capital projects; for Finance and Market Credit Risk to support the growth in these areas to support the organization ($3.2M)
- Network Operations increases for transition of communication lines to new technologies, for data redundancy, and for inflationary and communication line increases ($0.3M)
- Data services subscriptions for Market Monitoring utilization and for vendor third party risk assessment ($0.1M)

2026 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2026 Initiatives

Changes in budget for Responsive Market Designs: $4.0M

- Information Technology and System Planning support for resource adequacy and capacity market modeling, which is essential to the redesign of the capacity market under the Capacity Auction Reforms project $(1.2M)
- Funding for 5.0 FTEs related to this goal includes: Market Development in design of market overhauls including prompt seasonal capacity market, resource capacity accreditation, and flexible response services; Operations Training and Integration to design and support training needs of Operations and Market Administration staff for new market features; Information Technology and Advanced Technology staffing to support and integrate new market features into applications and tools; and Planning and Transmission Services that will continue to be heavily involved with new market designs, identifying enhancements to existing reliability modeling and researching and developing modeling techniques for emerging technologies ($1.1M)
- Support in Advanced Technology Solutions and Market Development for Capacity Auction Reforms work including gas modeling and other analysis ($0.7M)
- Increase for nGEM vendor support with the Real-Time Market Clearing Engine application that is a higher costs than the legacy Real-Time application ($0.5M)
- Funding for commencement of work on tariff required Net CONE (Cost of New Entry) recalculation ($0.5M)

2026 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2026 Initiatives

Changes in budget for Progress and Innovation: $2.7M

- Funding for 10.0 FTEs including Information Technology and Advanced Technology for bringing ISO-NE developed advanced technologies into the operating environment to increase our situational awareness capabilities and for migration of applications to the cloud; System Operations and System Planning positions for forecasting and energy analysis across different timespans as the system's resource mix continues to evolve, for modeling and electromagnetic transient analyses for market and reliability operating limits of Inverter Based Resources, for expansion of both short-term and long-term forecasting needs, and to support the continued growth and development of Power System Computer Aided Design (PSCAD) modeling capability (including database development and maintenance) for inverter-based resources ($2.1M)
- Computer service-related costs under NERC CIP Synchrophasor compliance adoption ($0.5M)
- Photovoltaic Data and Forecasting service-related costs ($0.1M)

2026 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2026 Initiatives

Changes in budget for Stakeholder Engagement: $1.7M

- Asset Condition Review work that will only be used for this purpose, and if not needed will not be reallocated for use elsewhere ($1.0M)
- Funding for 2.0 FTEs in Participant Relations and Services for project services (gathering, managing, and supporting the assessment of participant requests), to provide technical readiness and real-time support on corporate initiatives (FERC Orders 2222, 881, 2023), and for support on Capacity Auction Reforms to support this multi-component initiative impacting many ISO-NE teams, and coordinating with participants ($0.4M)
- Funding for 0.5 of an FTE in Legal to support RFP proposals under Long-Term Transmission Planning rules for which proposals are expected to be made annually ($0.2M)
- Funding for 0.5 of an FTE in System Planning to perform economic evaluations in support of the new Long-Term Transmission Planning process and potential RFP solution reviews as well as to accommodate requests from NESCOE/States for various supporting analyses ($0.1M)

2026 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2026 Initiatives

Other Increases: $0.4M

- Increases in Building Service costs due to cyclical maintenance items that are due for completion in 2026, higher utility expense largely for delivery service fees at Windsor facility, and inflationary and other small increases across line items ($0.3M)
- Lower forecasted Interest Income due to projecting lower operating cash balance from expected withdrawals under FERC Order 2023 partially offset by higher miscellaneous revenue ($0.1M)

APPENDIX 2: 5 YEAR BUDGET COMPARISON

2026 Preliminary Budget – 5 Year Comparison

(Budget Amounts are in Millions)	2026	% Change	2025	% Change	2024	% Change	2023	% Change	2022
Operating Budget Before Depr and Regulatory Fees	$282.1	8.4%	$260.2	10.1%	$236.3	17.0%	$201.9	10.6%	$182.6
Capital Budget	42.5	0.0%	42.5	21.4%	35.0	4.5%	33.5	4.7%	32.0
Total Cash Budget	**$324.6**	**7.2%**	**$302.7**	**11.6%**	**$271.3**	**15.2%**	**$235.4**	**9.7%**	**$214.6**
Operating Budget Before Depr and Regulatory Fees	$282.1	8.4%	$260.2	10.1%	$236.3	17.0%	$201.9	10.6%	$182.6
Depreciation and Regulatory Fees **(1)**	48.7	5.4%	46.2	13.8%	40.6	6.1%	38.3	17.9%	32.5
Revenue Requirement Before True-up	330.8	8.0%	306.4	10.7%	276.9	15.3%	240.2	11.7%	215.1
True up	(15.6)		4.8		(3.0)		(14.6)		1.1
Revenue Requirement	**$315.2**	**1.3%**	**$311.2**	**13.6%**	**$273.9**	**21.4%**	**$225.6**	**4.4%**	**$216.1**
Forecast – TWhs (2)	**124.7**	**(8.6)%**	**136.5**	**(3.0)%**	**140.7**	**(1.6)%**	**143.0**	**(1.0)%**	**144.4**
$/KWh Rate	**$0.00253**	**10.8%**	**$0.00228**	**17.2%**	**$0.00195**	**23.4%**	**$0.00158**	**5.4%**	**$0.00150**
Average Monthly Consumer Cost (3)	**$1.90**		**$1.71**		**$1.46**		**$1.18**		**$1.12**

(1) The 2026 *preliminary* depreciation budget is a placeholder. The 2026 *proposed* budget will result in a detailed review of project budgets and estimated go-live dates for the impact on depreciation expenses.

(2) 2026 Forecast based on May 2025 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.

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

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

APPENDIX 3: Forward Looking Capital Budget Spending

Forward Looking Capital Budget Spending

- The capital budget over the next five years and beyond will continue to support the Company's strategic goals with specific focus on three primary drivers with the fourth wrapping up in 2026:
  - nGem platform (replacing the current market system) set to finish in 2026
  - Major market and reliability related efforts
  - Cyber security
  - IT asset and infrastructure replacement
- In order to achieve these goals, ISO has increased the capital spending over the last few years with spending of $35M in 2024; $42.5M in 2025 and remains $42.5M in 2026 with the potential to increase upwards of $50M in future years; the capital costs are dependent on various factors, including regulatory orders and approvals and the use of professional services or internal staff
  - The ISO will continue with its current practice of providing a rolling two-year look-ahead window

Forward Looking Capital Budget Spending *(cont.)*

nGEM Platform Replacement (*)

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

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

Forward Looking Capital Budget Spending *(cont.)*

Major Market and Reliability Related Efforts

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

Forward Looking Capital Budget Spending *(cont.)*

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

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

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

Forward Looking Capital Budget Spending *(cont.)*

Cyber Security & IT Asset and Infrastructure Replacement

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

APPENDIX 4: 2026 Preliminary Capital Budget

Capital Budget

2026 Expenditures

Goal: Responsive Market Designs

Project	2026 Budget	Total Project Cost	Estimated Completion Date	Project Stage
EMP 3.5 Upgrade	$4.0 M	$5.0 M	TBD	Planning/Conceptual Design
Enterprise Core Network Refresh	$0.1 M	$2.1 M	08/2026	In Development
Capacity Auction Reform (CAR)	$2.5 M	$2.5 M	TBD	Planning/Conceptual Design
2026 Issue Resolution Project	$1.5 M	$1.5 M	10/2026	Planning/Conceptual Design
GridOS Connect	$1.0 M	$1.5 M	TBD	Planning/Conceptual Design
Storage as Transmission Only Asset	$0.5 M	$1.0 M	TBD	Planning/Conceptual Design
Resource Capacity Accreditation	$0.2 M	$0.8 M	TBD	Planning/Conceptual Design
Total:	$9.8 M			

Goal: Progress and Innovation

Project	2026 Budget	Total Project Cost	Estimated Completion Date	Project Stage
nGEM Real-Time Market Clearing Engine Implementation	$2.2 M	$14.8 M	05/2026	In Development
Single Interval MCE Improvements (SIMI)	$5.0 M	$5.2 M	TBD	Planning/Conceptual Design
Advanced Technology Initiatives	$2.0 M	$4.0 M	12/2026	Planning/Conceptual Design
nGEM Software Development Part IV	$2.0 M	$2.0 M	TBD	Planning/Conceptual Design
Atlassian Cloud Migration	$0.5 M	$0.8 M	TBD	Planning/Conceptual Design
Total:	$11.7 M			

Note 1: nGEM related projects will advance multiple goals including Responsive Market Designs, Progress and Innovation, and Operational Excellence. For purposes of this presentation, nGEM projects have been grouped under the Progress and Innovation strategic goal.

Capital Budget
2026 Expenditures *(cont.)*

- Goal: Operational Excellence

Project	2026 Budget	Total Project Cost	Estimated Completion Date	Project Stage
. Managing Transmission Line Ratings [3]	$0.3 M	$8.0 M	12/2026	In Development
. Non-Project Capital Expenditures	$5.5 M	$5.5 M	TBD	Planning/Conceptual Design
. Distributed Energy Resources - Order 2222	$2.0 M	$2.1 M	TBD	Planning/Conceptual Design
. Windows Server Replacement Phase II	$1.5 M	$1.7 M	TBD	Planning/Conceptual Design
. MW Dependent Fuel Price Adjustment	$1.5 M	$1.6 M	11/2026	Planning/Conceptual Design
. Integrated Market Simulator Enhancement	$1.5 M	$1.5 M	TBD	Planning/Conceptual Design
. Adoption of NERC CIP Compliance of Synchrophaser Systems	$0.8 M	$1.1 M	08/2026	Planning/Conceptual Design
. IMM Data Analysis Phase 5	$1.0 M	$1.0 M	08/2026	Planning/Conceptual Design
. EMS CFE Refresh	$0.1 M	$0.8 M	06/2026	In Development
. Tie Line Telemetry and PCEC Upgrade Phase II	$0.5 M	$0.7 M	TBD	Planning/Conceptual Design
. Replace Employee & Pager Application [5]	$0.5 M	$0.6 M	TBD	Planning/Conceptual Design
. Oracle 23c Refresh	$0.5 M	$0.5 M	TBD	Planning/Conceptual Design
. Solar Do Not Exceed Dispatch Phase III	$0.5 M	$0.5 M	TBD	Planning/Conceptual Design
. Centralized Application Security	$0.5 M	$0.5 M	TBD	Planning/Conceptual Design
. Circuit Inventory Management Platform	$0.4 M	$0.4 M	TBD	Planning/Conceptual Design
. Microsoft 365 Phase II	$0.2 M	$0.3 M	TBD	Planning/Conceptual Design
. Operations Document Management System MS 365 Conversion	$0.3 M	$0.3 M	TBD	Planning/Conceptual Design
. Enterprise Document Library MS 365 Conversion	$0.1 M	$0.1 M	TBD	Planning/Conceptual Design
Total:	**$17.7 M**			

Capital Budget
2026 Expenditures Summary

- 2026 Capital Budget Expenditure Summary

Allocation Category	2026 Budget
Goal: Responsive Market Designs	$9.8 M
Goal: Progress and Innovation	$11.7 M
Goal:Operational Excellence	$17.7 M
Other Emerging Work	$2.1 M
Capital Interest	$1.2 M
Total:	**$42.5 M**

APPENDIX 5: CAPITAL STRUCTURE

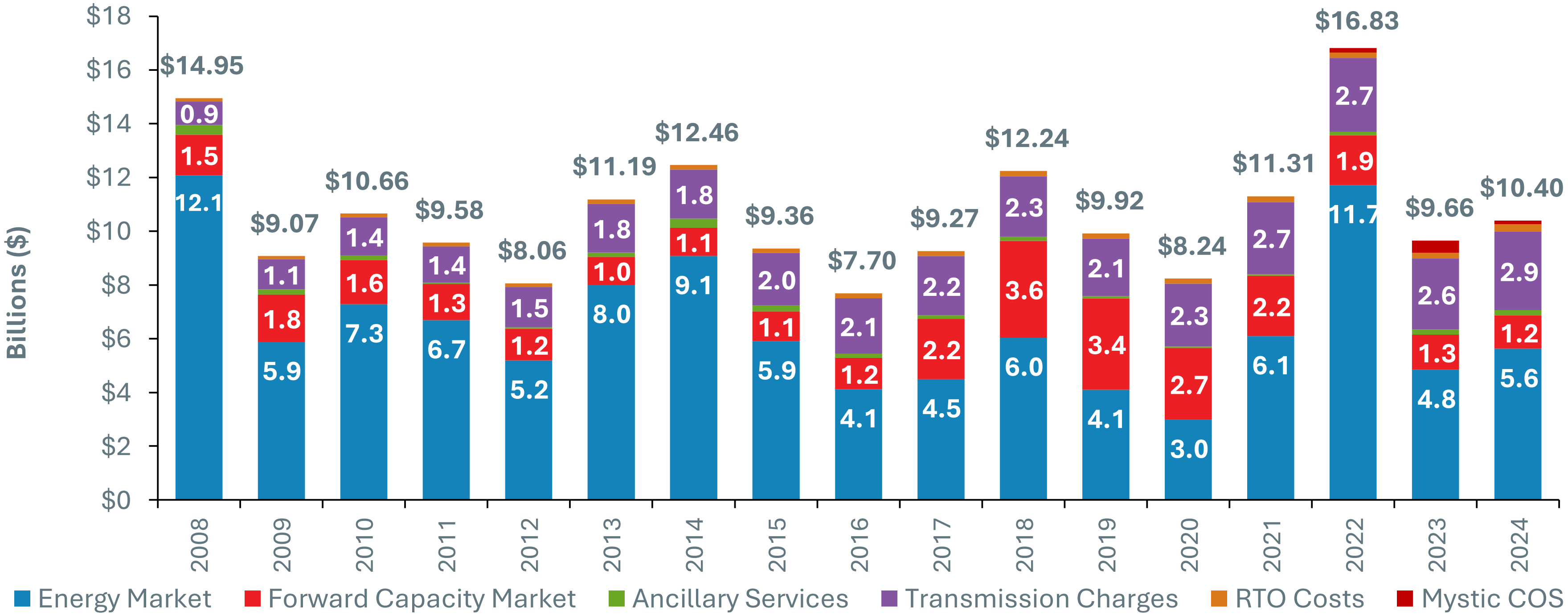
Capital Structure

- The ISO increased its working capital line from $20M to $40M in March of 2024; the working capital line, which will expire on March 1, 2028, covers the ISO's operational needs and cash flow risks, including lower than projected load driving decreased Tariff collections, a continued increase in budgetary needs over the next 3 - 4 years, and more recently the issuance of FERC Order 2023 which may increase withdrawals of system impact studies
- Capital project costs are largely funded by $75M in Private Placement Notes that were increased in 2024, from $50M, and require interest only payments until full payment of principal in 2034
  - As noted in last year's budget materials, the private placement note increase in 2024 was to support increased capital spending, that has occurred over the past several years, and longer lead times to complete projects resulting in a greater period of time from when the ISO spends capital funds to tariff recovery through depreciation expense of these projects
- For the three months ended March 31, 2025, the ISO's total weighted average cost of capital was 4.4%, excluding fees charged on the various debt financing; fees ranged from .075% to .38%

APPENDIX 6: HISTORICAL NEW ENGLAND WHOLESALE AND RETAIL ENERGY COSTS

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; ***2024 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)

	2020		2021		2022		2023		2024**	
	$ Mil.	¢/kWh	$ Mil.	¢/kWh	$ Mil.	¢/kWh	$ Mil.	¢/kWh	$ Mil.	¢/kWh
Wholesale Market Costs										
Energy (LMPs)(b)	$2,996	2.4	$6,101	4.8	$11,712	9.0	$4,847	3.9	$5,624	4.4
Ancillaries(c)	$62	0.1	$52	0.0	$124	0.1	$183	0.1	$183	0.1
Capacity(d)	$2,662	2.2	$2,243	1.8	$1,864	1.4	$1,308	1.1	$1,248	1.0
Subtotal	*$5,720*	*4.7*	*$8,404*	*6.6*	*$13,701*	*10.5*	*$6,338*	*5.1*	*$7,054*	*5.5*
Transmission charges(e)	$2,331	1.9	$2,688	2.1	$2,739	2.1	$2,640	2.1	$2,931	2.3
RTO costs(f)	$191	0.2	$216	0.2	$214	0.2	$214	0.2	$275	0.2
	Mystic Cost of Service Agreement				$173	0.1	$465	0.4	$139	0.1
Total	**$8,242**	**6.7**	**$11,308**	**8.9**	**$16,828**	**13.0**	**$9,657**	**7.8**	**$10,399**	**8.2**

(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 2024 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.

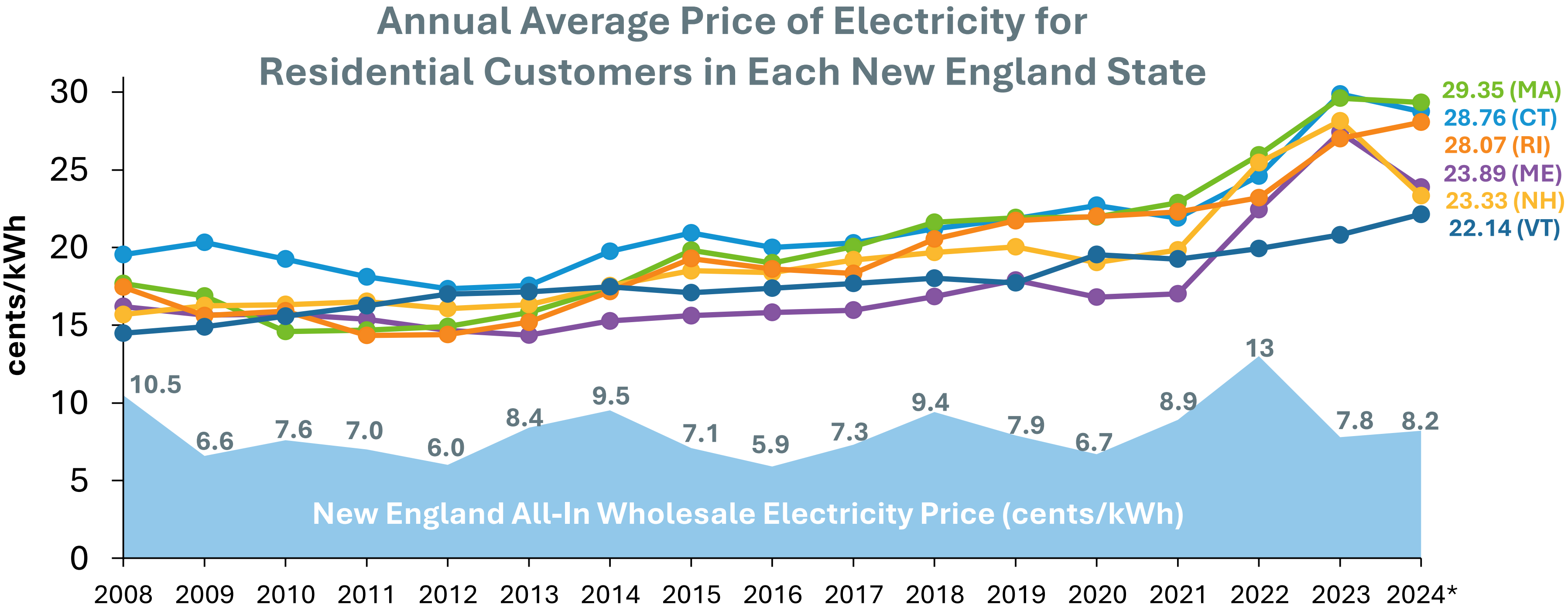
(d) Capacity charges are those associated with the Forward Capacity Market (FCM).

(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*.

** 2024 figures are preliminary

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



Sources: U.S. Energy Information Administration, *Electric Power Annual*, Table 2.10 Average Price of Electricity to Ultimate Customers by End-Use Sector, by State; and 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. 2024); 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) *2024 values are preliminary

APPENDIX 7: RETHINKING WORKSPACE AT THE ISO

Overview

- The primary office space for the ISO workforce in Holyoke has remained materially the same for approximately twenty years
- The ISO's Holyoke Campus was designed and built in 2003 - 2007; it was designed to support a headcount of 560
  - Holyoke campus currently has 603 work points (offices and workstations) plus 35 collaboration spaces and 564 parking spaces, including visitor parking
- The ISO's Windsor Campus was built in 2012 and has a seating capacity for 150
- Continued maintenance on aging building (facilities workplan)

FTE Data

Current authorized headcount	746.5
Work points (offices and workstations) at Holyoke	603

	Total	Fully Remote	Ctrl Rm	Holyoke	Windsor	
Employees as of March 2025	687	43	22	513	109	BCC (74 Sys Planning & 35 IT/OPTI)
Open Positions, per staffing rpt 3-25-25	60	0	0	51	9	
	747	43	22	564	118	
Interns working spring 2025	6			6		
Interns over summer	25			25		
Consultants - 83 active staff augmenation assuming 50% hybrid vs fully remote.	41			41		
As of end of 2025	819	43	22	636	118	
Less 6% budgeted vacancy				-38		
Max seating needed at peak days, in the office for 2025				**597**		
As of end of 2025	819	43	22	636	118	
Expected increase in Headcount in 2026	24			17	7	
As of end of 2026	843	43	22	653	125	
Less 5.5% budgeted vacancy				-36		
Max seating needed at peak days, in the office for 2026				**617**		
As of end of 2026	843	43	22	653	125	
Bring System Planning back onto one campus				81	-81	
Estimated increase in Headcount by 2028/2029	60			60		
As of end of 2028/2029	903	43	22	794	44	
Less 5% budgeted vacancy	-42			-40	-2	
Max seating needed at peak days, in the office for 2028/2029	**796**			**754**	**42**	

Challenges with the current Holyoke campus

- ISO believes there is a need to address a redesign or new build at the Holyoke campus to accommodate the larger workforce needed to meet the region's needs
- Several factors had triggered a review on how we utilize office space in Holyoke
  - Current seating constraints (e.g., limited seating space for authorized headcount increases for certain Departments; increasing need for collaborative working spaces)
  - Expectation of continued strategic growth in the workforce in the near term and the next 5-10 years
  - Parking constraints associated with growth
  - Newer workforce and need to be on campus for training and collaboration
  - Many current and future projects contain complex designs with cross functional team involvement
  - We conducted a preliminary study that accounted for 900 employees (leaving the parking constraint unsolved) that would take approximately 2-3 years either renovating existing building to an activity-based concept or developing a new building, both at a cost estimate of $50M; by deferring this effort for a couple of years, we would expect the cost estimate to increase

Changes made since 2024

- First Stage is complete
  - Leased the adjacent property to the Holyoke campus – quickly solves for the parking constraints (significant open land exists) and offers a hedge on utilizing the building itself
    - Lease was signed on July 2024; annual cost approximately $225,000, included in the 2025 budget
    - Lease contains an option to purchase
    - Completed environmental testing to ensure the land was usable
  - Develop and update annually a 3-year Facilities Plan that will evolve to meet the organizations needs; consider steady ongoing improvements and refurbishment of the buildings over a span of many years
  - Relocated approximately 80 employees in the System Planning department to the Windsor campus; the Windsor facility will be able to accommodate System Planning near-term growth
    - Some investment was required at the Windsor campus such as 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; we incurred additional cost to cover mileage and other miscellaneous expenses for employees required to move
  - Reprogram the Holyoke Campus with the vacancy of approximately 80 employees

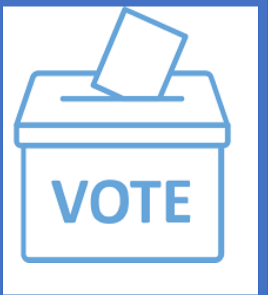
Potential Next Steps

ISO believes that the integrated nature of the work promotes the need for one campus and collaboration is one of our five core values

- Second Stage
  - Engage architects/engineering firm to develop pricing and plans for the adjacent property to the Holyoke campus (if the lease purchase option is executed)
- Third Stage
  - Obtain tax-exempt bond financing for construction of building
    - Tax-exempt bond for Holyoke campus for $45.5M will expire in February 2032; the building construction is amortized over the life of the bonds and collected via depreciation for which the collection is used to pay the principal payments
    - Payment for the proposed new building (estimated cost of $50M) would begin when the building is completed and in production, and therefore would not impact revenue requirements until such time
    - While there will be a temporary increase in depreciation from the time the new building goes into production until 2031, the long run net impact to the revenue requirement will be relatively small

Questions

7 FAP Changes – LC Issuer Eligibility, Forms of LC, Security and BlackRock Control Agreements



66.67%

To consider and take action, as appropriate, on changes to the Financial Assurance Policy (FAP) (including LC issuer eligibility), and to the forms of Standby Letter of Credit (LC), Security Agreement and Blackrock Control Agreement.

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

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Rosendo Garza, NEPOOL Counsel

DATE: June 16, 2025

RE: Updates to the Financial Assurance Policy

At the June 24, 2025 Participants Committee Summer Meeting, members will be asked to vote on proposed revisions to the Financial Assurance Policy (FAP), including changes to the Standby Letter of Credit (LOC) form (Attachment 2 to the FAP). As ISO-NE explained, these revisions are intended to mitigate risks of Market Participant defaults and LOC issuer credit downgrades. Included with this memorandum are the following materials:

- Attachment A: ISO-NE's Redlined FAP Sheets
- Attachment B: ISO-NE's Revisions to the Security Agreement and Control Agreement
- Attachment C: ISO-NE's March 2025 Presentation
- Attachment D: ISO-NE's April 2025 Presentation
- Attachment E: ISO-NE's May 2025 Presentation
- Attachment F: NEPOOL Counsel Memorandum dated May 29, 2025 (without attachment)

BACKGROUND & OVERVIEW

Currently, ISO-NE's LOC ensures that funds are available from the issuing bank if a Market Participant fails to pay its invoice on time. However, if a LOC expires before a default occurs, ISO-NE cannot draw on it, exposing ISO-NE and Market Participants to increased risk. ISO-NE also raised similar concerns about situations in which the issuing bank's credit rating drops below the FAP's minimum required threshold, potentially impairing the bank's ability to honor the LOC and impacting ISO-NE's ability to receive payment under the LOC.

To address these concerns, ISO-NE's proposal would introduce two new triggers that would allow it to draw on a LOC upon a bank credit downgrade or within 30 days of the LOC expiration. Specifically, it proposes the new Risk Mitigation Draw mechanism that would it to draw up to the lesser of the LOC amount or the required financial assurance amount. If a Risk Mitigation Draw is made, the funds, subject to certain conditions, would be held as financial assurance for the Market Participant. To document these funds properly as financial assurance, ISO-NE also proposes related administrative updates and conforming changes to the Security and Control Agreements. ISO-NE's full explanations are provided in Attachment C, Attachment D, and Attachment E.[1]

STAKEHOLDER PROCESS TO DATE

ISO-NE first presented its proposal at the March 2025 Budget & Finance (B&F) Subcommittee meeting and circulated an initial set of redlines in April, covering proposed revisions to the FAP, LOC, and the Security and Control Agreements. During the March and April meetings, stakeholders provided feedback and expressed concerns. In response, ISO-NE revised its proposal and presented an updated package of redlines at the May B&F meeting. At that meeting, ENGIE proposed several amendments to address unresolved issues with ISO-NE's revised proposal. After considering ENGIE's input, ISO-NE agreed to incorporate several changes. However, some concerns remained outstanding at the close of the meeting.

After the May B&F meeting, and at the B&F Chair's encouragement, ENGIE and ISO-NE continued discussions offline to explore further refinements. These efforts led to a revised proposal that addressed most of ENGIE's remaining concerns. ENGIE has confirmed that it supports the revised proposal and does not intend to seek further amendments at this meeting. For a summary of ENGIE's amendments and the outcome of the post-meeting discussions, see Attachment F. ISO-NE's revised proposal, as reflected in the redlines in Attachment A and Attachment B, is now ready for the NEPOOL Participants Committee's consideration and vote.

The Participants Committee may use the following form of resolution for action:

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

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[1] Note the redlines shown in Attachment C, Attachment D, and Attachment E were later modified, as explained in this memorandum and reflected in Attachment A.

EXHIBIT IA

ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY

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X. ACCEPTABLE FORMS OF FINANCIAL ASSURANCE

Provided that the requirements set forth herein are satisfied, acceptable forms of financial assurance include shares of registered or private mutual funds held in a shareholder account or a letter of credit, each in accordance with the provisions of this Section X. All costs associated with obtaining financial security and meeting the provisions of the ISO New England Financial Assurance Policy are the responsibility of the Market Participant or Non-Market Participant Transmission Customer providing that security (each a "Posting Entity"). ~~Any Posting Entity requesting a change to one of the model forms attached to the ISO New England Financial Assurance Policy which would be specific to such Posting Entity (as opposed to a generic improvement to such form) shall, at the time of making that request, pay a $1,000 change fee, which fee shall be deposited into the Late Payment Account maintained under the ISO New England Billing Policy.~~

A. Shares of Registered or Private Mutual Funds in a Shareholder Account

Shares of registered or private mutual funds in a shareholder account are an acceptable form of financial assurance provided that the Posting Entity providing such collateral (i) completes all required documentation to open an account with the financial institution selected by the ISO, after consultation with the NEPOOL Budget and Finance Subcommittee, (ii) completes and executes a security agreement ("Security Agreement") in the form of Attachment 1 to the ISO New England Financial Assurance Policy (as may be modified pursuant to Section X.B.1) and is in compliance with the Security Agreement, and (iii) completes and executes a Control Agreement in the form posted on the ISO website (as may be modified pursuant to Section X.B.1) and is in compliance with the Control Agreement. Any material variation from the form of Security Agreement included in Attachment 1 to the ISO New England Financial Assurance Policy (other than as modified pursuant to Section X.B.1) or the form of Control Agreement (other than as modified pursuant to Section X.B.1) posted on the ISO website must be approved by the ISO after consultation with the NEPOOL Budget and Finance Subcommittee and, in the case of the Security Agreement, filed with the Commission. To the extent any amount of shares contained in the shareholder account is no longer required hereunder, the ISO shall return such collateral to the Posting Entity providing it within four (4) Business Days of a request to do so.

If the amount of collateral maintained in the shareholder account is below the required level (including by reason of losses on investments), the Posting Entity shall immediately replenish or increase the amount to the required level. The collateral will be held in an account maintained in the name of the Posting Entity and invested in the investment selected by that Posting Entity from a menu of investment options listed at the time on the ISO's website, which menu will be approved by the NEPOOL Budget and Finance Subcommittee, with discounts applied to the investments in certain of such options if and as determined by the NEPOOL Budget and Finance Subcommittee. If a Posting Entity does not select an investment for its collateral, that collateral will be invested in the "default" investment option selected by the ISO and approved by the NEPOOL Budget and Finance Subcommittee from time to time. Any dividends and distribution on such investment will accrue to the benefit of the Posting Entity. The ISO may sell or otherwise liquidate such investments at its discretion to meet the Posting Entity's obligations to the ISO. In no event will the ISO or NEPOOL or any NEPOOL Participant have any liability with respect to the investment of collateral under this Section X.A.

Notwithstanding the foregoing, an investment in shares of a registered fund in a shareholder account shall not be an acceptable form of financial assurance for a Posting Entity that is not a U.S. Person, as defined in Regulation S under the Securities Act of 1933, as amended, unless the financial institution selected by the ISO allows such Posting Entity to invest in the investment options listed at the time on the ISO's website or the Posting Entity is invested in the investment options listed on the ISO's website as of March 19, 2015.

B. Letter of Credit

An irrevocable standby letter of credit provides an acceptable form of financial assurance to the ISO. For purposes of the ISO New England Financial Assurance Policy, the letter of credit shall be valued at $0 at the end of the Business Day that is 30 days prior to the termination of such letter of credit. If the letter of credit amount is below the required level, the Posting Entity shall immediately replenish or increase the letter of credit amount or obtain a substitute letter of credit. The account party on a letter of credit must be either the Posting Entity whose obligations are secured by that letter of credit or an Affiliate of that Posting Entity.

1. Risk Mitigation Draws

The ISO may draw against a letter of credit for two reasons in addition to a failure to pay under the ISO New England Billing Policy: i) an expiring letter of credit has not been renewed, or ii) the issuing bank is downgraded below the minimum ratings requirement, each in accordance with the terms of the letter of credit (the "Risk Mitigation Draws"). The ISO may exercise its rights under the Risk Mitigation Draws up to the amount that a Posting Entity's financial assurance requirements are not covered by acceptable forms of financial assurance. The ISO will hold such funds as a security deposit for the satisfaction of all obligations owed to the ISO by the Posting Entity (the "Risk Mitigation Drawn Funds"). The Risk Mitigation Drawn Funds shall be considered an appropriate form of financial assurance as described in this Section X. The ISO will hold all right, title, and interest in the Risk Mitigation Drawn Funds and the Posting Entity shall have a contingent right to such funds less any amounts applied to any debts owed to the ISO (pursuant to the Tariff, including the ISO New England Billing Policy): (i) upon the termination of its Market Participant Financial Assurance Requirement in accordance with Section III of the Financial Assurance Policy, (ii) upon the Posting Entity's provision of an alternative form of acceptable financial assurance in accordance with this Section X, or (iii) to the extent that any portion of the Risk Mitigation Drawn Funds are no longer required hereunder, upon the Posting Entity providing a written request to the ISO to return such portion of the funds (which request shall be honored within four (4) Business Days).

Upon request of the ISO, but no later than five (5) Business Days after the Risk Mitigation Draw, the Posting Entity shall execute a Security Agreement in the form of Attachment 1 to the ISO New England Financial Assurance Policy, provided that such form shall be modified to include within the definition of Collateral, funds received from a Risk Mitigation Draw, or an amendment to its existing Security Agreement in a form acceptable to the ISO in its sole discretion. Within thirty (30) days of the Risk Mitigation Draw the Posting Entity shall satisfy its obligations pursuant to the paragraph immediately below to direct the deposit of the Risk Mitigation Drawn Funds into the Posting Entity's shareholder account as described in Section X.A. Notwithstanding the prior sentence, if the Posting Entity provides written documentation to the ISO (which documentation must be to the ISO's reasonable satisfaction) of its inability to open a shareholder account as described in Section X.A, and the Posting Entity has executed a Security Agreement or an amendment to its existing Security Agreement as required above, the ISO shall continue to hold the Risk Mitigation Drawn Funds (and such amount shall continue to be considered financial assurance), subject to the Posting Entity's contingent right to such funds as described above, in a form determined by the ISO in its sole discretion, and any interest or income accrued on such funds, if applicable, shall be considered part of the Posting Entity's financial assurance.

Upon a Risk Mitigation Draw and unless the Posting Entity has either posted other appropriate financial assurance in the forms permitted by this Section X or provided written documentation of its inability to do so in accordance with the preceding paragraph, the Posting Entity shall within thirty (30) days of the Risk Mitigation Draw complete any steps required by the ISO to (a) open a shareholder account as described in Section X.A, (b) execute any necessary documentation, including any amendments to the Security Agreement and Control Agreement deemed necessary by the ISO in a form acceptable to the ISO in its sole discretion, for the ISO to deposit the Risk Mitigation Drawn Funds into the Posting Entity's shareholder account, and (c) direct the ISO to deposit the Risk Mitigation Default Drawn Funds into that Posting Entity's shareholder account as described in Section X.A. Upon the Posting Entity's completion of the foregoing steps in (a) through (c) to the ISO's satisfaction, ISO shall deposit the Risk Mitigation Default Drawn Funds into that Posting Entity's shareholder account and the balance of the funds then on deposit in such account shall continue to be the collateral of the ISO.

The ISO may apply any funds received from a letter of credit, including the Risk Mitigation Drawn Funds held as a security deposit, to amounts owed by the Posting Entity in accordance with the ISO New England Billing Policy. If a Posting Entity fails to comply with the provisions of this Section X.B.1, then the Posting Entity will be suspended as described in Section III.B.3 of the ISO New England Financial Assurance Policy until the deficiency is rectified.

2. Requirements for Banks

Each bank issuing a letter of credit that serves as financial assurance must meet the requirements of this Section X.B.2~~1~~. Each such bank must be on the ISO's "List of Eligible Letter of Credit Issuers" which shall be established pursuant to this Section X.B.2~~1~~. The ISO will post the current List of Eligible Letter of Credit Issuers on its website, and update that List and posting no less frequently than quarterly; provided that if a change is made to~~bank is removed from~~ the List of Eligible Letter of Credit Issuers, the ISO shall update the List and provide notice to the NEPOOL Budget & Finance Subcommittee. To be included on the List of Eligible Letter of Credit Issuers, (i) the bank must be organized under the laws of the United States or any state thereof, or be the United States branch of a foreign bank; ~~and either: (i) be recognized by the Chicago Mercantile Exchange (“CME”) as an approved letter of credit bank; or (ii) have a minimum long-term debt rating (or, if the bank does not have minimum long-term debt rating, than a minimum corporate rating) of “A-” by S&P, or “A3” by Moody’s or “A-” by Fitch so long as its letter of credit is confirmed by a bank that is recognized by CME as an approved letter of credit issuer as described in clause (i) above; or (iii)~~ (ii) have a minimum long-term debt rating (or, if the bank does not have a minimum long-term debt rating, than a minimum corporate rating) of “A-” by S&P, or “A3” by Moody’s, or “A-” by Fitch; and (iii) be approved by the ISO in its sole discretion~~(the ISO will promptly advise the NEPOOL Budget and Finance Subcommittee of any additional bank approved by it under this provision)~~. ~~Because the ratings described in clauses (ii) and (iii) are minimum ratings, a bank will not be considered to have satisfied the requirement of those clauses~~ In the event that a bank is rated by multiple Rating Agencies, if any applicable rating from the Rating Agencies falls below the levels listed, then a bank will not be considered to have satisfied the requirement under this paragraph~~in those clauses~~. In addition, no Posting Entity may provide a letter of credit that has been issued ~~or confirmed~~ by a bank that is an Affiliate of that Market Participant.

If a bank that is included on the List of Eligible Letter of Credit Issuers fails to satisfy ~~any of~~ the criteria set forth above or if the ISO determines in its sole discretion that despite satisfying ~~any of~~ the criteria set forth above, accepting a letter of credit from a bank on the List of Eligible Letter of Credit Issuers ~~-~~presents an unreasonable risk that a bank may fail to honor the terms of such letter of credit, the applicable Posting Entity will have five (5) Business Days from the date on which the ISO provides notice of such failure or removal to replace the letter of credit with a letter of credit from a bank satisfying the~~those~~ criteria or provide other financial assurance satisfying the requirements of the ISO New England Financial Assurance Policy. The ISO may extend that cure period to twenty (20) Business Days in its sole discretion. The ISO must promptly advise the NEPOOL Budget and Finance Subcommittee of any extension of a cure period beyond five (5) Business Days under this provision. For purposes of the ISO New England Financial Assurance Policy, the letter of credit shall be valued at $0 at the expiration of the five (5) or twenty (20) Business Day cure period, as applicable.

