NEPOOL
NEW ENGLAND POWER POOL
Sebastian Lombardi
Secretary

February 26, 2026

VIA E-MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of March 5, 2026 Participants Committee Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the March 2026 meeting of the Participants Committee will be held **in person on Thursday, March 5, 2026, at 10:00 a.m. at the Sheraton Boston Hotel, located at 39 Dalton St., Boston, MA 02199** for the purposes set forth on the attached agenda and posted with the meeting materials at nepool.com/meetings/.

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

Looking ahead, please mark your calendars for the following 2026 Participants Committee meetings:

- April 9: Manchester Village, VT at the Equinox (https://www.equinoxresort.com)

- May 7: West Hartford, CT at the Delamar (https://www.delamar.com/hotels/delamar-west-hartford)

- June 16-18: Newport, RI at the Newport Habor Island on Goat Island (www.newportharborisland.com).

As the dates each draw nearer, we will provide information regarding overnight accommodations and, with respect to the 2026 NPC Summer Meeting, a link to the registration page and the room reservations block, once those are open.

Respectfully yours,

/s/

Sebastian Lombardi, Secretary

FINAL AGENDA

1. To approve the draft minutes of the February 5, 2026 Participants Committee meeting. A copy of the draft minutes, marked to show changes since the minutes were circulated with the initial notice, are included with this supplemental notice and posted with the meeting materials.

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

2A. To consider, and take action, as appropriate, on revisions to Appendix A (Itemized Equipment) to OP-2 (Maintenance of Communications, Computers, Metering and Computer Support Equipment). Background materials, including a draft resolution, are included and posted with this supplemental notice.

3. To receive an update on activities of the Joint Nominating Committee and information from and about the two incumbent ISO Board members eligible for re-election to the Board this year (Mark Vannoy and Craig Ivey). Background materials are included and posted with this supplemental notice. *Please note that the Participants Committee may conduct some discussion on this item upon completion of the rest of the business agenda, in executive session if and as appropriate.*

4. To receive an ISO Chief Executive Officer Report. A summary of the ISO Board and Board Committee meetings held since the last Participants Committee meeting will be circulated and posted in advance of the meeting.

5. To receive a Systems and Market Operations Report. The March Systems and Market Operations Report, reflecting February data, will be circulated and posted in advance of the meeting.

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

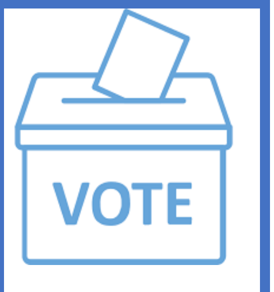
7. To receive reports from Committees, Subcommittees and other working groups:
   - Markets Committee
   - Reliability Committee
   - Transmission Committee
   - Budget & Finance Subcommittee
   - Membership Subcommittee
   - Others

8. Administrative matters.

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

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

1 February 5, 2026 Minutes



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RESOLVED, that the Participants Committee approves the preliminary minutes of the February 5, 2026 meeting, as circulated in advance of this meeting, with additional non-material clarifications, as the final minutes of the February 5, 2026 meeting.

PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held beginning at 10:00 a.m. on Thursday, February 5, 2026, at the Colonnade Hotel, Boston, Massachusetts. A quorum, determined in accordance with the Second Restated NEPOOL Agreement, was present and acting throughout the meeting. Attachment 1 identifies the members, alternates, and temporary alternates who participated in the meeting.

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

APPROVAL OF JANUARY 8, 2026 MEETING MINUTES

Ms. Bresolin referred the Committee to the preliminary minutes of the January 8, 2026 meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of that meeting were unanimously approved as circulated, with an abstention by Mr. Jon Lamson noted.

ISO CEO REMARKS

In his first prepared remarks to the Participants Committee as the ISO's President and Chief Executive Officer (CEO), Dr. Vamsi Chadalavada began by highlighting a few fundamental themes that would be initial points of emphasis for the ISO under his watch, including: (i) the ISO's role and mission to serve the New England region and its collective interests, (ii) facilitating balanced collaboration and consensus (particularly amongst and between load, supply and public policy interests), and (iii) with the cooperation and support of stakeholders, increased ISO agility and efficiency in identifying durable solutions to the challenges presented and changes required. He committed the ISO to be increasingly mindful of opportunities to be more agile in identifying and pursuing solutions, taking the luxury of additional time only when and as necessary and appropriate.

Dr. Chadalavada continued by addressing more directly a few of the specific reforms to be pursued in 2026, including refinements to the Day-Ahead Ancillary Services (DAAS) Market, particularly the adjustments proposed by the Internal Market Monitor (IMM) the day before, improvements to the Pay-for-Performance (PFP) rate, and compliance obligations in response to the *NEPGA Complaint Order* and a related commitment to address an imbalance between charges imposed on imports and exports. With respect to DAAS, he said that the design had been very effective, resulting in significant performance improvements as demonstrated during the week leading up to the meeting. He also acknowledged, however, that the cost of the market had exceeded expectations, suggesting a pressing need for the region to identify and implement refinements to better balance outcomes. Consistent with his earlier comments on agility, he noted efforts underway to have solutions proposed in the near term and implemented by the start of Winter 2026/27. While generally aggressive schedule-wise, he believed the approach and timing was called for under the circumstances. He said details would be forthcoming.

Similarly, he hoped the ISO could identify improvements to the PFP rate, so as to achieve a better balance among impacted interests, without sacrificing the success seen in incenting high -level fleet performance, as demonstrated over the extreme cold weather days leading up to the meeting. He remarked that operations over that period had in fact been nothing short of extraordinary. He congratulated the many groups that comprise the ISO team for their 24/7 efforts, as well as the States and generation owners, for their remarkable behind-the-scenes efforts that exceeded expectations. Noting the many, concurrent challenges, he emphasized the level and depth of cooperation that he had not seen before in his time with the ISO and commended all those involved for their resilience dealing with the churn and stress of the event, achieving a remarkable level of reliability in the face of higher loads and less margin. All-in-all, he claimed, a positive outcome and great story for New England.

Many members then echoed their appreciation for the responsiveness and performance shown by all levels of the ISO during the cold weather event. They reiterated how the ISO's transparency and willingness to work with Participants were critical to getting through the circumstances presented. Members also emphasized their appreciation for the ISO's expressed willingness to consider refinements to the DAAS market and PFP rate. A number identified a desire to better understand the additional reliability benefits attributed to DAAS implementation, particularly in view of the costs experienced. There was a general resolve expressed to work with the ISO and other stakeholders to efficiently and expeditiously identify appropriate adjustments in the areas identified, with the goal of achieving in each case a more finely tuned and widely accepted balance consistent with the intended DAAS design, all the while without losing ground or sacrificing progress on ongoing Capacity Auction Reforms (CAR).

Dr. Chadalavada concluded his remarks by specifically recognizing the leadership shown by Mr. Stephen George, ISO Vice President, System & Market Operation and Capital Projects, during the cold weather event. Although there had been an extraordinary ISO team effort, Dr. Chadalavada said that Mr. George's unflappable leadership, which inspired a high level of confidence throughout the ISO, deserved special recognition. He was pleased to have Mr. George in that role and thanked him for all he had done thus far.

There were no questions or comments on the summary of ISO Board and Board Committee meetings held since the January Participants Committee meeting, which had been circulated and posted with the materials for the meeting.

ISO SYSTEM & MARKET OPERATIONS REPORT

Monthly Operations Highlights

Mr. George began his first in-~~-~~person report by referring the Committee to the February System & Market Operations Report (Report), which had been circulated and posted in advance of the meeting. Noting that January had overall been 2°F colder than normal and that data in the Report was through January 28, 2026, unless otherwise noted, he reviewed Report highlights, which included: (i) that the Peak Hour for January 2026, with 20,221 MW of Revenue Quality Metered (RQM) Data, occurred on January 25 during the hour ending at 2:00 p.m.; (ii) December averages for Day-Ahead Hub Locational Marginal Price (LMP) ($165.45/MWh), Real-Time Hub LMP ($142.78/MWh), and natural gas prices ($22.71/MMBtu); (iii) Energy Market value for January 2026 was $2.7 billion, up from $1.6 billion in January 2025 and December 2025's Energy Market value of $1.8 billion, making January 2026 the highest overall Energy Market value since Standard Market Design (SMD) was implemented; (iv) Ancillary Markets value ($86.9 million) was up from January 2025 ($6.6 million); (v) average Day-Ahead cleared physical energy during the peak hours as a percentage of forecasted load was 99.9% in January (the same percentage as reported for December 2025); (vi) Net Commitment Period Compensation (NCPC) payments for January totaled $5.1 million (again 0.2% of monthly Energy Market value), almost entirely consisting of First Contingency payments, including $1.2 million in Dispatch Lost Opportunity Costs (DLOC), $522,000 in Rapid Response Pricing (RRP) Opportunity Costs, and $17,000 in Generator Performance Auditing (GPA), with $112,000 paid to resources at external locations down $505,000 from December; and (vii) a Forward Capacity Market (FCM) market value of $88.9 million.

Expanding on the impacts of the extreme cold weather at the end of the month, at times up to 14°F colder than normal, Mr. George reported that January Energy Market value exceeded the previous post-SMD record of $2.2 billion set in January 2014, with the highest Day-Ahead natural gas price (MA average) of $122/MMBtu far exceeding the $82/MMBtu average (and previous record) set on January 23, 2014. Daily Energy Market Value also set records, with January 25-28 each exceeding the prior January 23, 2014 record of $170 million (of those four days, January 27, 2026 was the highest daily value at $422 million). He noted that, although January 2026 average fuel prices and LMPs were lower than those of January 2014, Day-Ahead loads were relatively higher.

With respect to DAAS results, Mr. George said that, prior to the extreme cold weather setting in, costs were trending in a similar way, if not a bit lower, to December. With the extreme cold weather, though, there was a coincident spike in costs, primarily related to fuel costs, but also to variations in the level of imports and to the number of units offered into the market. As Dr. Chadalavada had indicated previously, Mr. George said that more DAAS analysis would be forthcoming.

As for other regional developments, Mr. George reported that, for the next few months, no significant transmission outages that would decrease transfer capability between New England and its neighboring Control Areas were planned or expected. He added that, as expected, the New England Clean Energy Connect (NECEC) transmission facility became commercial on January 16, 2026.

Preliminary Winter Weather Operations Summary: January 24 - February 1

Turning to materials preliminarily summarizing the operations experience with the prolonged cold weather that began on January 24, and noting that final and more complete information would be provided and considered as part of the New England Winter 2025/26 review at the next (March) Participants Committee meeting, Mr. George proceeded to run through winter weather highlights from January 24 to February 1.