No letter of credit bank may issue ~~or confirm~~ letters of credit under the ISO New England Financial Assurance Policy in an amount exceeding either: (i) $100 million in the aggregate for any single Posting Entity; or (ii) $150 million in aggregate for a group of Posting Entities that are Affiliates. If a bank is removed from the List of Eligible Letter of Credit Issuers based on the ISO's determination that there is an unreasonable risk that a bank may fail to honor the terms of such letter of credit, the ISO in its sole discretion may reinstate eligibility, provided that the bank otherwise meets the conditions of this Section X.B.2~~1~~.

The following provisions shall apply when a bank fails to honor the terms of one or more letters of credit issued ~~or confirmed~~ by the bank in favor of the ISO: (i) if the bank fails to honor the terms of one letter of credit in a rolling seven hundred and thirty day period, then the ISO will issue a notice of such failure to the NEPOOL Budget and Finance Subcommittee, to all members and alternates of the Participants Committee, to the New England governors and utility regulatory agencies and to the billing and credit contracts for all Market Participants; (ii) if the bank fails to honor either the terms of one letter of credit twice or the terms of two letters of credit in a rolling seven hundred and thirty day period, then (A) the ISO shall issue a notice described in subsection (i) above, (B) the bank will no longer be eligible to issue ~~or confirm~~ letters of credit in favor of the ISO, (C) any letters of credit issued ~~or confirmed~~ by such bank in favor of the ISO will not be renewed, and (D) any letters of credit issued ~~or confirmed~~ by such bank in favor of the ISO must be replaced with another acceptable form of financial assurance within five (5) Business Days from the date on which the ISO provides notice of such failure (the ISO may extend that cure period to twenty (20) Business Days in its sole discretion). For purposes of the ISO New England Financial Assurance Policy, the letter of credit shall be valued at $0 at the expiration of the five (5) or twenty (20) Business Day cure period, as applicable. Notwithstanding the foregoing, the ISO in its sole discretion may reinstate eligibility after not less than two years from the loss of eligibility, provided that the bank otherwise meets the conditions of this Section X.B.2~~1~~.

~~Any letter of credit provided for a new Posting Entity for the purpose of covering the Initial Market Participant Financial Assurance Requirement must have a minimum term of 120 days.~~

3~~2~~. Form of Letter of Credit

Attachment 2 provides a generally acceptable sample "clean" letter of credit, and all letters of credit provided by Posting Entities shall be in this form (with only minor, non-material changes), unless a variation therefrom is approved by the ISO after consultation with the NEPOOL Budget and Finance Subcommittee and filed with the Commission. Notwithstanding the foregoing, Posting Entities that have provided a letter of credit in a form that was previously acceptable (e.g., under a prior version of Attachment 2) shall not be required to resubmit such letter of credit until the earlier of (a) the amendment or expiration of such letter of credit, in which case Posting Entity shall be required to provide a l~~L~~etter of c~~C~~redit in the f~~F~~orm of Attachment 2, or (b) September 1, 2026~~December 31, 2021~~. Any letter of credit provided for a new Posting Entity, for the purpose of covering the Initial Market Participant Financial Assurance Requirement, must have a minimum term of 120 days. All costs incurred by the ISO in collecting on a letter of credit provided under the ISO New England Financial Assurance Policy shall be paid, or reimbursed to the ISO, by the Posting Entity providing that letter of credit.

C. Special Provisions for Provisional Members

Notwithstanding any other provision of the ISO New England Financial Assurance Policy to the contrary, due to the temporary nature of a Market Participant's status as a Provisional Member and the relatively small amounts due from Provisional Members, any Provisional Member required to provide additional financial assurance under the ISO New England Financial Assurance Policy may only satisfy the portion of that requirement attributable to Participant Expenses under the RNA by providing collateral maintained in a shareholder account~~a cash deposit~~ in accordance with Section X.A. Provisional Members will not have any other Non-Hourly Requirements under the ISO New England Financial Assurance Policy. If a Provisional Member uses a standing instruction to pay its Invoices pursuant to the ISO New England Billing Policy, in order to avoid a default and/or a Late Payment Charge, the total amount of collateral maintained in a shareholder account~~the cash deposited~~ by that Provisional Member should be equal to the sum of (x) the Provisional Member's Financial Assurance Requirement under the ISO New England Financial Assurance Policy that is attributable to Participant Expenses under the RNA and (y) the amount due from that Provisional Member on its next Invoice under that ISO New England Billing Policy (not including the amount of any Qualification Process Cost Reimbursement Deposit (including the annual true-up of that amount) due from such Provisional Member). Provisional Members are also required to satisfy all other provisions of the ISO New England Financial Assurance Policy, and any additional financial assurance required to be provided by a Provisional Member that is not attributable to Participant Expenses may be satisfied by providing an acceptable form of financial assurance in accordance with this Section X ~~cash deposit or letter of credit in accordance with this Section X but shall not be satisfied through the provision of the cash deposit described in this Section X.C~~. Without limiting or reducing in any way the requirements of the ISO New England Financial Assurance Policy that apply to a Provisional Member, the amount of collateral maintained in a shareholder account ~~the cash deposit~~ initially provided by a Provisional Member that is attributable to Participant Expenses (including any amounts provided in connection with the standing instruction under the ISO New England Billing Policy described above) shall be at least $2,500, and each Provisional Member will replenish that collateral maintained in a shareholder account~~cash deposit~~ to at least that $2,500 level on December 31 of each year.

XI. MISCELLANEOUS PROVISIONS

A. Obligation to Report Material Adverse Changes

Each Market Participant and each Non-Market Participant Transmission Customer is responsible for informing the ISO in writing within five (5) Business Days of any Material Adverse Change in its financial status. A "Material Adverse Change" in financial status includes, but is not limited to, the following: a downgrade to below an Investment Grade Rating by any Rating Agency; being placed on credit watch with negative implication by any Rating Agency if the Market Participant or Non-Market Participant Transmission Customer does not have an Investment Grade Rating; a bankruptcy filing or other insolvency; a report of a significant quarterly loss or decline of earnings; the resignation of key officer(s); the sanctioning of the Market Participant or Non-Market Participant Transmission Customer or any of its Principals imposed by the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity Futures Trading Commission, any exchange monitored by the National

ATTACHMENT 2

SAMPLE STANDBY LETTER OF CREDIT

[DATE PROVIDED]

IRREVOCABLE NON-TRANSFERABLE STANDBY LETTER OF CREDIT NO.

[EXPIRATION DATE]

WE DO HEREBY ISSUE THIS IRREVOCABLE NON-TRANSFERABLE STANDBY LETTER OF CREDIT BY ORDER OF AND FOR THE ACCOUNT OF [POSTING ENTITY OR AFFILIATE OF POSTING ENTITY ON BEHALF OF POSTING ENTITY] ("ACCOUNT PARTY") IN FAVOR OF ISO NEW ENGLAND INC. ("ISO" OR "BENEFICIARY") ("STANDBY LETTER OF CREDIT").

THIS STANDBY LETTER OF CREDIT IS IRREVOCABLE AND IS ISSUED, PRESENTABLE AND PAYABLE AND WE GUARANTY TO THE DRAWERS, ENDORSERS AND BONA FIDE HOLDERS OF THIS STANDBY LETTER OF CREDIT THAT DRAFTS UNDER AND IN COMPLIANCE WITH THE TERMS OF THIS STANDBY LETTER OF CREDIT WILL BE HONORED ON PRESENTATION OF THIS STANDBY LETTER OF CREDIT.

THIS STANDBY LETTER OF CREDIT IS AVAILABLE IN ONE OR MORE DRAFTS AND MAY BE DRAWN HEREUNDER FOR THE ACCOUNT OF THE ACCOUNT PARTY UP TO AN AMOUNT NOT EXCEEDING US$ ______.00 (UNITED STATES DOLLARS ____________ AND 00/100) .

THIS STANDBY LETTER OF CREDIT IS DRAWN AGAINST BY PRESENTATION TO US AT OUR OFFICE LOCATED AT THE FOLLOWING ADDRESS:

____

____

__________________;

OF A DRAFT IN THE FORM OF A DRAWING CERTIFICATE THAT IS SIGNED BY A PURPORTED OFFICER OR AUTHORIZED AGENT OF THE ISO AND DATED THE DATE OF

PRESENTATION CONTAINING THE FOLLOWING STATEMENT IN (1) BELOW ALONG WITH THE APPROPRIATE STATEMENT IN (2) BELOW:

(1) "THE UNDERSIGNED HEREBY CERTIFIES TO [BANK] ("ISSUER"), WITH REFERENCE TO IRREVOCABLE NON-TRANSFERABLE STANDBY LETTER OF CREDIT NO. [------] (THE "STANDBY LETTER OF CREDIT") ISSUED BY ISSUER IN FAVOR OF ISO NEW ENGLAND INC. ("ISO"), THAT

(2) [POSTING ENTITY] HAS FAILED TO PAY THE ISO, IN ACCORDANCE WITH THE TERMS AND PROVISIONS OF THE TARIFF FILED BY THE ISO, AND THUS THE ISO IS DRAWING UPON THE STANDBY LETTER OF CREDIT IN AN AMOUNT EQUAL TO $______________.]; ~~"~~ **OR**

[ISSUER HAS FAILED TO MAINTAIN A MINIMUM LONG-TERM DEBT RATING FROM ANY APPLICABLE RATING AGENCY (OR, IF THE ISSUER DOES NOT HAVE A MINIMUM LONG-TERM DEBT RATING, THEN A MINIMUM CORPORATE RATING) OF "A-" BY STANDARD AND POOR'S , OR "A3" BY MOODY'S OR "A-" BY FITCH, AND THUS THE ISO IS DRAWING UPON THE STANDBY LETTER OF CREDIT IN AN AMOUNT EQUAL TO $______________. **]; OR**

[**INCLUDE ONLY IN FORM IF LETTER OF CREDIT HAS A FIXED EXPIRATION DATE:]** [AS OF THE CLOSE OF BUSINESS ON ________________, 20__ (FILL IN DATE WHICH IS WITHIN 30 DAYS BEFORE THE EXPIRATION DATE OF THE STANDBY LETTER OF CREDIT), [ACCOUNT PARTY] HAS FAILED TO RENEW THE STANDBY LETTER OF CREDIT IN A MANNER ACCEPTABLE TO THE ISO, AND THUS THE ISO IS DRAWING UPON THE STANDBY LETTER OF CREDIT IN AN AMOUNT EQUAL TO $______________. **]; OR**

[**INCLUDE ONLY IN FORM IF LETTER OF CREDIT HAS AUTOMATIC RENEWAL LANGUAGE:]** [AS OF THE CLOSE OF BUSINESS ON ________________, 20__ (FILL IN DATE WHICH IS WITHIN 30 DAYS BEFORE THE EXPIRATION DATE OF THE STANDBY LETTER OF CREDIT IF NOT AUTORENEWING), WE HAVE BEEN PROVIDED NOTICE FROM [ACCOUNT PARTY] [ISSUER] THAT THE STANDBY LETTER OF CREDIT WILL NOT BE

EXTENDED FOR AN ADDITIONAL ONE (1) YEAR PERIOD, AND THUS THE ISO IS DRAWING UPON THE STANDBY LETTER OF CREDIT IN AN AMOUNT EQUAL TO $______________.]

IF PRESENTATION OF ANY DRAWING CERTIFICATE IS MADE ON A BUSINESS DAY AND SUCH PRESENTATION IS MADE AT OUR COUNTERS ON OR BEFORE 10:00 A.M. _________ TIME, WE SHALL SATISFY SUCH DRAWING REQUEST ON THE SAME BUSINESS DAY. IF THE DRAWING CERTIFICATE IS RECEIVED AT OUR COUNTERS AFTER 10:00 A.M. ___________ TIME, WE WILL SATISFY SUCH DRAWING REQUEST ON THE NEXT BUSINESS DAY. FOR THE PURPOSES OF THIS SECTION, A BUSINESS DAY MEANS A DAY, OTHER THAN A SATURDAY OR SUNDAY, ON WHICH THE FEDERAL RESERVE BANK OF NEW YORK IS NOT AUTHORIZED OR REQUIRED TO BE CLOSED. DISBURSEMENTS SHALL BE IN ACCORDANCE WITH THE INSTRUCTIONS OF THE ISO.

THE FOLLOWING TERMS AND CONDITIONS APPLY:

THIS STANDBY LETTER OF CREDIT SHALL EXPIRE AT THE CLOSE OF BUSINESS [DATE] [AT LEAST 120 DAYS AFTER ISSUANCE FOR NEW POSTING ENTITIES].

[INCLUDE ONLY IF LETTER OF CREDIT HAS A FIXED EXPIRATION DATE:] [IF [ACCOUNT PARTY] HAS FAILED TO RENEW THIS STANDBY LETTER OF CREDIT IN A MANNER ACCEPTABLE TO THE ISO, YOU MAY DRAW ON THIS STANDBY LETTER OF CREDIT WITHIN THE THIRTY (30) DAYS PRIOR TO THE EXPIRY DATE BY PRESENTING YOUR ONE OR MORE PAYMENT DEMANDS TO US FOR AN AGGREGATE AMOUNT UP TO THE UNUSED BALANCE OF THIS STANDBY LETTER OF CREDIT.]

[INCLUDE ONLY IF LETTER OF CREDIT IS TO HAVE AUTOMATIC RENEWAL LANGUAGE:] [IT IS A CONDITION OF THIS STANDBY LETTER OF CREDIT THAT IT WILL BE AUTOMATICALLY EXTENDED WITHOUT AN AMENDMENT FOR A (1) YEAR PERIOD BEGINNING ON THE INITIAL EXPIRATION DATE HEREOF AND UPON EACH ANNIVERSARY OF SUCH DATE, UNLESS AT LEAST [THIRTY (30) **OR** SIXTY (60) **OR** NINETY (90)] DAYS PRIOR TO ANY SUCH EXPIRATION DATE WE HAVE SENT YOU, OR THE ACCOUNT PARTY HAS SENT YOU, WRITTEN NOTICE BY

REGULAR AND REGISTERED MAIL OR COURIER SERVICE THAT WE OR THE ACCOUNT PARTY ELECT NOT TO PERMIT THIS LETTER OF CREDIT TO BE SO EXTENDED, AND THAT THIS LETTER OF CREDIT WILL EXPIRE ON ITS THEN CURRENT EXPIRATION DATE. UPON RECEIPT OF SUCH NOTICE, YOU MAY DRAW ON THIS STANDBY LETTER OF CREDIT WITHIN THE THIRTY (30) DAYS PRIOR TO THE THEN RELEVANT EXPIRY DATE BY PRESENTING YOUR ONE OR MORE PAYMENT DEMANDS TO US FOR AN AGGREGATE AMOUNT UP TO THE UNUSED BALANCE OF THIS STANDBY LETTER OF CREDIT.]

IT IS A CONDITION OF THIS STANDBY LETTER OF CREDIT THAT WE SHALL MAINTAIN A MINIMUM LONG-TERM DEBT RATING (OR, IF WE DO NOT HAVE A MINIMUM LONG-TERM DEBT RATING, THEN A MINIMUM CORPORATE RATING) OF "A-" BY STANDARD AND POOR'S, OR "A3" BY MOODY'S OR "A-" BY FITCH. IN THE EVENT THAT WE ARE RATED BY MULTIPLE RATING AGENCIES, IF ANY APPLICABLE RATING FROM THE RATING AGENCIES FALLS BELOW THE LEVELS LISTED, THEN WE SHALL NOT BE CONSIDERED TO HAVE SATISFIED THIS CONDITION. IN THE EVENT THAT WE DO NOT SATISFY THE CONDITION REQUIRED BY THIS PARAGRAPH, YOU MAY DEMAND PAYMENT FROM US AT THE ADDRESS ABOVE, BY PRESENTING YOUR ONE OR MORE PAYMENT DEMANDS TO US FOR AN AGGREGATE AMOUNT UP TO THE UNUSED BALANCE OF THIS STANDBY LETTER OF CREDIT.

THE AMOUNT WHICH MAY BE DRAWN BY YOU UNDER THIS STANDBY LETTER OF CREDIT SHALL BE AUTOMATICALLY REDUCED BY THE AMOUNT OF ANY DRAWINGS HEREUNDER AT OUR COUNTERS. ANY NUMBER OF PARTIAL DRAWINGS ARE PERMITTED FROM TIME TO TIME HEREUNDER.

ALL COMMISSIONS AND CHARGES WILL BE BORNE BY THE ACCOUNT PARTY.

THIS STANDBY LETTER OF CREDIT IS NOT TRANSFERABLE OR ASSIGNABLE. THIS STANDBY LETTER OF CREDIT DOES NOT INCORPORATE AND SHALL NOT BE DEEMED MODIFIED, AMENDED OR AMPLIFIED BY REFERENCE TO ANY DOCUMENT, INSTRUMENT OR AGREEMENT (A) THAT IS REFERRED TO HEREIN (EXCEPT FOR THE ISP, AS DEFINED BELOW) OR (B) IN WHICH THIS STANDBY

LETTER OF CREDIT IS REFERRED TO OR TO WHICH THIS STANDBY LETTER OF CREDIT RELATES.

THIS STANDBY LETTER OF CREDIT SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE INTERNATIONAL STANDBY PRACTICES (“ISP98”) OF THE INTERNATIONAL CHAMBER OF COMMERCE PUBLICATION NO. 590, INCLUDING ANY AMENDMENTS, MODIFICATIONS, OR REVISIONS THEREOF (THE “ISP”), EXCEPT TO THE EXTENT THAT THE TERMS HEREOF ARE INCONSISTENT WITH THE PROVISIONS OF THE ISP, IN WHICH CASE THE TERMS OF THIS STANDBY LETTER OF CREDIT SHALL GOVERN. THIS STANDBY LETTER OF CREDIT SHALL BE GOVERNED BY THE INTERNAL LAWS OF THE COMMONWEALTH OF MASSACHUSETTS TO THE EXTENT THAT THE TERMS ARE NOT GOVERNED BY THE ISP.

THIS STANDBY LETTER OF CREDIT MAY NOT BE AMENDED, CHANGED OR MODIFIED WITHOUT THE EXPRESS WRITTEN CONSENT OF THE ISO AND ISSUER.

WE HEREBY ENGAGE WITH YOU THAT DOCUMENTS DRAWN UNDER AND IN COMPLIANCE WITH THE TERMS OF THIS STANDBY LETTER OF CREDIT SHALL BE DULY HONORED UPON PRESENTATION AS SPECIFIED AND WE REPRESENT THAT THE ACCOUNT PARTY IS NOT AN AFFILIATE OF THE ISSUER.

PRESENTATION OF ANY DRAWING CERTIFICATE UNDER THIS STANDBY LETTER OF CREDIT MAY BE SENT TO US BY COURIER, CERTIFIED MAIL, REGISTERED MAIL, OR FACSIMILE (WITH A CONFIRMING COPY OF SUCH FACSIMILE SENT AFTER THE DRAWING BY CERTIFIED MAIL TO THE ADDRESS SET FORTH BELOW; PROVIDED HOWEVER, THAT THE CONFIRMING COPY SHALL NOT BE A PREREQUISITE FOR US TO HONOR ANY PRESENTATION OTHERWISE MADE IN ACCORDANCE WITH THE TERMS OF THIS STANDBY LETTER OF CREDIT), OR SUCH OTHER ADDRESS AS MAY HEREAFTER BE FURNISHED BY US. OTHER NOTICES CONCERNING THIS STANDBY LETTER OF CREDIT MAY BE SENT BY SIMILAR COMMUNICATIONS FACILITY TO THE RESPECTIVE ADDRESSES SET FORTH BELOW. ALL SUCH NOTICES AND COMMUNICATIONS SHALL BE EFFECTIVE ~~WHEN ACTUALLY RECEIVED~~UPON RECEIPT BY THE INTENDED RECIPIENT PARTY.

IF TO THE BENEFICIARY OF THIS STANDBY LETTER OF CREDIT:

ISO NEW ENGLAND INC.
ATTENTION: CREDIT DEPARTMENT
1 SULLIVAN RD. HOLYOKE, MA 01040
FAX: 413-540-4569
EMAIL: CREDITDEPARTMENT@ISO-NE.COM

IF TO THE ACCOUNT PARTY:
[NAME]
[ADDRESS]
[FAX]
[PHONE]

IF TO ISSUER:
[NAME]
[ADDRESS]
[FAX]
[PHONE]

_______________________________ _______________________________

[~~signature~~SIGNATURE] [~~signature~~SIGNATURE]

AMENDMENT TO SECURITY AGREEMENT

This Amendment to Security Agreement (this "**Amendment**") is effective as of this [__] day of [_____________], 20[_], by and between [INSERT NAME], a [_____________], having its principal office and place of business at [_________________________] (the "**Debtor**"), and ISO New England Inc., a Delaware nonprofit corporation (the "**Secured Party**" and collectively with the Debtor, the "**Parties**").

WHEREAS, the Parties are parties to that certain Security Agreement dated as of [_____________], 20[_] (the "**Agreement**") and wish to amend the Agreement to clarify that the definition of Collateral thereunder.

NOW, THEREFORE, in consideration of the covenants hereinafter set forth, and other good and valuable consideration, the receipt of which is hereby acknowledged, the Parties agree as follows:

1. Capitalized Terms: Capitalized terms used but not otherwise defined in this Amendment shall have the meanings ascribed to them in the Agreement.

2. Amendment to Agreement: The definition of "Collateral" in Section 1.a.ii. of the Agreement shall be deleted in its entirety and replaced with the following:

    "Collateral" shall mean (a) all cash provided, submitted, wired or otherwise transferred or deposited by the Debtor or another party (including, without limitation, the Secured Party) to or with the Secured Party or a financial institution, investment firm, or other designee selected by the Secured Party or acting on the Secured Party's behalf, to hold or invest such cash deposit, from time to time in satisfaction of, pursuant to, or in compliance with, the ISO Financial Assurance Policy; (b) all securities or other investment property (as defined in the Code) of the Debtor, whether or not purchased with such cash deposit, submitted, wired or otherwise transferred, deposited or maintained by the Debtor or another party (including, without limitation, the Secured Party) to or with the Secured Party or its designee, in each case in satisfaction of, pursuant to, or in compliance with, the ISO Financial Assurance Policy; (c) all other property of Debtor submitted, pledged, assigned or otherwise transferred by the Debtor or another party (including, without limitation, the Secured Party) to the Secured Party or its designee, in each case, in satisfaction of, pursuant to, or in compliance with, the ISO Financial Assurance Policy; (d) all cash provided, submitted, wired or otherwise transferred or deposited with the Secured Party or a financial institution, investment firm, or other designee selected by the Secured Party or acting on the Secured Party's behalf, to hold or invest such cash, pursuant to the drawing(s) of any letter of credit provided in satisfaction of, pursuant to, or in compliance with, the ISO Financial Assurance Policy; and (e) the products and proceeds of each of the foregoing.

3. Effect on Agreement: Except as expressly amended hereby, the provisions of the Agreement shall remain in full force and effect, and the provisions of the Agreement are incorporated herewith.

4. Governing Law: This Amendment shall be interpreted and enforced in accordance with the laws of the State of Connecticut without reference to its choice of law provisions.

5. Counterparts; Electronic Signature: This Amendment may be executed in separate counterparts, and each counterpart, when so executed, shall be deemed to be an original and all of which together shall constitute one and the same agreement. It may also be executed by way of facsimile or electronic signature, and if so, shall be considered an original. A signed copy of this Amendment transmitted by facsimile, email or other means of electronic transmission shall be deemed to have the same legal effect as delivery of an original executed copy of this Amendment.

IN WITNESS WHEREOF, the Parties have caused this Amendment to be executed by their duly authorized officers, effective as of the day and year first above written.

ISO New England Inc.	**[DEBTOR]**
Signature: ______________________	Signature: ______________________
Name:	Name:
Title:	Title:

AMENDMENT TO UNCERTIFICATED SECURITIES CONTROL AGREEMENT

This Amendment to Uncertificated Securities Control Agreement (this "**Amendment**") is effective as of this [__] day of [_____________], 20[_], among [_________________], a [_______________] [corporation] (the "Grantor"), ISO NEW ENGLAND INC., a Delaware non-profit corporation, in its individual capacity and as agent for the entities that are Market Participants and participants from time to time in the New England Power Pool (the "Secured Party"), and BLACKROCK LIQUIDITY FUNDS (the "Issuer" and collectively with the Debtor and Secured Party, the "**Parties**").

WHEREAS, the Parties are parties to that certain Uncertificated Securities Control Agreement dated as of [_____________], 20[_] (the "**Agreement**") and wish to amend the Agreement to clarify the definitions of Cash Deposit and Collateral thereunder and to clarify the delivery of Cash Deposits.

NOW, THEREFORE, in consideration of the covenants hereinafter set forth, and other good and valuable consideration, the receipt of which is hereby acknowledged, the Parties agree as follows:

1. Capitalized Terms: Capitalized terms used but not otherwise defined in this Amendment shall have the meanings ascribed to them in the Agreement.

2. Amendment to Agreement:

(a) The definitions of "Cash Deposit" and "Collateral" in Section 1 of the Agreement shall be deleted in their entirety and replaced with the following:

"Cash Deposit" shall mean one or more cash deposits provided, submitted, wired or otherwise transferred by the Grantor or on behalf of the Grantor by the Secured Party to the Secured Party or to a financial institution, investment firm, or other designee selected by the Secured Party or acting on the Secured Party's behalf in accordance with the Financial Assurance Policy to hold or invest such cash deposits, including, without limitation, cash deposits provided, submitted, wired or otherwise transferred pursuant to the drawing(s) of any letter of credit provided in satisfaction of, pursuant to, or in compliance with, the ISO Financial Assurance Policy.

"Collateral" shall mean (i) all cash provided, submitted, wired or otherwise transferred or deposited by the Grantor or on behalf of the Grantor by the Secured Party to or with the Secured Party or to a financial institution, investment firm, or other designee selected by the Secured Party or acting on the Secured Party's behalf, to hold or invest such cash ~~deposit~~, from time to time in satisfaction of, pursuant to, or in compliance with the Financial Assurance Policy; (ii) all securities or other investment property (as defined in the UCC) of the Grantor, including, without limitation, the Pledged Securities, whether or not purchased with such cash ~~deposit~~, but solely to the extent such securities or investment property are held in the account[s] identified on Attachment B; (iii) in each case the products and proceeds thereof; and (iv) without duplication, all Collateral as defined in the Security Agreement.

(b) Section 4 of the Agreement shall be deleted in its entirety and replaced with the following:

"Section 4. Delivery of Cash Deposit. The Secured Party directs the Grantor or the Secured Party on its behalf holding a Cash Deposit to wire transfer, or cause to be wire transferred, to the account listed on Attachment C, immediately available funds as the initial Cash Deposit hereunder and under the Security Agreement. The Grantor or the Secured Party holding a Cash Deposit may from time to time make additional transfers of funds to the account listed on Attachment C as additional Cash Deposits to purchase Pledged Securities. All Cash Deposits will be used by the Grantor to pay the purchase price of Pledged Securities, and immediately upon the Issuer's receipt of (i) any Cash Deposit in the account listed on Attachment C, and (ii) a direction to use that Cash Deposit to purchase Pledged Securities, the Grantor shall be, for all purposes, the owner of the Pledged Securities purchased therewith. Until the Issuer's receipt of a Notice of Exclusive Control, the Grantor may change all or a portion of any Permitted Investment to another Permitted Investment at any time and from time to time in accordance with and subject to Section 11(e) hereof. In the event that (a) the Grantor fails to notify the Secured

Party and the Issuer of at least one Permitted Investment hereunder in which a Cash Deposit is to be invested, or (b) any Permitted Investment ceases to be a Permitted Investment and the Grantor fails to exchange the shares that formerly constituted a Permitted Investment for shares that then constitute a Permitted Investment, the Secured Party may issue instructions to the Issuer to effect such an investment (in the case of clause (a) of this sentence) or exchange (in the case of clause (b) of this sentence), specifying a Permitted Investment in which the applicable portion of the Collateral is to be invested (in accordance with any applicable requirements in the Financial Assurance Policy regarding a default investment, the "Default Investment"). The Issuer shall comply with any instructions given by the Secured Party under the preceding sentence. The Default Investment as of the date of this Agreement is designated on Attachment B. The Secured Party shall give notice to the Issuer and the Grantor of any change in the Default Investment."

3. Effect on Agreement: Except as expressly amended hereby, the provisions of the Agreement shall remain in full force and effect, and the provisions of the Agreement are incorporated herewith.

4. Governing Law: This Amendment shall be interpreted and enforced in accordance with the laws of the State of Connecticut without reference to its choice of law provisions.

5. Counterparts; Electronic Signature: This Amendment may be executed in separate counterparts, and each counterpart, when so executed, shall be deemed to be an original and all of which together shall constitute one and the same agreement. It may also be executed by way of facsimile or electronic signature, and if so, shall be considered an original. A signed copy of this Amendment transmitted by facsimile, email or other means of electronic transmission shall be deemed to have the same legal effect as delivery of an original executed copy of this Amendment.

IN WITNESS WHEREOF, the Parties have caused this Amendment to be executed by their duly authorized officers, effective as of the day and year first above written.

[GRANTOR]

By:__________________________________

Name:

Title:

ISO NEW ENGLAND INC.

By:__________________________________

Name:

Title:

BLACKROCK LIQUIDITY FUNDS

By:__________________________________

Name:

Title:

MARCH 25, 2025 | HOLYOKE, MA

STANDBY LETTER OF CREDIT FORM FOR FINANCIAL ASSURANCE & LIST OF ELIGIBLE LETTER OF CREDIT ISSUERS

NEPOOL Budget and Finance Subcommittee Meeting

CHRISTOPHER NOLAN

DIRECTOR, MARKET AND CREDIT RISK

ISO's Standby Letter of Credit (LC) Form

Proposed Effective date: September 1, 2025 with a phased in approach

- ISO-NE's Irrevocable Standby Letter of Credit (LC) Form, Attachment 2 of the Financial Assurance Policy (FAP), lacks several structural features that mitigate the risk of socialized default losses
  - Per the FAP, the ISO can only accept minor, non-material changes to the Form without refiling with FERC
- This presentation introduces these issues to stakeholders, presents the ISO's concerns with the current LC form and shares our approach to address such issues and mitigate the risk
- Additionally, there are two new administrative updates included in the new LC form regarding the "evergreen" clause and drawing certificates presented by email

ISO's Standby Letter of Credit (LC) Form

Proposed Effective date: September 1, 2025 with a phased in approach

- The ISO's form LC in the FAP is to cover market obligations; a similar form was used for Order 2023 Commercial Readiness Deposits, which is posted on the ISO's website but is not filed as part of the tariff
- The ISO will update the Commercial Readiness Deposit Form LC, if applicable, based on the changes discussed herein
- Conforming changes to the body of the FAP are also required

ISO's Standby Letter of Credit (LC) Form

Proposed Effective date: September 1, 2025 with a phased in approach

The current ISO Letter of Credit Form ensures payment if a MP fails to pay its invoice on time

- The ISO uses LCs to ensure the timely payment of a Market Participant's (MP) obligations arising from market activities should the MP fail to pay the ISO (i.e., a billing default)
- The bank wires cash to the ISO upon presentation of a drawing certificate related to a billing default ("a failure to pay") and these funds are then used to clear the market per the ISO's weekly settlement billing cycle

There are other scenarios where the ISO's ability to settle the market may be placed in jeopardy due to the lack of protections within the current LC form

What happens if the MP is unable to replace an LC which is due to expire?

- In a scenario where the MP has been unable to renew, replace or amend the current expiring LC posted to the ISO and that MP continues to have financial assurance requirements (such as FCM Delivery FA over future time periods), the ISO clearly cannot draw on the LC once it expires should a payment default occur thereafter
- Successfully drawing the full notional value of the LC before expiration eliminates this risk

Proposed new mitigation: A new draw trigger, upon failure to renew, replace or amend an existing LC within 30 days of the expiration of the LC will be added to the form LC

What happens if the LC Bank no longer satisfies the ISO's minimum credit rating requirements?

- ISO has several requirements for a Bank to be (and remain) included on its List of Eligible LC Issuers including minimum credit ratings
  - A-, A3 and A-, by S&P, Moody's and Fitch, respectively
- Banks that were previously approved by the ISO that are downgraded below any of these minimum credit ratings are ineligible to post new LCs to the ISO
- After a 5-day grace period (or 20-day grace period, if extended by the ISO) the LC is valued at $0 and MPs are required to replace ineligible existing LCs with those from another bank that satisfies the ISO's requirements including the minimum credit rating requirement
- The ISO is exposed to the worsening credit condition of the bank until the LC is successfully replaced by the MP

Proposed new mitigation: A new drawing right in the LC form upon the downgrade of the LC Bank below the minimum credit rating requirements

What happens currently if a bank is downgraded below the minimum credit ratings but is on the CME approved list of banks?

- The ISO currently accepts Letters of Credit from banks that are on the CME's list of approved banks even if their credit rating is below A- subject to satisfying other criteria outlined in the FAP
- The ISO, therefore, intends to change the LC Issuer eligibility criteria in the FAP such that it no longer refers to CME's list of approved banks as some of those banks are rated below the A- minimum credit rating threshold that the ISO otherwise requires

All Banks on the ISO's List of Eligible LC Banks will be required to satisfy the minimum credit rating requirement of A-

Drawing certificates presented by email offer additional operational flexibility to the ISO

- Currently, the ISO can present a drawing certificate to the issuing LC Bank by means of courier, certified mail, registered mail, or facsimile
- Facsimile is the predominant method currently used by the ISO to present drawing certificates as we can meet the 10:00am presentation deadline for same day payment which wouldn't typically be possible by courier or mail
  - Confirming copies are sent after the fax but the receipt of such by the Bank is not a prerequisite to honor the faxed drawing certificate
- The ISO wants to ensure that it has all standard presentation delivery options available to it in its updated LC form (for example, in cases where the fax is not operational or available)

The new LC form will include additional language to allow presentation of drawing certificates by email

The evergreen clause is now included as a standard option in the new LC form

- Some MPs provide LCs that contain an evergreen clause which permits the automatic extension of the LC for a period of one year beginning on the initial expiration date (and upon the anniversary of such date) unless at least 30 days prior to such expiration the ISO has been notified that it will not be extended
- Currently, MPs are required to request the inclusion of this feature in the LC form; however, the ISO considers it administratively beneficial to offer it as an option within the standard LC form instead of having to repeatedly process the extension of expiring LCs

The new LC form will include additional language to provide the evergreen clause as an option within the standard LC form

ISO is proposing a phased-in approach to implementing the new LC form

- A transitional implementation approach is designed to give MPs adequate time to replace the current LCs with the new LC form during 2025 and 2026
- ISO is considering an effective date on September 1, 2025
- Between September 1, 2025 and June 1, 2026, any LC which is required to be newly posted or replaces / amends an existing LC will be required to be written under the new LC form
- From June 1, 2026 onwards, all LCs posted to the ISO by MPs will be required to be under the new LC form

Including these features in the ISO's LC form are reasonable from a risk management perspective

- Each of the proposed drawing features has precedent in other Letter of Credit forms required by other ISOs / RTOs
- The vast majority of banks on ISO's Eligible Bank LC Issuer List currently underwrite LCs which allow the presentation of the drawing certificate by email
- The ISO is interested in understanding if any of our stakeholders have any concerns with including these new drawing features in the Sample Standby Letter of Credit form (FAP Attachment 2) for financial assurance
- Given the protections afforded by LCs with these additional risk mitigation features, the ISO considers them a reasonable and prudent addition to our standard LC form

Stakeholder Process and Next Steps

Steps	Timeline
Initial discussion with Budget and Finance Subcommittee	March 25th
Presentation of Redline Standby Letter of Credit Form and FAP	April 15th
Vote at the Participants Committee	May 1st
FERC Filing	May-June
Effective Date	September 1, 2025 including a transitional implementation period

APRIL 15, 2025 | HOLYOKE, MA

STANDBY LETTER OF CREDIT FORM FOR FINANCIAL ASSURANCE & LIST OF ELIGIBLE LETTER OF CREDIT ISSUERS

NEPOOL Budget and Finance Subcommittee Meeting

Zach Shell

LEAD MARKET AND CREDIT RISK ANALYST

Contents of Presentation

The ISO proposed several changes to the Standby Letter of Credit (LC) Form and Financial Assurance Policy (FAP) at the March Budget & Finance (B&F) meeting

Summary of Proposed Updates

- Standby LC Form to include two new Non-Payment Default Draw triggers
  - Failure to renew LC within 30 days of expiration
  - Downgrade of LC Bank credit rating below A-/A3 by any agency
- FAP criteria for LC Issuer Eligibility
  - Remove Chicago Mercantile Exchange (CME) approval as criteria for eligibility
  - Remove confirmation by CME approved banks as a criteria for eligibility
- Administrative updates to Standby LC Form
  - Include evergreen clause as an option within the standard Standby LC Form
  - Allow presentation of drawing certificate by email

Additional drawing triggers mitigate the risk posed by MPs and banks showing signs of deteriorating creditworthiness

Additional Recommended Changes

- Redlines to the ISO Security Agreement and BlackRock Control Agreement
  - The additional draw triggers proposed at the March B&F require conforming changes to the Security and Control Agreements
- Additional administrative and conforming FAP language updates
  - Deletion of language regarding penalties for requested changes to the LC Form
  - Conforming language updates in the FAP based on redlines to the Security and Control Agreements

The ISO recommends additional changes along with all the proposed changes discussed at the March B&F meeting

Contents of Presentation

Non-Payment Default Draw Trigger - Failure to Renew LC

- The ISO recommends updating the Standby LC Form such that the ISO has the right to draw on the LC if the Market Participant (MP) fails to renew the LC prior to 30 days from its expiration date
  - Once an LC is within 30 days of expiration, the LC is valued at $0 in Financial Assurance Management (FAM) and the ISO will have the right to draw on the LC for an amount up to its full value
  - The drawing right is an option to draw at any point during the 30-day window prior to expiration, not a requirement
  - The drawing right is specific to the expiration of the LC, so even if the MP has additional forms of collateral fully covering their FA requirements, the ISO still has the right to draw (ISO will return excess collateral within 4 days of request)
  - The ISO will consider several factors when utilizing professional judgement to determine how much, if at all, to draw down on the LC in this circumstance
    - Amount of current obligations
    - Amount of other Financial Assurance (FA) currently provided
    - Assessment of various pertinent risk factors

Drawing on an expiring LC eliminates the risk posed when a MP has FA requirements that will persist past the date of the LC's expiration

Non-Payment Default Draw Trigger – Rating Downgrade

- The ISO recommends updating the Standby LC Form such that the ISO has the right to draw on the LC if the LC Issuer's credit rating is downgraded below A-/A3 by any agency
  - If the minimum credit rating of the LC Issuing Bank falls below A-/A3, the ISO will have the right to immediately draw on the LC for an amount up to its full value
  - Minimum credit rating is determined by the lowest credit rating issued for the LC Issuing Bank by S&P, Moody's, or Fitch
  - LC will be valued at $0 for Financial Assurance purposes in FAM after a 5-day grace period from the time of the failure notification issued by the ISO (can be extended to 20 days at the sole discretion of the ISO)
  - The ISO will consider several factors when utilizing professional judgement to determine how much, if at all, to draw down on the LC in this circumstance
    - Amount of current obligations
    - Amount of other Financial Assurance (FA) currently provided
    - Assessment of various pertinent risk factors
    - Financial risk assessment of bank

This drawing trigger mitigates the exposure to LC Issuing banks with worsening credit

Funds from LC Draws

- When the ISO draws on an LC for either Non-Payment Default Draw trigger, the funds (and any accrued interest or income from such funds) will count as an acceptable form of FA towards covering the MPs Financial Assurance Requirements
- The ISO holds all right, title, and interest in the Non-Payment Default Drawn Funds
- The MP has a contingent right to the funds less amounts applied to amounts owed by the MP to the extent the amount is not necessary to meet the MPs Financial Assurance Requirements

MP Requirements for Non-Payment Default Draws

- Upon request of the ISO, but no later than 5 Business Days after the Non-Payment Default Draw, the Posting Entity shall execute a Security Agreement or an amended Security Agreement

- Within 30 days of the Non-Payment Default Draw complete any steps required by the ISO to complete all the following actions
  - Open a BlackRock account (or notify ISO of inability to do so, i.e., Canadian MPs)
  - Execute any necessary documentation (e.g., an amendment to the Control Agreement) for the ISO to deposit the Non-Payment Default Drawn Funds into the Posting Entity's BlackRock account
  - Direct the ISO to transfer the Non-Payment Default Drawn Funds into the BlackRock account

- Non-Payment Default Drawn Funds transferred into the Posting Entity's BlackRock account continues to be counted as Financial Assurance of the MP

Failure to comply with the recommended procedures will result in default under the FAP

Non-Payment Default Draw - Failure to Renew LC Example[1]

- A Market Participant has a $5 MM LC with an expiration date of 11/30/2026 and has a total Financial Assurance Requirement of $4 MM

- On 11/1/2026 the LC remains in place with the ISO for $5 MM, but it is valued in FAM at $0 because it is within 30 days of its expiration date. This causes the MP to go into FA default because the MP doesn't have other forms of sufficient Financial Assurance posted to cover its $4 MM Financial Assurance Requirement

- On 11/1/2026 the option to draw on the LC under the new draw trigger for failure to renew LC within 30 days of expiration is triggered, and the ISO has the right to draw up to the full $5 MM at any point until the LC expires

- On 11/2/2026 the MP hasn't cured its FA default by providing another form of sufficient collateral, so the ISO suspends the MP

- On 11/29/2026 the MP still hasn't provided sufficient FA to cover its requirements which are now $6 MM and the MP remains suspended. The ISO considers it appropriate to draw the full $5 MM and completes the draw

- On 11/29/2026 drawn funds are received by the ISO, the funds will count towards the Market Participant collateral, which is still insufficient to cover the $6 MM FA requirement, and the MP remains suspended until it can provide sufficient collateral

(1) All situations are dependent upon specific facts and circumstances. This example does not cover all situations.