Overall, he said that the severe cold temperatures during that time had led to the most challenging winter conditions since 2017/18, with elevated peak and overall demand, record high natural gas prices, oil often on the margin, and significant reduction in available fuel oil supplies. He reported that, for the first time since 2017/18, peak load exceeded 18,900 MW for nine consecutive days, with little relief to the system stress during overnight hours (load remaining consistently high). While the ISO's load forecast performed relatively well (less than 1.5% peak load error on average), he reported on a significant deviation on January 25, the day of Winter Storm Fern. On that day, temperatures were 5-6°F colder than forecast (driving the early morning peak higher), with winds much higher than anticipated.

Mr. George explained how the significant snowfall from Winter Storm Fern, the most widespread snowfall since 2015, had impacted generating resources, leading to a reduction in solar production, and related challenges with fuel and demineralized water logistics and availability, thereby raising energy adequacy concerns. From the outset, the demand for fuel burn was high. Generators with dual-fuel capability switched from gas to oil. Fuel oil burn – 66 million gallons burned – was more significant than the past four winters combined. Mr. George reported that fuel replenishment, which had taken some time to begin in earnest, was well underway, with approximately 25 million gallons (50/50 residual and distillate fuel) already replenished and another 26 million gallons expected to be replenished prior to February 9. He expected reserves to fully return to historical levels as the weather improved and replenishment continued.

Addressing imports, Mr. George reported that net interchange decreased beginning on January 24, as neighboring Control Areas managed their internal peak and firm customer loads. Imports averaged approximately 1,900 MW/hr during the January 24 - February 1 period. Throughout, the ISO maintained close, hour-by-hour communications with neighboring Control Areas so as to stay abreast and ahead of the impacts of expected import levels. He noted that, given the short time that NECEC had been commercial, it was too early to draw any conclusions with respect to future expected NECEC-related outcomes or behaviors.

Further describing the ISO's efforts to maximize the availability of resources during the expected 2-3 week of extreme cold weather, Mr. George addressed the first-ever ISO request of the U.S. Department of Energy (DOE) for an order pursuant to Section 202(c) of the Federal Power Act to allow generating units located in New England to operate up to their maximum generation output levels, notwithstanding air quality or other permit limitations. The DOE had issued the requested emergency order on January 25, 2026 (Emergency Order), and had subsequently extended the Emergency Order through February 14, 2026, allowing for the operation and dispatch of "Specified Resources" to meet the emergency. The number of Specified Resources at that point totaled 57, and they were identified in postings on the ISO and DOE websites. In response to questions, he said that, of those resources, 21 had exceeded some limit once or several times (info that had also been shared with DOE). He added that, the day before, the DOE had clarified that any emissions, hours of operation, or fuel burned to comply with the Emergency Order could not be counted towards rolling average-based limitations. He encouraged those with remaining questions as to the ramifications of the Emergency Order to reach out to their local and state contacts.

In summary, Mr. George said that generator performance and the regional response had been strong. He appreciated the cooperation and support, not only of the many resources that ran (particularly those that would not otherwise be expected to run), but of the federal and state agencies, and electric distribution companies (EDCs). He noted that many resources took advantage of tools available (e.g. opportunity cost mechanisms, Limited Energy Generation (LEG) offers, etc.) to manage fuel levels. For its part, the ISO redoubled its efforts to be responsive and communicative. Mr. George highlighted the implementation of daily fuel surveys, and daily 21-day assessments, shared with the region, to keep information flowing and support stakeholder decisions through the period. He also described efforts undertaken in partnership with DOE and NEPGA, to alleviate challenges experienced by certain generators in obtaining required de-mineralized water, which emerged as a scarce commodity and for a time limited some generator availability. He pledged that the ISO would use that experience when identifying and evaluating broader system limiting risks.

Members thanked the ISO for its efforts, responsiveness and information dissemination during the challenging period. The ISO, acknowledging the mutual benefits, agreed to continue to make available as much information as permitted and reasonable to support stakeholder decisions.

In response to questions, Mr. George said that approximately 1 Bcf of liquefied natural gas (LNG) had been injected into pipelines from St. John and Everett. He said the ISO tracked, and was pleased to see, the frequency of LNG deliveries. He also confirmed that off-shore wind performance during the period was strong, which he said highlighted the value of off-shore wind during extreme winter conditions.– Mr. George said that, while offshore wind data was included in aggregated ISO Express data, and the time was not yet right, he expected that, in the future and subject to addressing any Information Policy concerns, offshore wind data would be broken out separately to support general performance evaluation. Similarly, a member requested, and Mr. George agreed to consider, additional granularity with respect to the contributions by grid-scale storage and demand response.

In response to additional questions, Mr. George clarified that exports to Quebec on January 26/27 had cleared through the normal Day-Ahead Market clearing process, and were not emergency or other out-of-market sales. He was not in a position to quantify the impact of DAAS costs on those exports. Finally, for information on how Regional Greenhouse Gas Initiative (RGGI) costs were impacting overall LMPs (up significantly since 2009), Mr. Matt White, the ISO's Chief Economist and Vice President of Market Development and Settlements, directed the member asking the RGGI cost questions to the annual and quarterly reports by the Internal Market Monitor (IMM) and External Markt Monitor (EMM), which reported on that information given their visibility into offer composition, including RGGI costs (~~and~~ information not otherwise available to those preparing the monthly System Markets & Operations Report).

LITIGATION REPORT

Mr. Lombardi referred the Committee to the February 4, 2026 Litigation Report that had been circulated and posted before the meeting. Mr. Lombardi highlighted 2 matters: (i) the preliminary injunctions and stays issued by DC and Massachusetts federal courts since the last Participants Committee meeting as to the second round of stop work orders issued by the U.S. Department of Interior's Bureau of Ocean Energy Management (BOEM) in December with respect to, among others, New England's off-shore wind projects under construction, allowing construction to proceed while the lawsuits remain pending; and (ii) the comments submitted in the Prompt Capacity Market and Deactivation Framework (CAR-PD) proceeding, none adverse (including NEPOOL's supplemental comments that provided additional context for the FERC record regarding NEPOOL's CAR-PD stakeholder process), and the expected timing for FERC action in that proceeding. Mr. Lombardi invited those with questions on the matters highlighted, or any matter in the Litigation Report, to reach out to NEPOOL Counsel. Ms. Bresolin encouraged members to avail themselves of the information provided in the Litigation Report.

COMMITTEE REPORTS

Markets Committee (MC). Mr. Ben Griffiths, MC Vice-Chair, reported that the next MC meeting would be on February 10-11, 2026 at the Westborough DoubleTree. He noted that discussion would focus principally on Capacity Auction Reforms – Seasonal Accreditation (CAR-SA), including treatment of intermittent power resources, hybrid resource modeling and accreditation, and impact analysis. And, as noted earlier in the meeting, he said that the IMM would present targeted recommendations on potential DAAS market improvements, followed by a summary of the IMM's Fall 2025 quarterly markets report.

Reliability Committee (RC). Mr. Frank Ettori, the RC Vice-Chair, reported that the next RC meeting would be held on February 12, 2026 also at the Westborough DoubleTree. He noted that, in addition to consideration of a VELCO Proposed Plan Application (PPA) and a Transmission Cost Allocation (TCA) for a National Grid Asset Condition Refurbishment project, the RC would consider changes to Operating Procedure Nos. 5 (to align Resource Outage Coordination Process with Prompt Auction Structure), 12 (updates to the Voltage Schedule Annual Transmittal Form) and 22 (changes to support ISO Phasor Measurement Unit/Central Phasor Data Concentrator Infrastructure Critical Infrastructure Protection compliance).

Transmission Committee (TC). Mr. Dave Burnham, TC Vice-Chair, reported that the next TC meeting would be held on February 24, 2026 at the Westborough DoubleTree. He reported that the TC was expected to continue discussion from January on Surplus Interconnection Service and the development of, and Tariff changes required to implement, the ISO's advisory role as asset condition project (ACP) reviewer.

Budget & Finance Subcommittee (B&F). Mr. Tom Kaslow, B&F Chair, reported that the B&F would meet the following day and that the previously scheduled February 19 B&F meeting had been cancelled.

Membership Subcommittee. Mr. Brian Thom~~p~~son, the Membership Subcommittee Chair, reported that the next Membership Subcommittee meeting would be held virtually on February 9. He encouraged those interested to participate and reach out to NEPOOL Counsel for the Zoom information.

Joint Nominating Committee (JNC). Ms. Bresolin reported that the two incumbent ISO Board Directors eligible for re-election in 2026 for an additional term (Messrs. Mark Vannoy and Craig Ivey) had been invited and were expected to join the Participants Committee in March to discuss their experiences serving on the ISO Board and answer Participant questions. Participant feedback on those Board members would be solicited following that discussion. Ms. Bresolin further noted that the JNC was looking forward to a collaborative process to identify and introduce later in the Spring an additional, new candidate for the 2026 slate. She encouraged members wishing to propose a candidate for consideration to do so by contacting their Sector JNC representative, who could also be contacted for a position specification for the new Board member candidate.

ADMINISTRATIVE MATTERS

Mr. Lombardi highlighted that the next Participants Committee meeting would be held in person, on March 5, 2026, at the nearby Sheraton Boston Hotel. Details for that meeting and overnight accommodations the night before would be provided early the following week.

There being no other business, the meeting adjourned at 11:31 am.