Non-Payment Default Draw - Bank Downgrade Example(1)

- A Market Participant has a $5 MM LC issued by Bank of America and the MP has a Financial Assurance Requirement of $4 MM
- On 11/1/2026 Bank of America is rated A- by S&P, A3 by Moody's, but is downgraded by Fitch to BBB+ and the ISO removes the bank from its List of Eligible LC Issuers
- On 11/1/2026 the option to draw on the LC is also triggered, and the ISO has the right to draw up to the full $5 MM at any point until the expiration of the LC
- On 11/1/2026 the LC is valued in FAM at $5 MM and MPs have 5-days to replace the LC with an acceptable form of collateral sufficient to cover their Financial Assurance Requirements
- On 11/6/2026 the LC remains in place with the ISO for $5 MM but is valued in FAM at $0. This causes the MP to go into FA default because the MP doesn't have other forms of sufficient collateral posted to cover its $4 MM Financial Assurance Requirement
- On 11/7/2026 the ISO elects to exercise its option to draw on the LC for the full $5 MM. Once the funds are received, they will count towards the MPs collateral and potentially cure the FA default. Any excess FA may be returned to the MP upon request.

(1) All situations are dependent upon specific facts and circumstances. This example does not cover all situations.

The recommended new draw triggers within the Standby LC Form impact the FAP and subsequently the Security and Control Agreements

Impact of New Draw Triggers

- The recommended Non-Payment Default Draw triggers create a situation where the ISO may be holding drawn funds in an ISO bank account or in an ISO BlackRock account
  - With only payment default draws, this was not the case as the drawn funds were immediately applied to cover the payment default
- As a result, the ISO must update the FAP to include language that reflects how the funds from Non-Payment Default Draws will be treated
- The recommended FAP updates treat the funds from Non-Payment Default Draws as Financial Assurance
- To ensure the ISO retains its rights to the Non-Payment Default Drawn Funds, the ISO will require MPs with LCs with triggered Non-Payment Default Draws to amend their Security and Control Agreement to cover the drawn funds

Contents of Presentation

The ISO recommends changing the LC Issuer Eligibility criteria in the FAP to remove the reference to CME's approved list of LC Issuing Banks

FAP Criteria for LC Issuer Eligibility

- Currently, the FAP requires LC issuing banks to meet the following criteria
  - Be organized under the laws of the United States or any state thereof, or be the United States branch of a foreign bank and either
  - (i) be recognized by the Chicago Mercantile Exchange ("CME") as an approved letter of credit bank; or
  - (ii) have a minimum long-term debt rating (or, if the bank does not have minimum long-term debt rating, than a minimum corporate rating) of "A-" by S&P, or "A3" by Moody's or "A-" by Fitch so long as its letter of credit is confirmed by a bank that is recognized by CME as an approved letter of credit issuer as described in clause (i) above; or
  - (iii) have a minimum long-term debt rating (or, if the bank does not have minimum long-term debt rating, than a minimum corporate rating) of "A-" by S&P, or "A3" by Moody's, or "A-" by Fitch and be approved by the ISO in its sole discretion
- The ISO recommends changing the criteria to remove (i) and (ii) listed above which means all banks would be required to have a minimum rating of A-/A3 or better (by all rating agencies which supply a credit rating for the specific bank) and be approved by the ISO in its sole discretion to become eligible

Removing reference to the CME approved list mitigates the risk posed by banks that don't meet the minimum credit criteria, and eliminates reliance on credit criteria determined by a 3rd party

Contents of Presentation

The ISO recommends including the evergreen clause as a standard option in the new Standby LC Form

Evergreen Clause

- Some MPs provide LCs that contain an evergreen clause which permits the automatic extension of the LC for a period of one year beginning on the initial expiration date (and upon the anniversary of such date) unless at least 30 days prior to such expiration the ISO has been notified that it will not be extended
- This feature has historically never been included in the standard Standby LC Form but is an available option to be added to the form upon the MPs request
- The ISO considers it administratively beneficial to offer it as an option within the standard Standby LC Form instead of requiring MPs to specifically request its addition

The ISO recommends including the option in the new Standby LC Form for drawing certificates to be presented by email

Drawing Certificates Presented by Email

- Currently, the ISO can present a drawing certificate to the Issuing LC Bank by means of courier, certified mail, registered mail, or facsimile
- Facsimile is the predominant method currently used by the ISO to present drawing certificates as we can meet the 10:00am presentation deadline for same day payment which wouldn't typically be possible by courier or mail – Confirming copies are sent after the fax but the receipt of such by the Bank is not a prerequisite to honor the faxed drawing certificate
- The ISO recommends including email as an additional presentation option for the drawing certificate
  - The ISO will work directly with the Issuing LC banks to ensure email presentations are sent and received securely

The ISO recommends a phased-in approach to the implementation of the new Standby LC Form

Implementation and Transitional Period

- A transitional implementation approach is designed to give MPs adequate time to replace the current LCs with the new Standby LC Form during 2025 and 2026
- ISO recommends an effective date on September 1, 2025
- Between September 1, 2025 and September 1, 2026, any LC which is required to be newly posted or any amendment to an existing LC will be required to be written under the new Standby LC Form
  - The ISO lengthened the transitional period from 9 months to 12 months based on stakeholder feedback on the proposal made during the March B&F meeting
- From September 1, 2026 onwards, all LCs posted to the ISO by MPs will be required to be under the new Standby LC Form
- Additionally, the ISO will update the Commercial Readiness Deposit LC Form to align with the terms of the evergreen clause and new draw triggers recommended for the Standby LC Form
- No updates to the Billing Policy are required

Contents of Presentation

FAP Redlines

X. ACCEPTABLE FORMS OF FINANCIAL ASSURANCE

Provided that the requirements set forth herein are satisfied, acceptable forms of financial assurance include shares of registered or private mutual funds held in a shareholder account or a letter of credit, each in accordance with the provisions of this Section X. All costs associated with obtaining financial security and meeting the provisions of the ISO New England Financial Assurance Policy are the responsibility of the Market Participant or Non-Market Participant Transmission Customer providing that security (each a "Posting Entity"). ~~Any Posting Entity requesting a change to one of the model forms attached to the ISO New England Financial Assurance Policy which would be specific to such Posting Entity (as opposed to a generic improvement to such form) shall, at the time of making that request, pay a $1,000 change fee, which fee shall be deposited into the Late Payment Account maintained under the ISO New England Billing Policy.~~

The ISO is not accepting changes to the model forms, therefore this language is not applicable

FAP Redlines

A. Shares of Registered or Private Mutual Funds in a Shareholder Account

Shares of registered or private mutual funds in a shareholder account are an acceptable form of financial assurance provided that the Posting Entity providing such collateral (i) completes all required documentation to open an account with the financial institution selected by the ISO, after consultation with the NEPOOL Budget and Finance Subcommittee, (ii) completes and executes a security agreement ("Security Agreement") in the form of Attachment 1 to the ISO New England Financial Assurance Policy (as may be modified pursuant to Section X.B.1) and is in compliance with the Security Agreement, and (iii) completes and executes a Control Agreement in the form posted on the ISO website (as may be modified pursuant to Section X.B.1) and is in compliance with the Control Agreement. Any material variation from the form of Security Agreement included in Attachment 1 to the ISO New England Financial Assurance Policy (other than as modified pursuant to Section X.B.1) or the form of Control Agreement (other than as modified pursuant to Section X.B.1) posted on the ISO website must be approved by the ISO after consultation with the NEPOOL Budget and Finance Subcommittee and, in the case of the Security Agreement, filed with the Commission. To the extent any amount of shares contained in the shareholder account is no longer required hereunder, the ISO shall return such collateral to the Posting Entity providing it within four (4) Business Days of a request to do so.

Additional language to account for the changes made to the Control Agreement and Security Agreement

FAP Redlines

1. Non-Payment Default Draws

If the ISO has drawn against a letter of credit for any reason other than a failure to pay under the ISO New England Billing Policy (e.g., an expiring letter of credit has not been renewed or the issuing bank is downgraded below the minimum ratings requirement) (the "Non-Payment Default Draw") the ISO will hold such funds as a security deposit for the satisfaction of all obligations owed to the ISO by the Posting Entity (the "Non-Payment Default Drawn Funds"). The Non-Payment Default Drawn Funds shall be considered an appropriate form of financial assurance as described in this Section X. The ISO will hold all right, title, and interest in the Non-Payment Default Drawn Funds and the Posting Entity shall have a contingent right to such funds less any amounts applied to any debts owed to the ISO (pursuant to the Tariff, including the ISO New England Billing Policy): (i) upon the termination of its Market Participant Financial Assurance Requirement in accordance with Section III of the Financial Assurance Policy, (ii) upon the Posting Entity's provision of an alternative form of acceptable financial assurance in accordance with this Section X, or (iii) to the extent that any portion of the Non-Payment Default Drawn Funds are no longer required hereunder, upon the Posting Entity providing a written request to the ISO to return such portion of the funds (which request shall be honored within four (4) Business Days).

FAP Redlines

Upon request of the ISO, but no later than five (5) Business Days after the Non-Payment Default Draw, the Posting Entity shall execute a Security Agreement in the form of Attachment 1 to the ISO New England Financial Assurance Policy, provided that such form shall be modified to include within the definition of Collateral, funds received from a Non-Payment Default Draw, or an amendment to its existing Security Agreement in a form acceptable to the ISO in its sole discretion. Within thirty (30) days of the Non-Payment Default Draw the Posting Entity shall satisfy its obligations pursuant to the paragraph immediately below to direct the deposit of the Non-Payment Default Drawn Funds into the Posting Entity's shareholder account as described in Section X.A. Notwithstanding the prior sentence, if the Posting Entity provides written documentation to the ISO (which documentation must be to the ISO's reasonable satisfaction) of its inability to open a shareholder account as described in Section X.A, and the Posting Entity has executed a Security Agreement or an amendment to its existing Security Agreement as required above, the ISO shall continue to hold the Non-Payment Default Drawn Funds (and such amount shall continue to be considered financial assurance), subject to the Posting Entity's contingent right to such funds as described above, in a form determined by the ISO in its sole discretion, and any interest or income accrued on such funds, if applicable, shall be considered part of the Posting Entity's financial assurance.

FAP Redlines

Upon a Non-Payment Default Draw and unless the Posting Entity has either posted other appropriate financial assurance in the forms permitted by this Section X or provided written documentation of its inability to do so in accordance with the preceding paragraph, the Posting Entity shall within thirty (30) days of the Non-Payment Default Draw complete any steps required by the ISO to (a) open a shareholder account as described in Section X.A, (b) execute any necessary documentation, including any amendments to the Security Agreement and Control Agreement deemed necessary by the ISO in a form acceptable to the ISO in its sole discretion, for the ISO to deposit the Non-Payment Default Drawn Funds into the Posting Entity's shareholder account, and (c) direct the ISO to deposit the Non-Payment Default Drawn Funds into that Posting Entity's shareholder account as described in Section X.A. Upon the Posting Entity's completion of the foregoing steps in (a) through (c) to the ISO's satisfaction, ISO shall deposit the Non-Payment Default Drawn Funds into that Posting Entity's shareholder account and the balance of the funds then on deposit in such account shall continue to be the collateral of the ISO.

The ISO may apply any funds received from a letter of credit, including the Non-Payment Default Drawn Funds held as a security deposit, to amounts owed by the Posting Entity in accordance with the ISO New England Billing Policy. If a Posting Entity fails to comply with the provisions of this Section X.B.1, then the Posting Entity will be suspended as described in Section III.B.3 of the ISO New England Financial Assurance Policy until the deficiency is rectified.

New section describing the procedures and treatment of funds related to Non-Payment Default Draws

~~1~~2. Requirements for Banks

Each bank issuing a letter of credit that serves as financial assurance must meet the requirements of this Section X.B.1. Each such bank must be on the ISO's "List of Eligible Letter of Credit Issuers" which shall be established pursuant to this Section X.B.1. The ISO will post the current List of Eligible Letter of Credit Issuers on its website, and update that List and posting no less frequently than quarterly; provided that if a change is made to ~~bank is removed~~ from the List of Eligible Credit Issuers, the ISO shall update the List and provide notice to the NEPOOL Budget & Finance Subcommittee. To be included on the List of Eligible Letter of Credit Issuers, (i) the bank must be organized under the laws of the United States or any state thereof, or be the United States branch of a foreign bank; ~~and either: (i) be recognized by the Chicago Mercantile Exchange ("CME") as an approved letter of credit bank; or (ii) have a minimum long-term debt rating (or, if the bank does not have minimum long-term debt rating, than a minimum corporate rating) of "A-" by S&P, or "A3" by Moody's or "A-" by Fitch so long as its letter of credit is confirmed by a bank that is recognized by CME as an approved letter of credit issuer as described in clause (i) above; or (iii)~~ (ii) have a minimum long-term debt rating (or, if the bank does not have a minimum long-term debt rating, than a minimum corporate rating) of "A-" by S&P, or "A3" by Moody's, or "A-" by Fitch; and (iii) be approved by the ISO in its sole discretion ~~(the ISO will promptly advise the NEPOOL Budget and Finance Subcommittee of any additional bank approved by it under this provision)~~. ~~Because the ratings described in clauses (ii) and (iii) are minimum ratings, a bank will not be considered to have satisfied the requirement of those clauses~~In the event that a bank is rated by multiple Rating Agencies, if any applicable rating from the Rating Agencies falls below the levels listed, then a bank will not be considered to have satisfied the requirement under this paragraph ~~in those clauses~~. In addition, no Posting Entity may provide a letter of credit that has been issued ~~or confirmed~~ by a bank that is an Affiliate of that Market Participant.

If a bank that is included on the List of Eligible Letter of Credit Issuers fails to satisfy ~~any of~~ the criteria set forth above or if the ISO determines in its sole discretion that despite satisfying ~~any of~~ the criteria set forth above, accepting a letter of credit from a bank on the List of Eligible Letter of Credit Issuers presents an unreasonable risk that a bank may fail to honor the terms of such letter of credit, the applicable Posting Entity will have five (5) Business Days from the date on which the ISO provides notice of such failure or removal to replace the letter of credit with a letter of credit from a bank satisfying the ~~those~~ criteria or provide other financial assurance satisfying the requirements of the ISO New England Financial Assurance Policy. The ISO may extend that cure period to twenty (20) Business Days in its sole discretion. The ISO must promptly advise the NEPOOL Budget and Finance Subcommittee of any extension of a cure period beyond five (5) Business Days under this provision. For purposes of the ISO New England Financial Assurance Policy, the letter of credit shall be valued at $0 at the expiration of the five (5) or twenty (20) Business Day cure period, as applicable.

FAP Redlines

No letter of credit bank may issue ~~or confirm~~ letters of credit under the ISO New England Financial Assurance Policy in an amount exceeding either: (i) $100 million in the aggregate for any single Posting Entity; or (ii) $150 million in aggregate for a group of Posting Entities that are Affiliates. If a bank is removed from the List of Eligible Letter of Credit Issuers based on the ISO's determination that there is an unreasonable risk that a bank may fail to honor the terms of such letter of credit, the ISO in its sole discretion may reinstate eligibility, provided that the bank otherwise meets the conditions of this Section X.B.1.

The following provisions shall apply when a bank fails to honor the terms of one or more letters of credit issued ~~or confirmed~~ by the bank in favor of the ISO: (i) if the bank fails to honor the terms of one letter of credit in a rolling seven hundred and thirty day period, then the ISO will issue a notice of such failure to the NEPOOL Budget and Finance Subcommittee, to all members and alternates of the Participants Committee, to the New England governors and utility regulatory agencies and to the billing and credit contracts for all Market Participants; (ii) if the bank fails to honor either the terms of one letter of credit twice or the terms of two letters of credit in a rolling seven hundred and thirty day period, then (A) the ISO shall issue a notice described in subsection (i) above, (B) the bank will no longer be eligible to issue ~~or confirm~~ letters of credit in favor of the ISO, (C) any letters of credit issued ~~or confirmed~~ by such bank in favor of the ISO will not be renewed, and (D) any letters of credit issued ~~or confirmed~~ by such bank in favor of the ISO must be replaced with another acceptable form of financial assurance within five (5) Business Days from the date on which the ISO provides notice of such failure (the ISO may extend that cure period to twenty (20) Business Days in its sole discretion). For purposes of the ISO New England Financial Assurance Policy, the letter of credit shall be valued at $0 at the expiration of the five (5) or twenty (20) Business Day cure period, as applicable. Notwithstanding the foregoing, the ISO in its sole discretion may reinstate eligibility after not less than two years from the loss of eligibility, provided that the bank otherwise meets the conditions of this Section X.B.1.

~~Any letter of credit provided for a new Posting Entity for the purpose of covering the Initial Market Participant Financial Assurance Requirement must have a minimum term of 120 days.~~

Redlines to update Eligible LC Issuer criteria to remove reference to CME approved banks along with conforming language changes

FAP Redlines

~~2~~3.Form of Letter of Credit

Attachment 2 provides a generally acceptable sample "clean" letter of credit, and all letters of credit provided by Posting Entities shall be in this form (with only minor, non-material changes), unless a variation therefrom is approved by the ISO after consultation with the NEPOOL Budget and Finance Subcommittee and filed with the Commission. Notwithstanding the foregoing, Posting Entities that have provided a letter of credit in a form that was previously acceptable (e.g., under a prior version of Attachment 2) shall not be required to resubmit such letter of credit until the earlier of (a) the amendment or expiration of such letter of credit, in which case Posting Entity shall be required to provide a Letter of Credit in the Form of Attachment 2, or (b) September 1, 2026 ~~December 31, 2021~~. Any letter of credit provided for a new Posting Entity, for the purpose of covering the Initial Market Participant Financial Assurance Requirement, must have a minimum term of 120 days. All costs incurred by the ISO in collecting on a letter of credit provided under the ISO New England Financial Assurance Policy shall be paid, or reimbursed to the ISO, by the Posting Entity providing that letter of credit.

Redlines to reflect the transitional period and additional clarifying language

FAP Redlines

C. Special Provisions for Provisional Members

Notwithstanding any other provision of the ISO New England Financial Assurance Policy to the contrary, due to the temporary nature of a Market Participant's status as a Provisional Member and the relatively small amounts due from Provisional Members, any Provisional Member required to provide additional financial assurance under the ISO New England Financial Assurance Policy may only satisfy the portion of that requirement attributable to Participant Expenses under the RNA by providing collateral maintained in a shareholder account ~~a cash deposit~~ in accordance with Section X.A. Provisional Members will not have any other Non-Hourly Requirements under the ISO New England Financial Assurance Policy. If a Provisional Member uses a standing instruction to pay its Invoices pursuant to the ISO New England Billing Policy, in order to avoid a default and/or a Late Payment Charge, the total amount of collateral maintained in a shareholder account ~~the cash deposited~~ by that Provisional Member should be equal to the sum of (x) the Provisional Member's Financial Assurance Requirement under the ISO New England Financial Assurance Policy that is attributable to Participant Expenses under the RNA and (y) the amount due from that Provisional Member on its next Invoice under that ISO New England Billing Policy (not including the amount of any Qualification Process Cost Reimbursement Deposit (including the annual true-up of that amount) due from such Provisional Member). Provisional Members are also required to satisfy all other provisions of the ISO New England Financial Assurance Policy, and any additional financial assurance required to be provided by a Provisional Member that is not attributable to Participant Expenses may be satisfied by providing an acceptable form of financial assurance in accordance with this Section X ~~cash deposit or a letter of credit in accordance with this Section X but shall not be satisfied through the provision of the cash deposit described in this Section X.C~~. Without limiting or reducing in any way the requirements of the ISO New England Financial Assurance Policy that apply to a Provisional Member, the amount of ~~the cash deposit~~ financial assurance initially provided by a Provisional Member that is attributable to Participant Expenses (including any amounts provided in connection with the standing instruction under the ISO New England Billing Policy described above) shall be at least $2,500, and each Provisional Member will replenish that financial assurance ~~cash deposit~~ to at least that $2,500 level on December 31 of each year.

Redlines to clarify language related to cash in BlackRock accounts

Contents of Presentation

Standby Letter of Credit Form Redlines

IRREVOCABLE NON-TRANSFERABLE STANDBY LETTER OF CREDIT NO.

[EXPIRATION DATE]

WE DO HEREBY ISSUE THIS IRREVOCABLE NON-TRANSFERABLE STANDBY LETTER OF CREDIT BY ORDER OF AND FOR THE ACCOUNT OF [POSTING ENTITY OR AFFILIATE OF POSTING ENTITY ON BEHALF OF POSTING ENTITY] ("ACCOUNT PARTY") IN FAVOR OF ISO NEW ENGLAND INC. ("ISO" OR "BENEFICIARY") ("STANDBY LETTER OF CREDIT").

Redline to include "Non-Transferable" in the title

Standby Letter of Credit Form Redlines

OF A DRAFT IN THE FORM OF A DRAWING CERTIFICATE THAT IS SIGNED BY A PURPORTED OFFICER OR AUTHORIZED AGENT OF THE ISO AND DATED THE DATE OF PRESENTATION CONTAINING THE FOLLOWING STATEMENT IN (1) BELOW ALONG WITH THE APPROPRIATE STATEMENT IN (2) BELOW:

(1) "THE UNDERSIGNED HEREBY CERTIFIES TO [BANK] ("ISSUER"), WITH REFERENCE TO IRREVOCABLE NON-TRANSFERABLE STANDBY LETTER OF CREDIT NO. [------] (THE "STANDBY LETTER OF CREDIT") ISSUED BY ISSUER IN FAVOR OF ISO NEW ENGLAND INC. ("ISO"), THAT

(2) [POSTING ENTITY] HAS FAILED TO PAY THE ISO, IN ACCORDANCE WITH THE TERMS AND PROVISIONS OF THE TARIFF FILED BY THE ISO, AND THUS THE ISO IS DRAWING UPON THE STANDBY LETTER OF CREDIT IN AN AMOUNT EQUAL TO $_______________.]; **OR**

[ISSUER HAS FAILED TO MAINTAIN A MINIMUM LONG-TERM DEBT RATING FROM ANY APPLICABLE RATING AGENCY (OR, IF THE ISSUER DOES NOT HAVE A MINIMUM LONG-TERM DEBT RATING, THEN A MINIMUM CORPORATE RATING) OF "A-" BY STANDARD AND POOR'S , OR "A3" BY MOODY'S OR "A-" BY FITCH, AND THUS THE ISO IS DRAWING UPON THE STANDBY LETTER OF CREDIT IN AN AMOUNT EQUAL TO $_______________.]; **OR**

Standby Letter of Credit Form Redlines

[INCLUDE ONLY IN FORM IF LETTER OF CREDIT HAS A FIXED EXPIRATION DATE:] [AS OF THE CLOSE OF BUSINESS ON __________________, 20__ (FILL IN DATE WHICH IS WITHIN 30 DAYS BEFORE THE EXPIRATION DATE OF THE STANDBY LETTER OF CREDIT), [ACCOUNT PARTY] HAS FAILED TO RENEW THE STANDBY LETTER OF CREDIT IN A MANNER ACCEPTABLE TO THE ISO, AND THUS THE ISO IS DRAWING UPON THE STANDBY LETTER OF CREDIT IN AN AMOUNT EQUAL TO $________________.]; **OR**

[INCLUDE ONLY IN FORM IF LETTER OF CREDIT HAS AUTOMATIC RENEWAL LANGUAGE:] [AS OF THE CLOSE OF BUSINESS ON __________________, 20__ (FILL IN DATE WHICH IS WITHIN 30 DAYS BEFORE THE EXPIRATION DATE OF THE STANDBY LETTER OF CREDIT IF NOT AUTORENEWING), WE HAVE BEEN PROVIDED NOTICE FROM [ACCOUNT PARTY] [ISSUER] THAT THE STANDBY LETTER OF CREDIT WILL NOT BE EXTENDED FOR AN ADDITIONAL ONE (1) YEAR PERIOD, AND THUS THE ISO IS DRAWING UPON THE STANDBY LETTER OF CREDIT IN AN AMOUNT EQUAL TO $________________.]

Redlines to add new drawing triggers

Standby Letter of Credit Form Redlines

THIS STANDBY LETTER OF CREDIT SHALL EXPIRE AT THE CLOSE OF BUSINESS [DATE] [AT LEAST 120 DAYS AFTER ISSUANCE FOR NEW POSTING ENTITIES].

[INCLUDE ONLY IF LETTER OF CREDIT HAS A FIXED EXPIRATION DATE:] [IF [ACCOUNT PARTY] HAS FAILED TO RENEW THIS STANDBY LETTER OF CREDIT IN A MANNER ACCEPTABLE TO THE ISO, YOU MAY DRAW ON THIS STANDBY LETTER OF CREDIT WITHIN THE THIRTY (30) DAYS PRIOR TO THE EXPIRY DATE BY PRESENTING YOUR ONE OR MORE PAYMENT DEMANDS TO US FOR AN AGGREGATE AMOUNT UP TO THE UNUSED BALANCE OF THIS STANDBY LETTER OF CREDIT.]

[INCLUDE ONLY IF LETTER OF CREDIT IS TO HAVE AUTOMATIC RENEWAL LANGUAGE:] [IT IS A CONDITION OF THIS STANDBY LETTER OF CREDIT THAT IT WILL BE AUTOMATICALLY EXTENDED WITHOUT AN AMENDMENT FOR A ONE (1) YEAR PERIOD BEGINNING ON THE INITIAL EXPIRATION DATE HEREOF AND UPON EACH ANNIVERSARY OF SUCH DATE, UNLESS AT LEAST THIRTY (30) DAYS PRIOR TO ANY SUCH EXPIRATION DATE WE HAVE SENT YOU, OR THE ACCOUNT PARTY HAS SENT YOU, WRITTEN NOTICE BY REGULAR AND REGISTERED MAIL OR COURIER SERVICE THAT WE OR THE ACCOUNT PARTY ELECT NOT TO PERMIT THIS LETTER OF CREDIT TO BE SO EXTENDED, AND THAT THIS LETTER OF CREDIT WILL EXPIRE ON ITS THEN CURRENT EXPIRATION DATE. UPON RECEIPT OF SUCH NOTICE, YOU MAY DRAW ON THIS STANDBY LETTER OF CREDIT WITHIN THE THIRTY (30) DAYS PRIOR TO THE THEN RELEVANT EXPIRY DATE BY PRESENTING YOUR ONE OR MORE PAYMENT DEMANDS TO US FOR AN AGGREGATE AMOUNT UP TO THE UNUSED BALANCE OF THIS STANDBY LETTER OF CREDIT.]

Redlines for evergreen clause explanation of draw triggers

Standby Letter of Credit Form Redlines

IT IS A CONDITION OF THIS STANDBY LETTER OF CREDIT THAT WE SHALL MAINTAIN A MINIMUM LONG-TERM DEBT RATING (OR, IF THE ISSUER DOES NOT HAVE A MINIMUM LONG-TERM DEBT RATING, THEN A MINIMUM CORPORATE RATING) OF “A-” BY STANDARD AND POOR’S, OR “A3” BY MOODY’S OR “A-” BY FITCH. IN THE EVENT THAT WE ARE RATED BY MULTIPLE RATING AGENCIES, IF ANY APPLICABLE RATING FROM THE RATING AGENCIES FALLS BELOW THE LEVELS LISTED, THEN WE SHALL NOT BE CONSIDERED TO HAVE SATISFIED THIS CONDITION. IN THE EVENT THAT WE DO NOT SATISFY THE CONDITION REQUIRED BY THIS PARAGRAPH, YOU MAY DEMAND PAYMENT FROM THE ISSUER AT THE ADDRESS ABOVE, BY PRESENTING YOUR ONE OR MORE PAYMENT DEMANDS TO US FOR AN AGGREGATE AMOUNT UP TO THE UNUSED BALANCE OF THIS STANDBY LETTER OF CREDIT.

Redlines for explanation of credit rating downgrade draw trigger

Standby Letter of Credit Form Redlines

PRESENTATION OF ANY DRAWING CERTIFICATE UNDER THIS STANDBY LETTER OF CREDIT MAY BE SENT TO US BY COURIER, CERTIFIED MAIL, REGISTERED MAIL, EMAIL OR FACSIMILE (WITH A CONFIRMING COPY OF SUCH EMAIL OR FACSIMILE SENT AFTER THE DRAWING BY CERTIFIED MAIL TO THE ADDRESS SET FORTH BELOW; PROVIDED HOWEVER, THAT THE CONFIRMING COPY SHALL NOT BE A PREREQUISITE FOR US TO HONOR ANY PRESENTATION OTHERWISE MADE IN ACCORDANCE WITH THE TERMS OF THIS STANDBY LETTER OF CREDIT), OR SUCH OTHER ADDRESS AS MAY HEREAFTER BE FURNISHED BY US. OTHER NOTICES CONCERNING THIS STANDBY LETTER OF CREDIT MAY BE SENT BY SIMILAR COMMUNICATIONS FACILITY TO THE RESPECTIVE ADDRESSES SET FORTH BELOW. ALL SUCH NOTICES AND COMMUNICATIONS SHALL BE EFFECTIVE ~~WHEN ACTUALLY RECEIVED~~ UPON RECEIPT BY THE INTENDED RECIPIENT PARTY.

Redlines for option to present draw certificate by email

Contents of Presentation

Security Agreement Redlines

2. Amendment to Agreement: The definition of "Collateral" in Section 1.a.ii. of the Agreement shall be deleted in its entirety and replaced with the following:

"Collateral" shall mean (a) all cash provided, submitted, wired or otherwise transferred or deposited by the Debtor or another party (including, without limitation, the Secured Party) to or with the Secured Party or a financial institution, investment firm, or other designee selected by the Secured Party or acting on the Secured Party's behalf, to hold or invest such cash deposit, from time to time in satisfaction of, pursuant to, or in compliance with, the ISO Financial Assurance Policy; (b) all securities or other investment property (as defined in the Code) of the Debtor, whether or not purchased with such cash deposit, submitted, wired or otherwise transferred, deposited or maintained by the Debtor or another party (including, without limitation, the Secured Party) to or with the Secured Party or its designee, in each case in satisfaction of, pursuant to, or in compliance with, the ISO Financial Assurance Policy; (c) all other property of Debtor submitted, pledged, assigned or otherwise transferred by the Debtor or another party (including, without limitation, the Secured Party) to the Secured Party or its designee, in each case, in satisfaction of, pursuant to, or in compliance with, the ISO Financial Assurance Policy; (d) all cash provided, submitted, wired or otherwise transferred or deposited with the Secured Party or a financial institution, investment firm, or other designee selected by the Secured Party or acting on the Secured Party's behalf, to hold or invest such cash, pursuant to the drawing(s) of any letter of credit provided in satisfaction of, pursuant to, or in compliance with, the ISO Financial Assurance Policy; and (~~d~~e) the products and proceeds of each of the foregoing.

Redlines to Security Agreement to reflect that cash deposited by the ISO into a MP's BlackRock account is considered Collateral

Control Agreement Redlines

2. Amendment to Agreement

(a) The definitions of "Cash Deposit" and "Collateral" in Section 1 of the Agreement shall be deleted in their entirety and replaced with the following:

"Cash Deposit" shall mean one or more cash deposits provided, submitted, wired or otherwise transferred by the Grantor or on behalf of the Grantor by the Secured Party to the Secured Party or to a financial institution, investment firm, or other designee selected by the Secured Party or acting on the Secured Party's behalf in accordance with the Financial Assurance Policy to hold or invest such cash deposits, including, without limitation, cash deposits provided, submitted, wired or otherwise transferred pursuant to the drawing(s) of any letter of credit provided in satisfaction of, pursuant to, or in compliance with, the ISO Financial Assurance Policy.

"Collateral" shall mean (i) all cash provided, submitted, wired or otherwise transferred or deposited by the Grantor or on behalf of the Grantor by the Secured Party to or with the Secured Party or to a financial institution, investment firm, or other designee selected by the Secured Party or acting on the Secured Party's behalf, to hold or invest such cash ~~deposit~~, from time to time in satisfaction of, pursuant to, or in compliance with the Financial Assurance Policy; (ii) all securities or other investment property (as defined in the UCC) of the Grantor, including, without limitation, the Pledged Securities, whether or not purchased with such cash ~~deposit~~, but solely to the extent such securities or investment property are held in the account[s] identified on Attachment B; (iii) in each case the products and proceeds thereof; and (iv) without duplication, all Collateral as defined in the Security Agreement.

Control Agreement Redlines

(b) Section 4 of the Agreement shall be deleted in their entirety and replaced with the following:

"Section 4. Delivery of Cash Deposit. The Secured Party directs the Grantor or the Secured Party on its behalf holding a Cash Deposit to wire transfer, or cause to be wire transferred, to the account listed on Attachment C, immediately available funds as the initial Cash Deposit hereunder and under the Security Agreement. The Grantor or the Secured Party holding a Cash Deposit may from time to time make additional transfers of funds to the account listed on Attachment C as additional Cash Deposits to purchase Pledged Securities. All Cash Deposits will be used by the Grantor to pay the purchase price of Pledged Securities, and immediately upon the Issuer's receipt of (i) any Cash Deposit in the account listed on Attachment C, and (ii) a direction to use that Cash Deposit to purchase Pledged Securities, the Grantor shall be, for all purposes, the owner of the Pledged Securities purchased therewith. Until the Issuer's receipt of a Notice of Exclusive Control, the Grantor may change all or a portion of any Permitted Investment to another Permitted Investment at any time and from time to time in accordance with and subject to Section 11(e) hereof. In the event that (a) the Grantor fails to notify the Secured Party and the Issuer of at least one Permitted Investment hereunder in which a Cash Deposit is to be invested, or (b) any Permitted Investment ceases to be a Permitted Investment and the Grantor fails to exchange the shares that formerly constituted a Permitted Investment for shares that then constitute a Permitted Investment, the Secured Party may issue instructions to the Issuer to effect such an investment (in the case of clause (a) of this sentence) or exchange (in the case of clause (b) of this sentence), specifying a Permitted Investment in which the applicable portion of the Collateral is to be invested (in accordance with any applicable requirements in the Financial Assurance Policy regarding a default investment, the "Default Investment"). The Issuer shall comply with any instructions given by the Secured Party under the preceding sentence. The Default Investment as of the date of this Agreement is designated on Attachment B. The Secured Party shall give notice to the Issuer and the Grantor of any change in the Default Investment."