Respectfully submitted,

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Sebastian Lombardi, Secretary

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN THE FEBRUARY 5, 2026 MEETING

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Acadia Center	End User	Joe LaRusso (W)		
Advanced Energy United	Assoc. Non-Voting		Alex Lawton (W)	
AR Large RG Group Member	AR-RG	Aidan Foley (W)		
Ashburnham Municipal Light Plant	Publicly Owned Entity		Matt Ide (W)	Dan Murphy (W)
AVANGRID (CMP/UI)	Transmission	Alan Trotta (W)	Jason Rauch (W)	
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		Matt Ide (W)	Dan Murphy (W)
BP Energy Company (BP)	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity	Dave Cavanaugh		
Brookfield Energy Trading and Marketing LLC	Supplier	Aleks Mitreski		
Chester Municipal Light Department	Publicly Owned Entity		Dan Murphy (W)	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Matt Ide (W)	Dan Murphy (W)
Clear River Electric	Publicly Owned Entity		Dave Cavanaugh	
CLEAResult Consulting, Inc.	AR-DG	Tamera Oldfield (W)		
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw (W)	Richard Gaudet (W)	
Connecticut Office of Consumer Counsel	End User	Claire Coleman (W)	Jamie Talbert-Slagle (W)	JR Viglione (W)
Conservation Law Foundation	End User	Phelps Turner (W)		
Consolidated Edison Co. of New York, Inc.	Supplier	Matthew Napoli (W)		
Constellation Energy Generation (Constellation)	Supplier	Gretchen Fuhr (W)	Bill Fowler (W)	
CPV Towantic, LLC (CPV)	Generation	Joel Gordon (W)		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Dartmouth Power Associates, L.P.	Generation	Sarah Yasutake (W)		
Dominion Energy Generation Marketing, Inc.	Generation	Wes Walker (W)		
DTE Energy Trading, Inc. (DTE)	Supplier			José Rotger
Elektrisola, Inc.	End User			Bill Short
Emera Energy Services	Supplier			Bill Fowler (W)
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Eversource Energy	Transmission	Vandan Divatia (W)	Dave Burnham	
First Point Power	Supplier	Peter Schieffelin (W)	Bryan Amaral(W)	
FirstLight Power Management, LLC	Generation	Tom Kaslow (W)		
Fiscal Alliance Foundation, Inc.	End User	Paul Craney		
Gabel Associates, Inc.	Supplier	Sarah Yasutake (W)		
Galt Power, Inc.	Supplier	José Rotger	Jeff Iafrati (W)	
Garland Manufacturing Company	End User			Bill Short
Generation Bridge Companies	Generation		Steve Kirk	Bill Fowler (W)
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Green Oceans	End User		Lauren Knight (W)	
Groton Electric Light Department	Publicly Owned Entity		Matt Ide (W)	Dan Murphy (W)
Granite Shore Companies	Generation			Bob Stein
Grid United LLC	Provisional Member	Mike Spector		
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQUS)	AR-RG	Louis Guilbault (W)	Bob Stein	
Hammond Lumber Company	End User			Bill Short
Harvard Dedicated Energy Limited	End User	Joyceline Chow (W)		Doug Hurley (W)
High Liner Foods (USA) Inc.	End User		Bill Short	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Holyoke Gas & Electric Department	Publicly Owned Entity		Matt Ide (W)	Dan Murphy (W)
Hudson Light and Power Department	Publicly Owned Entity			Dave Cavanaugh
Hull Municipal Lighting Plant	Publicly Owned Entity		Matt Ide (W)	Dan Murphy (W)

(W) = Webex

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN THE FEBRUARY 5, 2026 MEETING

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Icetec Energy Services, LLC	AR-LR	Doug Hurley (W)		
Industrial Wind Action Group	End User	Lisa Linowes (W)		
Ipswich Municipal Light Department	Publicly Owned Entity		Matt Ide (W)	Dan Murphy (W)
Lamson, Jon	End User	Jon Lamson		
Littleton (MA) Electric Light and Water Dept.	Publicly Owned Entity		Dave Cavanaugh	
Long Island Power Authority (LIPA)	Supplier		Bill Kilgoar (W)	
Maine Power LLC	Supplier	Jeff Jones (W)		
Maine Public Advocate's Office	End User	Drew Landry		
Mansfield Municipal Electric Department	Publicly Owned Entity		Matt Ide (W)	Dan Murphy (W)
Marble River, LLC	Supplier	John Brodbeck (W)		
Marblehead Municipal Light Department	Publicly Owned Entity		Matt Ide (W)	Dan Murphy (W)
Mass. Attorney General's Office (MA AG)	End User	Jackie Bihrle	Jamie Donovan	Chris Modlish
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Department of Capital Asset Management	End User		Paul Lopes (W)	
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Matt Ide (W)	Dan Murphy (W)	
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	
Messer Energy Services, Inc.	Supplier		Bertin Legendre (W)	
Midcoast Regional Redevelopment Authority	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	Claire Lang-Ree			
Nautilus Power, LLC	Generation		Bill Fowler (W)	
New England Power (d/b/a National Grid)	Transmission	Tim Brennan	Tim Martin	
New England Power Gens. Assoc. (NEPGA)	Assoc. Non-Voting	Bruce Anderson	Dan Dolan	Molly Connors (W)
New Hampshire Electric Cooperative	Publicly Owned Entity			Brian Forshaw (W)
New Hampshire Office of Consumer Advocate	End User	Matthew Fossum		
NextEra Energy Resources, LLC	Generation	Michelle Gardner (W)		
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
NRG Business Marketing, LLC	Supplier	Ben Griffiths		
Nylon Corporation of America	End User			Bill Short
Pawtucket Power Holding Company	Generation	Dan Allegretti		
Paxton Municipal Light Department	Publicly Owned Entity		Matt Ide (W)	Dan Murphy (W)
Peabody Municipal Light Department	Publicly Owned Entity		Matt Ide (W)	Dan Murphy (W)
PowerOptions, Inc.	End User		Zach Gray-Traverso	Doug Hurley (W)
Princeton Municipal Light Department	Publicly Owned Entity		Matt Ide (W)	Dan Murphy (W)
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
RENEW Northeast, Inc.	Assoc. Non-Voting	Francis Pullaro		Carter Scott (W)
Rhode Island Energy (Narragansett Electric Co.)	Transmission	Brian Thomson		
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity		Matt Ide (W)	Dan Murphy (W)
Saint Anselm College	End User			Bill Short
Shell Energy North America (US), L.P.	Supplier	Jeff Dannels		
Shipyard Brewing LLC	End User			Bill Short
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Matt Ide (W)	Dan Murphy (W)
Sliski, Alan	End User	Alan Sliski (W)		
South Hadley Electric Light Department	Publicly Owned Entity		Matt Ide (W)	Dan Murphy (W)
Sterling Municipal Electric Light Department	Publicly Owned Entity		Matt Ide (W)	Dan Murphy (W)
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Taunton Municipal Lighting Plant	Publicly Owned Entity	Nick Parrotta (W)	Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity		Matt Ide (W)	Dan Murphy (W)

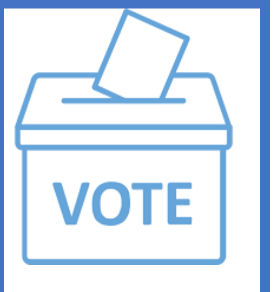
(W) = Webex

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN THE FEBRUARY 5, 2026 MEETING

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

(W) = Webex

2 Consent Agenda



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1. Revisions to OP-5 (to align Resource Outage Coordination Process with Prompt Auction Structure)
2. Revisions to Appendix D to OP-12 (Biennial Review – Updates to Options A and B High Side Visibility to Match NX Application Nomenclature)
3. Revisions to OP-22 and Appendix C to OP-22 (PMU/Central PDC Infrastructure CIP Compliance Revisions)

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

CONSENT AGENDA

Reliability Committee (RC)

From the previously-circulated notice of actions of the RC's ***February 12, 2026*** meeting, dated February 12, 2026.[1]

1. **Revisions to OP-5 (to align Resource Outage Coordination Process with Prompt Auction Structure)**

   Support proposed revisions to OP-5 (Resource Maintenance and Outage Scheduling),[2] as recommended by the RC at its February 12, 2026 meeting, together with such non-material changes as may be approved by the RC Chair and Vice-Chair.

   The motion to recommend Participants Committee support was approved unanimously.

2. **Revisions to Appendix D to OP-12 (Biennial Review – Updates to Options A and B High Side Visibility to Match NX Application Nomenclature)**

   Support proposed revisions to OP-12 (Voltage and Reactive Control), Appendix D (Voltage Schedule Annual Transmittal Form),[3] as recommended by the RC at its February 12, 2026 meeting, together with such non-material changes as may be approved by the RC Chair and Vice-Chair.

   The motion to recommend Participants Committee support was approved unanimously.

3. **Revisions to OP-22 and Appendix C to OP-22 (PMU/Central PDC Infrastructure CIP Compliance Revisions)**

   Support proposed revisions to OP-22 (Disturbance Monitoring Requirements) and Appendix C to OP-22 (New England PMU Registration),[4] as recommended by the RC at its February 12, 2026 meeting, together with such non-material changes as may be approved by the RC Chair and Vice-Chair.

   The motion to recommend Participants Committee support was approved unanimously.

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

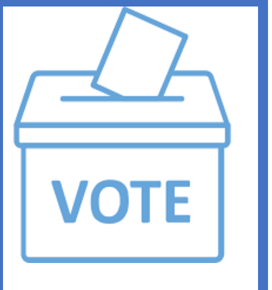
[2] The OP-5 revisions include: (i) streamlined outage submission requirements for generators and intermittent power resources; (ii) changed Demand Response Resource (DRR) submission requirements and import capacity resource outage requirements clarifications; (iii) reflect end to annual and monthly reliability reviews upon occurrence of first prompt auction; (iv) revised planned outage request evaluation process to support prompt auction structure, including addition of pre- and post-annual auction flowcharts; (v) definition of outage status within the outage scheduling software; (vi) simplifications to the reliability resolution process; and (vii) clarifications and grammar edits throughout.

[3] The OP-12, Appendix D changes primarily update Options A and B High Side Visibility to Voltage Control Bus Visibility to match NX Application nomenclature.

[4] The OP-22 and OP-22 Appendix C changes are primarily to support ISO Phasor Measurement Unit (PMU)/Central Phasor Data Concentrator (PDF) Infrastructure CIP (Critical Infrastructure Protection) compliance. The proposed revisions complement the revisions to OP-2, Appendix A.

2A

OP-2A Revisions



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To consider, and take action, as appropriate, on revisions to Appendix A (Itemized Equipment) to OP-2 (Maintenance of Communications, Computers, Metering and Computer Support Equipment)

RESOLVED, that the Participants Committee supports the OP-2A Revisions, as proposed by the ISO and as circulated to the Participants Committee in advance of its March 5, 2026 meeting, together with [any changes agreed to at the meeting and] such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.

MEMORANDUM

TO: NEPOOL Participants Committee

FROM: Eric Runge, NEPOOL Counsel

DATE: February 26, 2026

RE: Vote on Appendix A to Operating Procedure No. 2 (“OP-2A”) Revisions

---

At the March 5, 2026, Participants Committee (“NPC”) meeting, you will be asked to vote on proposed revisions to Appendix A to OP-2 (“OP-2A Revisions”). The OP-2A Revisions relate to OP-2A’s itemized listing of system communications, computers, metering and computer support equipment and the maintenance priority for such equipment. Background materials are included with this memorandum.[1]

The Reliability Committee (“RC”) unanimously recommended NPC support for revisions to OP-2, together with the OP-2A Revisions in a vote on August 19, 2025. Since that vote, the ISO determined that it needed to do further work with stakeholders on the related Operating Procedure No. 22 (“OP-22”) before bringing the OP-2A Revisions for a vote by the NPC. The additional OP-22 work concluded with a unanimous vote by the RC at its February 12 meeting to recommend NPC support for the OP-22 revisions. Those revisions are on the Consent Agenda for the March 5 NPC meeting.