Redlines to Control Agreement to reflect that cash deposited by the ISO into a MP's BlackRock account is considered Cash Deposit and Collateral

Contents of Presentation

Stakeholder Process and Next Steps

Steps	Timeline
~~Initial discussion with Budget and Finance Subcommittee~~	~~March 25th~~
Presentation of FAP redlines, Attachment 2 Sample Standby LC redlines, amended Security Agreement redlines, and Control Agreement redlines	April 15th*
Vote at the Participants Committee	May 1st
FERC Filing	May-June
Effective Date	September 1, 2025 including a transitional implementation period

*We will add an additional B&F meeting if there are any material / substantive items pending stakeholder review after this meeting

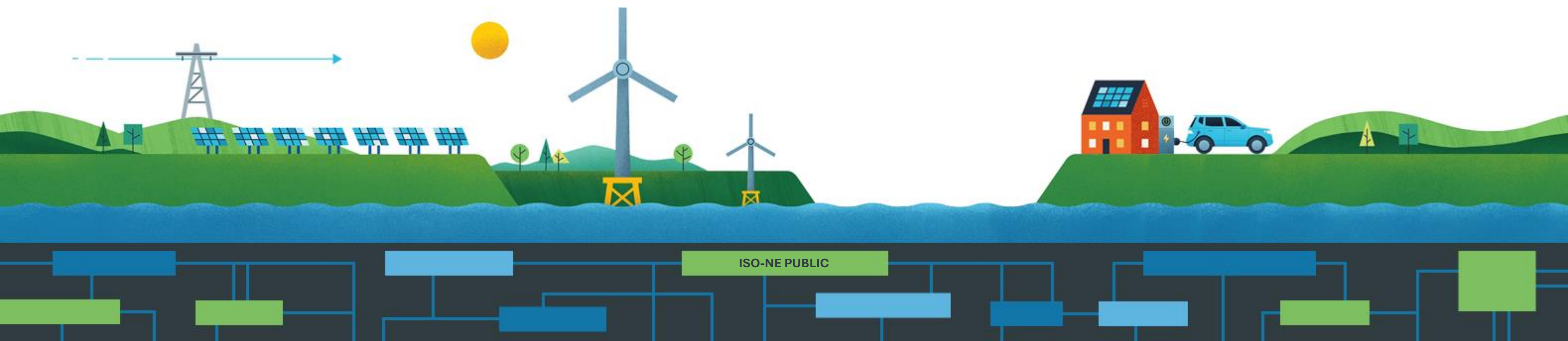
MAY 9, 2025 | HOLYOKE, MA

STANDBY LETTER OF CREDIT FORM FOR FINANCIAL ASSURANCE

NEPOOL Budget and Finance Subcommittee Meeting

Joshua LaRoche

MANAGER MARKET AND CREDIT RISK ANALYTICS



Contents of Presentation

The ISO is responding to questions asked by Stakeholders as well as incorporating some feedback into the FAP / Standby LC form redlines

Executive Summary

- Today, we are providing the ISO's responses to several Stakeholder questions and requests posed during the prior Budget and Finance Subcommittee meeting regarding the ISO recommended updates to the Standby LC (LC) form and Financial Assurance Policy (FAP)
- We are also presenting incremental redlines to the FAP and LC form for financial assurance reflecting feedback from Stakeholders concerning the following
  - The evergreen non-renewal notice period in the LC form
  - Drawing certificates presented by email in the LC Form
  - Other minor edits in the redlines to the FAP
- The ISO intends to present this updated recommendation to the Participants Committee on June 5th and subsequently file with FERC
- The effective date is expected to be September 1st and will include a transitional implementation period

Contents of Presentation

What are some factors that would go into determining if the ISO would draw on an expiring LC within the 30-day window?

- Several factors may enter the decision on whether to draw upon the affected LC which include but are not limited to:
  - Market Participant's (MP) current Financial Assurance (FA) levels relative to their current and potential future FA requirements
  - Communication between the MP and ISO on the status of a renewal or replacement LC
  - Proximity to the actual expiration date (as the expiration date approaches, the ISO is more likely to make the draw request)
  - Current financial market conditions
  - The occurrence of any Material Adverse Change events

What are some factors that would go into determining if the ISO would draw on an LC following a credit downgrade below A-/A3 of the issuing bank?

- Several factors would enter the decision on whether to draw upon the affected LC including but not limited to:
  – Sufficient other collateral being in place
  – If the rating downgrade was not severe (e.g., A- to BBB+ with positive outlook), ISO is less likely to immediately draw and may extend the cure period while a more severe downgrade (e.g., A to BB) will cause ISO to draw
  – Communication between the MP and ISO NE on the status of a renewal or replacement LC
  – Current financial market conditions or deterioration (e.g., high systemic banking sector risk like in 2008 and 2009) may cause ISO to draw following the downgrade

Would the ISO draw upon the LC for a non-Payment Default if the participant has sufficient alternative collateral currently posted?

- Typically, Market Participants don't have duplicative forms of financial assurance posted where each form is independently sufficient to cover FA obligations, but if a participant is transitioning from one form of collateral to another (e.g., LC to BlackRock) they will post the full amount in the BlackRock account before canceling the LC.
- Market Participants today have the right to request a reduction in their posted financial assurance obligations
- Upon such requests, the ISO determines if the funds in Blackrock or the LC is needed to cover the financial assurance requirements of the MP
- Such requests are agreed to by the ISO is there remains sufficient collateral to cover the MP's financial assurance requirements
- Such requests are rejected by the ISO if the collateral is required to cover the MP's financial assurance obligation
- Therefore, if a Non-Payment Default Draw arises, unless a participant has provided sufficient alternative collateral (in which case they can cancel their LC) it is unlikely that a participant will have enough alternative collateral in place
- However, the ISO will consider other collateral in place when determining whether to make a draw and a participant can avoid a draw by posting alternative collateral and canceling the LC

MPs have the right to terminate Letters of Credit which are not required for financial assurance

Would the ISO consider issuing a minimum notice prior to a non-Default Payment draw request?

- No, the ISO will not be providing a notice prior to a non-payment default draw request as it would diminish the ISO's timeframe to draw upon the LC, potentially resulting in a socialized default
  - MP's do already receive notifications ~20 days prior to LCs reaching 30 days from expiration making them aware their LC is approaching expiration
  - This notification serves to prompt the MP to arrange acceptable collateral before entering the 30-day window from expiration
  - Failure to arrange acceptable collateral prior to the 30-day window may result in suspension as the LC will be valued at $0 in FAM
- Under the scenario of the issuing bank experiencing a rating downgrade below A-/A3, the longer the ISO waits to draw, the higher the probability of the issuing bank being unable to fulfill the draw request due to deteriorating liquidity

Will the ISO change the Evergreen extension from one year to be more open-ended?

- No, the purpose of the Evergreen clause is to extend the expiration of an LC into theoretical perpetuity with an option for the Issuing Bank or participant to choose not to renew the LC's expiration on a yearly basis
- Changing the expiration renewal to something other than a year makes the theoretical perpetuity concept a moot point and increases the administrative burden on the bank and the participant
- Should an MP want an LC for less than a one-year term they should elect a fixed expiration date, and not use the automatic renewal language

Why does the ISO need an amended Security Agreement within 5 Business Days?

- Upon request of the ISO, but no later than 5 Business Days after the Non-Payment Default Draw, the Posting Entity shall execute a Security Agreement or an amended Security Agreement
- To ensure the ISO retains its rights to the Non-Payment Default Drawn Funds, the ISO will require MPs with LCs with triggered Non-Payment Default Draws to amend their Security and Control Agreement to cover the drawn funds
- The recommended FAP updates treat the funds from Non-Payment Default Draws as Financial Assurance
- If, after a Non-Payment Default Draw, a Posting Entity does not execute a Security Agreement or an amended Security Agreement within 5 business days they are not in compliance with the FAP Section X.A and will be suspended

The amended Security Agreement and amended Control Agreement protect the ISO from competing priority claims from other creditors.

Concern that "If the ISO has drawn against a letter of credit for any reason" is too broad

1. Non-Payment Default Draws

If the ISO has drawn against a letter of credit for any reason other than a failure to pay under the ISO New England Billing Policy (e.g., an expiring letter of credit has not been renewed or the issuing bank is downgraded below the minimum ratings requirement) (the "Non-Payment Default Draw") the ISO will hold such funds as a security deposit for the satisfaction of all obligations owed to the ISO by the Posting Entity (the "Non-Payment Default Drawn Funds").

- This paragraph must be read in its entirety. "[F]or any reason other than a failure to pay" refers only to Tariff-defined reasons (1) an expiring letter of credit has not been renewed and (2) the issuing bank is downgraded below the minimum ratings requirement
- The two new Non-Payment Default Draws are time-limited and Tariff-defined

ISO-NE cannot add new draw triggers without a filing pursuant to the Federal Power Action Section 205 and FERC approval

Contents of Presentation

Concern that drawing via email may require additional language because terms may differ from bank to bank

- The ISO will remove the email draw requirement from the Standby Letter of Credit Form and continue to use existing means to issue draw requests (see changes (deletions) in Standby Letter of Credit form redline)

- PRESENTATION OF ANY DRAWING CERTIFICATE UNDER THIS STANDBY LETTER OF CREDIT MAY BE SENT TO US BY COURIER, CERTIFIED MAIL, REGISTERED MAIL~~, EMAIL~~, OR FACSIMILE (WITH A CONFIRMING COPY OF SUCH ~~EMAIL OR~~ FACSIMILE SENT AFTER THE DRAWING BY CERTIFIED MAIL TO THE ADDRESS SET FORTH BELOW; PROVIDED HOWEVER, THAT THE CONFIRMING COPY SHALL NOT BE A PREREQUISITE FOR US TO HONOR ANY PRESENTATION OTHERWISE MADE IN ACCORDANCE WITH THE TERMS OF THIS STANDBY LETTER OF CREDIT), OR SUCH OTHER ADDRESS AS MAY HEREAFTER BE FURNISHED BY US. OTHER NOTICES CONCERNING THIS STANDBY LETTER OF CREDIT MAY BE SENT BY SIMILAR COMMUNICATIONS FACILITY TO THE RESPECTIVE ADDRESSES SET FORTH BELOW. ALL SUCH NOTICES AND COMMUNICATIONS SHALL BE EFFECTIVE UPON RECEIPT BY THE INTENDED RECIPIENT PARTY.

ISO agrees with Stakeholder proposal regarding evergreen non-renewal notice to be extended to 60 or 90 days

- The ISO will amend the evergreen non-renewal notice in the Standby Letter of Credit Form to allow for 30, 60 or 90 days
- This gives market participants ample time to replace the LC before it is valued at $0 when it is within 30 days of expiration (see changes in Standby Letter of Credit form redline)

Incremental redline regarding evergreen notice of non-renewal language

- [**INCLUDE ONLY IF LETTER OF CREDIT IS TO HAVE AUTOMATIC RENEWAL LANGUAGE:]** [IT IS A CONDITION OF THIS STANDBY LETTER OF CREDIT THAT IT WILL BE AUTOMATICALLY EXTENDED WITHOUT AN AMENDMENT FOR A (1) YEAR PERIOD BEGINNING ON THE INITIAL EXPIRATION DATE HEREOF AND UPON EACH ANNIVERSARY OF SUCH DATE, UNLESS AT LEAST [THIRTY (30) **OR** SIXTY (60) **OR** NINETY (90)] DAYS PRIOR TO ANY SUCH EXPIRATION DATE WE HAVE SENT YOU, OR THE ACCOUNT PARTY HAS SENT YOU, WRITTEN NOTICE BY REGULAR AND REGISTERED MAIL OR COURIER SERVICE THAT WE OR THE ACCOUNT PARTY ELECT NOT TO PERMIT THIS LETTER OF CREDIT TO BE SO EXTENDED, AND THAT THIS LETTER OF CREDIT WILL EXPIRE ON ITS THEN CURRENT EXPIRATION DATE. UPON RECEIPT OF SUCH NOTICE, YOU MAY DRAW ON THIS STANDBY LETTER OF CREDIT WITHIN THE THIRTY (30) DAYS PRIOR TO THE THEN RELEVANT EXPIRY DATE BY PRESENTING YOUR ONE OR MORE PAYMENT DEMANDS TO US FOR AN AGGREGATE AMOUNT UP TO THE UNUSED BALANCE OF THIS STANDBY LETTER OF CREDIT.]

The ISOs right to draw is still only within 30 days of expiration

Other Administrative LC Form Redline Updates

Requirements for Banks

IT IS A CONDITION OF THIS STANDBY LETTER OF CREDIT THAT WE SHALL MAINTAIN A MINIMUM LONG-TERM DEBT RATING (OR, IF ~~THE ISSUER~~ WE DO~~ES~~ NOT HAVE A MINIMUM LONG-TERM DEBT RATING, THEN A MINIMUM CORPORATE RATING) OF “A-” BY STANDARD AND POOR’S, OR “A3” BY MOODY’S OR “A-” BY FITCH. IN THE EVENT THAT WE ARE RATED BY MULTIPLE RATING AGENCIES, IF ANY APPLICABLE RATING FROM THE RATING AGENCIES FALLS BELOW THE LEVELS LISTED, THEN WE SHALL NOT BE CONSIDERED TO HAVE SATISFIED THIS CONDITION. IN THE EVENT THAT WE DO NOT SATISFY THE CONDITION REQUIRED BY THIS PARAGRAPH, YOU MAY DEMAND PAYMENT FROM ~~THE ISSUER~~ US AT THE ADDRESS ABOVE, BY PRESENTING YOUR ONE OR MORE PAYMENT DEMANDS TO US FOR AN AGGREGATE AMOUNT UP TO THE UNUSED BALANCE OF THIS STANDBY LETTER OF CREDIT.

Other Administrative FAP Redline Updates

Requirements for Banks

Each bank issuing a letter of credit that serves as financial assurance must meet the requirements of this Section X.B.2. Each such bank must be on the ISO's "List of Eligible Letter of Credit Issuers" which shall be established pursuant to this Section X.B.2.

No letter of credit bank may issue letters of credit under the ISO New England Financial Assurance Policy in an amount exceeding either: (i) $100 million in the aggregate for any single Posting Entity; or (ii) $150 million in aggregate for a group of Posting Entities that are Affiliates. If a bank is removed from the List of Eligible Letter of Credit Issuers based on the ISO's determination that there is an unreasonable risk that a bank may fail to honor the terms of such letter of credit, the ISO in its sole discretion may reinstate eligibility, provided that the bank otherwise meets the conditions of this Section X.B.2.

C. Special Provisions for Provisional Members

Without limiting or reducing in any way the requirements of the ISO New England Financial Assurance Policy that apply to a Provisional Member, the ~~cash deposit Financial Assurance~~ amount of collateral maintained in a shareholder account initially provided by a Provisional Member that is attributable to Participant Expenses (including any amounts provided in connection with the standing instruction under the ISO New England Billing Policy described above) shall be at least $2,500, and each Provisional Member will replenish that ~~cash deposit Financial Assurance~~ collateral maintained in a shareholder account to at least that $2,500 level on December 31 of each year.

Contents of Presentation

Stakeholder Process and Next Steps

Steps	Timeline
~~Initial discussion with Budget and Finance Subcommittee~~	~~March 25th~~
~~Presentation of Redline Standby Letter of Credit Form and FAP~~	~~April 15th~~
Presentation of Updated Redlines for Standby Letter of Credit Form	May 9th
Vote at the Participants Committee	June 5th
FERC Filing	June
Effective Date	September 1, 2025 including a transitional implementation period

MEMORANDUM

TO: NEPOOL Budget & Finance Subcommittee

FROM: Rosendo Garza, NEPOOL Counsel

DATE: May 29, 2025

RE: Update on ENGIE's Amendments to the ISO's Letter of Credit and Financial Assurance Policy Revisions

At the March, April, and May Budget & Finance Subcommittee (B&F) meetings, the ISO presented its proposal to revise the Standby Letter of Credit (LOC) form and the Financial Assurance Policy to address specific risk management concerns. At these meetings, it proposed to introduce new triggers—Non-Payment Default Draws—that would allow the ISO to draw on a LOC and retain the drawn funds as a security deposit against amounts owed by a Market Participant. The ISO also proposed changes to LOC issuer eligibility criteria and various administrative updates.

At the May meeting, ENGIE proposed amendments to limit the ISO's new discretionary draw rights, including renaming the draws as "Risk Mitigation Draws," capping the draw amounts to the minimum required for financial assurance, and incorporating procedural safeguards such as mandatory notice periods. A number of stakeholders expressed support for ENGIE's amendments. Accordingly, the only aspects of the ISO's proposal that remained unresolved were those related to ENGIE's proposed amendments and concerns. At the end of the meeting, the B&F Chair encouraged ENGIE and the ISO to continue discussions offline to explore revisions that would address ENGIE's concerns in a manner acceptable to the ISO.

Following the May B&F meeting, consistent with the B&F Chair's encouragement and in the spirit of the stakeholder process, the ISO and ENGIE engaged in offline discussions. As a result of those conversations, the ISO agreed to incorporate certain aspects of ENGIE's proposed amendments, as reflected in the marked redlines included as Attachment A. Regarding ENGIE's concerns about the notice requirements, the ISO provided additional explanation that resolved those concerns without the need for further modifications.[1] ENGIE has confirmed that it does not intend to propose any additional amendments and supports the ISO's revised proposal.

The concerns raised with the ISO's proposal at the May B&F meeting appear to have been resolved. Consequently, the B&F Chair does not anticipate the need for further discussion of the ISO's revised proposal at the June 20, 2025 B&F meeting. Accordingly, absent objections,

[1] *See* ISO New England Financial Assurance Policy § X.B.1 (providing that if a bank on the ISO's list of eligible LOC issuers fails to meet specified criteria—or is deemed by the ISO to present an unreasonable credit risk—the Market Participant must replace the LOC or post alternative financial assurance within five Business Days, subject to a possible 20-day extension; otherwise, the LOC is valued at zero).

the proposal will not be noticed for discussion at the June B&F meeting but will instead be noticed for consideration at the NPC's June summer meeting.

If you have any concerns or objections, please let me know (rgarza@daypitney.com or 860.275.0660) by **Friday, June 6, 2025**.

7A Plainfield Renewable Energy Request for of GIS Operating Rules/Agreement Waiver

VOTE

66.67%

To consider and take action, as appropriate, on the request for a waiver of the NEPOOL Generation Information System (GIS) Operating Rules and the GIS Agreement by Plainfield Renewable Energy LLC.

DEFERRED

RESOLVED, that the Participants Committee [grants] [denies] Plainfield Renewable Energy, LLC's request to waive certain NEPOOL Generation Information System Operating Rules and sections of the Amended and Restated Generation Information System Administration Agreement dated as of October 1, 2017, between APX, Inc. and NEPOOL as discussed in the materials circulated for this meeting.

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Paul Belval and Samantha Regan, NEPOOL Counsel

DATE: June 16, 2025

RE: Request by Plainfield Renewable Energy for Waiver of GIS Operating Rules and GIS Agreement

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At the June 24, 2025 Participants Committee Summer Meeting, you may be asked to consider a request to waive certain NEPOOL Generation Information System ("GIS") requirements in order to change renewable energy Certificates for a generator for the third quarter of 2024. To provide the requested relief, NEPOOL would need to waive provisions of both the GIS Operating Rules ("Rules") and the Amended and Restated Generation Information System Administration Agreement dated as of October 1, 2017, between APX, Inc. ("APX") and NEPOOL, as amended and extended (the "GIS Agreement"). As further explained below, Plainfield Renewable Energy, LLC ("Plainfield")[1] is seeking to have 15,679 Certificates for its 37.5 MW biomass generating project in Plainfield Connecticut (the "Project") reclassified as Class I/IA qualified under the Connecticut and Maine renewable portfolio standards ("RPS").

This waiver request was previously noticed for the May 1, 2025 Participants Committee meeting but was withdrawn at the request of Plainfield before it was acted upon, with the item deferred to the June 24 meeting.

Relevant Background & Overview

The Project is qualified as a renewable generating unit under the Connecticut and Maine RPSs and sells its energy and environmental attributes to the Connecticut Light and Power Company ("Eversource") under 2008 power purchase agreements. In its letter attached as Attachment 1 to this memorandum, Plainfield states that it must demonstrate that the Project complies with the statutory NOx quarterly emissions limit for its output to remain qualified under the Connecticut RPS. Plainfield failed to input the required emissions data into the GIS for September 2024. As a result of that failure and consistent with its established operating practices, APX, the GIS Administrator, did not designate the GIS Certificates as qualified under either the Connecticut RPS or the Maine RPS when it issued those Certificates in January. Plainfield states that the Project is not required to comply with emissions requirements under the Maine RPS. Plainfield states that the inability to obtain RPS-compliant Certificates will cause it to lose more than $600,000 in revenue

Through its waiver request, Plainfield is seeking to have its September 2024 Certificates retroactively designated as Connecticut Class I and Maine Class I/IA qualified in the GIS. APX does not have the authority to change the RPS designation on the Certificates without both APX

[1] Plainfield is a NEPOOL Participant and a member of the Generation Sector Group Seat.

and NEPOOL waiving Section 4.2 of the GIS Agreement and Rule 1.4, which require APX to administer and operate the GIS in accordance with the Rules. APX, as the GIS Administrator, has under those provisions "the sole responsibility for the compilation, indexing, reasonable interpretation and implementation of the GIS Operating Rules." Since APX believes it has administered correctly what is prescribed by the Rules and the GIS Agreement, the only way it can change Plainfield's Certificates as requested is if Rule 1.4 and Section 4.2 of the GIS Agreement are waived. APX has indicated that it would be willing to waive the applicable requirements but only if NEPOOL, as the counterparty to the GIS Agreement, agrees to such a waiver and directs APX to correct the Certificates.

We informed Plainfield that when other GIS account holders requested waivers of the Rules in similar circumstances, many members of the Participants Committee have stated that the issue should be determined by the appropriate state regulatory agencies, not NEPOOL. Plainfield has requested that both the Connecticut Public Utilities Regulatory Authority and the Maine Public Utilities Commission designate Plainfield's September 2024 Certificates as qualified under its RPS.[2] Those requests are included as <u>Attachment 2</u> and <u>Attachment 3</u> to this memorandum. The Connecticut Public Utilities Regulatory Authority denied Plainfield's request, and a copy of that decision is included as <u>Attachment 4</u> to this memorandum.

The following resolution can be used for Participants Committee action on Plainfield's request:

> RESOLVED, that the Participants Committee [grants] [denies] Plainfield Renewable Energy, LLC's request to waive certain NEPOOL Generation Information System Operating Rules and sections of the Amended and Restated Generation Information System Administration Agreement dated as of October 1, 2017, between APX, Inc. and NEPOOL as discussed in the materials circulated for this meeting.

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[2] Plainfield is required under its agreement with Eversource to sell Connecticut Class I Certificates to Eversource, so the Maine RPS designation would permit Plainfield to sell its Certificates in the open market, but it would not permit Plainfield to comply with the requirements under that agreement.

Plainfield Renewable Energy, an affiliate of
Greenleaf POWER

February 19, 2025

SUBMITTED VIA EMAIL (pnbelval@daypitney.com)

Paul N. Belval
Day Pitney LLP
225 Asylum Street
Hartford, CT 06103-1212

Dear Mr. Belval:

Plainfield Renewable Energy, LLC ("PRE" or the "Company") respectfully requests the New England Power Pool's ("NEPOOL") review and consideration of an issue surrounding the creation of Connecticut/Maine Class I/IA Renewable Energy Certificates ("RECs") due to the inadvertent failure to enter emissions data into the NEPOOL Generation Information System ("NEPOOL GIS") for the third quarter of 2024 ("Q3").

PRE owns and operates a biomass electric generating facility in Plainfield, Connecticut (the "Plainfield Facility"). The Plainfield Facility is a Connecticut and Maine certified renewable energy source[1] that began commercial operation at the end of 2013, supplying energy and capacity to the wholesale and capacity markets. On May 8, 2008 and April 12, 2019, The Connecticut Light and Power Company d/b/a Eversource Energy ("Eversource") and PRE entered into PPAs relating to the sale and purchase of electricity produced by the Plainfield Facility and associated environmental attributes.

As it had done every quarter since obtaining Class I/IA certification, the Company timely entered the Plainfield Facility's Nitrogen Oxides ("NO_x") emissions data into the NEPOOL GIS. Although there is no emissions requirement for the Plainfield Facility's output to qualify for Maine Class I/IA RECs, to qualify for Connecticut Class I RECs, the Plainfield Facility must demonstrate compliance with the statutory NO_x quarterly emissions limit. For this reason, as a prerequisite to generate Connecticut Class I RECs, PRE is obligated to periodically enter emissions data into NEPOOL GIS. However, due to an inadvertent administrative error that PRE did not discover until after the Q3 RECs

[1] The Plainfield Facility was certified as a Connecticut Class I renewable energy source by the Connecticut Public Utilities Regulatory Authority on April 9, 2014. *See* Docket No. 13-12-22, *Application of Plainfield Renewable Energy, LLC For Qualification of Plainfield Renewable Energy as a Class I Renewable Energy Source*, April 9, 2014, Final Decision. The Plainfield Facility was also certified as a Maine Class I/IA facility by the Maine Public Utilities Commission in 2019/2020. *See* Docket No. 2019-00142, *Request for Approval of Certification as a Maine Class 1 New Renewable Resource Pertaining to Plainfield Renewable Energy, LLC*, June 21, 2019, Order Granting New Renewable Resource Certification at 1; *See also* Docket No. 2019-00142, *Commission Initiated Rulemaking Amendments to Portfolio Requirements for Commission Initiated Rulemaking (LD1494) Chapter 311, Order Adopting Final Rule Provision*, April 2, 2020, Final Rule.

were issued on January 15, 2025, the Company determined that the September emissions data, unlike the July and August emissions data, had not been entered into NEPOOL GIS. Due to this inadvertent error, the Plainfield Facility was issued approximately 15,679 RECs for the Q3 period (the "September RECs") that were designated as neither Connecticut Class I nor Maine Class I/IA compliant. Thus, only the July and August Class I/IA RECs could be transferred to Eversource as stipulated in the PPAs.

As previously discussed, there is no emissions requirement for the Plainfield Facility's output to qualify for Maine Class I/IA RECs. Additionally, the Plainfield Facility met the Connecticut statutory emissions limit for that month.[2] The September RECs were not designated as Connecticut Class I RECs solely because the emissions data for the month was not entered into NEPOOL GIS, not because the Plainfield Facility had exceeded the NO_x statutory emissions limit. For this reason, the Company's inadvertent failure to enter emissions data into NEPOOL GIS for the month of September should not preclude PRE from generating Maine Class I/IA RECs, which are not subject to an emissions limit, or Connecticut Class I RECs when the Plainfield Facility did not exceed the statutory NO_x emissions limit. The inability to obtain Connecticut Class I or Maine Class I/IA designation for these RECs would represent a loss of revenue for the Company in excess of $600,000. This loss would compromise PRE's ability to effectively operate the Plainfield Facility and could jeopardize jobs that the Company provides directly and indirectly.

Although PRE does not expect this type of error to reoccur, PRE is taking proactive steps to improve company procedures or processes concerning the RECs to ensure that this data entry step is not missed. Concurrently with this request, PRE is filing a request with the Connecticut Public Utilities Regulatory Authority and the Maine Public Utilities Commission for the designation of the September RECs as Connecticut Class I and Maine Class I/IA compliant, respectively.

For the foregoing reasons, PRE respectfully requests that NEPOOL amend the certificates issued with the September RECs and designate such RECs as Connecticut Class I and Maine Class I/IA compliant and thereby allow the RECs to be transferred to Eversource in accordance with the terms of the PPAs or to be sold on the open market, as needed. Even though the Company has sought relief from Connecticut and Maine, PRE believes that the ability to track certificates' eligibility using the GIS process is critical to the functioning of the market for these certificates. Further, NEPOOL is able to provide the requested relief prior to the end of the third quarter trading period on March 15, 2025,

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[2] In October 2024, the Company submitted its quarterly compliance filing to the Public Utilities Regulatory Authority attesting to the Plainfield Facility's compliance with the NO_x emissions statutory limit for Q3, along with the relevant emissions data. *See* Docket No. 13-12-22, *Application of Plainfield Renewable Energy, LLC For Qualification of Plainfield Renewable Energy as a Class I Renewable Energy Source*, October 24, 2024, Compliance Filing.

which could minimize or eliminate the economic impacts of not having generated Connecticut Class I or Maine Class I/IA certificates in the first instance.

Very truly yours,

Geoffrey M Harmon

Geoffrey M. Harmon, Treasurer
Plainfield Renewable Energy LLC

cc: NEPOOL GIS Administrator (*via electronic mail - gis@apx.com*)

February 19, 2025

VIA ELECTRONIC FILING

Jeffrey R. Gaudiosi, Esq.
Executive Secretary
Public Utilities Regulatory Authority
Ten Franklin Square
New Britain, CT 06051

Re: Docket No. 13-12-22, Application of Plainfield Renewable Energy, LLC For Qualification of Plainfield Renewable Energy as a Class I Renewable Energy Source

Dear Mr. Gaudiosi:

Plainfield Renewable Energy, LLC ("PRE" or the "Company") respectfully requests the Public Utilities Regulatory Authority's ("PURA" or the "Authority") review and consideration of an issue surrounding the creation of Class I Renewable Energy Certificates (RECs") due to the inadvertent failure to enter emissions data into the New England Power Pool Generation Information System ("NEPOOL GIS") for the third quarter of 2024 ("Q3").

PRE owns and operates a 37.5 megawatt ("MW") biomass electric generating facility in Plainfield, Connecticut (the "Plainfield Facility"). The Plainfield Facility is a certified renewable energy source that has been operating since the end of 2013, supplying energy and capacity to the wholesale and capacity markets. PRE's facility creates clean energy by burning on an annual basis approximately 350,000 tons of clean wood recovered from construction and demolition activities, including sustainable wood from forestry and land-clearing activities. On May 8, 2008, The Connecticut Light and Power Company d/b/a Eversource Energy ("Eversource") and PRE entered into a PPA relating to the sale and purchase of electricity produced by the Plainfield Facility and associated environmental attributes, specifically eighty percent (80%) of PRE's output or thirty (30) MW. On April 12, 2019, Eversource and PRE entered into a second PPA relating to the sale and purchase of the remaining twenty percent (20%) of PRE's output or 7.5 MW.

On April 9, 2014, the Authority determined that pursuant to Conn. Gen. Stat. §16-1(a), the Plainfield Facility qualifies as a Class I renewable energy source and assigned the facility Connecticut Renewable Portfolio Standard Registration No. CT00666-13. *See* Docket No. 13-12-22, *Application of Plainfield Renewable Energy, LLC For Qualification of Plainfield Renewable Energy as a Class I Renewable Energy Source*, April 9, 2014, Final Decision ("Qualification Final Decision") at 2. Pursuant to Order No. 2 of the Qualification Final Decision, each quarter, PRE must file with PURA documentation depicting that the Plainfield Facility's Nitrogen Oxides ("NO_x") emissions for the previous calendar quarter are less than the statutory emissions limit of 0.075 lb/MMBtu. *See* Qualification Final Decision at 3. PRE also reports this emissions information into the NEPOOL GIS system each quarter.

As it had done every quarter since obtaining Class I certification, on October 24, 2024, the Company submitted their quarterly compliance filing to PURA attesting to the Plainfield Facility's compliance with the NO_x emissions statutory limit for Q3. *See* Docket No. 13-12-22, *Application of Plainfield Renewable Energy, LLC For Qualification of Plainfield Renewable Energy as a Class I Renewable Energy Source*, October 24, 2024, Compliance Filing. Subsequently, PRE timely entered the Q3 emissions data into the NEPOOL GIS. However, due to an inadvertent administrative error that PRE did not discover until after the Q3 RECs were issued on January 15, 2025, the Company determined that the September emissions data, unlike the July and August emissions data, had not been entered into NEPOOL GIS. Due to this inadvertent error, the Plainfield Facility was issued approximately 15,679 RECs for the Q3 period (the "September RECs") that were not designated as Connecticut Class I compliant. Thus, only the July and August Connecticut Class I RECs could be transferred to Eversource as stipulated in the PPAs.

Under NEPOOL's advice, the Company is filing this request with PURA for the designation of the September RECs as Connecticut Class I compliant. In the past, the Authority has retroactively designated RECs as Connecticut Class I compliant, when a company inadvertently failed to enter emissions data into the NEPOOL GIS. *See* Docket No. 99-11-14*, Application of Constellation NewEnergy f/k/a AES for an Electric Supplier License,* Letter dated March 11, 2008 re: Connecticut Class I Renewable Energy Certificates, June 4, 2008 ("[The] Department believes that [Constellation NewEnergy (CNE)] should not be penalized for omitting the generators emissions data. Therefore, the Department will allow CNE to use its second quarter RECs for 2007 Connecticut Class I compliance.").[1] Consequently, historically, the Authority has exercised its discretionary

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[1] *See also*, Docket No. 20-10-07, *Application of NuPower Cherry Street FC, LLC for Qualification of 375 Howard Avenue, Bridgeport, CT as a Class I Renewable Energy Source,* Letter dated May 12, 2021 regarding Motion No. 122 ("…NuPower's fourth quarter RECs can be used for 2020 Connecticut Class I compliance. Conn. Gen. Stat. §16-1(a)(20) does not require emissions data for the particular type of generator in question.").

power to designate RECs as Connecticut Class I compliant under limited circumstances, i.e., due to an administrative error.

As previously discussed, the Plainfield Facility has been operational since December 2013 and the NO_x emissions have been consistently well below the statutory emissions limit. Thus, the September RECs were not designated as Connecticut Class I RECs solely because the emissions data had not been entered into the system, not because the Plainfield Facility had exceeded the NO_x statutory emissions limit. Further, in the past decade that the Plainfield Facility has been in operation, the Company has never previously had a data entry error of this type. Even though PRE does not expect this type of error to reoccur, PRE is taking proactive steps to improve company procedures or processes concerning the RECs to ensure that this data entry step is not missed.

For the foregoing reasons, PRE respectfully requests that PURA designate the September RECs as Connecticut Class I compliant and thereby allow the RECs issued by NEPOOL to be transferred to Eversource in accordance with the terms of the PPAs. The inability to obtain Connecticut Class I designation for these RECs would represent a loss of revenue for the Company in excess of $700,000. This loss would compromise PRE's ability to effectively operate the Plainfield Facility and could jeopardize jobs that the Company provides directly and indirectly. Therefore, the Company also respectfully requests that PURA provide an expedited ruling on this request, prior to the end of the third quarter trading period on March 15, 2025.

I certify that a copy hereof has been furnished on this date via electronic mail to all parties, intervenors and participants of record according to the Authority's service list for this docket as of this date. A copy has also been filed with the Authority as an electronic web filing and is complete.

Very truly yours,

Geoffrey M Harmon

Geoffrey M. Harmon, Treasurer
Plainfield Renewable Energy, LLC

15713406.v1

February 19, 2025

VIA ELECTRONIC FILING

Amy Dumeny
Administrative Director
Maine Public Utilities Commission
18 State House Station
Augusta, ME 04333-0018

Re: Docket No. 2019-00142, Request for Approval of Certification as a Maine Class 1 New Renewable Resource Pertaining to Plainfield Renewable Energy, LLC

Dear Ms. Dumeny:

Plainfield Renewable Energy, LLC ("PRE" or the "Company") respectfully requests the Maine Public Utilities Commission's (the "Commission") review and consideration of an issue surrounding the creation of Class I/IA Renewable Energy Certificates ("RECs") due to the inadvertent failure to enter emissions data into the New England Power Pool Generation Information System ("NEPOOL GIS") for the third quarter of 2024 ("Q3").

PRE owns and operates a 38.5 megawatt biomass electric generating facility in Plainfield, Connecticut (the "Plainfield Facility"). The Plainfield Facility is a certified renewable energy source that began commercial operation at the end of 2013, supplying energy and capacity to the wholesale and capacity markets. PRE's facility creates clean energy by burning clean wood recovered from construction and demolition activities, including sustainable wood from forestry and land-clearing activities. On May 8, 2008 and April 12, 2019, The Connecticut Light and Power Company d/b/a Eversource Energy ("Eversource") and PRE entered into PPAs relating to the sale and purchase of electricity produced by the Plainfield Facility and associated environmental attributes.

On June 21, 2019, the Commission certified the Plainfield Facility as a Class I new renewable resource that is eligible to satisfy Maine's new renewable resource portfolio requirement pursuant to Chapter 311, § 3(B)(3)(a) of the Commission's rules. *See* Docket No. 2019-00142, *Request for Approval of Certification as a Maine Class 1 New Renewable Resource Pertaining to Plainfield Renewable Energy, LLC*, June 21, 2019, Order Granting New Renewable Resource Certification at 1. On April 2, 2020, the Commission issued an Order adopting an amendment to its portfolio requirement rule, Chapter 311, which automatically certified certain Class I generation facilities (including the Plainfield Facility) as Class IA generation facilities.[1] *See* Docket No. 2019-00142, *Commission Initiated Rulemaking Amendments to Portfolio Requirements for Commission Initiated Rulemaking (LD1494) Chapter 311, Order Adopting Final Rule Provision*, April 2, 2020, Final Rule. It is noted that the Plainfield Facility was also certified as a Connecticut Class I renewable energy source by the Connecticut Public Utilities Regulatory Authority on April 9, 2014. *See* Docket No. 13-12-22, *Application of Plainfield Renewable Energy, LLC For Qualification of Plainfield Renewable Energy as a Class I Renewable Energy Source*, April 9, 2014, Final Decision.

As it had done every quarter since obtaining Class I/IA certification, the Company timely entered the Plainfield Facility's Nitrogen Oxides ("NO_x") emissions data into the NEPOOL GIS. Although there is no emissions requirement for the Plainfield Facility's output to qualify for Maine Class I/IA RECs, to qualify for Connecticut Class I RECs, the Plainfield Facility must demonstrate compliance with the statutory NO_x quarterly emissions limit. For this reason, as a prerequisite to generate Connecticut Class I RECs, PRE is obligated to periodically enter emissions data into NEPOOL GIS. However, due to an inadvertent administrative error that PRE did not discover until after the Q3 RECs were issued on January 15, 2025, the Company determined that the September emissions data, unlike the July and August emissions data, had not been entered into NEPOOL GIS. Due to this inadvertent error, the Plainfield Facility was issued approximately 15,679 RECs for the Q3 period (the "September RECs") that were designated as neither Connecticut nor Maine Class I/IA compliant. Thus, only the July and August Class I/IA RECs could be transferred to Eversource as stipulated in the PPAs.

Under NEPOOL's advice, the Company is filing this request with the Commission for the designation of the September RECs as Maine Class I/IA compliant. Concurrently with this filing, PRE is filing a similar request with the Connecticut Public Utilities Regulatory Authority.

As previously discussed, there is no emissions requirement for the Plainfield Facility's output to qualify for Class I/IA RECs.[2] Therefore, the mere failure to enter emissions data into NEPOOL GIS for the month of September should not preclude PRE from generating Maine Class I/IA RECs for that month. In the past decade that the Plainfield Facility has been commercially operating, the Company has never previously

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[1] "All Class I generation facilities certified by the Commission as of September 19, 2019 are automatically certified as Class IA generation facilities without any filing requirements except those existing generation facilities that were certified as Class I resource on the basis that for at least 2 years the generation facility was not operated or was not recognized by the New England independent system operator as a capacity resource and, after September 1, 2005, resumed operation or was recognized by the New England independent system operator as a capacity resource." *See* 65-407 C.M.R. ch. 311, § 3(C).