Since the August 19 RC vote, the ISO also made a minor change to the OP-2A revisions that the RC previously recommended. That change removes Dynamic Data Recorders from the items listed in OP-2A. Aside from this removal of Dynamic Data Recorders from the scope of OP-2A, the OP-2A Revisions are the same as what the RC reviewed and unanimously recommended for Participants Committee support. These OP-2A revisions would have been on the Consent Agenda but for this minor but substantive change.

The following resolution could be used for NPC consideration of the OP-2A Revisions:

> RESOLVED, that the Participants Committee supports the OP-2A Revisions, as proposed by the ISO and as circulated to the Participants Committee in advance of its March 5, 2026 meeting, together with [any changes agreed to at the meeting and] such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.

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[1] Background materials include: (i) A memo from the ISO on the OP-2A Revisions; (ii) OP-2A marked to show (a) the Aug. 19 RC-recommended changes and (b) the subsequent minor, but substantive changes (highlighted in yellow); and (iii) the ISO presentation for the Aug, 19 RC meeting at which OP-2 and OP-2A were voted.

memo

To: NEPOOL Participants Committee (PC)

From: Andrew Kopacka, Manager, Resource Outage Coordination and Dean LaForest, Manager, Real-Time Studies

Date: February 26, 2026

Subject: ISO New England Operating Procedure No. 2, Appendix A

The ISO is requesting a vote on revisions to ISO New England Operating Procedure No. 2, Appendix A – Itemized Equipment (OP-2A). By way of background, in response to stakeholder feedback, the ISO elected to defer its requested September 2025 PC vote on OP-2A to align with the timing for completing the stakeholder process for Operating Procedure No. 22 – Disturbance Monitoring Requirements (OP-22). At the February 2026 Reliability Committee (RC) meeting, the committee completed its discussions of the OP-22 revisions and unanimously recommended PC support.

The revisions to OP-2A document required response times for Phasor Measurement Unit (PMU) and Phasor Data Concentrator (PDC) infrastructure repair notifications and were supported by the RC at its August 2025 meeting. These revisions complement the RC-recommended OP-22 revisions and allow the ISO to achieve the full benefit from Critical Infrastructure Protection (CIP) compliance.

Following the August RC meeting, the ISO has made further changes to OP-2A in response to stakeholder feedback. Specifically, these additional revisions remove required response times for Dynamic Data Recorders (DDRs)[1]. In addition, the ISO removed a proposed footnote that was originally intended to clarify the effective date of OP-2A in relation to OP-22. This footnote is no longer applicable as the ISO is now proposing that both OP-2A and OP-22 will be made effective in April 2026, following PC approval.

The proposed revisions to OP-2A for the PC's consideration have been presented at the RC meeting dates outlined below:

- June 17, 2025; agenda item #6.1
- July 15-16, 2025; agenda item #14.1
- August 19, 2025; agenda item #6.1

[1] The removal of DDRs from OP-2A was noted in the February 2026 RC OP-22 materials.

ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841

Appendix A - Itemized Equipment Maintenance of Communications, Computers, Metering and Building Services

Effective Date: ~~October 4, 2023~~Draft

Review By Date: ~~October 4, 2025~~Month day, year

Table of Contents

This document is controlled when viewed on the ISO New England Internet web site. When downloaded and printed, this document becomes ***UNCONTROLLED****, and users should check the Internet web site to ensure that they have the latest version.*

NOTE

1. The following indicate that resources are needed to accomplish repairs per OP-2:
   A. Immediate.
   B. Regular staff hours except if more than sixteen (16) hours removed from service.
   C. Regular staff hours.
2. Any equipment **not** specifically mentioned in Table 1 will be assessed on a case-by-case basis with the Operating Staffs at ISO New England, the Local Control Center (LCC) and supervisory control and data acquisition (SCADA) Centers.

Table 1 - Itemized Equipment Maintenance of Communications, Computers, Metering and Building Services

	Maintenance Priority (See NOTE 1)
Control Room Computer Equipment for ISO New England MCC or BCC	
Any equipment or device that may interrupt or alter the flow of data critical to system operation via the Energy Management System (EMS) / unit dispatch and scheduling (UDS)	A
Control Room:	
Printers / copiers	B
Operator console keyboards / mouse	A
Operator console monitors	A
Operator console computers	A
Control Room Support Equipment for ISO New England MCC or BCC	
Computer heating, ventilation and air conditioning (HVAC) equipment	A
Fire protection system	A
Control Room HVAC equipment	A
Uninterruptible power supply (UPS)	A
Frequency measurement devices	B
Security system devices	B
Pool Control Error Calculator (PCEC)	A
Wallboard / situational awareness displays	B
Outage scheduling software	B
Telephone voice recorder	A

Communication Systems	
Dispatcher microwave telephone equipment - microwave equipment directly affecting the ISO New England facility. Includes all channels such as loop and spur RF equipment affecting loop operation, all loop closing equipment, and all other loop and Local Control Center spur station equipment having an effect on ISO New England channels	A
ISO New England Voice Communication Systems	
Telephone circuit - ISO New England / Local Control Center / SCADA Centers; or resources' Designated Entity or Demand Designated Entity	B
Telephone circuit - ISO New England/NYISO	A
Telephone circuit - ISO New England/New Brunswick	A
Telephone circuit - ISO New England/Hydro Quebec-TransEnergie	A
Control room direct dial outside lines	A
Shared telecommunication network (STN) voice circuits	A
Emergency notification system (ENS)	A
ISO New England Telemetering, and Data Communications	
Data links and circuits supporting ICCP - ISO New England/ Local Control Center /SCADA Centers	A
ISO New England tie-line telemetering - primary circuit	A
ISO New England tie-line telemetering - secondary circuit	B
Reliability Coordinator Information System (RCIS)	A
Weather services (includes data links, and monitors)	B
Remote Terminal Units (RTUs) located at ISO	A
Shared Telecommunication Network (STN) data circuits supporting ICCP	A
ISO New England Control Center, Local Control Center, SCADA Center Computers, Inter Control Center Communications Protocol (ICCP), Phasor Measurement Unit (PMU), ~~Dynamic Data Recorder (DDR)~~ and Remote Terminal Unit (RTU) Equipment ~~1~~	
Any equipment or device that may interrupt or alter the flow of data critical to system operation via the ISO New England EMS / electronic dispatch software	A
RTU communication, and control circuits for units capable of providing regulation	A
RTU for electronic dispatch of generation	A
RTU and analog telemetry supplying data to Local Control Center computers	B
Phasor Data Concentrator (PDC) and related equipment	A
PMU ~~/ DDR~~ and related equipment	B
Communications channels for RAS/ACS protection systems	A

~~1 Note that the revisions to include PMUs, DDRs, and PDCs contained in this table will not be effective until corresponding changes to Operating Procedure 22 are made effective by the end of Q4 2025.~~

OP-2 Appendix A Revision History

Document History (This Document History documents action taken on the equivalent NEPOOL Procedure prior to the RTO Operations Date as well revisions made to the ISO New England Procedure subsequent to the RTO Operations Date.)

Rev. No.	Date	Reason
--~~Rev 1~~	Draft~~02/01/05~~	For previous revision history, refer to Rev 10 available through Ask ISO.~~Updated to conform to RTO terminology~~
~~Rev 2~~	~~02/22/05~~	~~Update to include the Outage Scheduler under the 'A' requirements which prioritizes it as requiring immediate attention for repairs~~
~~Rev 3~~	~~03/23/05~~	~~Update to include the ICU Auto Call and the ENS under the 'A' requirements which prioritizes it as requiring immediate attention for repairs~~
~~Rev 4~~	~~12/18/08~~	~~Annual Review by Procedure Owner.~~ ~~Revised terminology for current equipment~~ ~~Changed Outage Scheduler to Outage Scheduling software~~
~~Rev 5~~	~~6/1/10~~	~~Add Demand Designated Entity Communications equipment to the procedure~~
~~Rev 6~~	~~08/03/12~~	~~Biennial review by procedure owner;~~ ~~Administrative changes: changed font to Arial, converted text to a table format, changed pagination format to "x of y", Added Uncontrolled disclaimer to 1st page Footer, added "Hard Copy is Uncontrolled" disclaimer to all page Footers, modified to provide Headings for automatic TOC generation, added a TOC.~~ ~~In Control Room Support Equipment at ISO New England, deleted ICU Auto Call data row, defined and added acronym ENS;~~ ~~In LCC, SCADA Center etc section, defined and added acronym ICCP, defined and added acronym for RTU for use in later instances modified section titles and edited Note 2 to delete reference to Mystic and FPL.~~
~~Rev 7~~	~~05/07/14~~	~~Biennial review by procedure owner;~~ ~~Updated to remove DMT language;~~ ~~Administrative changes required to publish the next Revision~~
~~Rev 8~~	~~03/14/16~~	~~Biennial review by procedure owner completed;~~ ~~Added "OP-2" to the note in the last item in the ISO New England Telemetering, and Data Communications section of Table 1;~~
~~Rev 8.1~~	~~02/01/18~~	~~Biennial review by procedure owner completed requiring no changes;~~ ~~Made administrative changes required to publish a Minor Revision (including adding required corporate document identity to all page footers);~~
~~Rev 9~~	~~11/01/19~~	~~Biennial review by procedure owner completed;~~ ~~Globally, editorial changes consistent with current conditions, practices and management expectations;~~
~~Rev 10~~	~~10/07/21~~	~~Biennial review by procedure owner completed; Deleted reference to party line in ISO New England Voice Communications section; Clarified what removed meant in Note section above Table 1;~~
Rev 10.1	10/04/23	Biennial review by procedure owner requiring no intent changes; Defined acronyms; Removed reference to SPS; Made administrative changes required to publish a Minor Revision.

Rev 11	Draft	Biennial review performed by procedure owner; Added PDC and PMU ~~/ DDR~~ to Table 1; ~~Added Note 1 on page 3 to clarify PMU/DDR/PDC effective dates based on OP22 publication.~~

NEPOOL RELIABILITY COMMITTEE | AUGUST 19, 2025 | WESTBOROUGH, MA

OP-2 and Appendix A – Maintenance of Communications, Computers, Metering and Computer Support Equipment

Revisions to add NERC standards to references, update listings of Control Centers, Phasor Measurement Units (PMUs), and Dynamic Data Recorders (DDRs), update language to reflect current practice, and other minor revisions

Dean LaForest

MANAGER, REAL-TIME STUDIES

Operating Procedure No. 2 and Appendix A Overview

- The ISO is proposing changes to OP-2 and Appendix A with two unique drivers and effective dates:
  - Updates associated with the scheduling of planned maintenance
    - Removal of steps for the Resource Analyst to approve or disapprove OP-2, Appendix C requests to align with current practice
    - Addition of steps to verify all OP-2, Appendix C submission information is included, and to resolve any conflicts
    - Proposed Effect Date – By 9/30/25
  - Updates to achieve compliance with NERC Standard CIP-002-5.1a
    - Addition of PDCs, DDRs, and PMUs to the list of itemized equipment and their associated maintenance priority (Table 1)
      - Maintenance priority is based upon impact to PMU data availability.
        - » Equipment with “A” priority requires immediate repair (PDCs)
        - » Equipment with “B” priority requires repair during regular staff hours, except if more than 16 hours removed from service (PMUs/DDRs)
    - Proposed Effect Date – By January 2026

Clarification of Equipment Repair Timeline

- As stated in OP-2 (Part III.I), the ISO does not expect equipment repairs to be completed within a two-day timeframe
  - “The following criteria identify required response times to ***begin*** repair of failed equipment”
- The expectation is to begin repairs within two days of equipment failure and to return to service in a reasonable amount of time
- In circumstances where unforeseen delays occur, equipment owners should contact the ISO with regular updates and a timeline for the affected equipment’s return to service
  - The ISO is willing to work with equipment owners, assuming reasonable efforts being made toward repair

Example of Acceptable Equipment Repair Timeline

Equipment Failure Occurs

- Priority "A" devices
- Includes PDCs

Begin Repairs

- Repairs are expected to begin immediately after outage

Complete Repairs

- Repairs are expected to be completed immediately after outage
- Equipment owners shall communicate updated repair schedule in situations where repairs will not be completed in time

Equipment Failure Occurs

- Priority "B" devices
- Includes PMUs, DDRs

Begin Repairs

- Repairs are expected to begin within 16 regular staff hours of outage

Complete Repairs

- Repairs are expected to be completed within a reasonable amount of time and equipment owners shall communicate updated repair schedule in situations where repairs will not be completed in time

OP-2 and Appendix A Changes – Updated

Section	Procedure Change	Reason for Change
OP-2 Appendix A – Footnote 1	1 Note that the revisions to include PMUs, DDRs, and PDCs contained in this table will not be effective until corresponding changes to Operating Procedure 22 are made effective by the end of Q4 2025.	Effective date for Table 1 revisions will coincide with upcoming revisions to OP-22
OP-2 Appendix A – Note	**NOTE** 1. The following indicate that resources are needed to accomplish repairs per OP-2: A. Immediate. B. Regular staff hours except if more than sixteen (16) hours removed from service. C. Regular staff hours. 2. Any equipment **not** specifically mentioned in Table 1 will be assessed on a case-by-case basis with the Operating Staffs at ISO New England, the Local Control Center (LCC) and supervisory control and data acquisition (SCADA) Centers.	Aligns repair timelines between OP-2 and Appendix A

Conclusion

- The ISO is proposing changes to OP-2 and Appendix A with two unique drivers and effective dates:
  - Updates associated with the scheduling of planned maintenance
  - Updates to achieve compliance with NERC Standard CIP-002-5.1a
- Proposed Effective Dates:
  - Updates to scheduling of planned maintenance – By 09/30/25
  - Updates to Achieve CIP Compliance – By January 2026

Stakeholder Schedule

Stakeholder Committee and Date	Scheduled Project Milestone
Reliability Committee June 17, 2025	Initial presentation and questions
Reliability Committee July 15-16, 2025	Additional background and questions
Reliability Committee August 19, 2025	Respond to any remaining questions and vote
Participants Committee September 4, 2025	Vote

APPENDIX

OP-2 and Appendix A Redlines Presented at June RC and July RC Meetings

OP-2 and Appendix A Changes

Section	Procedure Change	Reason for Change
OP-2 References	**ISO New England Operating Procedure No. 2** **Maintenance of Communications, Computers, Metering and Computer Support Equipment** **Effective Date:** **~~May 22, 2024~~Draft** **Review By Date:** **~~May 22, 2026~~Month day, year** **References:** NERC Reliability Standard IRO-002, Reliability Coordination - Monitoring and Analysis NERC Reliability Standard IRO-010, Reliability Coordinator Data and Information Specification and Collection NERC Reliability Standard TOP-001, Transmission Operations NERC Reliability Standard TOP-003, Transmission Operator and Balancing Authority Data and Information Specification and Collection	Adds NERC Standards IRO-010 and TOP-003

OP-2 and Appendix A Changes, cont'd

Section	Procedure Change	Reason for Change
OP-2 Part II – Scope	**PART II - SCOPE** This OP covers certain critical equipment located at: • Main Control Centers[1] (MCCs) and Backup Control Centers (BCCs) for: o ISO o ~~CONVEX~~Local Control Centers (LCCs) ~~o Maine~~ ~~o New Hampshire~~ ~~o NGRID~~ ~~o NSTAR~~ ~~o RIE~~ ~~o VELCO~~ • Supervisory Control and Data Acquisition[2] (SCADA) Centers located ~~at:~~in New England. ~~o Versant Power~~ ~~o National Grid Companies~~ ~~o United Illuminating Company~~ • Microwave, Phasor Measurement Unit (PMU), Dynamic Data Recorder (DDR) / related equipment and communication facilities located remotely from ISO and the ~~Local Control Centers (~~LCCs~~)~~, that have an impact on operations.	Removes listing of each individual LCC and SCADA Center Adds PMUs and DDRs

OP-2 and Appendix A Changes, cont’d

Section	Procedure Change	Reason for Change
OP-2 Part III – Procedure, Section IV: Scheduling of Planned Maintenance Throughout OP-2 for grammar and position changes	**C. Procedure to Schedule ISO Control Center ~~Routine~~ Planned Maintenance** 1. The ISO contact listed in OP-2B shall: a. Determine the equipment involved in the planned maintenance request b. Determine the effect on system operations c. Complete the Equipment Maintenance Request Form OP-2C d. Make any preliminary notifications to contacts at the affected LCCs ~~counterparts~~ e. By 1200 on Friday, forward the planned maintenance request for work beginning the following Monday at 0700 through the next seven (7) day period to the ISO ~~Outage Coordinator~~Resource Analyst~~.~~ 2. By 1500 on Friday t~~T~~he ISO ~~Outage Coordinator~~Resource Analyst shall~~, by 1500 on Friday~~: a. Review each received planned maintenance request submitted via OP-2C and ensure all required information is included ~~a.~~b. Resolve any noted conflicts ~~submitted maintenance request and provide verbal approval or disapproval to the applicant.~~ ~~b.~~c. Electronically communicate the final approved maintenance schedule (~~see~~ OP-2D) for the following week to each organization listed in OP-2B~~.~~ ~~c.~~d. Electronically communicate the planned maintenance request to each appropriate RC contact listed in OP-2D~~.~~	Removes steps for the Resource Analyst to approve or disapprove OP-2, Appendix C requests to align with current practice Adds steps to verify all OP-2, Appendix C submission information is included, and to resolve any conflicts Replaces “routine” and “proposed” with “planned” Replaces “Outage Coordinator” with “Resource Analyst”

OP-2 and Appendix A Changes, cont'd

<table>
<tr><th>Section</th><th>Procedure Change</th><th>Reason for Change</th></tr>
<tr><td>OP-2
Appendix A –
Table I</td><td>
<table>
<tr><th>ISO New England Control Center, Local Control Center, SCADA Center Computers, Inter Control Center Communications Protocol (ICCP), Phasor Measurement Unit (PMU), Dynamic Data Recorder (DDR) and Remote Terminal Unit (RTU) Equipment</th><th></th></tr>
<tr><td>Any equipment or device that may interrupt or alter the flow of data critical to system operation via the ISO New England EMS / electronic dispatch software</td><td>A</td></tr>
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<tr><td>PMU / DDR and related equipment</td><td>B</td></tr>
<tr><td>Communications channels for RAS/ACS protection systems</td><td>A</td></tr>
</table>
</td><td>Adds PDCs, PMUs and DDRs</td></tr>
</table>

3 JNC Update

CRAIG IVEY

MARK VANNOY

MARCH 5,2026

NEPOOL Participants Committee

2026 Joint Nominating Committee

Cheryl LaFleur, Board Chair

Brook Colangelo, JNC Committee Chair

Goal for 2026 Joint Nominating Committee (JNC)

To nominate and present the slate of ISO New England Board of Directors candidates for election and/or re-election to the Participants Committee for vote.

Critical Success Factors for Directors

- Belief in our purpose as defined by our Mission, Vision, Values
- Commitment to inclusion and a diversity of backgrounds and experiences
- Comfort in an ever-changing environment
- Comprehension and support of our strategic goals
- Expertise in critical skills and experiences required for success and compliance with the Participant Agreement

Critical Skills and Experience Required on the ISO-NE Board of Directors

- Electric Industry/Transmission Experience (at least 3 Directors per the Participants Agreement)
- Markets Expertise (Energy and/or Financial)
- Top Corporate Officer with strong leadership, governance, human resources skills
- Public Service/Regulatory Experience
- Audit and Financial Expertise
- Information Technology/Cyber Security Expertise
- Regional Presence (New England Residents preferred per the Participant's Agreement)

2026 JNC Process Schedule

Date	Action
January 21	JNC Kickoff
February	Virtual review of candidate profiles
March 5	Brook & Cheryl to give JNC overview to PC; Craig Ivey and Mark Vannoy to present to PC
March 17	Interview with candidates, in Boston
April 7/8	Dates held for follow-up candidate interviews, if needed
April/May	NEPOOL and NECPUC socialize resumes with necessary parties and provide feedback to JNC
May	ISO Board members, not on finalist slate, meet candidate; search firm completes background and reference check
June	NEPOOL PC to vote
June or September	N&G Committee nominates and Board elects Directors

2026 Slate for Presentation to NEPOOL

In 2026, three Directors' terms end, and two are eligible for re-election. The two incumbents eligible for re-election are:

- **Craig Ivey**
- **Mark Vannoy**

The Nominating and Governance Committee of the ISO New England Board recommends these two directors be re-elected given their clear demonstration of all six critical success factors and the importance of continuity on the Board.