[2] The Plainfield Facility met the Connecticut statutory emissions limit for that month. The September RECs were not designated as Connecticut Class I RECs solely because the emissions data for the month was not entered into the system, not because the Plainfield Facility had exceeded the NO_x statutory emissions limit.

had a data entry error of this type. Even though PRE does not expect this type of error to reoccur, PRE is taking proactive steps to improve company procedures or processes concerning the RECs to ensure that this data entry step is not missed.

For the foregoing reasons, PRE respectfully requests that the Commission designate the September RECs as Maine Class I/IA compliant and thereby allow the RECs issued by NEPOOL to be transferred to Eversource in accordance with the terms of the PPAs or to be sold on the open market, as needed. The inability to obtain Maine Class I/IA designation for these RECs would represent a loss of revenue for the Company in excess of $600,000. This loss would compromise PRE's ability to effectively operate the Plainfield Facility and could jeopardize jobs that the Company provides directly and indirectly. However, if the Commission were to designate the September RECs as Maine Class I/IA compliant, PRE would be able to recuperate the lost revenue on the open market, as applicable. Consequently, the Company also respectfully requests that the Commission provide an expedited ruling on this request, prior to the end of the third quarter trading period on March 15, 2025.

Very truly yours,

Geoffrey M Harmon

Geoffrey M. Harmon, Treasurer
Plainfield Renewable Energy LLC

cc: Lucretia A. Smith (*via electronic mail*)

STATE OF CONNECTICUT
PUBLIC UTILITIES REGULATORY AUTHORITY

April 7, 2025
In reply, please refer to:
Docket No. 13-12-22
Motion No. 1

Geoffrey M. Harmon
Greenleaf Power
3600 American River Dr., Suite 160
Sacramento, CA 95864

Re: Docket No. 13-12-22 – Application of Plainfield Renewable Energy, LLC for Qualification of Plainfield Renewable Energy as a Class I Renewable Energy Source

Dear Mr. Harmon:

On February 19, 2025, Plainfield Renewable Energy, LLC, (Plainfield or Company) submitted a motion (Motion No. 1) to the Public Utilities Regulatory Authority (Authority or PURA), requesting that PURA determine that the 15,679 renewable energy certificates (RECs) the Company generated at a biomass electric generating facility in Plainfield, Connecticut for the third quarter of 2024 production (Plainfield RECs) be deemed Class I RECs notwithstanding their current designation. Motion No. 1, p. 1. The Company requests the Authority to reclassify the Plainfield RECs because the company failed to provide the required emissions data to NEPOOL GIS for September. Motion No. 1 is denied.

On April 1, 2025, the Authority's Office of Education, Outreach, and Enforcement (EOE) submitted a comment in response to Motion No. 1. EOE recommended that the Authority deny Motion No. 1 because strict compliance with NEPOOL GIS reporting requirements is mandatory to maintain the integrity of Connecticut's Renewable Portfolio Standards (RPS). EOE Comment, Apr. 1, 2025, p. 1. In addition, EOE noted that the Authority recently concluded that there is no provision that provides the Authority with discretion to grant exceptions to NEPOOL GIS classification of RECs. Id., p. 2.

The Company cites prior instances in which the Authority granted similar relief to other generators. Motion No. 1, p. 2. Until recently, however, the Authority had not expressly addressed whether the statutory framework permits the Authority to recognize non-NEPOOL GIS certificates. See Motion Ruling No. 4, Mar. 27, 2025, Docket No. 08-01-03, Application of Burlington Electric Department for Qualification of McNeil Generating Station as a Class I Renewable Source (Docket No. 08-01-03 Motion Ruling No. 4), p. 1. After considering the language of the applicable statutes and regulations, the Authority concluded that it does not have the discretion to grant the requested relief. Motion Ruling No. 3, March 13, 2025, Docket No. 08-01-03, Application of Burlington Electric Department for Qualification of McNeil Generating Station as a Class I

Renewable Source (Docket No. 08-01-03 Motion Ruling No. 3), p. 3. The Authority also noted that,

> even if the Authority had discretion under the statutes to reclassify non-NEPOOL RECs, the increased administrative burden on the Authority and docket participants in Docket No. 25-06-01, Annual Review of Connecticut's Electric Suppliers' and Electric Distribution Companies' Compliance with Connecticut's Renewable Energy Portfolio Standards in the Year 2024, weighs against the exercise of such discretion. . . . [T]he Authority [has recognized] the standard to which electric suppliers and electric distribution companies are held with respect to RPS compliance. See [Docket No. 08-01-03] Motion Ruling No. 3, p. 3 ("Suppliers are rightly held accountable for complying with RPS requirements by procuring and properly settling all their required RECs; the Authority has repeatedly held that failure to comply with RPS requirements for electric suppliers and EDCs cannot be excused by scrivener's errors or failing to obtain sufficient load in the last quarter of a year."). As the Authority also noted in that ruling, however, "[c]ompliance with NEPOOL GIS is necessary to prevent situations such as this, which require the Authority and docket participants to ***expend unnecessary administrative resources to correct a generator's administrative error***." Id. (emphasis added). Granting the type of relief requested by . . . any . . . generator who makes a similar error . . . imposes real costs on and disrupts the Authority's orderly regulation of RPS.
>
> In short, the Authority's priorities are compliance with its statutory mandate and protecting the orderly administration of the RPS program. Granting [an exception to reclassify non-NEPOOL RECs] contravenes these priorities.

Docket No. 08-01-03 Motion Ruling No. 4, pp. 2–3.

Although unfortunate, this situation arose solely from the Company's error in entering information into the NEPOOL GIS system. The Authority is not empowered to indemnify the Company from the consequences of its error.

Accordingly, Motion No. 1 is denied.

By Direction of the Authority,

Jeffrey R. Gaudiosi, Esq.
Executive Secretary

cc: Service List

8 Litigation Report

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of June 23, 2025

The following activity, as more fully described in the attached Litigation Report, has occurred since the report dated April 30, 2025 ("last Report") was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

Executive Orders

*	1	Reinvigorating the Nuclear Industrial Base (EO 14302)	May 23	DOE directed to increase domestic nuclear energy capacity through accelerated construction of new reactors, power uprates, and fuel supply chain expansion
*	1	Reforming Nuclear Reactor Testing at the Department of Energy (EO 14301)	May 23	DOE directed to expedite testing and deployment of nuclear reactors by streamlining reviews and establishing a new pilot program for three test reactors
*	1	Ordering the Reform of the Nuclear Regulatory Commission (EO 14300)	May 23	NRC directed to streamline licensing deadlines, cap its fees, and expedite deployment of nuclear reactor designs already tested by the DOE or DoD
*	2	Deploying Advanced Nuclear Reactor Technologies for National Security (EO 14299)	May 23	DOE secretary tasked with designating (i) AI data centers as critical defense facilities and (ii) DOE-owned sites for deployment of nuclear reaction technology to power AI infrastructure by ***Aug 21, 2025***, with operation at first site within 30 months

I. Complaints/Section 206 Proceedings

	3	Consumers RTP Complaint (EL25-44)	May 20	ISO-NE answers Complainants' Answer Reply comments filed by: NESCOE, MOPA, MPUC, AMP

II. Rate, ICR, FCA, Cost Recovery Filings

No Activity to Report

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

	10	Waiver Request: Late Stage SIS Process (GDQ ESS) (ER24-2926)	May 21	GDQ ESS supports Tariff Revisions in ER25-2149 and, if accepted by the FERC, commits to withdrawing this Waiver Request

IV. OATT Amendments / TOAs / Coordination Agreements

*	10	Order 2023-Related Section 205 Transition Tariff Revisions (ER25-2149)	May 2 May 5-23	ISO-NE, PTO-AC and NEPOOL jointly file revisions Calpine, ENE, Glenvale, MA AG, National Grid, NESCOE, SEIA intervene
	10	Economic Studies Process Improvements Phase 2 Changes (ER25-2023; ER25-2024)	May 5, 12 May 9 Jun 20	Calpine, National Grid intervene ISO-NE amends filing to remove comments from certain Attachment K sheets FERC accepts Revisions, eff. *Jun 23, 2025*
	11	NECEC Operational Documents – TOA/IOA/AOA (ER25-2011)	May 5-12	Calpine, Eversource, National Grid intervene FERC accepts NECEC Operational Documents, eff. *Jun 21, 2025*
	11	*RENEW O&M Complaint Order* Compliance Changes (ER25-1324)	May 2 Jun 2	FERC conditionally accepts Compliance Changes, subject to a further 30-day compliance filing PTO-AC and ISO-NE submit 30-day compliance revisions; comment deadline ***Jun 23, 2025***

	12	*Order 2023* Compliance Revisions (ER24-2009) and Related Changes (ER24-2007)	Jun 3	ISO-NE and the PTO-AC file Further Compliance Changes in response to the requirements of the *Order 2023 Compliance Order*; comment deadline ***Jun 24, 2025***
	12	Effective Date Deferral Request – Order 881 Compliance Filing (ER22-2357; ER25-410)	May 30	FERC grants deferral of effective dates to implement *Order 881* compliance Tariff revisions up to and including ***Dec 15, 2026***

V. Financial Assurance/Billing Policy Amendments

*	13	Updates to FAP Definitions of ABR and CWAP (ER25-2403)	Jun 2	ISO-NE and NEPOOL file changes to the FAP definitions of ABR and CWP
			Jun 9-23	Calpine, National Grid, NEPGA intervene
	13	Billing Policy Changes (Conforming Changes to Incorporate the New FCM Affiliate Guaranty) (ER25-1606)	May 29	FERC accepts Billing Policy revisions (to account for the fact that ISO-NE may collect funds from a guaranty to meet a Participant's invoice obligations), eff. *Jun 1, 2025*
			Jun 1	Changes become effective

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

	13	Schedule 21-ES: NSTAR/ISONE/Pittsfield LSA (ER25-1524)	May 1	FERC accepts Agreement for Local Point-to-Point Service associated with Pittsfield's 193 MW combined cycle generating facility, eff. *May 6, 2025*
	14	Schedule 21-VEC and 20-VEC: Annual Informational Filing (ER10-1181)	Apr 30	VEC submits its annual update to its Schedule 21-VEC and 20-VEC formula rates covering the Jul 1, 2024-Jun 30, 2025 period

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

*	14	Capital Projects Report – 2025 Q1 (ER25-2200)	May 12	ISO-NE files 2025 Q1 Report
			May 13	NEPOOL files comments in support of 2025 Q1 Report
			Jun 2	National Grid intervenes
*	14	IMM 2024 Annual Markets Report (ZZ25-4)	May 23	IMM files annual report covering calendar year 2024
*	14	IMM Quarterly Markets Report (ZZ25-4)	Jun 5	IMM files Winter 2024/25 Report
*	16	ISO-NE FERC Form 714 (undocketed)	May 30	ISO-NE submits its 2024 FERC Form 714
*	16	ISO-NE FERC Form 3-Q (undocketed)	May 29	ISO-NE submits its 2025 Q1 FERC 3-Q
*	16	ISO-NE FERC Form 715 (undocketed)	May 19	ISO-NE submits its 2024 Annual Transmission Planning and Evaluation Report (FERC Form 715)

IX. Membership Filings

*	16	Jun 2025 Membership Filing (ER25-2369)	May 30	***New Member:*** Apollo Power
	16	Apr 2025 Membership Filing (ER25-1820)	May 28	FERC accepts (i) the memberships of: Gabel Associates; NECEC Transmission; and Powervine Energy; (ii) the termination of Participant status of Power Kiosk; and (iii) the name changes of: Avangrid Power, LLC and NDC Partners Corp.

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

	17	Revised Reliability Standard: EOP-012-3 (RD25-7)	May 12	IRC submits comments seeking clarification; UCS submits comments suggesting modifications to the case-by-case list
			May 28	NERC answers UCS comments
	17	Revised Reliability Standards: PRC-029-1 and PRC-024-4 (RM25-3)	Jun 11	Deriva Energy submits out-of-time comments
	18	Revised Reliability Standards: CIP-002-7 through CIP-013-3 (Virtualization) (RM24-8)	May 20	NERC files errata and supplement to initial Petition

XI. Misc. - of Regional Interest

*	19	203 Application: CPower/NRG (EC25-102)	Jun 12	Applicants request authorization for NRG's indirect acquisition of 100% of the interests in CPower; comment deadline ***Aug 11, 2025***
			Jun 13-17	PJM IMM, Public Citizen intervene
			Jun 13, 17	Applicants supplement and amend application
*	19	203 Application: Burgess BioPower/ White Mountain Power (EC25-99)	Jun 10	Burgess BioPower requests FERC authorization for a transaction by which White Mountain Power (an affiliate of, among others, Bridgewater Power and David Energy Supply) will acquire all of the indirect ownership interests of Berlin Station in connection with a plan of reorganization under Chapter 11 of the US Bankruptcy Code; comment deadline ***Jul 1, 2025***
*	19	203 Application: Tomorrow Energy/Six One Commodities (EC25-98)	Jun 6 Jun 11, 23	Tomorrow Energy requests authorization for a transaction pursuant to which Six One Commodities will acquire 100% of the interests in Tomorrow Energy; comment deadline ***Jun 27, 2025***
*	20	203 Application: Icetec / Veolia (EC25-85)	May 2	Applicants request authorization for Veolia's acquisition of 100% of the interests in Icetec Energy Services
			May 12	PJM IMM intervenes
*	19	203 Application: Kleen Energy/Alpha Gen (EC25-77)	Jun 13	FERC authorizes Alpha Gen acquisition of Kleen Energy
	20	203 Application: Constellation/ Calpine (EC25-43)	May 19	PJM IMM, Public Citizen submit comments/protests
			Jun 3	Constellation/Calpine answer May 19 pleadings
			Jun 12	Constellation/Calpine supplement application; comment deadline ***Jun 23, 2025***
*	20	PURPA Enforcement Petition – Allco v. Connecticut (EL25-81-000 et. al.)	May 15	Allco Finance Limited petitions the FERC to initiate an enforcement action against Connecticut (DEEP, PURA, and as amended its DoA) to remedy what it asserts is CT's improper implementation of PURPA sec. 210
			Jun 6	Allco amends Petition to include CT Dept of Agriculture (DoA)
			Jun 10	CL&P intervenes
			Jun 20	Connecticut protests Allco's Complaint
*	20	Order 676-K Compliance Changes: Versant Power (ER25-2566)	Jun 23	Versant files compliance Changes; comment deadline ***Jul 14, 2025***
*	21	IA 3d Amendment: CMP / Sappi (ER25-2516)	Jun 13	CMP files a 3d Amended and Restated Interconnection Agreement to permit Presumpscot additional time (through the end of 2025) to establish separate interconnection for its Dundee and Eel Weir projects; comment deadline ***July 7, 2025***

*	21	Wholesale Distribution Tariff – Versant Power (ER25-2500)	Jun 12	Versant Power files new Wholesale Distribution Tariff to facilitate ESS resources' participation in the wholesale markets via distribution facilities owned by Versant Power; comment deadline ***Jul 3, 2025***
*	21	RFA – NSTAR / Fe Taft (ER25-2278)	May 21	NSTAR files Related Facilities Agreement
*	21	IA 2d Amendment: NSTAR / Braintree (ER25-2094)	Apr 30	NSTAR files 2nd Amendment to its interconnection agreement with Braintree
	21	IA 2d Amendment: CMP / Androscoggin Reservoir Co (ER25-1990)	Jun 12	FERC accepts IA, eff. *Apr 1, 2025*
	22	WDTs – National Grid (ER24-2796; ER24-2795)	May 21	National Grid submits notice that Wholesale Distribution Tariffs will become eff. *June 1, 2025*
	22	*Order 2023* Compliance Filing: Versant MPD OATT (ER24-2035)	May 30	FERC accepts additional compliance filing, eff. *Jan 1, 2025*
	22	CMP ESF Rate (ER24-1177)	May 1 May 15 May 20	Trial Staff supports Settlement Agreement Settlement Judge Hessler certifies uncontested settlement to the Commission Chief ALJ terminates settlement proceedings

XII. Misc. - Administrative & Rulemaking Proceedings

23	Tech Conf: Meeting the Challenge of Resource Adequacy in ISO/RTOs (AD25-7)	May 20 Jun 4-5 Jun 5	FERC issues second notice of its Jun 4-5 tech conf. FERC holds tech conference FERC notice that post-conference comments due on before ***Jul 7, 2025***
24	Joint Federal- State Current Issues Collaborative (AD24-7)	May 5 May 15	Industrial Energy Consumers of America submits comments FERC posts meeting transcript to eLibrary
24	Tech Conf: Increasing Market and Planning Efficiency Through Improved Software (AD10-12)	May 9	FERC issues supplemental notice of tech conf; post-tech conf comments due ***Aug 11, 2025***
22	*Order 904:* Compensation for Reactive Power Within the Standard Power Factor Range (RM22-2)	Jun 6	FERC issues *Order 904 Allegheny Order*, modifying the discussion in, but reaching the same result as, *Order 904*
26	*Orders 1920/1920-A/1920-B*: Transmission Planning Reforms (RM21-17)	May 15	FERC accepts ISO-NE's commitment to submit (i) an informational filing 30 days prior to the Sep 2026 initiation of its engagement with all stakeholders, and (ii) status reports every 90 days thereafter until it submits its compliance filings to demonstrate that it meets the requirements of *Order 1920*

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

*	28	GenOn (IN25-3)	May 20	FERC approves Stipulation and Consent Agreement that resolves OE's investigation into whether GenOn violated the PJM Tariff and FERC regulations by submitting bids for certain of its units below their ICAP Obligation (as a result of an inaccurate spreadsheet template); GenOn agrees to ***disgorge $172,306***, pay a ***$390,000 civil penalty***, and be subject to compliance monitoring
	28	American Efficient Show Cause Order (IN24-2)	May 7 May 13 Jun 2	American Efficient replies to OE Litigation Staff's Apr 15 reply American Efficient supplements answer with financial information American Efficient provides updates on potentially related legal proceedings

	Natural Gas-Related Enforcement Actions		
* 29	Green Plains (IN25-2)	Jun 13	FERC approves Stipulation and Consent Agreement that resolves OE's investigation into whether Green Plains violated the NGA and FERC regulations by selling monthly physical gas during bidweek at MichCon at a loss or negligible profit, while holding leveraged short financial basis positions that settled off the IFERC MichCon index; Green Plains agrees to ***make restitution of $19,306***, pay a ***$920,990 civil penalty***, be subject to 3 years' compliance monitoring; and certain MichCon trading restrictions

XIV. Natural Gas Proceedings

No Activity to Report

XV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XVI. Federal Courts

32	*Order 1920: Transmission Planning Reforms (4th Circuit – 24-1650)*	May 2	Parties propose to file an agreed-to briefing schedule on ***Jul 1, 2025***

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Pat Gerity and Joan Bosma, NEPOOL Counsel

DATE: June 23, 2025

RE: Status Report on Current Regional Wholesale Power and Transmission Arrangements Pending Before the Regulators, Legislatures and Courts

We have summarized below the status of key ongoing proceedings relating to NEPOOL matters before the Federal Energy Regulatory Commission ("FERC"),[1] state regulatory commissions, and the Federal Courts and legislatures through June 23, 2025. In addition, in the opening Section immediately below, we summarize recent Executive Orders issued by the President of the United States related to energy industry issues. If you have questions on any of these summaries, please contact us.

Executive Orders

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

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

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

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

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

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

Also on May 23, 2025, President Trump issued EO 14300 directing the Nuclear Regulatory Commission ("NRC") to overhaul its licensing and fee structures to expedite approvals. EO 14300 specifically mandates final decisions on applications for new reactors within 18 months, and for continued operation of existing reactors within one year, with caps on hourly fee recovery. EO 14300 also directs the NRC to streamline approval of

[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").

reactor designs already tested and demonstrated by the DOE or DoD, so to focus reviews only on new application-specific risks.

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

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

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

On April 9, 2025, President Trump issued an EO directing the FERC along with the DOE, Environmental Protection Agency ("EPA"), and the Nuclear Regulatory Commission ("NRC"), to incorporate conditional sunset provisions into specified "Covered Regulations" that requires these regulations expire after one year unless extended at the agency's discretion for a period of up to five years. The agencies must provide the public with an opportunity to comment on the costs and benefits of each such regulation prior to its expiration. For FERC, the EO applies to regulations promulgated under the Federal Power Act ("FPA"), Natural Gas Act, and the Powerplant and Industrial Fuel Use Act.

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

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

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

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

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

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

I. Complaints/Section 206 Proceedings

- **Consumers RTP Complaint (EL25-44)**

As previously reported, a group of "Consumer Complainants"[2] filed a complaint on December 19, 2024 against all FERC-jurisdictional public utility transmission providers with local planning tariffs (including ISO-NE and the remaining ISO/RTOs) asserting that their tariffs, which authorize individual transmission owners to plan FERC-jurisdictional transmission facilities at 100 kV and above ("Local Planning") without regard to whether such Local Planning approach is the more efficient or cost-effective transmission project for the interconnected transmission grid and cost-effective for electric consumers, coupled with the absence of an independent transmission system planner, "are unjust and unreasonable, having produced inefficient planning and projects that are not cost-effective, resulting in unjust and unreasonable rates for both individual projects and cumulative regional transmission plans and portfolios." Specifically, the Consumer Complainants asserted that the FERC must mandate (i) revision of local and regional planning tariffs to (a) prohibit individual transmission owner planning of FERC-jurisdictional transmission facilities 100 kV and above; and (b) require exclusive regional planning of all transmission facilities 100 kV and above, utilizing existing *Order 1000* regions; and (ii) that all regional planning must be conducted through an Independent Transmission Planner as described in their Complaint.

Answers, interventions, comments, and protests to the Consumers RTP Complaint were due on or before March 20, 2025[3] and were filed by, among others, ISO-NE, New England Transmission Owners ("NETOs"),[4] AEU, CT OCC, NECPUC, NESCOE, MA AG, NH OCA (supporting the Complaint), MPUC (urging the FERC to reject the remedies proposed by the Complainants and open its own investigations pursuant to Section 206 of the FPA), EEI, NARUC, Public Interest Organizations,[5] and WIRES. Interventions only were filed by more than 100 parties, including NEPOOL. On April 4, 2025, ISO-NE answered certain comments and reiterated its request that it be dismissed as a respondent to the proceeding. Answer and reply comments were also filed by Complainants (requesting FERC grant the Complaint and deny the motions to dismiss), NESCOE (addressing the standard of review that may apply to certain reforms), MOPA (asking FERC to reject motions to dismiss and open an

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

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

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

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

investigation), MPUC (requesting FERC accept its motion for to leave to answer and consider its answer), and AMP (asking FERC to deny motions to dismiss). On May 20, 2025, ISO-NE responded to Complainant's Answer and the responses of NESCOE, MPUC, and MOPA, again requesting it be dismissed as a respondent to the proceeding as a matter of law and because the Complainants failed to meet their burden under FPA Section 206. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

Also on December 19, 2024, Allco Finance Limited ("Allco") filed a complaint asking the FERC to (i) direct ISO-NE to abolish its Planning Procedure No. 5 ("PP5") procedures by (ii) finding that PP5's procedures are unjust and unreasonable and unduly discriminatory and/or preferential in violation of section 206 of the FPA; and (iii) find that ISO-NE has violated the FPA by forcing on State jurisdictional interconnections, such as Allco's, the requirement to pay for transmission level interconnection studies, to pay for Power Systems Computer Aided Design ("PSCAD") models in connection with such studies, and by causing delays to the execution by distribution utilities of State jurisdictional generator interconnection agreements (particularly for Allco's 2 MW Winsted solar energy project). Allco's arguments are very similar to those Allco raised in the *Order 2023* Compliance Revisions and Related Changes proceeding (*see* Section IV below). Comments on the Allco PP5 Complaint, following an ISO-requested and FERC-granted extension of time, were due on or before January 15, 2025. ISO-NE answered the Allco PP5 Complaint on January 15, 2025 (as corrected on January 30, 2025). On January 23, 2025, Allco answered ISO-NE's January 15 Answer. On February 7, 2025, ISO-NE answered Allco's January 23 Answer and on February 25, 2025 Allco answered ISO-NE's February 7 Answer. Doc-less interventions only were filed by NEPOOL, Calpine, National Grid, the MA DPU, and Public Citizen. There was no activity in this proceeding since the last Report. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

As previously reported, on June 13, 2024, the FERC instituted a Section 206 proceeding finding that the ISO-NE Tariff appears to be unjust, unreasonable, and unduly discriminatory or preferential because it includes provisions for transmission owners to unilaterally elect transmission owner ("TO") Initial Funding (the funding of network upgrade capital costs that the TO incurs to provide interconnection service to an interconnection customer, with the network upgrade capital costs subsequently recovered from the interconnection customer through charges that provide a return on and of those network upgrade capital costs).[6] 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.[7] 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.[8] 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.[9] The refund effective date for this proceeding is June 24, 2024.[10] 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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[6] *ISO New England Inc. et al.,* 187 FERC ¶ 61,170 (June 13, 2024) ("*TO Initial Funding Show Cause Order*").

[7] *Id.* at P 1.

[8] *Id.*

[9] *Id.* at P 2.

[10] 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:[11] NEPOOL, Advanced Energy United ("AEU"), Avangrid, Calpine, CMEEC (out-of-time), EDP Renewables, Eversource, Invenergy, MA AG, National Grid, NESCOE, NextEra, NRDC, PPL, Maine Public Utilities Commission ("MPUC"), Massachusetts Department of Public Utilities ("MA DPU"), American Clean Power Association ("ACPA"), American Council on Renewable Energy ("ACRE"), Edison Electric Institute ("EEI"), Electric Power Supply Association ("EPSA"), RENEW Northeast ("RENEW"), Solar Energy Industries Association ("SEIA"), WIRES, Cordelio Services, and Public Citizen.

NE Response to Show Cause Order (Attaching Substantive Response by NETOs). On September 11, 2024, ISO-NE submitted a response ("NE Response") explaining that, because the rules identified in the *TO Initial Funding Show Cause Order*[12] 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")[13] to the NE Response. NETOs' response identified several reasons why the FERC's proposal is in their view beyond the FERC's authority and power.

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

Federal Court Appeals. On August 30, 2024, certain parties[14] filed a petition for review of the FERC's orders in this proceeding in the 8th Circuit, since challenged by the FERC. Developments on the federal court appeals will be reported in Section XVI below. In the meantime, if you have questions on this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

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

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

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[11] 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).

[12] 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.

[13] 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").

[14] 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").

- ***Base ROE Complaint I (EL11-66)***. In the first Base ROE Complaint proceeding, the FERC concluded that the TOs' ROE had become unjust and unreasonable,[15] set the TOs' Base ROE at 10.57% (reduced from 11.14%), capped the TOs' total ROE (Base ROE *plus* transmission incentive adders) at 11.74%, and required implementation effective as of October 16, 2014 (the date of *Opinion 531-A*).[16] However, the FERC's orders were challenged, and in *Emera Maine,*[17] the U.S. Court of Appeals for the D.C. Circuit ("DC Circuit") vacated the FERC's prior orders, and remanded the case for further proceedings consistent with its order. The FERC's determinations in *Opinion 531* are thus no longer precedential, though the FERC remains free to re-adopt those determinations on remand as long as it provides a reasoned basis for doing so.

- ***Base ROE Complaints II & III (EL13-33 and EL14-86) (consolidated)***. The second (EL13-33)[18] and third (EL14-86)[19] ROE complaint proceedings were consolidated for purposes of hearing and decision, though the parties were permitted to litigate a separate ROE for each refund period. After hearings were completed, ALJ Sterner issued a 939-paragraph, 371-page *Initial Decision*, which lowered the base ROEs for the EL13-33 and EL14-86 refund periods from 11.14% to 9.59% and 10.90%, respectively.[20] The *Initial Decision* also lowered the ROE ceilings. Parties to these proceedings filed briefs on exception to the FERC, which has not yet issued an opinion on the ALJ's *Initial Decision*.

- ***Base ROE Complaint IV (EL16-64)***. The fourth and final ROE proceeding[21] also went to hearing before an Administrative Law Judge ("ALJ"), Judge Glazer, who issued his initial decision on March 27, 2017.[22] The *Base ROE IV Initial Decision* concluded that the currently-filed base ROE of 10.57%,

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[15] The TOs' 11.14% pre-existing Base ROE was established in *Opinion 489*. *Bangor Hydro-Elec. Co.*, Opinion No. 489, 117 FERC ¶ 61,129 (2006), *order on reh'g*, 122 FERC ¶ 61,265 (2008), *order granting clarif.*, 124 FERC ¶ 61,136 (2008), *aff'd sub nom.*, Conn. Dep't of Pub. Util. Control v. FERC, 593 F.3d 30 (D.C. Cir. 2010) ("*Opinion 489*")).

[16] *Coakley Mass. Att'y Gen. v. Bangor Hydro-Elec. Co.*, 147 FERC ¶ 61,234 (2014) ("*Opinion 531*"), *order on paper hearing*, 149 FERC ¶ 61,032 (2014) ("*Opinion 531-A*"), *order on reh'g*, 150 FERC ¶ 61,165 (2015) ("*Opinion 531-B*").

[17] *Emera Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017) ("*Emera Maine*"). *Emera Maine* vacated the FERC's prior orders in the Base ROE Complaint I proceeding, and remanded the case for further proceedings consistent with its order. The Court agreed with both the TOs (that the FERC did not meet the Section 206 obligation to first find the existing rate unlawful before setting the new rate) and "Customers" (that the 10.57% ROE was not based on reasoned decision-making, and was a departure from past precedent of setting the ROE at the midpoint of the zone of reasonableness).

[18] The 2012 Base ROE Complaint, filed by Environment Northeast (now known as Acadia Center), Greater Boston Real Estate Board, National Consumer Law Center, and the NEPOOL Industrial Customer Coalition ("NICC", and together, the "2012 Complainants"), challenged the TOs' 11.14% ROE, and seeks a reduction of the Base ROE to 8.7%.

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

[20] *Environment Northeast v. Bangor Hydro-Elec. Co. and Mass. Att'y Gen. v. Bangor Hydro-Elec. Co,* 154 FERC ¶ 63,024 (Mar. 22, 2016) ("*2012/14 ROE Initial Decision*").

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

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

which may reach a maximum ROE of 11.74% with incentive adders, was ***not*** unjust and unreasonable for the Complaint IV period, and hence was not unlawful under Section 206 of the FPA.[23] Parties in this proceeding filed briefs on exception to the FERC, which has not yet issued an opinion on the *Base ROE IV Initial Decision*.

October 16, 2018 Order Proposing Methodology for Addressing ROE Issues Remanded in Emera Maine and Directing Briefs. On October 16, 2018, the FERC, addressing the issues that were remanded in *Emera Maine,* proposed a new methodology for determining whether an existing ROE remains just and reasonable.[24] The FERC indicated its intention that the methodology be its policy going forward, including in the four currently pending New England proceedings (*see*, however, *Opinion 569-A*[25] (EL14-12; EL15-45) in Section XI below). The FERC established a paper hearing on how its proposed methodology should apply to the four pending ROE proceedings.[26]

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

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

The FERC provided preliminary analysis of how it would apply the proposed methodology in the Base ROE I Complaint, suggesting that it would affirm its holding that an 11.14% Base ROE is unjust and unreasonable. The FERC suggested that it would adopt a 10.41% Base ROE and cap any preexisting incentive-based total ROE at 13.08%.[27] The new ROE would be effective as of the date of *Opinion 531-A*, or October 16, 2014. Accordingly, the issue to be addressed in the Base ROE Complaint II proceeding is whether the ROE established on remand in the first complaint proceeding remained just and reasonable based on financial data for the six-month period September 2013 through February 2014 addressed by the evidence presented by the

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

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

[25] *Ass’n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569-A, 171 FERC ¶ 61,154 (2020) (“*Opinion 569-A*”). The refinements to the FERC’s ROE methodology included: (i) the use of the Risk Premium model instead of only relying on the DCF model and CAPM under both prongs of FPA Section 206; (ii) adjusting the relative weighting of long- and short-term growth rates, increasing the weight for the short-term growth rate to 80% and reducing to 20% the weight given to the long-term growth rate in the two-step DCF model; (iii) modifying the high-end outlier test to treat any proxy company as high-end outlier if its cost of equity estimated under the model in question is more than 200% of the median result of all the potential proxy group members in that model before any high- or low-end outlier test is applied, subject to a natural break analysis. This is a shift from the 150% threshold applied in *Opinion 569*; and (iv) calculating the zone of reasonableness in equal thirds, instead of using the quartile approach that was applied in *Opinion 569*.

[26] *Id.* at P 19.

[27] *Id.* at P 59.

participants in the second proceeding. Similarly, briefing in the third and fourth complaints will have to address whether whatever ROE is in effect as a result of the immediately preceding complaint proceeding continues to be just and reasonable.

The FERC directed participants in the four proceedings to submit briefs regarding the proposed approaches to the FPA section 206 inquiry and how to apply them to the complaints (separate briefs for each proceeding). Additional financial data or evidence concerning economic conditions in any proceeding must relate to periods before the conclusion of the hearings in the relevant complaint proceeding. Following a FERC notice granting a request by the TOs and Customers[28] for an extension of time to submit briefs, the latest date for filing initial and reply briefs was extended to January 11 and March 8, 2019, respectively. On January 11, initial briefs were filed by EMCOS, Complainant-Aligned Parties, TOs, Edison Electric Institute ("EEI"), Louisiana PSC, Southern California Edison, and AEP. As part of their initial briefs, each of the Louisiana PSC, SEC and AEP also moved to intervene out-of-time. Those interventions were opposed by the TOs on January 24, 2019. The Louisiana PSC answered the TOs' January 24 motion on February 12. Reply briefs were due March 8, 2019 and were submitted by the TOs, Complainant-Aligned Parties, EMCOS, and FERC Trial Staff.

TOs Request to Re-Open Record and file Supplemental Paper Hearing Brief. On December 26, 2019, the TOs filed a Supplemental Brief that addresses the consequences of the November 21 *MISO ROE Order*[29] and requested that the FERC re-open the record to permit that additional testimony on the impacts of the *MISO ROE Order*'s changes. On January 21, 2020, EMCOS and Complainant-Aligned Parties ("CAPs") opposed the TOs' request and brief. No action was ever taken in response to this activity.

Nov 2023 Supplemental Brief. As reported at the December 5, 2024 Annual Meeting, the TOs filed, on November 13, 2024, a "Motion to File Supplemental Brief Addressing the Inability of the [FERC]'s MISO Methodology to Satisfy the Mandate of the *Emera Maine* Court in these Cases, the Requirements of Section 206, and the Need to Promote Transmission Investment in New England". On December 13, 2024, WIRES/EEI supported the TOs Motion,[30] and CAPs[31] replied in opposition to the Motion. On December 20, 2024, the TOs filed an answer to the CAPs' statements concerning the FERC's authority to order refunds for the period from when the FERC issues its order on remand back to October 16, 2014.

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

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

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

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

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

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.[32] MOPA asserted that, (i) with respect to the cost of asset condition projects placed into service in 2022, Identified TOs[33] have refused to answer questions regarding investment policies and practices related to prudence of these investments and (ii) that the Identified TOs' decision not to respond to these questions violates their obligation under the OATT's Protocols. Comments on the MOPA Formal Challenge were due on or before February 21, 2024 and were filed by Consumer Advocates[34] (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 remains pending before the FERC. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com)

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[32] 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.

[33] "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").

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

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[35] to allow the SIS results for its facility[36] to be accepted after August 30, 2024 and thus to enable its LGIA to benefit from the proposed Late-Stage SIS Process and for GDQ ESS to be refunded its deposits associated with participation in the Transitional Cluster Study.[37] On September 6, 2024, ISO-NE protested the waiver request asserting that GDQ ESS does not meet the FERC's standard for granting waivers. NEPOOL and Calpine intervened. Since the last Report, in response to the Order 2023-Related Section 205 Transition Tariff Revisions filing in ER25-2149 (summarized immediately below), GDQ ESS committed to withdrawing its pending waiver request within three business days of a FERC order accepting the Transition Tariff Revisions. For now, the GDQ ESS waiver request remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

IV. OATT Amendments / TOAs / Coordination Agreements

- **Order 2023-Related Section 205 Transition Tariff Revisions (ER25-2149)**

May 2, 2025, ISO-NE, NEPOOL and the PTO-AC filed proposed revisions to Section 48 and Schedules 22, 23, and 25 of Section II of the Tariff, and Section III.13 of the Tariff, to update certain dates related to the implementation of ISO-NE's cluster study process transition required by *Orders 2023* and *2023-A* ("Transition Tariff Revisions"). The Filing Parties explained that the Transition Tariff Revisions are necessary to implement transition rules that could not proceed until the FERC issued its *Order 2023 Compliance Order*[38] and will facilitate implementation of the FERC-accepted Transition CNR Group Study in coordination with the 2025 FCM reconfiguration auction qualification process. The Participants Committee unanimously supported the Transition Tariff Revisions at its May 1, 2025 meeting (Agenda Item 6). A May 3, 2025 effective date was requested. Comments on this filing were due on or before May 23, 2025. The only comments filed were filed by GDQ ESS, which supported the Transition Tariff Revisions and committed to withdraw its pending waiver request (*see* ER24-2926 above) within three business days of a FERC order accepting the Transition Tariff Revisions. Doc-less interventions only were filed by Calpine, Energy New England ("ENE"), Glenvale, MA AG, National Grid, NESCOE, and SEIA. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617- 345-4735; ekrunge@daypitney.com).

- **Phase 2 Economic Study Revisions (ER25-2023; ER25-2024)**

On June 20, 2025, the FERC accepted without change or condition the revisions to the ISO-NE Tariff to implement Phase II of enhancements to the Economic Study process ("Phase 2 Economic Study Revisions") jointly submitted by ISO-NE, NEPOOL and the PTO-AC.[39] The Phase 2 Economic Study Revisions were accepted effective

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[35] 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").

[36] 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.

[37] 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.

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

[39] *ISO New England Inc.*, 191 FERC ¶ 61,211 (June 20, 2025) ("*Phase 2 Economic Study Revisions Order*").