To maintain the knowledge, skills, and experiences required for the ISO-NE Board, the JNC is focusing their external search on individuals with:

- **Information Technology and Cyber Security expertise**
- **Board governance experience**
- **Regional connection**

Information Technology and Cybersecurity

- Information Technology (IT) is critical to ISO-NE's ability to deliver on every element of its strategy especially during times of great change. IT enables the organization's success in markets, transmission, and planning, while also supporting a future ready workforce.
- Cybersecurity remains a top strategic risk as nation-state sponsored threats to the ISO's ability to reliably operate the grid and provide services to the region continue to evolve and become more sophisticated.
- In 2026, IT/Cybersecurity represents over 34% of ISO-NE's operating budget.
- The 2026 Capital budget is $42.5M, of which 44% are IT-specific projects (although a larger portion involve IT).
- IT/cybersecurity experts are prevalent on other ISO/RTO Boards as well as Boards throughout our industry. Surveys indicate that IT/cybersecurity expertise is the most sought-after skill in new Board members.
- The ISO Board will lose the current IT/cybersecurity expertise over the next three years

Craig Ivey

Craig Ivey joined the ISO New England Board in 2023. He served as president of Consolidated Edison Company of New York, Inc. for nine years, retiring in 2017. While in this role, he was responsible for all aspects of the electric system that serves over 9 million New Yorkers. Ivey previously spent 25 years at Dominion Energy, rising through the ranks from a part-time position during his college years to become senior vice president of transmission and distribution. He serves on the board for Ameren Corporation. Ivey has a Bachelor of Science degree in electrical engineering from North Carolina State University.

Craig currently sits on the ISO-NE Board of Directors' Markets Committee, Compensation & HR Committee, and the Audit & Finance Committee.

Mark Vannoy

Mark Vannoy is president of Maine Water, having joined that company in 2019 as vice president after serving on the Maine Public Utilities Commission (PUC) for seven years. During his tenure at the Maine PUC, which included serving four years as chairman, Vannoy adjudicated more than 2,200 cases involving electric, gas, and water utilities. He also served as a board member of the National Association of Regulatory Utility Commissioners, a member of the Critical Infrastructure and Water Committees, and board chair of the New England Utility Cybersecurity Information Collaborative. Vannoy proudly served in the US military for 20 years and is a retired US Navy officer. He is a graduate of the United States Naval Academy and has a master's degree in civil and environmental engineering from Cornell University.

Mark currently Chairs the ISO-NE Board of Directors' IT/Cyber Security Committee, and sits on the System Planning & Reliability Committee, and the Nominating & Governance Committee.

4 CEO Report

Mar 5, 2026
Meeting

NEPOOL
NEW ENGLAND POWER POOL
Participants Committee

Summary of ISO New England Board and Committee Meetings

March 5, 2026 Participants Committee Meeting

Since the last update, the Board and committees held virtual meetings as follows: the Compensation and Human Resources Committee on February 11; the Audit and Finance Committee and the Nominating and Governance Committee on February 18; the Information Technology and Cyber Security Committee and the Board of Directors on February 19.

The Compensation and Human Resources Committee discussed the Company's corporate performance for 2025, and reviewed the feedback from various committees of the Board regarding specific projects completed in 2025. The Committee then conducted its annual risk assessment and reviewed the key risks within the Committee's oversight. During executive session, the Committee preliminarily considered officer compensation for 2026, including information about the reasonableness of that compensation from Mercer, the Company's compensation consultant.

The Information Technology and Cyber Security Committee was provided with an update on the Company's cyber security plan, and discussed completed projects and the plan's major areas of emphasis going forward. The Committee also considered the sufficiency of the Company's cyber security insurance coverage during its annual cyber insurance review, and noted the coverage levels and the current cyber security insurance risk environment. The Committee also conducted its annual risk assessment and reviewed the key risks within its purview, as well as ways to mitigate those risks.

The Nominating and Governance Committee received an update on Joint Nominating Committee activities and reviewed the nomination process for 2026, and discussed the importance of insuring that the Board has adequate expertise in cyber security and information technology. The Committee then undertook its annual assessment of the risks within its purview. The Committee also considered topics for discussion at the Board's meeting with the states in March. The Committee then considered a draft of the Company's 2026 communications plan, and offered various comments. The Committee also agreed to launch the process for Board and committee self-evaluations in mid-March, and received an update on strategic planning activities.

The Audit and Finance Committee met with the Company's Investment Manager for a review of the Company's benefits plan assets and 401(k) plan, an analysis of investment options, and details regarding the mix, cost, and performance of plan investments. The Committee approved significant accounting estimates used in the Company's budgeting and financial statements, including earnings and discount rates, health care trends, and depreciation. The Committee then reviewed the annual vendor report, which illustrated the year over year change in vendor spending and highlighted key vendors and risks associated therewith. The Committee also considered the structure of the Company's compliance and risk management programs, which included a review of the Company's physical security, plans for business continuity during critical events, and a review of risks within the Committee's oversight. The Committee reviewed a proposal for bond-specific financing options for the purchase and construction of an additional facility at Whiting Farms Road, agreed to authorize the Company to borrow the proceeds of tax-exempt bonds, and considered the need for a zero-cost collar or similar hedging facility. The Committee then met in executive session and reviewed Internal Audit Department results for 2025 and reflected on the performance and 2026 compensation for the Director of Internal Audit.

The Board of Directors began its meeting in executive session, and considered and approved the recommendations of the Compensation and Human Resources Committee regarding corporate performance results for 2025 and officer compensation for 2026, after discussing the reasonableness of that compensation and competitive market conditions. The Board then received a report from the senior leadership team on current business. The report included an update on winter operations, highlighting the excellent performance by the ISO, the generation fleet, strong coordination with the states, federal agencies, stakeholders and several challenges. The Board also received an update on the Company's strategic planning process. The Board also received updates on the Capacity Auction Reforms project, which is proceeding on schedule, and progress toward the establishment of the Company as an Asset Condition Reviewer for the region. The Board then received reports from the standing committees, and discussed the Nominating and Governance Committee's recommended topics for discussion at the meeting with the states in March.

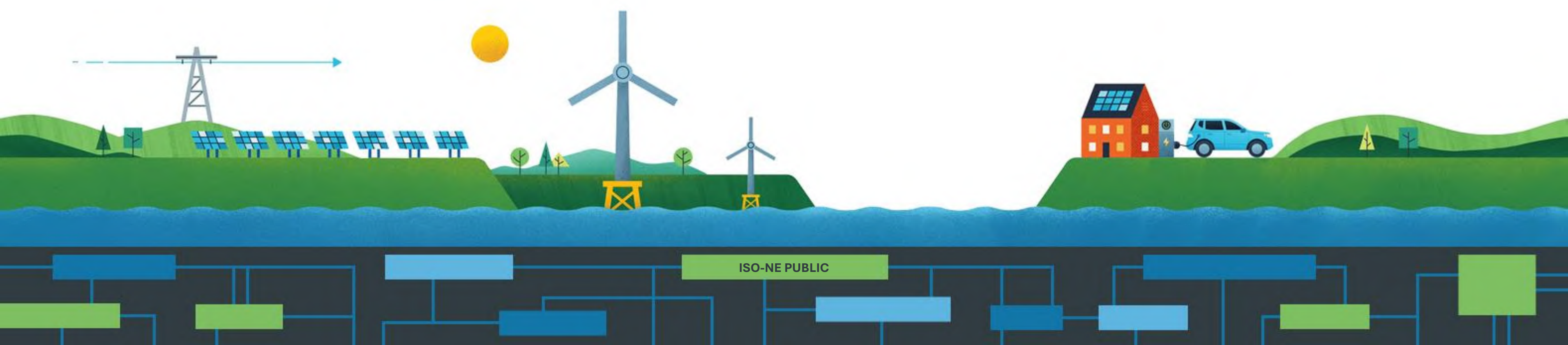
5 Systems & Market Operations Report

Mar 5, 2026
Meeting

NEPOOL Participants Committee

System & Market Operations Report – March 2026

Stephen M. George
VICE PRESIDENT, SYSTEM & MARKET OPERATIONS AND CAPITAL PROJECTS



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HIGHLIGHTS

Settled data through February 25th

Highlights: February 2026

- **Peak Hour** on February 8
  - 20,178 MW system peak (Revenue Quality Metered/RQM); hour ending 6:00 p.m.
- **Minimum Telemetered Load**
  - 11,064 MW; hour ending 1:00 p.m. on Sunday, February 15
- **Average Pricing**
  - Day-Ahead (DA) Hub Locational Marginal Price (LMP): $134.93/MWh
  - Real-Time (RT) Hub LMP: $136.29/MWh
  - Natural Gas: $15.44/MMBtu (MA Natural Gas Avg)
- **Energy Market** value $1.44B up from $1.38B in February 2025
  - Ancillary Markets* value $15.8M up from $4.8M in February 2025
  - Average DA cleared physical energy** during the peak hours as percent of forecasted load was 99.6% during February, down from 100.2% during January
  - Updated January Energy Market value: $2.7B
- **Net Commitment Period Compensation (NCPC)** total $3.4M
  - Represents 0.2% of monthly Energy Market value
  - First Contingency $3.4M
    - Dispatch Lost Opportunity Cost (DLOC) - $1.1M; Rapid Response Pricing (RRP) Opportunity Cost - $258K; Posturing - $0; Generator Performance Auditing (GPA) - $0
    - $28K paid to resources at external locations, down $85K from January
      - $9K charged to Day-Ahead Load Obligation (DALO) at external locations; $18K to Day-Ahead Generation Obligation (DAGO) at external locations; $1K to RT Deviations
  - 2nd Contingency, Distribution and Voltage was zero
- **Forward Capacity Market (FCM)** market value $88.9M
  - FCM peak for 2026 is currently 19,937 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: **20,182 MW**
  - hour ending 2:00 p.m. on Sunday, January 25
- RQM System Peak Load: **20,221 MW** (initial)
  - hour ending 2:00 p.m. on Sunday, January 25
- FCM Peak Load: **19,937 MW** (preliminary & subject to change)
  - hour ending 1:00 p.m. on Sunday, January 25
  - At this hour, the capacity zone-level FCM peak loads were 2,814 MW in Northern New England, 1,832 MW in Maine, 7,535 MW in Rest-of-Pool, and 7,756 MW in Southeast New England.

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

Day-Ahead Ancillary Services (DAAS) Results

- Average daily total DA E&AS Market value: **$59.3M**
- DAAS Settlements:
  - Average daily Gross (pre-closeout) DAAS Credits: **$1,784K**
    - Includes EIR, TMOR, TMNSR, and TMOR
  - Net (post-closeout) DAAS Credits per MWh Cleared: **$15.09/MWh**
  - Net (post-closeout) DAAS Credits as % of total DA E&AS Value: **1.5%**
- FER Credits* as % of total DA E&AS Market Value: **6.3%**
- Energy Gap:
  - Average hourly cleared EIR MWh: **115 MWh**
  - Average hourly cleared FER Price: **$9.56/MWh**

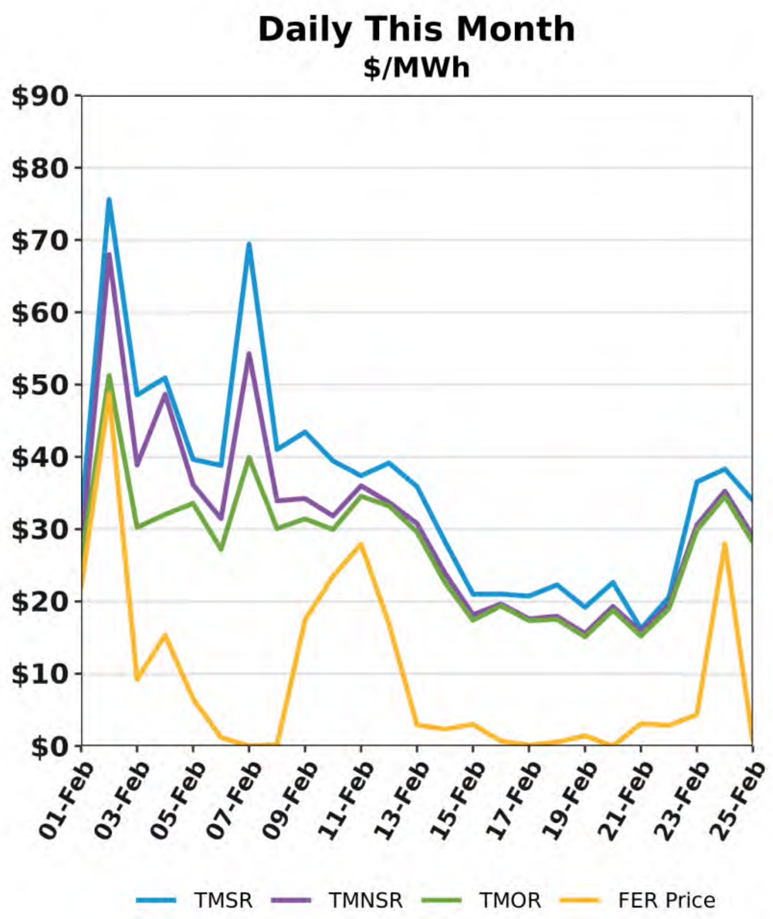
DA E&AS refers to DA Energy and Ancillary Services
*FER credits are paid to all DA cleared energy supply from physical resources (Gen, Imports, DRR)
FER credits are charged to RTLO excluding RTLO associated with RT Exports and Dispatchable Asset Related Demand (DARDs)

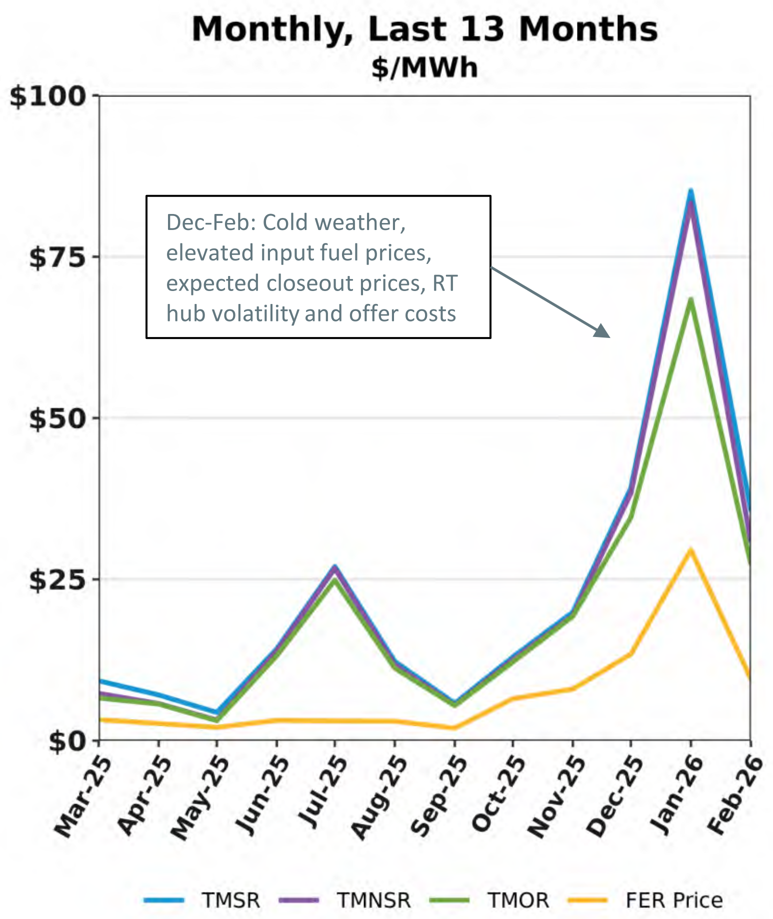
DAAS Results (continued)...

Month	Avg. Daily Total DA E&AS Credit	Avg. Daily DAAS Credit	Avg. Daily DAAS Net Credits (post-closeout)	DAAS Net Credits per MWh Cleared	DAAS Net Credits as % of Total DA E&AS Credit	Avg. Daily FER Credit	Avg. Daily Energy MWh Paid FER Price*	Avg. FER Price	FER Credit as % of Total DA E&AS Credit	Avg. Hourly Cleared EIR Obligation MWh
03/01/2025	$17.1M	$466K	$202K	$3.37	1.2%	$979K	175K	$3.25	5.7%	176
04/01/2025	$13.6M	$332K	$175K	$3.23	1.3%	$760K	127K	$2.66	5.6%	97
05/01/2025	$10.9M	$190K	$52K	$0.94	0.5%	$563K	163K	$2.06	5.2%	155
06/01/2025	$20.1M	$885K	$173K	$2.97	0.9%	$1,287K	160K	$3.15	6.4%	125
07/01/2025	$35.6M	$1,704K	$1,139K	$19.53	3.2%	$1,277K	114K	$3.06	3.6%	55
08/01/2025	$20.2M	$747K	$544K	$9.57	2.7%	$1,292K	147K	$3.02	6.4%	94
09/01/2025	$12.3M	$320K	$184K	$3.21	1.5%	$587K	138K	$1.94	4.8%	104
10/01/2025	$15.5M	$719K	$478K	$8.21	3.1%	$1,911K	202K	$6.50	12.3%	209
11/01/2025	$24.8M	$1,123K	$458K	$7.85	1.9%	$2,550K	210K	$8.00	10.3%	135
12/01/2025	$60.9M	$2,131K	$1,053K	$18.20	1.7%	$4,916K	227K	$13.42	8.1%	107
01/01/2026	$91.1M	$4,617K	$3,241K	$55.53	3.6%	$12,042K	203K	$29.54	13.2%	127
02/01/2026	$59.3M	$1,784K	$879K	$15.09	1.5%	$3,708K	165K	$9.56	6.3%	115

About the Table:
- DA E&AS refers to DA Energy and Ancillary Services
- DAAS Net Credits reflect combined EIR, TMSR, TMNSR, and TMOR credits reduced by closeout costs
- FER Credits are paid to all DA cleared energy supply from physical resources (Gen, Imports, DRR) and are charged to RTLO excluding RTLO associated with RT Exports and Dispatchable Asset Related Demand (DARDs)
- *'Avg Daily Energy MWh Paid FER Price' reflects Cleared DA Physical Gen and DRR MWh during non-zero FER prices
- FER Credits are included in the Monthly Market Operations Report (see Section 7.1.1) found on the ISO Website here. Additional information, such as EIR Credits and Closeout Charges are included in the same report (see Section 9.1.1)

Average Hourly DAAS Prices

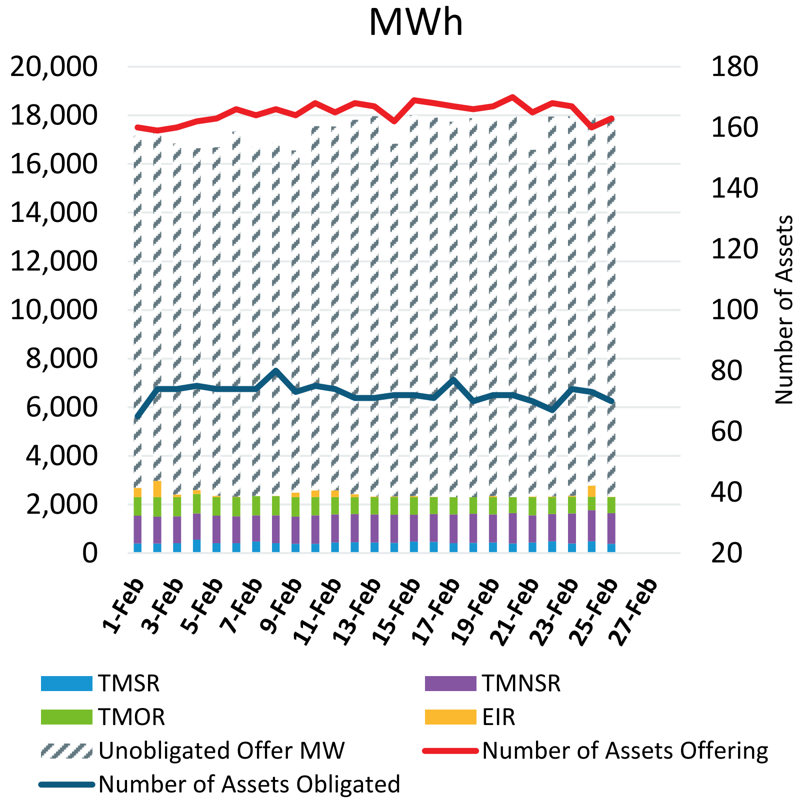




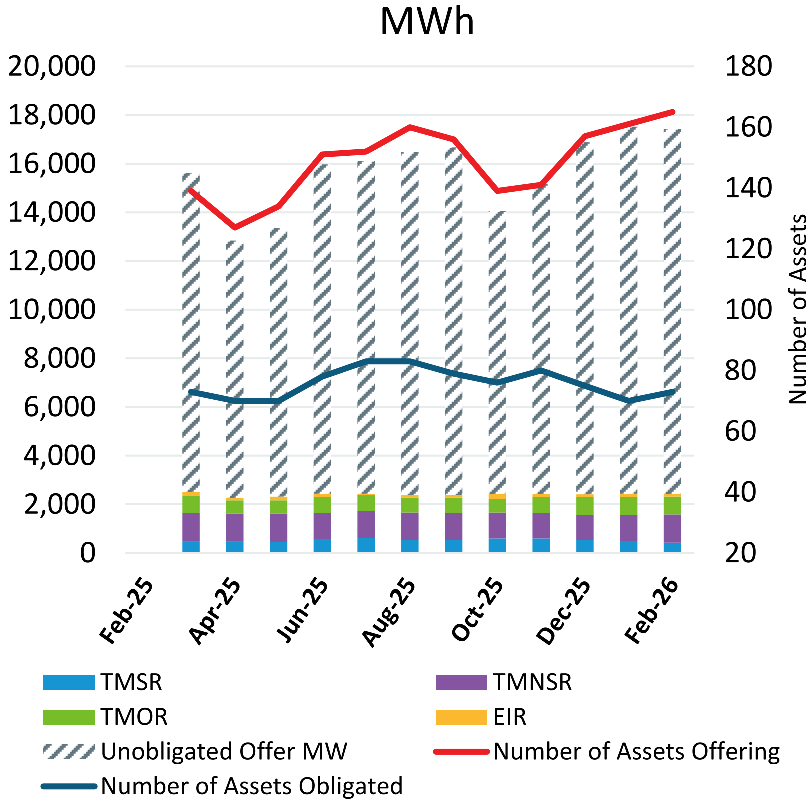
ISO-NE INTERNAL USE

Average Hourly DAAS Offered* and Awarded Amounts

Daily This Month



Monthly, Last 13 Months



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

System Planning Highlights

- The ISO is evaluating all LTTP RFP submissions and expects to provide an update on the initial review of proposals and results of the RFP objective analysis (transfer limits & wind accommodation) at the March Planning Advisory Committee meeting