June 23, 2025. As previously reported, the Phase 2 Economic Study Revisions build on Phase I revisions accepted by the FERC on March 30, 2023, and are intended to further refine the process for identifying and evaluating potential System Efficiency Transmission Upgrades.[40] Unless the *Phase 2 Economic Study Revisions Order* is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

- **NECEC Operational Documents – TOA/IOA/AOA (ER25-2011)**

Also on June 20, 2025, the FERC accepted the three agreements[41] to establish the framework for the operation and coordination of the NECEC Transmission Line, the NECEC-owned and operated portion of the of the 1,200 MW HVDC Appalaches-Maine Interconnection between New England and Québec.[42] The agreements were accepted effective *June 21, 2025*. Unless the *NECEC Operational Documents Order* is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

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

On March 19, 2025, ISO-NE and NEPOOL submitted revisions to Schedule 2 of the ISO-NE OATT in compliance with Order 904 ("Reactive Power Compensation Changes"). The Reactive Power Compensation Changes eliminate compensation for reactive power capability within the standard power factor range of 0.95 leading to 0.95 lagging, while continuing to allow compensation for capability outside that range. The proposed revisions to Schedule 2 of the OATT were supported by the Participants Committee at its March 6, 2025 meeting (Agenda Item #6). An effective date of 6-12 months from the date of an order accepting the filing, with an actual date to be submitted one month in advance, was requested. Comments on the filing were due on or before April 9, 2025. NEPGA filed supporting comments; doc-less interventions were filed by Calpine, CPV Towantic, MA AG, National Grid, Shell, Vistra, and SEIA. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

- ***RENEW O&M Complaint Order* Compliance Changes (ER25-1324)**

On May 2, 2025, the FERC conditionally accepted[43] the ISO-NE and the PTO-AC's proposed Tariff revisions in response to the requirements of the *RENEW O&M Complaint Order* ("*RENEW O&M Complaint Order Compliance Changes*").[44] In accepting the *RENEW O&M Complaint Order Compliance Changes,* the FERC directed ISO-NE to submit a further 30-day compliance filing that revises the Tariff to clarify "that Network Upgrade operations and maintenance ("O&M") costs accrued on or after December 19, 2024 will be returned to the interconnection customer, regardless of whether the interconnection customer made advance payments prior to

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[40] The Phase 2 Economic Study Revisions were filed in two parts — changes to the ISO-NE Tariff (part 1) and changes to the TOA (part 2). The Phase 2 Economic Study Revisions: (1) separate System Efficiency Needs Assessments from reliability Needs Assessments; (2) establish a threshold for the issuance of a Request for Proposals ("RFP") for System Efficiency Transmission Upgrades; (3) change the RFP process for System Efficiency Transmission Upgrades from the current two-phase RFP process to a single-phase RFP process; and (4) establish clearly defined metrics to evaluate System Efficiency Transmission Upgrade Proposals. Since the last Report, on May 9, 2025, ISO-NE filed an amendment to clean-up certain Attachment K sheets.

[41] The agreements are: (1) the NECEC Transmission Operating Agreement ("NECEC TOA"); (2) the Appalaches-Maine Interconnection Operators Agreement (the "IOA"); and (3) the Appalaches-Maine Interconnection Asset Owners Agreement (the "AOA").

[42] *ISO New England Inc. and NECEC Transmission LLC*, 191 FERC ¶ 61,213 (June 20, 2025) ("*NECEC Operational Documents Order*").

[43] *ISO New England Inc.*, 191 FERC ¶ 61,100 (May 2, 2025) ("*RENEW O&M Complaint Order Compliance Changes Order*").

[44] As previously reported, the RENEW O&M Complaint Order Compliance Changes proposed revisions to Schedules 11, 22, 23, and 25 and Attachment F, Appendix C of the OATT and remove from the OATT any language providing for the assignment of O&M costs for Network Upgrades to Interconnection Customers and revise the definition of Interested Party in the Formula Rate Protocols and to delete from § VI.7 of the Formula Rate Protocols the restriction that prevents all Interested Parties from attempting to resolve potential disputes.

December 19, 2024." The filing parties were granted the requested effective date of December 19, 2024 for the *RENEW O&M Complaint Order* Compliance Changes, subject to the further 30-day compliance filing.

30-Day Compliance Filing. On June 2, 2025, the PTO-AC and ISO-NE submitted revisions, as directed, in a 30-day compliance filing. The revisions "make clear that Network Upgrade O&M costs accrued on or after December 19, 2024 will be returned to the interconnection customer, regardless of whether the interconnection customer made advance payments prior to December 19, 2024." Comments, if any, on the 30-day compliance filing are due on or before ***June 23, 2025***. 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).

- ***Order 2023*** **Compliance Revisions (ER24-2009) and Related Changes (ER24-2007)**

As noticed, the FERC issued on April 4, 2025 its order on the region's *Order 2023* compliance filing and related changes.[45] In the *Order 2023 Compliance Order*, the FERC conditionally accepted most of the proposed tariff revisions from the *Order 2023* Compliance Revisions filing (with some directives to incorporate *pro forma* language, correct minor inconsistencies and provide further description), and accepted all of the proposed tariff revisions from the *Order 2023* Related Changes filing. Both sets of changes were accepted effective as of *August 12, 2024*. Materials summarizing the *Order 2023 Compliance Order* were circulated to and discussed with the Transmission Committee for its April 17 meeting.

Order 2023 Further Compliance Changes (ER24-2009-001). On June 3, 2025, ISO-NE and the PTO-AC filed revisions to Section I.2.2, Schedules 11, 22, 23, and 25 of Section II, and Section III.13 of the Tariff ("Further Compliance Changes"). The Further Compliance Changes were reviewed by the Transmission Committee at its May 22, 2025 meeting and unanimously recommended for Participants Committee approval at its June Summer Meeting (which will be considered as Consent Agenda Item #3). Comments on the Further Compliance Changes are due on or before ***June 24, 2025***. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com), Margaret Czepiel (202-218-3906; mczepiel@daypitney.com), or Joan Bosma (617-345-4651; jbosma@daypitney.com).

- ***Order 881*** **Compliance Filing (Transmission Line Rating Calculation and Submittal Timeframe Implementation Details) (Phase I/II HVDC-TF) (ER22-2468-001; ER22-2467-001)**

On November 22, 2024, ISO-NE, the Asset Owners,[46] and the Schedule 20A Service Providers[47] jointly submitted their compliance filing to address the sole directive in the June 15, 2023 *Phase I/II HVDC-TF Order 881 Compliance Order*[48] to provide implementation details regarding the calculation and submittal timeframes for the ambient-adjusted ratings ("AARs") required by *Order 881*. Comments on that filing were due on or before December 13, 2024; none were filed. The *Order 881* compliance filings are pending before the FERC. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Effective Date Deferral Request: Order 881*** **Compliance Filing (Transmission Line Rating Calculation and Submittal Timeframe Implementation Details) (ER22-2357; ER25-410)**

On May 30, 2025, the FERC granted the request by ISO-NE and the PTO-AC to defer the effective date of the *Order 881* Compliance Changes from July 12, 2025 back to, and including, *Dec 15, 2026* (due to delays in the delivery of software necessary to implement the *Order 881* requirements that make the Tariff rules' current July

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

[46] The "Asset Owners" are, collectively: New England Hydro-Transmission Elec. Co., Inc.; New England Hydro-Transmission Corp.; New England Elec. Transmission Corp.; and Vermont Elec. Transmission Co.

[47] The "Schedule 20A Service Providers" are the public utilities that provide transmission service under Schedule 20A to the ISO-NE OATT.

[48] *ISO New England Inc.*, 183 FERC ¶ 61,179 (June 15, 2023) ("*Phase I/II HVDC-TF Order 881 Compliance Order*").

12, 2025 effective date infeasible).[49] If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

- **Updates to FAP Definitions of ABR and CWAP (ER25-2403)**

On June 2, 2025, ISO-NE and NEPOOL jointly filed changes to the ISO-NE Financial Assurance Policy ("FAP") to update the definitions of ABR and CWAP, two variables used in the FCM Delivery Financial Assurance ("FA") formula. The FAP Definition Changes were supported unanimously by the Participants Committee at its May 1, 2025 meeting (Agenda Item #5). An August 4, 2025 effective date was requested. Comments on the FAP Definition Changes were due on or before June 23, 2025; none were filed. Calpine, NEPGA and National Grid intervened doc-lessly. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **Billing Policy Changes (New FCM Affiliate Guaranty Conforming Changes) (ER25-1606)**

On May 29, 2025, the FERC accepted the changes to the ISO-NE Billing Policy ("Billing Policy Changes")[50] to conform the Policy with recently-accepted changes to the ISO-NE Financial Assurance Policy ("FAP") pursuant to which ISO-NE may accept an FCM Affiliate Guaranty from Participants with a Capacity Supply Obligation ("CSO") following a corporate liquidity assessment.[51] The Billing Policy Changes filed in this proceeding reflect that ISO-NE may draw on such guaranties to satisfy a Participant's invoice obligations. The Billing Policy Changes were accepted as of and became effective on *June 1, 2025*, as requested. Unless the May 29 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

VI. Schedule 20/21/22/23 Changes & Agreements[52]

- **Schedule 21-ES: NSTAR/ISO-NE/Pittsfield LSA (ER25-1524)**

On May 1, 2025, the FERC accepted the fully executed Local Service Agreement ("LSA") among NSTAR, ISO-NE, and Pittsfield Generating Company, LP ("Pittsfield") for Local Point-to-Point Service under Section 21-ES (Part A) of the ISO-NE OATT associated with Pittsfield's 193 MW combined cycle generating facility.[53] As previously reported, the LSA replaces original Service Agreement No. TSA-NU-50, dated October 16, 2012, and was filed separately because it includes non-conforming provisions reflecting a recent agreement between NSTAR and Pittsfield as to the wheeling out rate applicable to the Pittsfield Units. The replacement LSA became effective *May 6, 2025*, as requested. The May 1 order was not challenged and is final and unappealable. If you have any questions concerning this matter, please contact please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On October 30, 2024, GMP submitted a notice of cancellation of the Network Integration Transmission Service Agreement and Local Operating Agreement ("NITSA") with the Village of Hardwick Electric Department ("Hardwick") filed under Schedule 21-GMP. GMP reported that, as of June 30, 2024, Hardwick is no longer

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49 *ISO New England Inc. and the Participating Transmission Owners Admin. Comm.*, 191 FERC ¶ 61,163 (May 30, 2025).

50 *ISO New England Inc.*, Docket No. ER25-1606-000 (May 29, 2025) (unpublished letter order).

51 *See ISO New England Inc.,* 190 FERC ¶ 61,063 (Jan. 31, 2025) ("*FAP Revisions Order").*

52 Reporting on the following Time Value Refunds Reports, which have each been pending before the FERC for more than a year and a half, has been suspended and will be continued if and when there is new activity to report: Schedule 21-VP: Versant/Jonesboro LSA (ER24-24); Schedule 21-GMP: National Grid/Green Mountain Power LSA (ER23-2804); and Schedule 21-VP: Versant/Black Bear LSAs (ER23-2035).

53 *ISO New England Inc.*, Docket No. ER25-1524-000 (May 1, 2025) (unpublished letter order).

taking service pursuant to the NITSA. GMP requested that the FERC grant waiver of its notice requirement[54] to the extent necessary to permit a requested June 30, 2024 effective date. Comments on this filing were due on or before November 20, 2024; none were filed. As of the date of this Report, the FERC has still not acted on this filing. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

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).

- **Schedule 21-VEC and 20-VEC: Annual Informational Filing (ER10-1181)**

On April 30, 2025, VEC submitted its annual update to its Schedule 21-VEC and 20-VEC formula rates covering the July 1, 2024 – June 30, 2025 period. The FERC will not notice this filing for public comment, and absent further activity, no further FERC action is expected. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activities to Report

VIII. Regional Reports[55]

- **Capital Projects Report – 2025 Q1 (ER25-2200)**

On May 12, 2025, ISO-NE filed its Capital Projects Report and Unamortized Cost Schedule covering the first quarter of 2025 (the "Report"). ISO-NE is required to file the Report under section 205 of the FPA pursuant to Section IV.B.6.2 of the Tariff. Report highlights include the following new projects: (i) Enterprise Core Network Refresh ($2.146 million); (ii) Forward Capacity Tracking System ("FCTS") to the Cloud ($1.148 million); (iii) Energy Management System Communication Front End ("EMS CFE"); and (iv) 2025 Issue Resolution Project ($703,000). One projects reported to have a significant budget change was "nGEM Software Development Part III", which was reduced by $3.007 million to $1.46 million. Comments were due on or before June 2, 2025. NEPOOL filed comments supporting the 2025 Q1 Report. National Grid intervened doc-lessly. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **IMM 2024 Annual Markets Report (ZZ25-4)**

On May 23, 2025, the IMM filed its annual Markets Report covering the 2024 calendar year ("2024 IMM Annual Report").[56] The 2024 IMM Annual Report addresses the development, operation, and performance of the

[54] 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.

[55] 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.

[56] Annual Markets Reports filings are not noticed for public comment by the FERC.

New England Markets and presents an assessment of each market based on market data, performance criteria, and independent studies, providing the information required under Section 17.2.4 of Appendix A to Market Rule 1. On the basis of its review of market outcomes and related information, the IMM concluded, that market outcomes were competitive overall, including an increased competitiveness in the two Forward Reserve Market ("FRM") auctions compared to 2023. Energy prices reflected changes in production costs and supply mix, with operating reserves falling short for only 2.3 hours of the year (0.03% of the year). The 2024 IMM Annual Report states that Day-Ahead and Real-Time Energy prices reflected higher productions costs driven by CO_2 emissions costs under RGGI and reduced net exports to Québec, with a 13% increase in Energy Market prices when compared to 2023. However, natural gas prices remained stable, averaging $3.06/MMBtu in 2024; higher gas prices during cold winter periods were driven by pipeline constraints and lower gas prices during warmer summer periods reflected high natural gas storage levels.

In 2024, New England energy prices totaled $10.2 billion, an 11% increase over 2023, primarily driven by a 24% increase in Energy Market costs. Changes to the energy supply mix were led by a near 30% year-over-year reduction in imports. The IMM found no evidence of market power or structural concerns.

Other 2024 highlights included:

- Total wholesale costs ($10.2 billion) increased 11% from 2023, driven by a 24% increase in energy costs, which totaled $5.6 billion and comprised 55% of the overall cost.
- Total transmission costs ($3 billion) comprised 30% of total costs (with increases attributed to ISO-identified reliability need investments, aging infrastructure replacement and inflationary pressures.
- A continued decrease in Capacity costs, which totaled $1.2 billion in 2024, a 5% decrease from 2023.
- Relatively flat Uplift costs -- Net Commitment Period Compensation ("NCPC") totaled $34.7 million. Mystic Cost of Service payments in 2024 totaled $139 million (through Mystic's retirement in May 2024).
- Day-Ahead and Real-Time LMPs averaged $44.52/MWh and $42.47/MWh, respectively, an increase of 13% and 11% over 2023 simple average levels (natural gas prices remained stable at $3.06/MMBtu).
- Real-Time net interchange averaged 1,175 MW per hour in 2024, the lowest level of net imports since 2011, and down from 1,724 MW per hour in 2023 (largely as a result of dry conditions in Québec and a prolonged outage of the Point Lepreau nuclear generating station).
- Net Energy for Load ("NEL") averaged 13,294 MW per hour, a 2% increase from 2023's historically low levels. Peak load in 2024 was 24,871 MW, which was well below the Capacity Commitment Period ("CCP") peak load forecast of 29,000 MW. Behind-the-meter ("BTM") solar and Energy Efficiency ("EE") measures continued to contribute to load reductions, by an estimated 600 MW and 2,000 MW, respectively, on an average hourly basis.
- RGGI allowance prices reached record levels and were a significant driver of energy prices, increasing 55% from 2023, averaging $21 per short ton of CO_2, and accounting for 11-13% of oil-fired generation production costs and up to 30% for natural gas-fired generators. RGGI and the Massachusetts Electricity Generator Emission Limits programs contributed an estimated $8/MWh in emissions costs, approximately 18% of the $44/MWh average annual load-weighted Energy price.
- Moderate Financial Transmission Rights ("FTR") profitability -- $1.5 million.
- The Regulation Market remained competitive, with available supply significantly exceeding the regulation requirement and no supplier controlling enough supply to potentially have market power.
- The frequency of pivotal suppliers declined slightly to 33% of Real-Time hours from 37% in 2023; and the Residual Supply Index improved from 103.5 to 104.2, reflecting fewer generator outages.
- Annual load-weighted markups increased to 2.4% (Day-Ahead) and 6.8% (Real-Time), which was driven by gas-fired generators offering above marginal cost; economic withholding, however, remained limited, with an output gap of under 2%.

In light of its review, the IMM made a number of recommendations for market enhancements, including the adoption of Capacity Auction Reforms ("CAR"), a Conduct and Impact framework for seller-side capacity market mitigation, and refinements to Pay-for-Performance ("PFP") and interconnection rights rules.

- **IMM Quarterly Markets Reports: Winter 2025 (ZZ25-4)**

On June 5, 2025, the IMM filed with the FERC its Winter 2025 report of "market data regularly collected by [the IMM] in the course of carrying out its functions under … Appendix A and analysis of such market data," as required pursuant to Section 12.2.2 of Appendix A to Market Rule 1. These filings are not noticed for public comment by the FERC. The Winter 2025 Report was discussed with the Markets Committee at the Markets Committee's June 11 meeting.

- **ISO-NE FERC Form 3Q (2025/Q1) (not docketed)**

On May 29, 2025, ISO-NE submitted its 2025/Q1 FERC Form 3-Q (quarterly financial report of electric utilities, licensees, and natural gas companies). FERC Form 3-Q is a quarterly regulatory requirement which supplements the annual FERC Form 1 financial reporting requirement. These filings are not noticed for public comment.

- **ISO-NE FERC Form 714 (2024) (not docketed)**

On May 30, 2025, ISO-NE submitted its Annual Electric Balancing Authority Area and Planning Area Report for calendar year 2024. Through its Form 714 filing, ISO-NE reports, among other things, generation in the New England Control Area, actual and scheduled inter-balancing authority area power transfers, and net energy for load, summer-winter generation peaks and system lambda. The FERC uses the data to obtain a broad picture of interconnected balancing authority area operations including comprehensive information of balancing authority area generation, actual and scheduled inter-balancing authority area power transfers, and load; and to prepare status reports on the electric utility industry including review of inter-balancing authority area bulk power trade information. Planning Area data will be used to monitor forecasted demands by electric utility entities with fundamental demand responsibility, and to develop hourly demand characteristics. These filings are not noticed for public comment.

- **FERC Form 715 (not docketed)**

On May 19, 2025, ISO-NE submitted its 2024 Annual Transmission Planning and Evaluation Report. The Full Report, which contains CEII, can be viewed, with appropriate authorization, on ISO-NE's website. These filings are not noticed for public comment.

IX. Membership Filings

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

- **June 2025 Membership Filing (ER25-2369)**

On May 30, 2025, NEPOOL requested that the FERC accept the following Applicant's membership in NEPOOL as of June 1, 2025: Apollo Power Inc. (Supplier Sector). Comments on this filing were due on or before June 20, 2025; none were filed. This matter is pending before the FERC.

- **May 2025 Membership Filing (ER25-2083)**

On April 30, 2025, NEPOOL requested that the FERC accept (i) the following Applicants' membership in NEPOOL: Cross Town Energy Storage LLC [Related Person to Energy Storage Resources and Cranberry Point Energy Storage (AR Sector; DG Sub-Sector)]; DV Trading, LLC (Supplier Sector); Mpower Energy NJ LLC (Supplier Sector); and RENEW Northeast (Associate Non-Voting Participant); and (ii) a change to the name of WEB Renewable Energy USA, LLC (f/k/a SWEB Development USA, LLC) and a correction to the name of Engelhart CTP

Energy Marketing, LLC. Comments on the May membership filing were due on or before May 21, 2025; none were filed. The May Membership Filing is pending before the FERC.

- **Apr 2025 Membership Filing (ER25-1820)**

On May 28, 2025, the FERC accepted: (i) the following Applicants' membership in NEPOOL: Gabel Associates, Inc. (Supplier Sector); NECEC Transmission LLC (Transmission Sector);[57] and Powervine Energy LLC (Supplier Sector); (ii) the termination of the Participant status of Data-Only member NRG Kiosk LLC ("Power Kiosk"); and (iii) the corporate name changes of Avangrid Power, LLC (f/k/a Avangrid Renewables, LLC) and NDC Partners Corp. (f/k/a NDC Partners LLC).[58] Unless the May 28 Order is challenged, this proceeding will be concluded.

X. Misc. - ERO Rules, Filings; Reliability Standards[59]

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

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

On April 10, 2025, NERC filed proposed Reliability Standard EOP-012-3 (Extreme Cold Weather Preparedness and Operations) in response to requirements in FERC's June 27, 2024 order. EOP-012-3 is intended to improve the efficiency and effectiveness of the Bulk-Power System in future cold weather seasons by providing clarity regarding the criteria for declaring Generator Cold Weather Constraints, shortening timelines for implementing corrective action plans following cold weather reliability events, and requiring more frequent review of validated constraints to reflect evolving technologies and operating conditions. The revised standard also includes new requirements for BES generating units entering commercial operation on or after October 1, 2027 to have cold weather capability upon entry, unless a validated constraint applies. Comments on EOP-012-3 were due on or before May 12, 2025, and were filed by the ISO/RTO Council ("IRC")[60] (requesting approval of the and clarification of FERC's expectation that NERC's criteria for reviewing Generator Cold Weather Constraint declarations be objectively documents with clear guidance from NERC) and by the Union of Concerned Scientists ("UCS") (suggesting the FERC adopt several modifications to the circumstances that qualify on the case-by-case list in order to remove ambiguity and possible conflicts of interest). On May 28, 2025, NERC answered UCS' comments, requesting the FERC reject the UCS-proposed modifications. Doc-less interventions only were filed by Calpine, ACPA, EPSA, and Public Citizen. EOP-012-3 is pending before the FERC.

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

On November 4, 2024, NERC filed for approval, in response to the requirements of *Order 901*, revisions to Reliability Standards PRC-029-1 and PRC-029-4, as well as a proposed change to the Glossary definition of "Ride-through" to establish voltage and frequency ride-through criteria for Generator Owners of IBRs to continue to inject current and perform voltage support during a BPS disturbance and prohibit momentary cessation in the no-

[57] NECEC Transmission is a Related Person to the following NEPOOL Participants that are members of the Transmission Sector: CMP; New York State Elec. & Gas Corp.; UI; UIL Distributed Resources LLC; GenConn Energy LLC (which is also a Related Person to Supplier Sector member Clearway Power Marketing LLC); Avangrid Power, LLC; Avangrid Networks, Inc.; and Vineyard Wind 1 LLC (which is also a Related Person to Generation Sector member Vineyard Offshore LLC).

[58] *New England Power Pool Participants Comm.*, Docket No. ER25-1820-000 (May 28, 2025) (unpublished letter order).

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

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

trip zone during disturbances. On December 19, 2024, the FERC issued a NOPR proposing to approve the Reliability Standards.[61] Comments on the *IBR Frequency and Ride-Through Reliability Standards NOPR* were due March 24, 2025.[62] Comments on the NOPR were filed by: NERC, CAISO, NYISO, NYSERDA, NYS Reliability Council, Western Interconnection Regional Advisory Body, EEI, DN VGL, Elevate Energy Consulting, Invenergy Renewables, LIPA, Orsted, AZ PSC, and LA PSC. Reply comments were filed by Invenergy Renewables, ACPA, EEI and NERC. Since the last Report, Deriva Energy filed comments out-of-time (asking the FERC not to change the proposed standard but to incorporate and emphasize NERC's conclusion that the exemption process under the standard is necessary). This matter remains pending before the FERC.

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

On July 10, 2024, as corrected and supplemented on May 20, 2025, NERC filed for approval 11 revised Critical Infrastructure Protection ("CIP") Reliability Standards,[63] as well as 18 new or revised definitions for inclusion in NERC's Glossary,[64] to facilitate the full implementation of virtualization and to address the risks associated with virtualized environments. The proposed CIP Reliability Standards would permit Responsible Entities with more "traditional" architecture to continue with their current configurations. As of the date of this Report, the FERC still has not yet noticed a proposed rulemaking proceeding or otherwise invited public comment.

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

On September 19, 2024, the FERC issued a NOPR[65] proposing to approve Reliability Standard CIP-015-1 (Cyber Security – Internal Network Security Monitoring) and to direct that NERC develop certain modifications to CIP-015-1 to extend internal network security monitoring ("INSM") to include electronic access control or monitoring systems and physical access control systems outside of the electronic security perimeter. Comments on the NOPR were filed by NERC, NESCOE, the IRC, APPA, and Open Policy. This matter is pending before the FERC.

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

Also on September 19, 2024, the FERC issued a NOPR proposing to direct NERC to develop and submit for FERC approval new or modified Reliability Standards that address the sufficiency of responsible entities' supply chain risk management plans related to the identification of, assessment of, and response to supply chain risks, and applicability of Reliability Standards' supply chain protections to protected cyber assets.[66] Comments on the NOPR were due on or before December 2, 2024[67] and were filed by, among others: NERC and its Regional Entities,

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[61] *Reliability Standards for Frequency and Voltage Protection Settings and Ride-Through for Inverter-Based Resources*, 189 FERC ¶ 61,212 (Dec. 19, 2024) ("*IBR Frequency and Ride-Through Reliability Standards NOPR*").

[62] The *IBR Frequency and Ride-Through Reliability Standards NOPR* was published in the *Fed. Reg.* on Jan. 21, 2025 (Vol. 90, No. 12) pp. 6,845-79,804.

[63] 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).

[64] 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").

[65] *Critical Infrastructure Protection Reliability Standard CIP-015-1 – Cyber Security – Internal Network Security Monitoring*, 188 FERC ¶ 61,175 (Sep. 19, 2024) ("*CIP-015 INSM NOPR*").

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

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

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

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

XI. Misc. - of Regional Interest

- **203 Application: CPower/NRG (EC25-102)**

On June 12, 2025, as amended and supplemented on June 17, 2025, NRG East Generation Holdings LLC ("NRG East Holdings"), NRG Demand Response Holdings LLC ("NRG DR Holdings"), Lightning Power, LLC ("Lightning Power" and together with NRG East Holdings and NRG DR Holdings, "NRG") and Enerwise Global Technologies, LLC d/b/a CPower ("CPower") (collectively, Applicants") requested authorization for NRG to acquire indirect interests in CPower. Comments on this application are due on or before ***Aug 11, 2025***. Thus far, the PJM IMM and Public Citizen have intervened doc-lessly. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On June 10, 2025, Burgess BioPower requested FERC authorization for a transaction by which White Mountain Power (an affiliate of, among others, Bridgewater Power and David Energy Supply) will acquire all of the indirect ownership interests of Berlin Station in connection with a plan of reorganization under Chapter 11 of the US Bankruptcy Code. Comments on this application are due on or before ***July 1, 2025***. f you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On June 6, 2025, Tomorrow Energy requested authorization for a transaction in which Six One Commodities LLC ("Six One Commodities") will acquire 100% of the equity interests of Tomorrow Energy. Comments on this application are due on or before ***June 27, 2025***. Thus far, PJM and Public Citizen have intervened doc-lessly. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Icetec/Veolia (EC25-85)**

On May 2, 2025, Icetec Energy Services, Icetec.com, and Veolia (together, "Applicants") requested authorization for Veolia's acquisition of 100% of the interests in Icetec Energy Services and Icetec.com. Comments on this application were due on or before May 23, 2025; none were filed. PJM intervened doc-lessly. This application 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: Kleen Energy/Alpha Gen (EC25-77)**

On June 13, 2025, the FERC authorized Alpha Gen's acquisition of Kleen Energy.[68] Pursuant to the June 13 order, Alpha Gen must file a notice within 10 days of consummation of the transaction, which as of the date of this

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

Report has not yet occurred. When consummated, Kleen Energy will become a Related Person to the Generation Bridge Companies.[69] If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On January 24, 2025, Constellation Energy Corporation and Constellation Energy Generation, LLC (together, "Constellation") and Calpine Corporation and its Public Utility subsidiaries[70] (collectively, "Applicants") requested authorization for a transaction through which Constellation will acquire Calpine. Comments on the 203 application were due on or before March 25, 2025. The PJM IMM and Public Citizen intervened and filed protests/comments. On March 27, 2025, FERC issued a deficiency letter directing the Applicants to provide additional information. That information was provided on April 28, 2025. Comments on the deficiency letter response were due on or before May 19, 2025 and were filed by the PJM IMM and Public Citizen. On June 12, Applicants further supplemented their application to address a Department of Energy ("DOE") order directing Constellation to ensure that its Eddystone Units 3 and 4 (the "Eddystone Units", which were otherwise scheduled to retire on May 31, 2025) remain in operation through August 28, 2025. Comments on the supplement are due on or before ***June 23, 2025***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **PURPA Enforcement Petition – Allco Finance Ltd/Connecticut (EL25-81)**

Allco Finance Limited ("Allco") has petitioned the FERC to initiate an enforcement action against the Connecticut Department of Energy and Environmental Protection ("CT DEEP"), Connecticut Public Utilities Regulatory Authority ("PURA"), and Connecticut Department of Agriculture ("CT DoA", and together with CT DEEP and PURA, "Connecticut" or "CT") to remedy what it asserts is Connecticut's improper implementation of section 210 of PURPA. Allco asserts that CT is improperly implementing PURPA by requiring the following criteria for participation in the Shared Clean Energy Facility ("SCEF") program: (i) that no more than 10% of the project site contains slopes greater than 15%; (ii) that separate QFs on the same parcel cannot receive a contract even when the total of the two QFs is less than 5MWs; (iii) documentation of "community outreach and engagement" regarding the bid for a contract; (iv) restrictions related to "Prime Farmland" location; (v) a QF cannot have been constructed or started construction; (vi) a workforce development program, and for certain projects a community benefits agreement; (vii) a contract that includes renewable energy credits; and (viii) a bidder must bear costs related to a utility's voluntarily seeking to re-sell the QF's energy in the ISO-NE market, if the utility chooses not to use the energy to supply its own customers. Allco argues that the criteria are neither objective nor reasonable and are unrelated to a QF's commercial viability or financial commitment. Allco further contends that some of CT's SCEF program requirements violate its constitutional rights. Allco also states that bids it submitted in 2024 and 2025 were rejected on the basis of these unlawful requirements. Comments and responses to the latest Allco complaint were due on or before June 20, 2025. Connecticut protested the Allco Complaint on June 20. CL&P intervened doc-lessly. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On June 23, 2025, Versant filed revisions to Section 4 of the Versant Power Open Access Transmission Tariff for Maine Public District (the "MPD OATT"), which incorporate by reference certain of the revisions required by *Order No. 676-K*. Versant also requested waiver of certain of the standards that Maine Public District ("MPD") is unable to meet. Versant requested effective dates of February 27, 2026 and August 27, 2026. Comments on

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

[70] The Calpine Public Utility Subsidiaries include each of the following NEPOOL Participants: Calpine Energy Services, LP; Calpine Community Energy, LLC; Calpine Energy Solutions, LLC; Champion Energy Marketing, LLC; and North American Power and Gas, LLC.

Versant's Order 676-K changes are due on or before ***July 14, 2025***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **IA 3d Amendment: CMP / Sappi (ER25-2516)**

On June 13, 2025, CMP filed a 3rd Amended and Restated Interconnection Agreement between CMP, Sappi North America and Presumpscot Hydro to permit Presumpscot additional time (through the end of 2025) to establish separate interconnection for its Dundee and Eel Weir projects. Comments on this IA Amendment are due on or before ***July 7, 2025***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On June 12, 2025, Versant Power filed a new Wholesale Distribution Tariff ("WDT") to provide for Versant's recovery of costs associated with the provision of Wholesale Distribution Service ("WDS") to customers who own electric energy storage systems ("ESS") connected to Versant's distribution system. The WDT allows such customers to utilize Versant's distribution system when charging their ESS for the purpose of participating in the wholesale (New England) market. A January 1, 2026 effective date was requested. Comments on the Versant Power WDT are due on or before ***July 3, 2025***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **RFA – NSTAR / Fe Taft (ER25-2278)**

On May 21, 2025, NSTAR filed a Related Facilities Agreement ("RFA") to set forth the terms and conditions under which it will construct Related Facilities in connection with the interconnection of Fe Taft's large generating facility (ISO-NE Queue Position 1320) in National Grid's service territory. A May 22, 2025 effective date was requested. Comments on the RFA filing were due on or before June 11, 2025; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **IA 2d Amendment: NSTAR/Braintree (ER25-2094)**

On April 30, 2025, NSTAR filed an Amended Interconnection Agreement ("IA") with the Town of Braintree acting by and through Braintree Electric Light Department (collectively, "Braintree"), designated as Service Agreement No. IA-NSTAR-49. The Amended IA updates the terms and conditions for interconnection service provided by NSTAR to Braintree including Article 3, 5.1 and 5.5 as well as reflecting a party name change. An effective date of May 1, 2025 was requested. The comment deadline was May 21, 2025; none were filed. Braintree intervened doc-lessly. This matter is pending before FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **IA 2d Amendment: CMP/Androscoggin Reservoir Co (ER25-1990)**

On June 12, 2025, the FERC accepted the Amended Interconnection Agreement ("IA") between CMP and Androscoggin Reservoir Company ("ARCO"), designated as Second Revised Service Agreement No. 193 under CMP's FERC Electric Tariff No. 3.[71] The Amended IA sets forth the terms and conditions for CMP's continuing provision of interconnection service to ARCO. The IA was accepted effective April 1, 2025, as requested. Unless the June 12 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).

- **Data Center Interconnection Study Agreement - PSNH/Granite Shore Power (ER25-1799)**

On May 27, 2025, the FERC accepted the Interconnection Study Agreement between PSNH and Granite Shore Power LLC (for the construction of a proposed data center facility and to establish a load interconnection to

[71] *Central Maine Power Co.*, Docket No. ER25-1990-000 (June 12, 2025) (delegated letter order).

the PSNH's transmission system), effective March 29, 2025, as requested.[72] The May 27 order was not challenged and is final and unappealable. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Data Center Interconnection Study Agreements - NSTAR/BXP (ER25-1796; ER25-1795)**

Also on May 27, 2025, the FERC accepted two Interconnection Study Agreement between NSTAR and BXP, Inc. ("BXP") (to initiate interconnection studies for the construction of a proposed data center facility and to establish a load interconnection to the NSTAR's transmission system), effective March 29, 2025, as requested.[73] This May 27 order was also not challenged and is final and unappealable. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

On February 25, 2025, Versant submitted a compliance filing in response to *Order 904*,[74] proposing revisions to its MPD OATT, effective June 1, 2025. Versant's filing: (i) revises Schedule 2 to exclude charges for reactive power within the standard power range; (ii) removes related payment provisions from the *pro forma* LGIA and SGIA; and (iii) removes Note 1 from Exhibit 1a in Attachment J. Comments on Versant's compliance filing were due on or before March 18, 2025; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Wholesale Distribution Tariffs – National Grid (ER24-2796; ER24-2795)**

On May 21, 2025, National Grid submitted the informational filing required by the March 28 order accepting its WDT Tariffs, specifying *June 1, 2025* as the actual effective date for implementation of the WDTs.[75] Reporting on this proceeding is now 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)**

The FERC has now accepted both of Versant Power's MPD OATT *Order 2023* compliance filings. As previously reported, the FERC accepted in part, on January 16, 2025, Versant's MPD OATT Order 2023 Compliance filing,[76] directing Versant to submit a further compliance filing on or before March 17, 2025 that (i) adopts without modification section 4.4.3.1 of the *pro forma* LGIP or demonstrates how the omission of this section satisfies the consistent with or superior to standard; and (ii) incorporates additional revisions to the FERC's *pro forma* LGIP, *pro forma* LGIA, and *pro forma* SGIA made in the FERC's August 20, 2024 Errata Notice.[77] Versant submitted that compliance filing on March 10, 2025. On May 30, 2025, the FERC accepted that further compliance filing, also

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[72] *Public Service Co. of New Hampshire*, Docket No. ER25-1799-000 (May 27, 2025 (delegated letter order).

[73] *NSTAR Electric Co.*, Docket No. ER25-1796-000 (May 27, 2025) (delegated letter order); *NSTAR Electric Co.*, Docket No. ER25-1795-000 (May 27, 2025) (delegated letter order).

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

[75] *Nantucket Elec. Co. and Mass. Elec. Co.*, 190 FERC ¶ 61,196 (Mar. 28, 2025) (accepting National Grid's two new Wholesale Distribution Tariffs (one for Massachusetts Electric Company (ER24-2796); the other for Nantucket Electric Company (ER24-2795), together the "WDTs") to provide for National Grid's recovery of costs associated with the provision of Wholesale Distribution Service to customers who own qualifying standalone electric energy storage systems 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).

[76] Versant Power*,* 190 FERC ¶ 61,021 (Jan. 16, 2025).

[77] Errata Notice, *Improvements to Generator Interconnection Procedures and Agreements*, 188 FERC ¶ 61,134 (Aug. 20, 2024) ("Errata Notice").

effective *January 1, 2025*.[78] Unless the May 30 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).

- **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").[79] CMP filed the ESF Rate following re-consideration by the MPUC of the jurisdictional applicability of the ESF rate (which, while it recovers costs associated with the use of local the distribution network, the MPUC found upon re-consideration to include charges related to a FERC-jurisdictional wholesale transaction per *Order 841*). CMP sought in this proceeding to obtain FERC approval of a modified version of the MPUC Rate, with the primary difference between the MPUC Rate and the ESF Rate being the removal of state benefit charges. In the *CMP ESF Rate Order*, the FERC found that CMP's filing had not been shown to be just and reasonable, and raised issues of material fact that could not be resolved based on the record and would be more appropriately addressed in hearing and settlement judge procedures.[80] 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 (which have been held in abeyance pending the outcome of the settlement judge proceedings summarized immediately below).[81]

Settlement Judge Proceedings. As directed, the Chief ALJ appointed Judge Jeremy Hessler as the settlement judge in this proceeding.[82] There were four settlement conferences (May 3, July 17, September 19, and December 10-11, 2024). On April 10, 2025, CMP filed a settlement agreement to resolve all issues set for settlement in this proceeding, supported by FERC Trial Staff on May 1, 2025. On May 15, 2025, Judge Hessler certified the uncontested settlement to the Commission. Judge Hessler issued a final status report on May 16, 2025 recommending that settlement judge procedures be terminated. As recommended, the Chief Judge terminated settlement proceedings on May 20, 2025. The Settlement Agreement is pending before the Commission. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

XII. Misc. - Administrative & Rulemaking Proceedings[83]

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

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

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[78] *Versant Power*, Docket No. ER24-2035-001 (May 30, 2025) (unpublished letter order).

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

[80] *Id.* at P 29.

[81] *Id*.

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

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

Stephen George (ISO-NE, Vice President of System Operations and Market Administration), Adam Evans (NY DPS, Chief of Wholesale and Clean Energy Markets), MPUC Chairman Phil Bartlett, CT DEEP Commissioner Katie Dykes, Michelle Gardner (NextEra Energy Resources, Executive Director Northeast Region), Pallas Lee VanShaick (Potomac Economics), and Sarah Bresolin (NEPOOL Chair).

Panelists pre-filed statements are posted in the FERC's eLibrary. A recording of the technical conference will be available for 90 days. On June 5, 2025, the FERC invited post-technical conference comments to be filed on or before ***July 7, 2025***. Those comments can address issues raised during the conference or presented in the conference agenda.

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

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

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

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

Second Meeting. The Federal and State Current Issues Collaborative ("Collaborative")[84] held its second public meeting on April 30, 2025 at FERC headquarters. The principal topic for discussion was gas-electric coordination. A transcript of the meeting is posted in eLibrary. Post-meeting comments were submitted by the Industrial Energy Consumers of America.

- **Tech Conf: Increasing Market and Planning Efficiency Through Improved Software (AD10-12)**

The FERC will hold its 16th annual technical conference addressing increasing Real-Time and Day-Ahead market efficiency through improved software from July 8-10, 2025. A detailed agenda with the list of and times for the selected speakers was published in a May 9, 2025 supplemental notice of this technical conference. Post-conference comments may be submitted on or before ***August 11, 2025***.

[84] *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.

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

On June 27, 2024, the FERC issued an advanced notice of proposed rulemaking ("ANOPR")[85] seeking comments on both the need for a dynamic line ratings ("DLRs")[86] requirement and proposed framework of DLR reforms to improve the accuracy of transmission line ratings. Proposed reforms would require transmission providers to implement, on all transmission lines, DLRs that reflect solar heating, based on the sun's position and forecastable cloud cover, and on certain transmission lines, DLRs that reflect forecasts of wind speed and wind direction. The FERC seeks comments about whether to reflect hourly solar conditions and wind conditions in all transmission line ratings, how transmission congestion levels and environmental factors could identify locations of transmission lines that would most benefit from DLR, and what other technical details of transmission line ratings reflect wind conditions. A more detailed summary of the ANOPR was provided to and reviewed with the Transmission Committee. Comments in response to the ANOPR were due October 15, 2024[87] and were filed by nearly 70 parties, including by the following New England parties: ISO-NE, AEU, Avangrid, Dominion, Eversource, MA AG, National Grid, NESCOE, NextEra (on October 22), EEI, EPSA, NASUCA, NERC, PIOs, Public Power,[88] TAPS, and R Street Institute. Nine sets of reply comments were filed, including from: ISO-NE, DC Energy, and the US DOE.

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

On October 17, 2024, the FERC issued *Order 904,*[89] which revises Schedule 2 of the *pro forma* OATT, § 9.6.3 of the *pro form* LGIA, and § 1.8.2 of the *pro forma* SGIA to prohibit separate compensation to generators for the provision of reactive power within the standard power factor range or "deadband."[90] The proposed change will affect revenues received by reactive power resources in New England.[91] New England's Order 904 filing was submitted on March 19, 2025 (*see* ER25-1703 in Section IV above). Challenges to *Order 904* were filed by: D. E. Shaw Renewable Investments, Invenergy Nelson, NYISO, the PSEG Companies,[92] and Vistra. On December 19, 2024, the FERC issued an "Allegheny Notice", noting that the requests for rehearing may be deemed to have been denied by operation of law, but noting that the requests will be addressed in a future order.[93] The FERC issued that order on June 6, 2025, modifying the discussion in *Order 904* but continuing to reach the same result.[94] The FERC's orders on *Order 904* have been appealed to the federal courts (*see* Section XVI below). If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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[85] *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.

[86] 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.

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

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

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

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

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

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

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

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

- ***Orders 1920/1920-A/1920-B*: Transmission Planning Reforms (RM21-17)**

On May 13, 2023, the FERC issued *Order 1920*,[95] its final rule on proposed reforms to existing the transmission planning and cost allocation requirements. In *Order 1920*, the FERC explained that under existing processes, transmission providers are not required to: (i) perform a sufficiently long-term assessment of transmission needs identifying Long-Term Transmission Needs; (ii) adequately account for known determinants of Long-Term Transmission Needs prospectively; and (iii) consider the broader benefits of regional transmission facilities planned to meet Long-Term Transmission Needs. The existing processes result in less efficient and cost-effective investment in transmission infrastructure and higher costs to customers and, therefore, unjust and unreasonable rates and need for reforms. *Order 1920* requires all transmission providers, *inter alia*, to

(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,*[96] 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.*[97] 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.

Order 1920-A. In response to requests for clarification and/or rehearing of *Order 1920*, the FERC issued its order on rehearing and clarification (*Order 1920-A*) on November 21, 2024.[98] In *Order 1920-A*, the FERC stated that it was refining and improving Long-Term Regional Transmission Planning ("LTRTP") "by building on the reforms adopted in Order No. 1920, with a particular focus on ensuring that states have a robust role" in LTRTP and cost allocation processes established in *Order 1920*. *Order 1920-A* largely sustained and further justified the findings and reforms of *Order 1920*, but granted several requests for rehearing and clarification. A significant focus of the modifications to *Order 1920* pertained to the role of the states in LTRTP and the related cost

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

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

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

[98] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, Order on Reh'g, Order No. 1920-A, 189 FERC ¶ 61,126 (Nov. 21, 2024) ("*Order 1920-A*"). Over 50 parties filed 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.

allocation requirements. *Order 1920-A* maintained the ***June 12, 2025*** compliance filing deadline for regional requirements[99] and the ***August 12, 2025*** deadline for interregional requirements. Any deviations from the final rule proposed on compliance must be justified under the "consistent with or superior to" standard. A memorandum providing a brief summary of the more important features of *Order 1920-A*, including a list and more detailed summary of the key modifications and clarifications made by the FERC in *Order 1920-A* was provided by NEPOOL Counsel to the Transmission Committee (and can be found here).

Order 1920-A Requests for Rehearing. Requests for clarification and/or rehearing of *Order 1920-A* were filed by West Connect TOs,[100] MISO TOs,[101] PJM TOs,[102] EEI, NRECA, SWEPCO, and WIRES. Those requests were denied by operation of law.

Order 1920-B (RM21-17-003). On April 11, 2025, the FERC issued *Order 1920-B*,[103] granting in part and denying in part requests for clarification of *Order 1920-A*. *Order 1920-B* does not change the outcome of *Order 1920*, amend FERC's regulations, or revise the provisions of the *pro forma* Tariff Attachment K. The FERC clarified that transmission providers are not required to plan for the Long-Term Transmission Needs of unenrolled non-jurisdictional transmission providers, but may include voluntary arrangements with such entities, provided those arrangements comply with the FPA and the FERC's cost causation precedent. The effective date of the underlying rule remains January 6, 2025.

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.

New England Motion for Extension of Time. On February 10, 2025, the FERC granted the New England request for extension of time to comply with *Order 1920*. The deadline for ISO-NE to submit its compliance filings

[99] MISO requested and was granted a one-year extension of time (to June 12, 2026) to submit its compliance filing (except for those related to interregional transmission coordination). Notice of Extension of Time, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, Docket No. ER21-17-000 (Dec. 10, 2024).

[100] "West Connect Coordinating TOs" are non-jurisdictional members of the WestConnect regional planning organization and include: Colorado Springs Utils., Imperial Irrigation District, Los Angeles Department of Water and Power, Platte River Power Authority, Sacramento Mun. Util. District, Salt River Project Agr. Improvement and Power District, and the Transmission Agency of N. California.

[101] "MISO TOs" are AEP Indiana Michigan Trans. Co., Ameren Srvcs. Co., as agent for Union Elec. Co. d/b/a Ameren Missouri, Ameren Illinois Co. d/b/a Ameren Illinois and Ameren Trans. Co. of Illinois; American Trans. Co.; Big Rivers Elec. Corp.; Central Minnesota Mun. Power Agency; City Water, Light & Power (Springfield, IL); Cleco Power LLC; Dairyland Power Coop.; Duke Energy Business Srvcs for Duke Energy Indiana; Great River Energy; Hoosier Energy Rural Elec. Coop.; Indiana Municipal Power Agency; Indianapolis Power & Light Co. d/b/a AES Indiana; Lafayette Utils. Sys.; MidAmerican Energy Co.; Minnesota Power (and its subsidiary Superior Water, L&P); Missouri River Energy Srvcs; Montana-Dakota Utils. Co.; Northern Indiana Pub. Srvc Co.; Northern States Power Co., a Minnesota corp., and Northern States Power Co., a Wisconsin corp., subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Elec. Co.; Otter Tail Power Co.; Prairie Power; Southern Illinois Power Coop.; Southern Indiana Gas & Elec. Co. (d/b/a CenterPoint Energy Indiana South); Southern Minnesota Mun. Power Agency; Wabash Valley Power Assoc.; and Wolverine Power Supply Coop.

[102] "PJM TOs" include: include: American Elec. Power Srvc. Corp. on behalf of its affiliates, Appalachian Power Co., Indiana Michigan Power Co., Kentucky Power Co., Kingsport Power Co., Ohio Power Co., Wheeling Power Co., AEP Appalachian Trans. Co., AEP Indiana Michigan Trans. Co., AEP Kentucky Trans. Co., AEP Ohio Trans. Co., and AEP West Virginia Trans. Co.; Dayton Power and Light Co. d/b/a AES Ohio; Dominion Energy Srvcs. on behalf of Virginia Elec. and Power Co. d/b/a Dominion Energy Virginia; Duke Energy Corp. on behalf of its affiliates Duke Energy Ohio, Duke Energy Kentucky, and Duke Energy Bus. Srvcs.; Duquesne Light Co.; East Kentucky Power Coop.; 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 Co., and Potomac Elec. Power Co.; FirstEnergy Srvc. Co., on behalf of its affiliates American Trans. Systems, Jersey Central Power & Light Co., Mid-Atlantic Interstate Trans., West Penn Power Co., The Potomac Edison Co., Monongahela Power Co., Keystone Appalachian Trans. Co., and Trans-Allegheny Interstate Line Co.; PPL Elec. Utils. Corp.; Public Service Elec. and Gas Co.; Rockland Elec. Co.; and UGI Utilities.

[103] *Building for the Future Through Elec. Regional Transmission Planning and Cost Allocation*, Order No. 1920-B, 191 FERC ¶ 61,026 (Apr. 11, 2025) ("Order 1920-B").

to meet all requirements of *Order 1920*, including those related to interregional transmission coordination, was extended to and is now ***June 14, 2027***. On May 16, 2025, the FERC accepted ISO-NE's commitment to submit (i) an informational filing 30 days prior to the Sep 2026 initiation of its engagement with all stakeholders, describing the stakeholder process schedule and consultation with the New England Power Pool regarding the development of that schedule; and (ii) status reports every 90 days thereafter until it submits its compliance filings to demonstrate that it meets the requirements of *Order 1920*. The FERC dismissed ISO-NE's request to adjust the implementation deadline as premature and specified that it be made on compliance and that ISO-NE's proposed date to commence the first LTRTP cycle must be no later than ***June 14, 2029***.

If you have any questions concerning *Orders 1920* or *1920-A*, 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

- **GenOn Stipulation and Consent Agreement (IN25-3)**

On May 20, 2025, the FERC approved a Stipulation and Consent Agreement with GenOn Holdings, Inc. ("GenOn") to resolve OE's investigation of whether GenOn violated FERC regulations and/or the PJM Tariff by submitting bids into the PJM energy market that were inconsistent with its units updated (higher) ICAP Obligations (as a result of the use of inaccurate daily spreadsheet offer templates to communicate offer parameters to PJM).[104] The investigation arose out of a referral from the PJM IMM. Under the Stipulation and Consent Agreement, GenOn agreed to ***disgorge $172,306*** to PJM, to pay a ***civil penalty of $390,000*** to the United States Treasury, and to be subject to compliance monitoring. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

On December 16, 2024, the FERC issued a show cause order[105] in which it directed American Efficient, LLC, its various subsidiary companies,[106] and its corporate parents[107] (collectively, "American Efficient") to show cause why they should not be found to have violated (i) Section 222 of the FPA and § 1c.2 of the FERC's regulations through a manipulative scheme and course of business in PJM and MISO that extracted millions of dollars in capacity payments for a purported energy efficiency project that did not actually cause reductions in energy use;[108] and (ii) provisions of MISO's and PJM's Tariffs for failure to satisfy the tariff requirements for participation as an Energy Efficiency Resource ("EER").[109] American Efficient was also directed to show cause why they should not (i) ***disgorge $2,116,057 and $250,937,821***, back to MISO and PJM, respectively (in each case plus interest); (ii)

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[104] *GenOn Holdings, Inc.*, 191 FERC ¶ 61,144 (May 20, 2025).

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

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

[107] Modern Energy Group LLC and MIH LLC.

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

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

disgorge additional unjust profits received between April 2024 and the date of any future FERC order directing disgorgement back to PJM; and (iii) pay a ***$722 million*** civil penalty. American Efficient may seek a modification of these amounts consistent with FPA § 31(d)(4).[110]

On March 17, 2025, American Efficient answered the show cause order explaining that American Efficient did not violate a tariff or commit fraud, requesting the FERC dismiss the proceeding and close its investigation without further action. OE replied to American Efficient's answer on April 15, 2025. Since the last Report, American Efficient responded to OE's April 15 reply, supplemented its answer with financial information, and provided updates on some related federal court developments, each of which it asserted weigh against rushing if not issuing a penalty order. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

Natural Gas-Related Enforcement Actions

- **Green Plains Stipulation and Consent Agreement (IN25-2)**

On June 13, 2025, the FERC approved a Stipulation and Consent Agreement with Green Plains Inc. ("Green Plains") to resolve OE's investigation of whether Green Plains violated NGA section 7(e) and FERC regulations by selling monthly physical gas during bidweek at MichCon at a loss or negligible profit, while holding leveraged short financial basis positions that settled off the FERC MichCon index (despite Green Plains' implementation but not effective implementation of compliance enhancements following substantively similar MichCon bidweek trading during four months in 2021).[111] Under the Stipulation and Consent Agreement, Green Plains agreed to ***pay restitution of $19,069***, to pay a ***civil penalty of $927,990*** to the United States Treasury, to be subject to compliance monitoring for at least three years, and to not trade monthly fixed price and physical basis at MichCon during bidweek if Green Plains holds a related financial position that settles on the IFERC MichCon index. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

Procedural Schedule Suspended. As previously reported, on May 24, 2022, the Honorable Judge Karen Gren Scholer of the U.S. District Court for the Northern District of Texas ("Northern District") issued an order staying this proceeding. Consistent with that order and out of an abundance of caution, ALJ Joel DeJesus, who will be the presiding judge for hearings in this matter,[112] 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,[113] 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.

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

[111] *Great Plains*, 191 FERC ¶ 61,200 (June 12, 2025).

[112] 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.

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

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

On December 16, 2021, the FERC issued a show cause order[114] 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,[115] 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;[116] (ii) failing to adequately monitor the right-of-way at the site of the Tuscarawas River HDD operation; and (iii) improperly disposing of inadvertently released drilling mud that was contaminated with diesel fuel and hydraulic oil. The FERC directed Respondents to show why they should not be assessed ***$40 million*** in civil penalties.

On March 21, 2022, Respondents answered and denied the allegations in the *Rover/ETP CPCN Show Cause Order*. On April 20, 2022, OE Staff answered Respondents' March 21 answer. On May 13, 2022, Respondents submitted a surreply, reinforcing their position that "there is no factual or legal basis to hold either [Respondent] liable for the intentional wrongdoing of others that is alleged in the Staff Report." The FERC denied Respondents' request for rehearing of the FERC's January 21, 2022 designation notice.[117] This matter is pending before the FERC.

XIV. Natural Gas Proceedings

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

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

- **Iroquois ExC Project (CP20-48)**
  - 125,000 Dth/d of incremental firm transportation service to ConEd and KeySpan by building and operating new natural gas compression and cooling facilities at the sites of four existing Iroquois compressor stations in Connecticut (Brookfield and Milford) and New York (Athens and Dover).
  - Three-year construction project; service now requested for ***March 25, 2027***.
  - On March 25, 2022, after procedural developments summarized in previous Reports, the FERC issued to Iroquois a certificate of public convenience and necessity, authorizing it to construct and operate the proposed facilities.[118] 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

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

115 *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*").

116 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.

117 *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.

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

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.
- On October 28, 2024, Iroquois requested an extension of time, until ***March 25, 2027***, to construct and place into service its Enhancement by Compression Project (Project) located in Greene and Dutchess Counties, New York and Fairfield and New Haven Counties, Connecticut as authorized in the *Iroquois Certificate Order*. (The *Iroquois Certificate Order* required Iroquois to complete construction of the Project and make it available for service within three years of the date of the Order or by March 25, 2025.) Iroquois stated that construction of the Project has been delayed due to pending state permit approvals, specifically air permits from the New York State Department of Environmental Conservation and the Connecticut Department of Energy and Environmental Protection. Iroquois asserts that it has been working in good faith with these agencies and expects to receive approvals for the Project in the near future.
- Comments on Iroquois' request were due on or before November 15, 2024. Protests and comments were filed by the Sierra Club of Connecticut, Save the Sound, and nearly 20 individual citizens. A number of others requested an extension of time to comment, but those requests have not been (nor should be expected to be) acted on by the FERC.[119]
- On February 19, 2025, the FERC granted the requested two-year extension of time, to March 25, 2027, to construct the project and place it into service.[120] The FERC found that Iroquois has worked and continues to work toward obtaining the state permits necessary to enable construction to commence, no bad faith or delay on Iroquois's behalf, and therefore good cause to grant the two-year extension of time to complete construction of the project.[121]

XV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XVI. Federal Courts

The following are matters of interest, including petitions for review of FERC decisions in NEPOOL-related proceedings, that are currently pending before the federal courts (unless otherwise noted, the cases are before the U.S. Court of Appeals for the District of Columbia Circuit ("DC Circuit")). An "**" following the Case No. indicates that NEPOOL has intervened or is a litigant in the appeal. The remaining matters are appeals as to which NEPOOL has no organizational interest but that may be of interest to Participants. For further information on any of these proceedings, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

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

[121] *Id*. at P 15.

- ***Order 904*: Compensation for Reactive Power Within the Standard Power Factor Range (2nd Circuit – 25-382; 5th Circuit – 25-60025; 7th Circuit – 25-1249)**
Underlying FERC Proceeding: RM22-22[122]
Status: Being Held in Abeyance

Order 904 has thus far been appealed to the 2nd (NYISO), 5th (Leeward Renewable Energy et al., Vistra et al.), and 7th (Invenergy) Circuit Court of Appeals (which agreed to transfer the case to the 5th Circuit). We expect that the Judicial Panel on Multidistrict Litigation will (but has not yet) select either the 2nd or 5th Circuits as the Circuit in which to consolidate all the petitions for review.

- ***Order 1920*: Transmission Planning Reforms (4th Circuit – 24-1650)**
Case Title: *Appalachian Voices v. FERC*
Underlying FERC Proceeding: RM21-17[123]
Status: Being Held in Abeyance; Briefing schedule to be file on July 1, 2025

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*.[124] Petitions were also filed in the First, Second, Fourth, Fifth, Sixth, Seventh, Ninth, and Eleventh Circuits. The Judicial Panel on Multidistrict Litigation randomly selected the Fourth Circuit as the Circuit in which to consolidate the petitions for review. The DC Circuit ordered that its cases be transferred to the 4th Circuit. The 4th Circuit lead case no. is 24-1650. On August 26, 2024, the 4th Circuit granted the FERC's motion to hold the petitions for review in abeyance. Since the last Report, the parties proposed that an agreed-to briefing schedule for the above-captioned appeals, and any forthcoming appeals so-consolidated, be filed on ***July 1, 2025***.

- ***Orders 2023 and 2023-A* (23-1282 et al.) (consolidated)**
Case Title: *Advanced Energy United, et al. v. FERC*
Underlying FERC Proceeding: RM22-14[125]
Status: Briefing Complete

Several Petitioners have challenged *Orders 2023 and 2023-A*. Those challenges were consolidated, with the AEU docket (23-1282) as the lead docket. Briefing is now complete. The parties will be informed later of the date of oral argument and the composition of the merits panel.

- ***CASPR* (20-1333, 21-1031) (consolidated)****
Case Title: *Sierra Club, et al. v. FERC*
Underlying FERC Proceeding: ER18-619[126]
Petitioners: Sierra Club, NRDC, RENEW Northeast, and CLF
Status: Being Held in Abeyance; Motions to Govern Future Proceedings Due Mar 2, 2026

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

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

[123] *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*").

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

[125] *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).

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

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[127]
  Petitioners: TOs (CMP et al.)
  Status: Being Held in Abeyance

On August 28, 2020, the TOs[128] 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*[129] 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 March 19, 2025.

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

[128] 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.

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

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NEPOOL
NEW ENGLAND POWER POOL
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11 EMM 2024 Annual Assessment Highlights

POTOMAC ECONOMICS

Highlights of the 2024 Assessment of the ISO New England Markets

Presented to:

NEPOOL Participants Committee Summer Meeting

David B. Patton, Ph.D.
Potomac Economics

June 24, 2025

Introduction

- Potomac Economics serves as the External Market Monitor ("EMM") for the ISO-NE. In this role, we:
  - Evaluate the competitive performance and operation of the markets
  - Identify and recommend necessary changes to existing and proposed market rules, tariff, and market design elements
  - Evaluate the mitigation by the Internal Market Monitor ("IMM")
- Our annual assessment of the ISO-NE markets complements the IMM's report, focusing on key market areas summarized in this presentation:
  - Cross-market comparison of key market outcomes and metrics
  - Navigating the clean energy transition
  - Competitive assessment of the energy and reserves markets
  - Real-time commitment and reserve pricing issues
  - Capacity availability and performance incentives

Summary of Findings

- The markets performed competitively but identify key improvements will be increasingly important in the coming years
- High priority recommendations to improve market performance and to facilitate the expected large-scale renewable resource entry include:
  - 2018-7: Modify the pay-for-performance rate to a reasonable level that would vary with the size of the operating reserve shortage
  - 2020-2: Accrediting capacity resources based on marginal reliability value
  - 2021-1: Replacing the FCM with a prompt seasonal capacity market
  - 2023-1: Evaluating a look-ahead dispatch model to manage fluctuations in net load and use of energy storage resources
- We recommend twelve other improvements to lower costs and improve market performance, which are lower in priority to those above

Cross-Market Comparison and Competitive Assessment

Cross-Market Comparison of Key Outcomes & Metrics

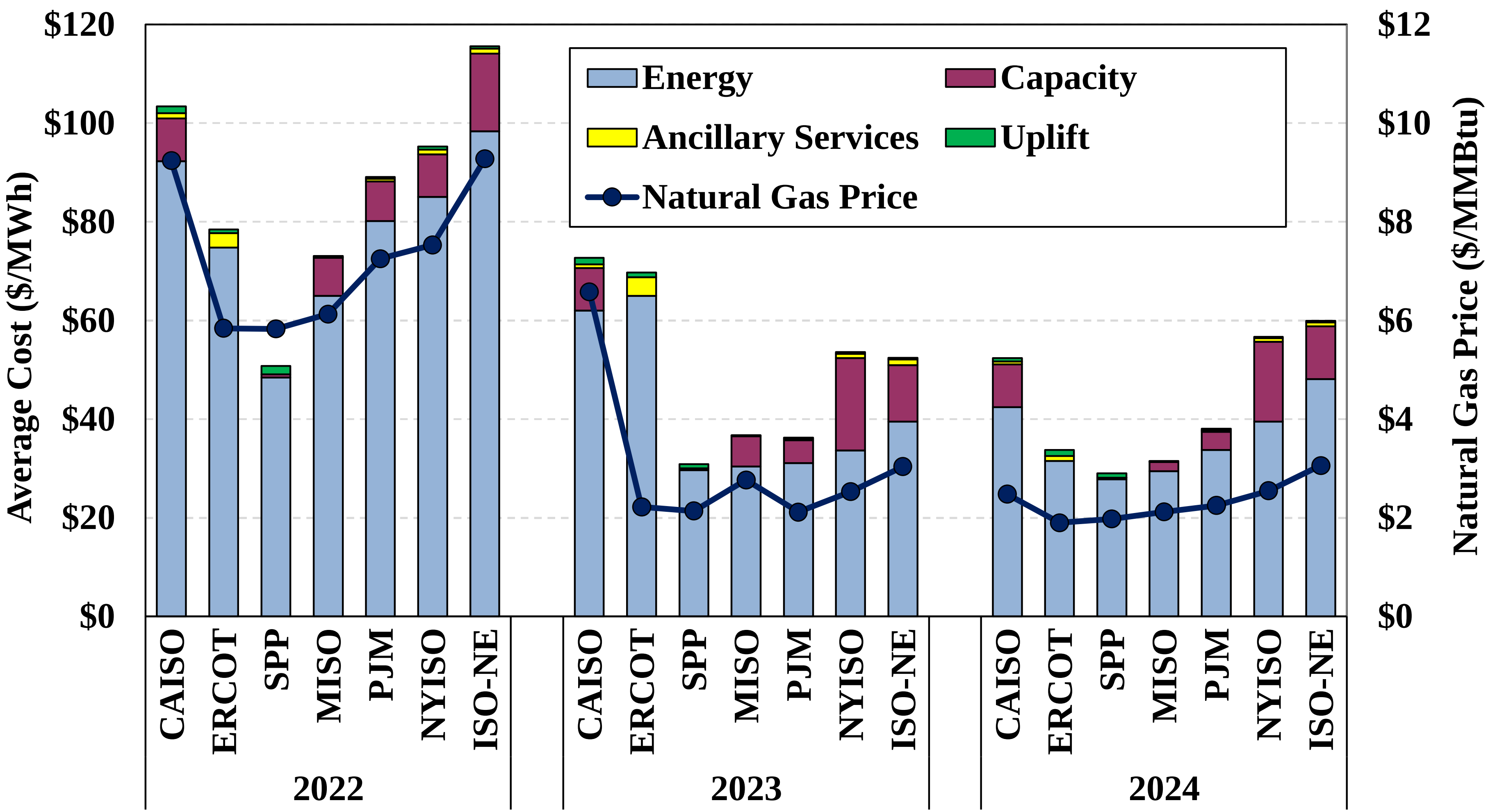
See Section I

Compared to most other RTO markets, ISO-NE has:

- The highest energy prices because it has the highest gas prices
- The highest capacity costs because of over-forecasted demand ahead of the FCAs, which are slow to correct in the FCM
  - Lower prices in other RTOs have been caused by larger surpluses and poor market design in MISO
  - Prices in NYISO rose after air permit restrictions caused GTs to retire
- Far less congestion (8-17% of other RTOs per MWh of load) because of transmission investments over the past decade
  - Tx. rates are more than double the average rates in other RTO markets
  - Increase trend of transmission planning to support renewables integration to drive rising transmission costs in several RTOs over next decade

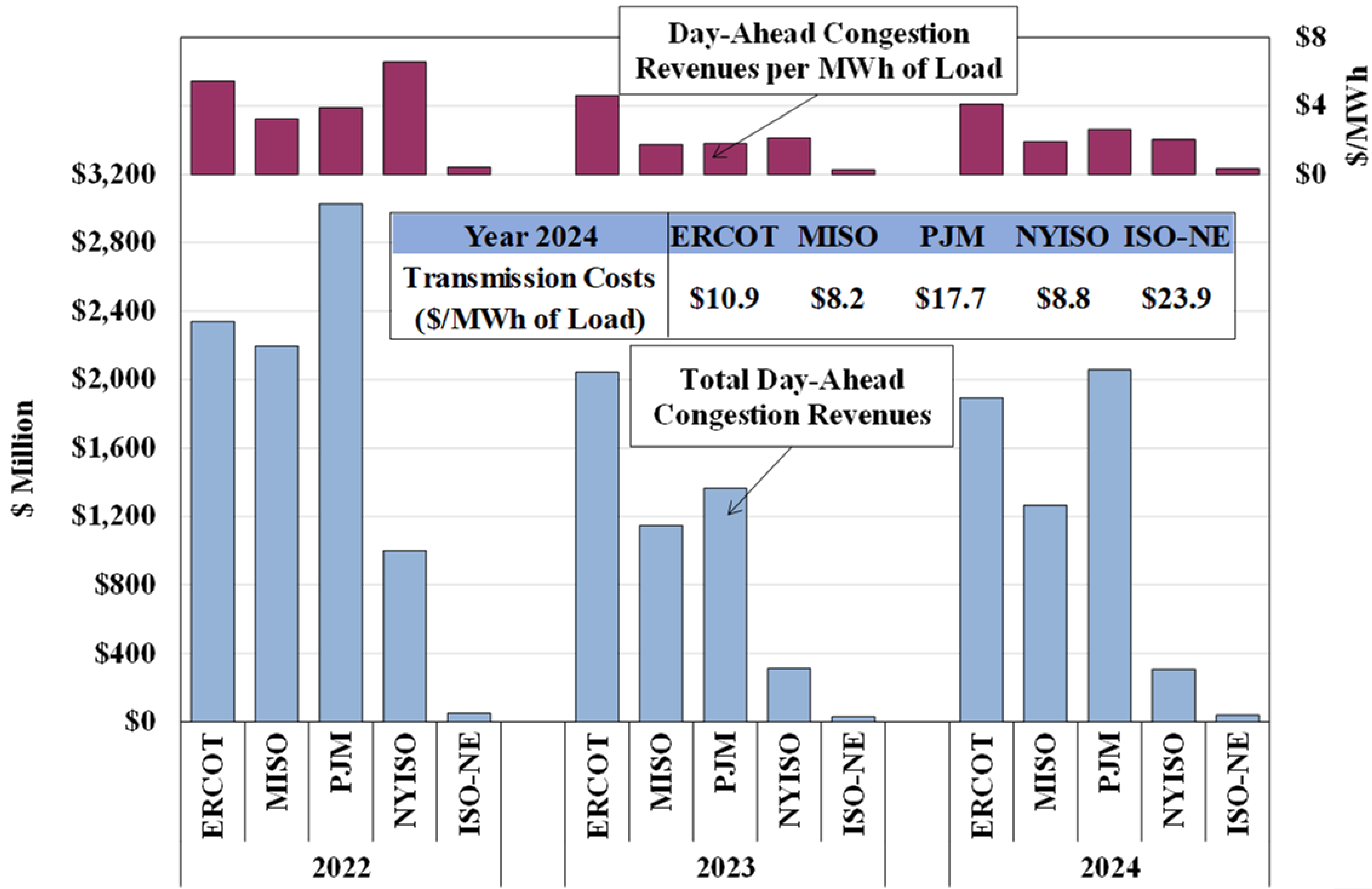
All-in Prices in RTO Markets

See Section I.A



Transmission Congestion Costs

See Section I.B



Cross-Market Comparison of Key Outcomes & Metrics

See Section I

In addition, ISO-NE has consistently exhibited:

- Less liquidity in the day-ahead market and poorer performance mainly because of the inefficient allocation of costs to virtual transactions
- Higher market-wide uplifts costs because of:
  - Higher fuel costs
  - Lack of day-ahead reserve markets
  - More circumstances when uplift compensation
    - Day-ahead reserve markets introduced in March 2025 should help reduce market-wide uplift
- Lower local reliability uplift because of past transmission upgrades

Virtual Transactions

See Section I.C

Market	Year	Virtual Load		Virtual Supply		Uplift Charge Rate
		MW as a % of Load	Avg Profit	MW as a % of Load	Avg Profit	
ISO-NE	2021	2.8%	-$1.29	4.5%	$2.07	$0.53
	2022	3.1%	-$1.75	4.8%	$3.23	$1.02
	2023	4.2%	-$2.09	6.3%	$1.28	$0.83
	2024	3.1%	-$2.64	6.6%	$2.21	$0.75
NYISO	2024	6.3%	-$0.64	7.4%	$0.82	< $0.1
MISO	2024	15.8%	$0.39	14.5%	$0.51	$0.11

Uplift Charges

See Section I.C

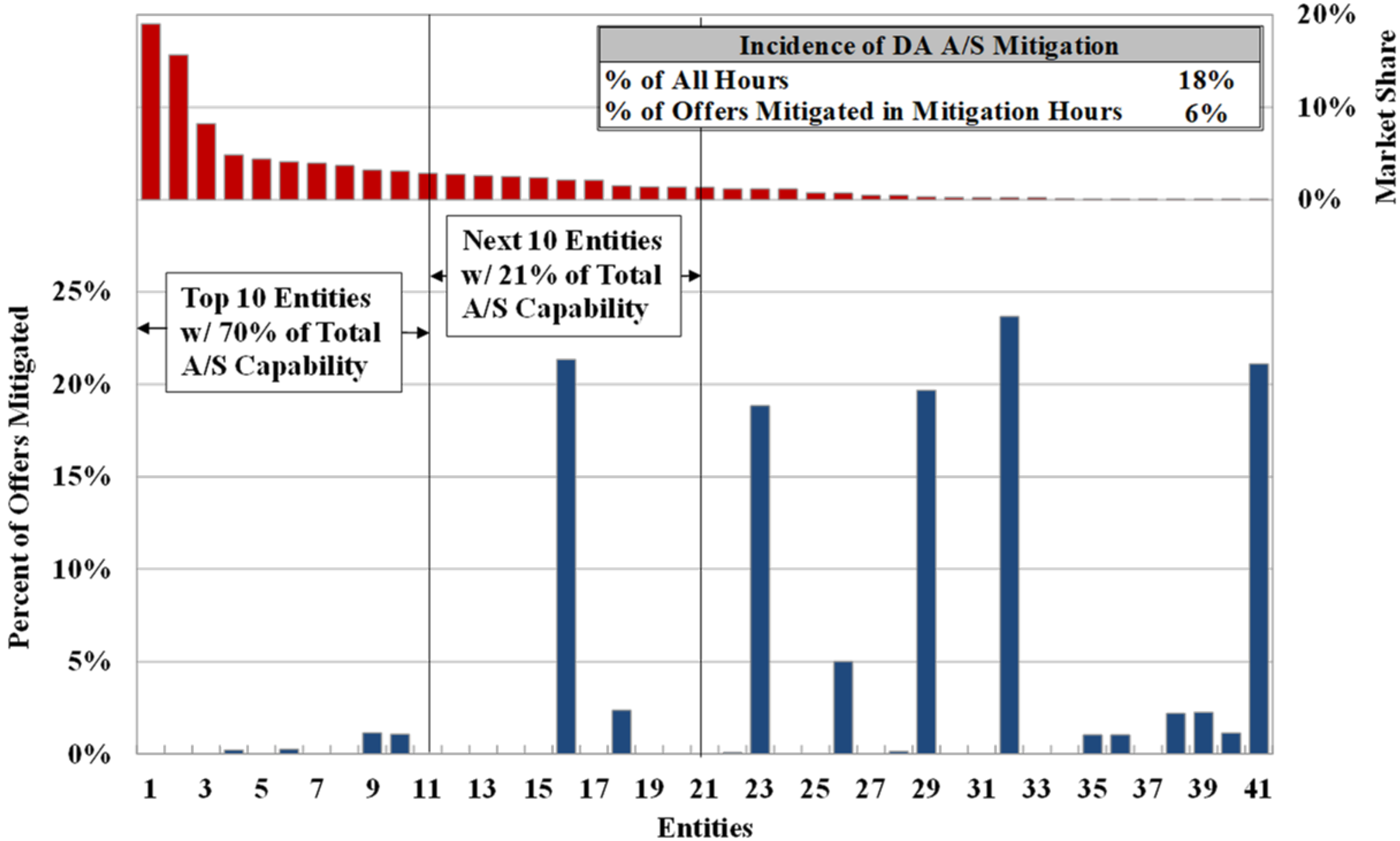
		ISO-NE			NYISO	MISO
		2022	2023	2024	2024	2024
Real-Time Uplift						
Total	**Local Reliability ($M)**	$1	$1	$1	$7	$2
	Market-Wide ($M)	$37	$25	$27	$18	$17
Per MWh of Load	**Local Reliability ($/MWh)**	$0.01	$0.01	$0.01	$0.05	$0.00
	Market-Wide ($/MWh)	$0.32	$0.22	$0.23	$0.12	$0.03
Day-Ahead Uplift						
Total	**Local Reliability ($M)**	$1	$1	$1	$9	$14
	Market-Wide ($M)	$13	$4	$6	$6	$17
Per MWh of Load	**Local Reliability ($/MWh)**	$0.01	$0.01	$0.01	$0.06	$0.02
	Market-Wide ($/MWh)	$0.11	$0.03	$0.05	$0.04	$0.03
Total Uplift						
Total	**Local Reliability ($M)**	$2	$2	$2	$16	$16
	Market-Wide ($M)	$50	$29	$33	$24	$35
Per MWh of Load	**Local Reliability ($/MWh)**	**$0.02**	**$0.01**	**$0.02**	**$0.11**	**$0.02**
	Market-Wide ($/MWh)	**$0.43**	**$0.26**	**$0.28**	**$0.16**	**$0.05**
	All Uplift ($/MWh)	**$0.45**	**$0.27**	**$0.30**	**$0.27**	**$0.08**

Competitive Assessment of Energy & Reserve Markets

See Section III

- Our competitive assessment of the energy & reserve markets indicated:
  - Little evidence of structural market power, either at the system level or in sub-regions;
  - No market power abuse or manipulation affecting clearing prices;
  - Mitigation has helped prevent the exercise of market power;
  - In the initial months of DASI implementation, market power mitigation was frequently and likely not triggered by attempts to exercise market power.
- Under DASI, small suppliers were mitigated most and the thresholds are low:
  - Conduct threshold based mostly on expected closeout costs often allow ~ $1/MWh increase even though actual closeout costs are volatile and often > $20/MWh
  - Impact test threshold can be as low as $1.50/MWh
  - The thresholds do not allow legitimate variation in risk preferences and can cause improper mitigation. We recommend revisiting them (**Recommendation # 2024-2**)
- We also recommend improving the current mitigation process by implementing hourly conduct and impact tests in the automated procedure (**Rec. # 2022-2a**)

Market Power Mitigation Under DASI



- Top 10 suppliers: 70% of Capability - 9% of Mitigation
- Small suppliers: 6% of Capability - 35% of Mitigation
- Frequent mitigation of small suppliers suggests that the current thresholds may lead to interference with competitive conduct

Navigating the Clean Energy Transition

Active Projects in ISO-NE Interconnection Queue

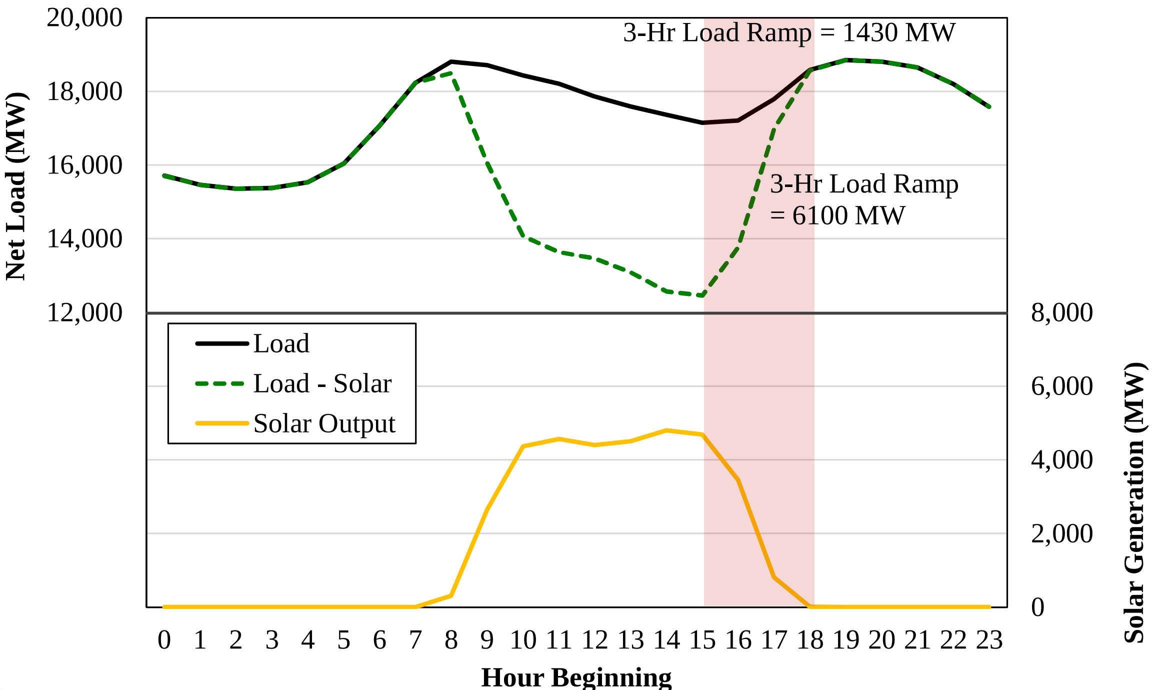
Technology	# Projects	GW	% of GWs
Solar*	228	4.9	12%
Battery Storage	122	18.4	45%
Land Based Wind	15	2.7	7%
Offshore Wind (Active Contract)	2	1.5	4%
Offshore Wind (No Contract)	19	11.9	29%
HVDC	1	1.2	3%
Fossil	6	0.1	0%

* Includes 94 hybrid solar projects (incl. storage) totaling 1.4 GW

- ISO-NE's queue is dominated by intermittent renewable projects
- Virtually no dispatchable generation / fossil retirements in recent FCA
- Offshore wind has higher capacity factor, but contracting/permitting is highly uncertain
- Storage may have low and diminishing contribution to winter reliability needs
- State permitting of backup on-site fuel storage at gas-fired plants could have great value for winter reliability with relatively low cost/emissions

Solar Output and Net Load Ramp (high load winter day)

- New England is planning for and pursuing a rapid increase in renewable resources to meet state carbon goals
- This will create new operational challenges
- The figure below shows how solar output affects the demand for conventional resources to ramp during the winter

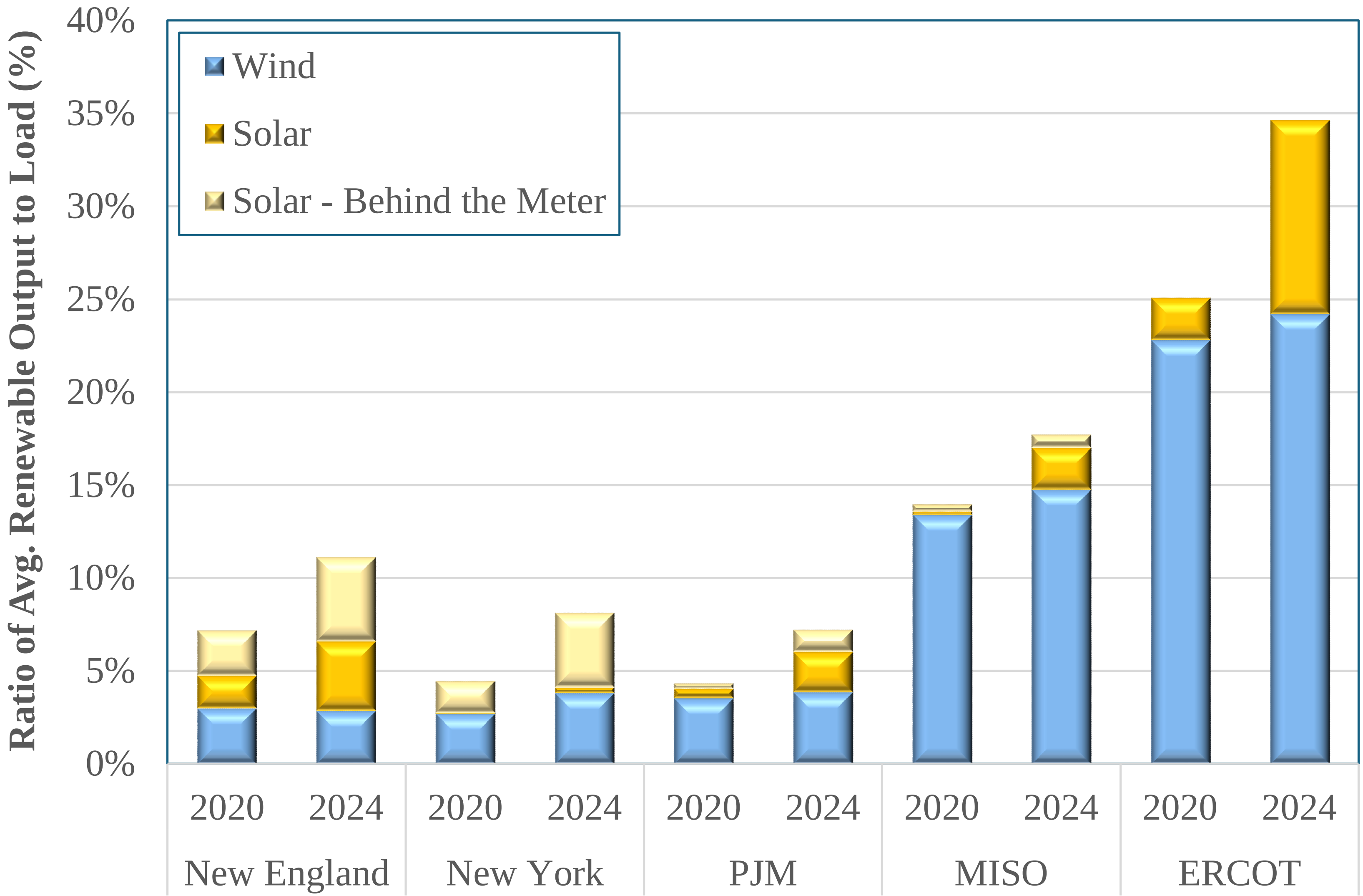


- The figure shows the typical dual peak load profile in the winter
- Falling solar in the evening as load rises will greatly increase the net demand on dispatchable resources

Navigating the Clean Energy Transition

- Renewable output as share of load is low in NE despite policy targets
  - High penetration in other RTOs (MISO, ERCOT) highlights future challenges
- Concerns about negative systemwide LMPs are largely unfounded:
  - 0.3% of intervals in ISO-NE in 2024 and only 2.4% of intervals in ERCOT
- Key challenges associated with growing renewable penetration:
  - Larger/more uncertain net load ramps which must be met by flexible units
  - Reduction in generation fleet's ability to support voltage and inertia creates need for interconnection requirements or planning changes
  - Poor incentives for renewables to follow dispatch instructions have led to constraint violations – requires dispatch deviation penalties
  - Forecasting renewable output in real-time and forward timeframes an issue
- ISO-NE's market is well-positioned to handle the renewable transition:
  - Shortage pricing is key and ISO-NE with PFP is more than adequate
  - We recommend development of a look-ahead dispatch model to address ramp needs and optimization of storage resources **(Rec. #2023-1)**

Renewable Output as a Share of Load



Resource Commitment and Pricing Issues

Resource Commitment and Reserve Pricing

See Section III

- Efficient real-time commitments and the pricing of fast-starting resources are important from both a cost and reliability perspective
- The real-time unit commitment (RTUC) model is a critical component of of the commitment process
  - RTUC runs each 15 minutes and identifies the units that may be committed in real time
  - It is important for RTUC prices to converge with the real-time UDS prices in order for the real-time commitments to be efficient
- This section of the report evaluates:
  - The performance of the RTUC and its convergence with UDS
  - ISO-NE's fast-start pricing

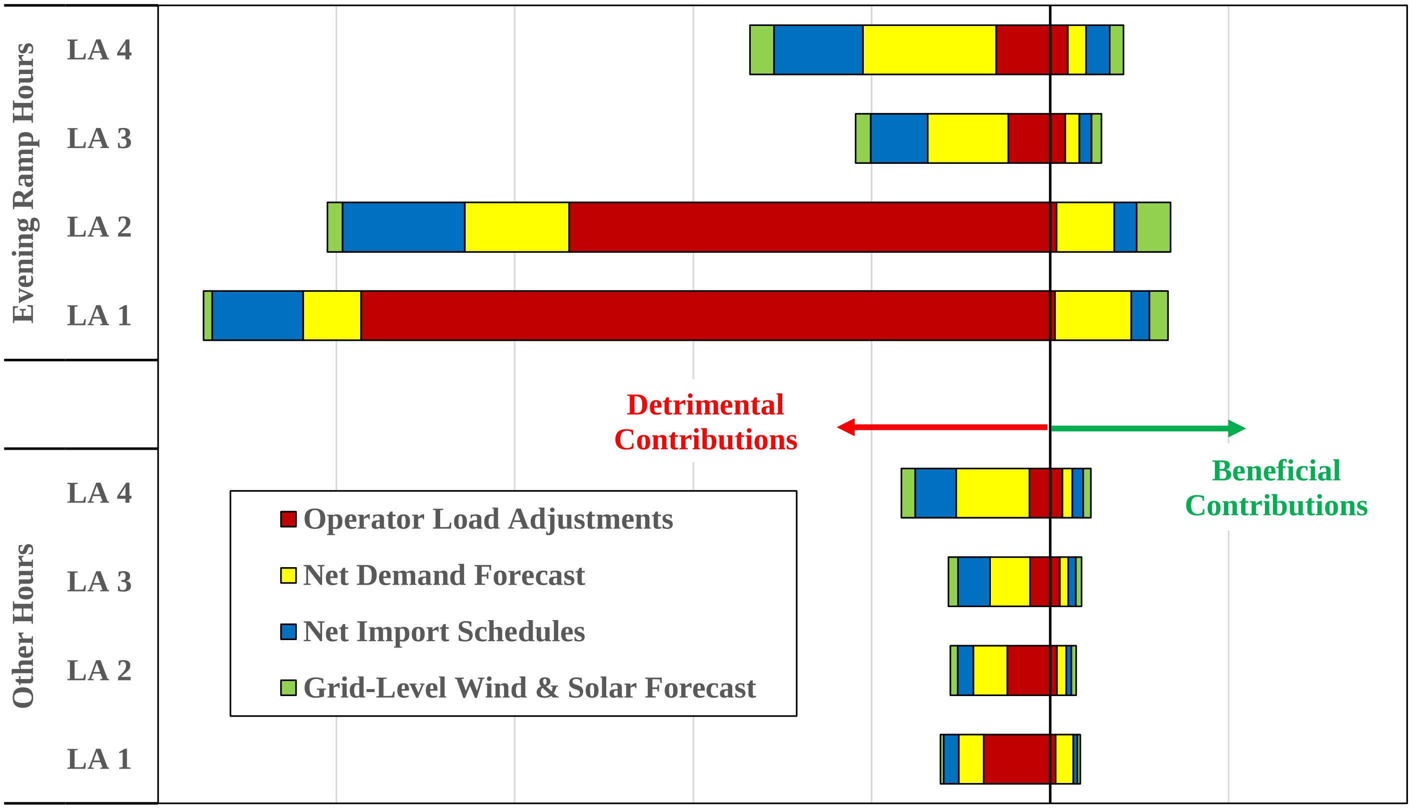
Resource Scheduling Efficiency by RTUC

RTUC Price Forecasting vs. UDS LMPs – See Section IV.B

- RTUC frequently recommended committing fast-start resources inefficiently during evening peak hours (HE17-21)
  - Our analysis indicates that this was due to the RTUC frequently over-forecasting the need to commit fast-start resources in these hours
  - Avg. RTUC LMPs exceeded UDS LMPs by as much as $64/MWh
  - Inefficient RTUC commitments also can undermine incentives to offer at marginal costs
- The analysis below identifies the factors that contribute to the divergence in prices between RTUC and UDS
- To address the inefficient commitments and associated NCPC, we recommend ISO-NE evaluate and address all causes of this price divergence **(Recommendation #2024-1)**

Resource Scheduling Efficiency by RTUC

Factors Contributing to RTUC Forecasting Errors – See Section IV.B

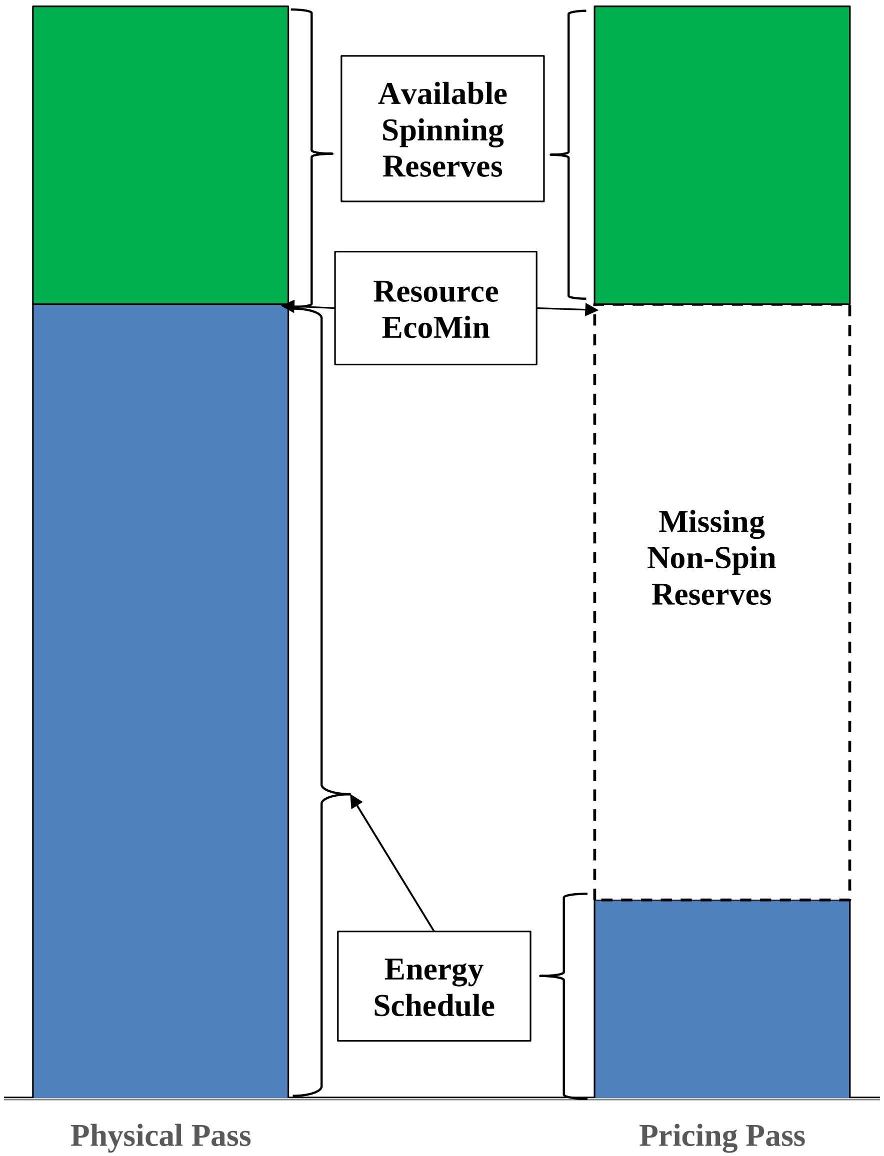


- We created a metric to show factors that contribute to divergence (<0) vs. convergence (>0 or beneficial)
- LA1 to 4 are 15 minute look-ahead intervals

- Operators frequently adjust the load upward manually in RTUC – these were the primary detrimental driver in LA1 & LA 2 during evening peak hours (HE17-21)
  - In **~10%** of intervals in LA1 & LA2, load adjustments were > 300 MW and median LMP differences up to $230/MWh

Reserve Pricing in the Fast-Start Pricing Logic

See Section IV.C



- *Pricing Logic* relaxes fast-start units' EcoMin to zero for pricing purposes
  - However, it does not allow reserves to be held below EcoMin
- The decrease in available NS reserves often raises energy and reserve prices inefficiently under tight conditions
- During intervals with binding reserve constraints in 2024, on average:
  - The 30-minute reserves in the dispatch was 360 MW > in the pricing model
  - 30-min OR prices: $113/MWh in pricing model vs. $44/MWh in physical dispatch
- We recommend ISO-NE modify the fast-start pricing to utilize the full capability of online units for reserves (**Rec. #2022-1**)

Capacity Availability and Performance Issues

Overvalued Qualified Cap. due to Ambient Conditions

See Section V.A

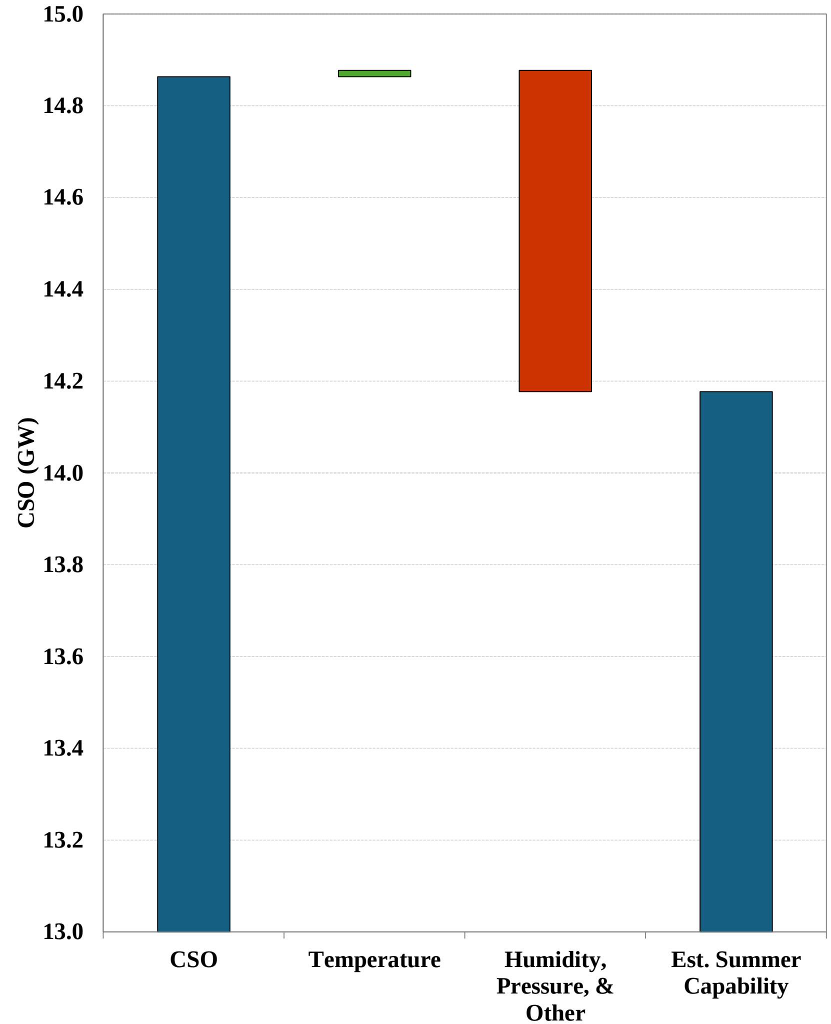
- Qualified capability are based on SCC audits, the results of which are affected by humidity and barometric pressure in peak load hours
- Peak load hours have shifted over time because of solar PV hour beginning 3 p.m. to hour beginning 6 p.m. (2015-2024)
  - This shift results in higher humidity and lower pressure in the peak hours
- Most SCC Audits are done at favorable pressure and humidity levels, inflating QC relative to peak load conditions – by roughly 300 MW
  - Over-estimate of capacity is larger under conditions that drive capacity requirements (e.g., 90/10 or 95/5)
- We estimated the total overstatement in qualified capacity in the summer 2024 in this report
- Based on this analysis, we recommend ISO-NE enforce forced derate requirements and reassess the ambient conditions used to determine qualified capacity **(Recommendation #2024-3)**

Overvalued QC and Reporting of Derates

See Section V.A

- Over 700 MW of QC identified as unavailable at peak summer conditions
  - Despite slightly cooler conditions.
  - 300 MW identified due to humidity and pressure conditions
- Possible causes of the 400 MW underperformance on peak days:
  - Unreported mechanical deratings
  - Underreported auxiliary loads during SCC Audits
  - Not offering less reliable auxiliary operating modes (e.g. peak firing)

Unavailable Capacity in 2024 Peak Conditions



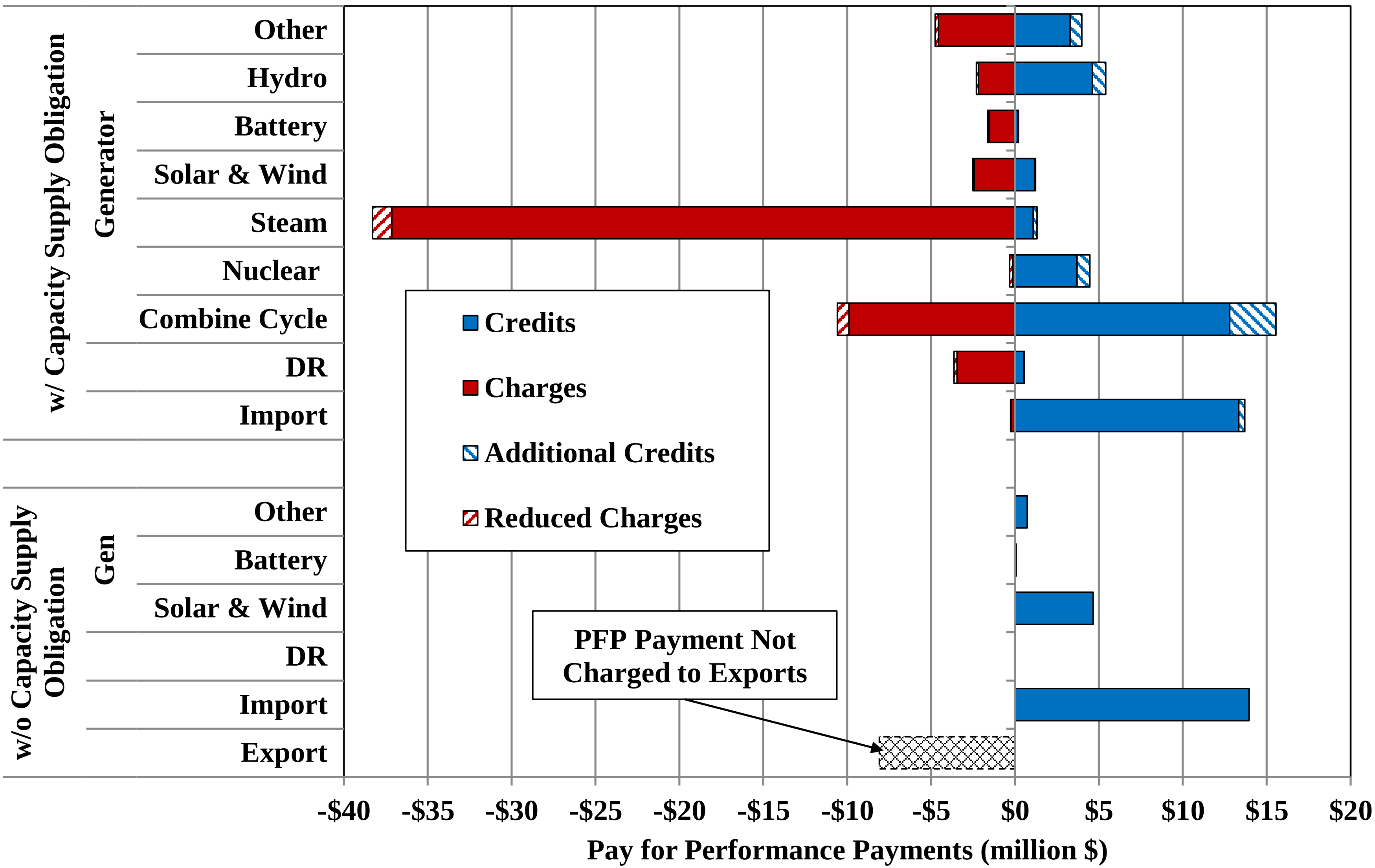
PFP Events on June 18 & August 1

See Section V.B

- Two capacity shortages occurred in 2024, ranging from roughly 30 to 90 minutes and averaging almost 250 MW
  - Shortage pricing + PFP settlements during these events exceeded $8,000 per MWh, vastly exceeding the value of energy during the two events
- The extraordinary prices during these events led to very large PFP credits and charges (shown in the following figures)
  - ~$14 million credits to non-CSO imports, while no charges to exports
  - ~$50 million charges to steam turbines and combined cycles, most of which were available but not committed in the day-ahead markets
- Imposing these charges on high-cost resources that were not scheduled in the day-ahead market (and not foreseeably needed) leads to:
  - Lower net revenues that may lead to premature retirements
  - Inefficient incentives to self-commit such resources
- Inconsistent settlements with imports and exports is inefficient and raising gaming concerns

PFP Credits and Charges

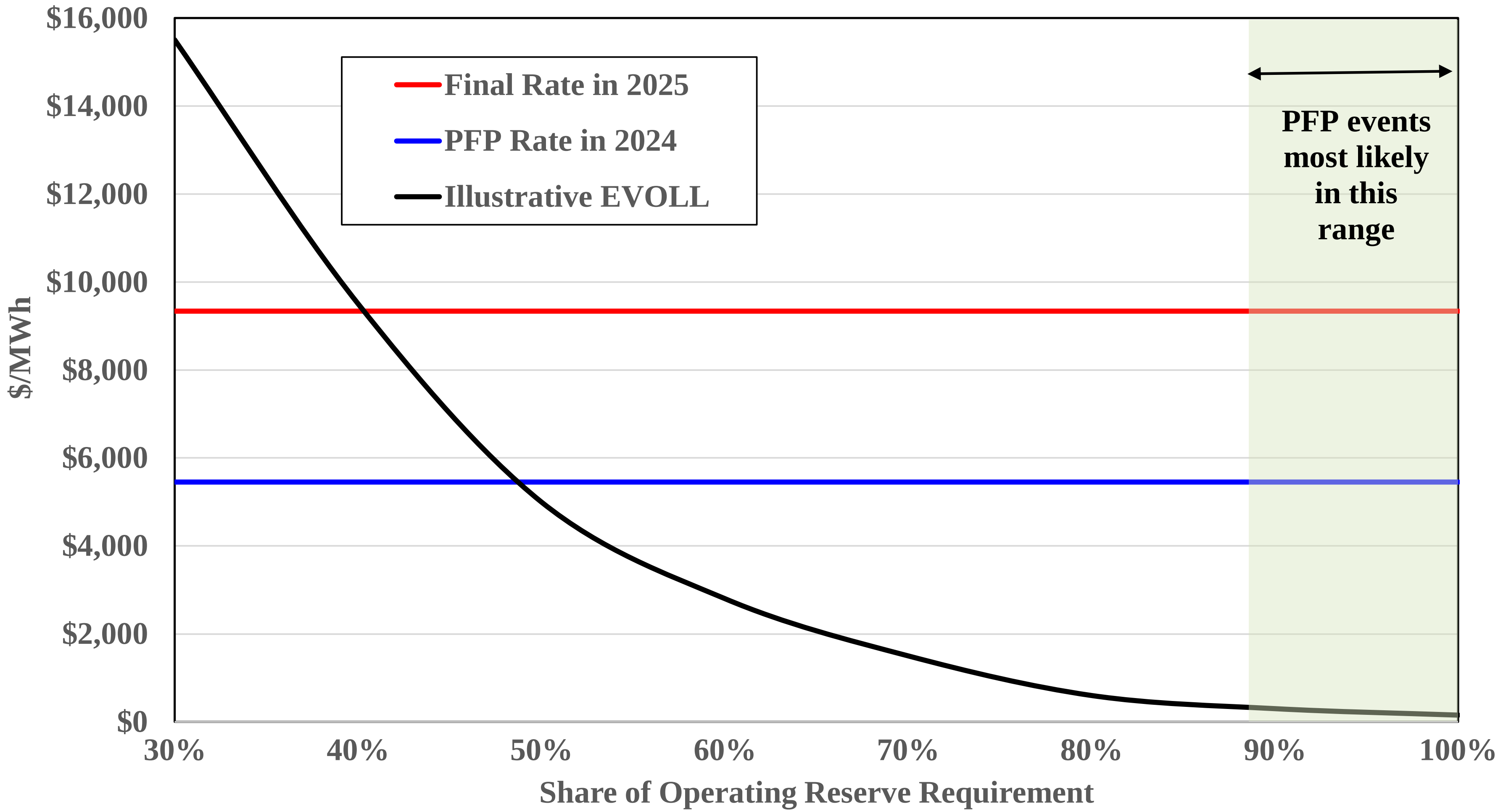
See Section V.B



PFP Rate and the Value of Lost Load

See Section V.B

- PFP rate not consistent with value of reserves – the rate is overstated and does not vary with the magnitude of shortage



Concerns Raised by the PFP Two Events

- **Concern #1:** Inefficient incentives to export may increase frequency of reserve shortages. Imports were paid the PFP rate of $5,455/MWh but exports were not charged the PFP rate
  - It can be simultaneously profitable to schedule in *both* directions - raises gaming concerns and disrupts import/export incentives
  - ***Recommend to revise PFP rules to charge exporters at the PFP rate*** (**Recommendation #2022-3**)
- **Concern #2:** PFP rate not consistent with value of reserves – the rate is overstated and does not vary with the magnitude of shortage
  - Available units not committed day ahead received excessive penalties
  - Problem will be *much* worse under the new rate of $9,337
  - ***Recommend to modify the PFP rates to levels that align with VOLL and reserve shortage severity*** (**Recommendation #2018-7**)

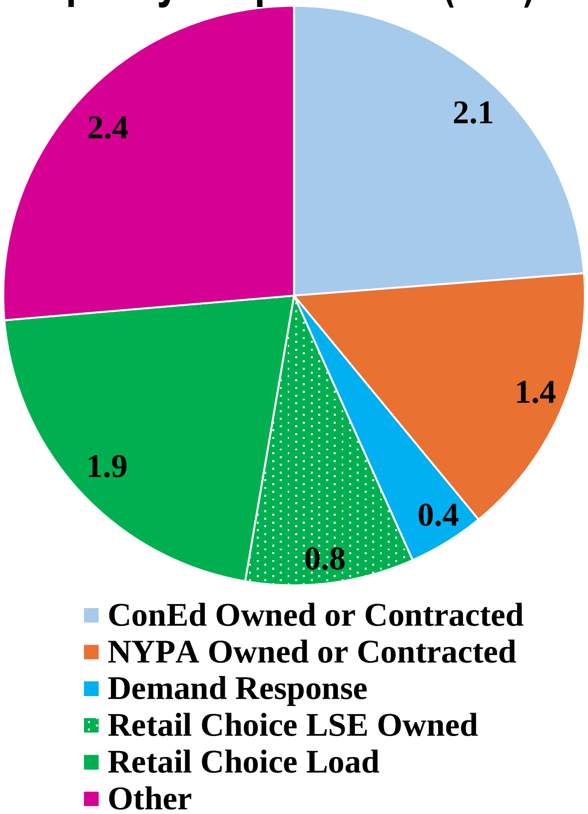
Conclusions on Winter Reliability in the FCM

- Future resource adequacy will be driven by winter - in extended cold periods where sufficient stored/contracted fuel supplies ("energy adequacy") are critical
  - Accurate capacity market incentives are needed to maintain reliability and attract efficient forms of new entry
  - Accreditation that does not reflect energy adequacy will vastly overvalue some resources (non-firm gas, storage) and undervalue others (generators w/ firm fuel)
- We recommend ISO-NE develop marginal accreditation for all resources and make needed RA modeling enhancements **(#2020-2)**, including:
  - Accredit all resource types based on their marginal contribution to reliability;
  - Explicitly represent fuel inventories in models used for accreditation and ICRs;
  - Use conservative assumptions for the amount of LNG that will be available to gas generators that do not contract for it in extreme winter conditions
- Other key capacity market recommendations:
  - Implement *a prompt capacity market* reflecting seasonal needs **(#2021-1)**
  - Replace descending clock auction format with sealed bid. **(#2015-7)**
  - Treat Energy Efficiency as a load reduction in the capacity market rather than a supply resource **(#2020-3)**

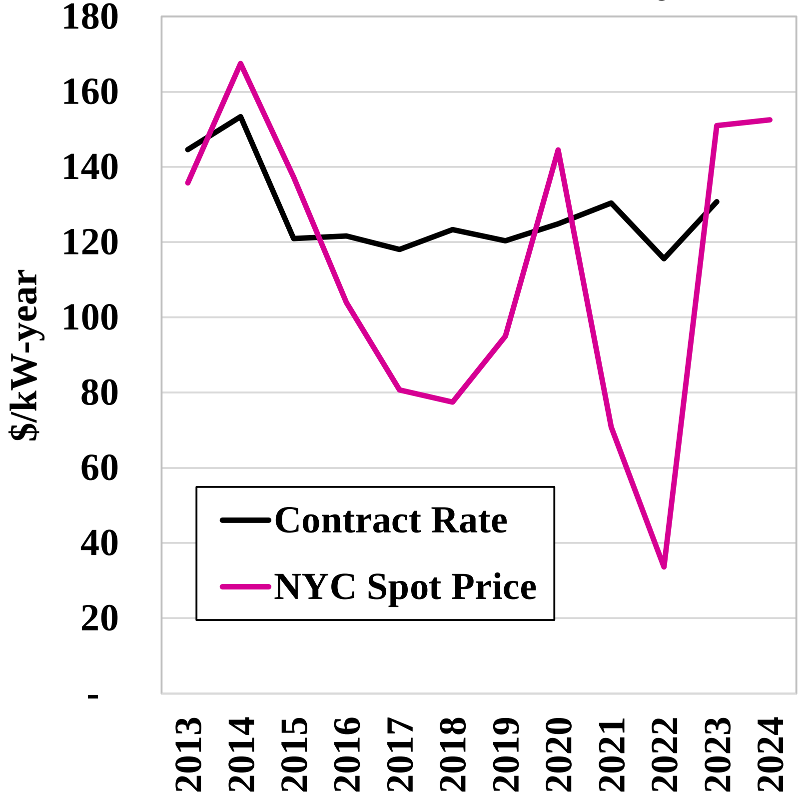
Managing Volatility in Prompt Capacity Market

See Section I.F

Breakdown of New York City 2023/24 Capacity Requirement (GW)



Reported Con Edison Capacity Contracts vs NYC Capacity Price



- In the NYISO prompt (monthly) auction, uncertainty of the monthly prices is hedged through bilateral contracts – facilitated by a robust prompt spot market
- Hedging with bilateral contracts is more difficult in a forward capacity market

Full List of Recommendations

List of Recommendations

Recommendation Number and Description		High Benefit[5]	Current/ Planned Efforts	Report Reference
Reliability Commitments and NCPC Allocation				
2020-1	Consider allowing firm energy imports to satisfy forecasted local second contingency requirements.			IIV.A
2014-5	Utilize the lowest-cost configuration for multi-unit generators when committed for local reliability.			III.D, IV.A
2010-4	Modify allocation of "Economic" NCPC charges to make it consistent with a "cost causation" principle.			III of 2018 Report
Energy and Operating Reserve Markets				
2024-1	Evaluate and address causes of the price divergences between RTUC model and the real-time dispatch.			IV.B
2023-1	Evaluate benefits and costs of a look-ahead dispatch model to optimally manage fluctuations in net load and the use of storage resources.	✓		II.B
2022-1	Allow fast-start pricing model to utilize the full capability of online units for energy or reserves.			IIV.C
2019-3	Dynamically define a full set of local operating reserve requirements in the day-ahead and real-time markets.			IV.A
Energy & Ancillary Services Market Mitigation				
2024-2	Evaluate the appropriateness of the current conduct and impact threshold levels for reserves in the DAM.			III.E
2022-2a	Implement hourly conduct and impact tests in the automated energy mitigation procedure in RT.			III.D

Notes: ***High Benefit*:** **Will likely produce considerable efficiency benefits.**

List of Recommendations

Recommendation Number and Description		High Benefit[5]	Current/ Planned Efforts	Report Reference
Energy & Ancillary Services Market Mitigation				
2024-2	Evaluate the appropriateness of the current conduct and impact threshold levels for reserves in the DAM.			III.E
2022-2a	Implement hourly conduct and impact tests in the automated energy mitigation procedure in RT.			III.D
Capacity Market				
2024-3	Enforce forced derate reporting and reassess the use of ambient conditions to determine Qualified Capacity.			V.A
2022-3	Charge exporters the PFP rate during reserve shortages.			V.B
2021-1	Replace the forward capacity market with a prompt seasonal capacity market.	✓	CAR-PD Filing Plan 2025-Q4, CAR-SA Filing Plan 2026-Q4	V.B of 2023 Report
2020-2	Improve capacity accreditation by a) accrediting all resources consistent with their marginal reliability value, and b) modify the planning model to accurately estimate marginal reliability values.	✓	CAR-SA Filing Plan 2026-Q4	V.A of 2023 Report
2020-3	Account for energy efficiency as a reduction in load instead of as a supply resource in the FCM.			V of 2020 Report
2018-7	Modify the PPR to rise with the reserve shortage level, and do not implement the planned increase in the PPR.	✓		V.B
2015-7	Replace the descending clock auction with a sealed-bid auction to improve competition in the FCA.		CAR-PD Filing Plan 2025-Q4	IV of 2017 Report