Forward Capacity Market (FCM) Highlights

- CCP 16 (2025-2026)
  - The third annual reconfiguration auction (ARA3) was held March 3-5, 2025 and results were posted on April 1, 2025
- CCP 17 (2026-2027)
  - The ISO filed the ICR and related values with FERC, for the ARA3 to be conducted in 2026, on November 21, 2025. FERC issued an order accepting the values on January 9, 2026.
  - The third annual reconfiguration auction (ARA3) will be held March 2-4, 2026. Final qualified capacities were issued on February 13, 2026.
- CCP 18 (2027-2028)
  - The first annual reconfiguration auction (ARA1) was held June 2-4, 2025 and results were posted on July 2, 2025
  - The ISO filed the ICR and related values with FERC, for the ARA2 to be conducted in 2026, on November 21, 2025. FERC issued an order accepting the values on January 9, 2026.

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP 19 (2028-2029)
  - The ISO filed market rule changes to delay FCA 19 for two additional years with FERC on April 5, 2024
    - On May 20, 2024 FERC issued an order accepting the additional delay
    - 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 completed on November 3, 2025
      - A total of 1,455 MW (summer Qualified Capacity) was qualified to participate in future reconfiguration auctions
      - The Transitional CNR Group Study was completed with the completion of the 2025 interim RA qualification process
    - The Show of Interest window for the 2026 interim RA qualification process will open on April 16, 2026
  - No ICR and related values will be calculated for CCP 19 until the CAR project is completed

Load Forecast

- Stakeholder discussions related to CELT 2026 will continue at the next Load Forecast Committee on March 27

NEW ENGLAND WINTER REVIEW 2025/2026

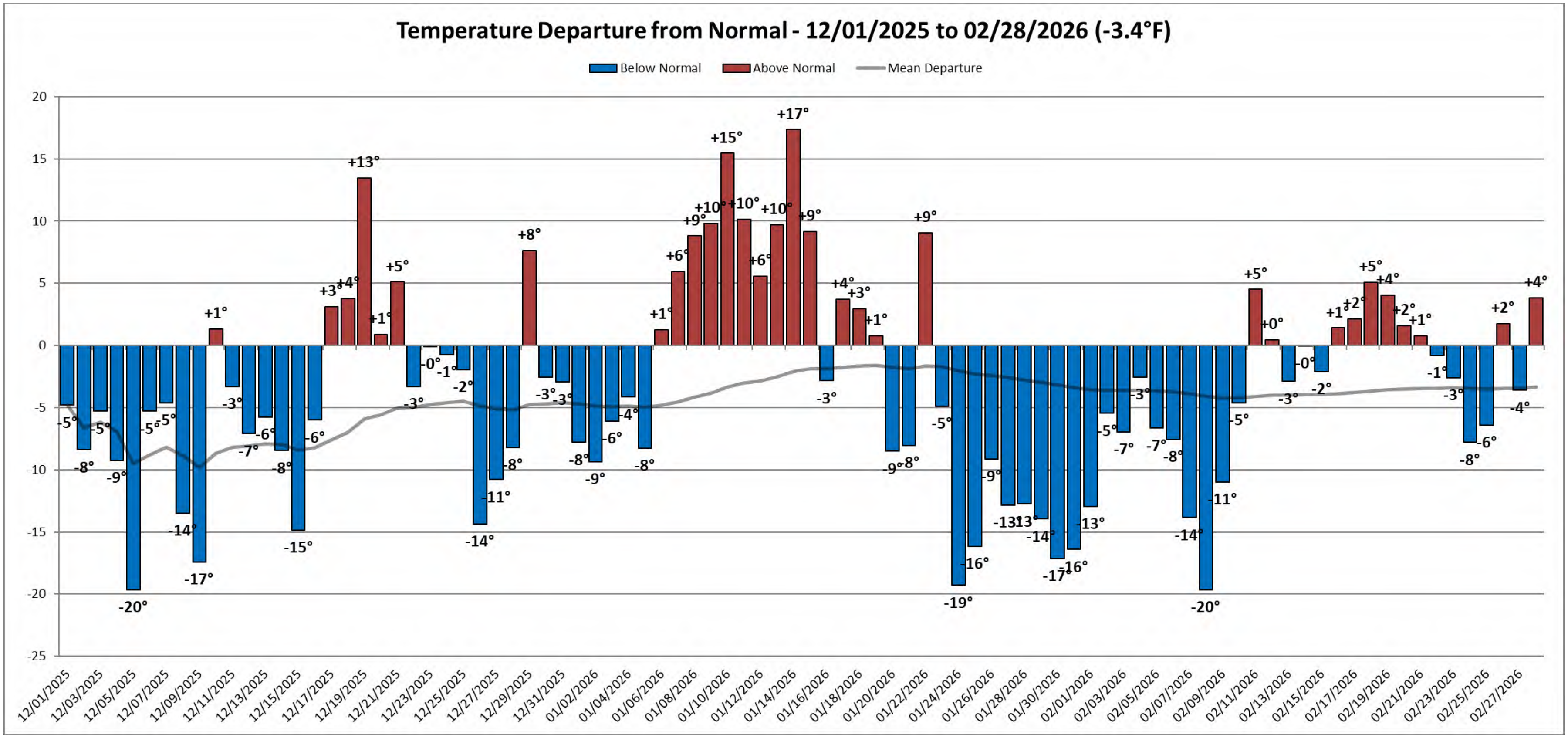
Winter 2025/2026 Highlights

- Winter 2025/2026 temperatures in New England were consistently below normal, making it the region's coldest winter in 20 years; average temperature departure from normal was -3.4°F
- Peak winter load reached 20,182 MW on January 25 - slightly above the 50/50 forecast of 20,056 MW; total winter energy demand was the highest in 11 years
- A widespread and long-duration cold weather outbreak occurred from January 23 through February 10
- Timely replenishment of LNG and fuel oil was essential to maintaining reliable operations; fuel oil inventories ended the winter ~19M gallons below starting levels following a record burn of ~139M gallons
- The New England generation fleet and transmission system performed well overall; surplus generating capacity was available throughout the winter and no capacity deficiency events occurred
- New records for Energy Market value were set this winter, both in total and for the months of December and January

Winter Preparations

- ISO staff met with industry and governmental officials to review communication protocols and seasonal expectations including capacity, energy, and demand forecasts
- ISO System Operations staff hosted a Generator Winter Readiness Webinar on October 29, 2025
- Annual Winter Generator Readiness Survey was distributed to all generating resources in the region
- The Annual Natural Gas Critical Infrastructure Survey process was completed to ensure critical infrastructure is not part of automatic or manual load shed schemes
- Dual fuel audits of ~30 generators totaling ~6,500 MW of capacity were completed ahead of winter
- ISO staff performed probabilistic winter energy assessments using the Probabilistic Energy Adequacy Tool (PEAT)

Winter Average Temperature Was 3.4°F Below Normal Resulting in the Coldest Winter in 20 Years

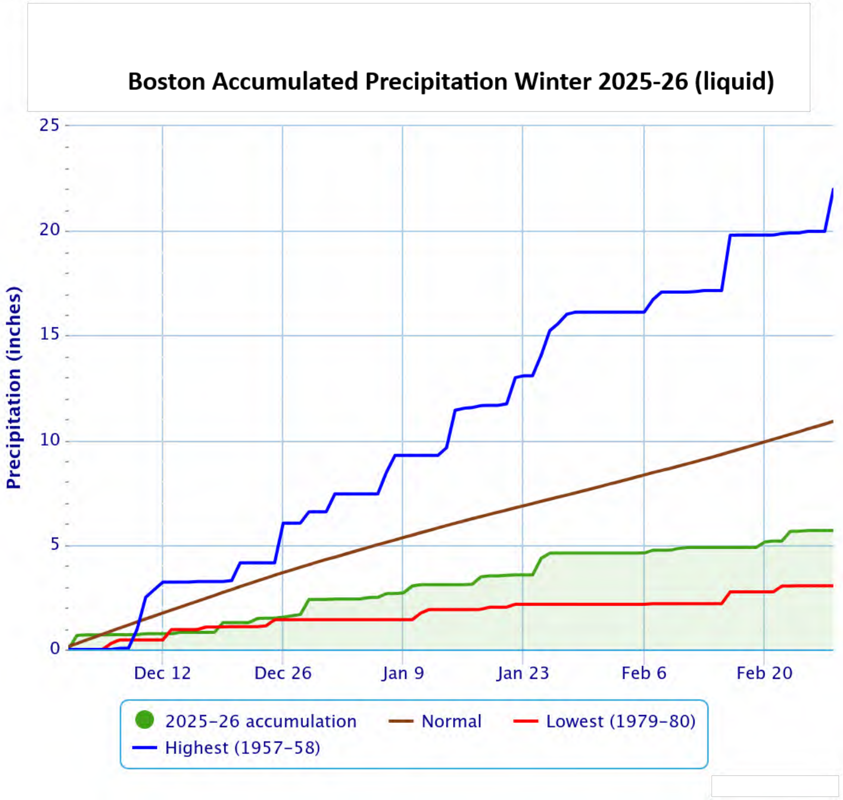


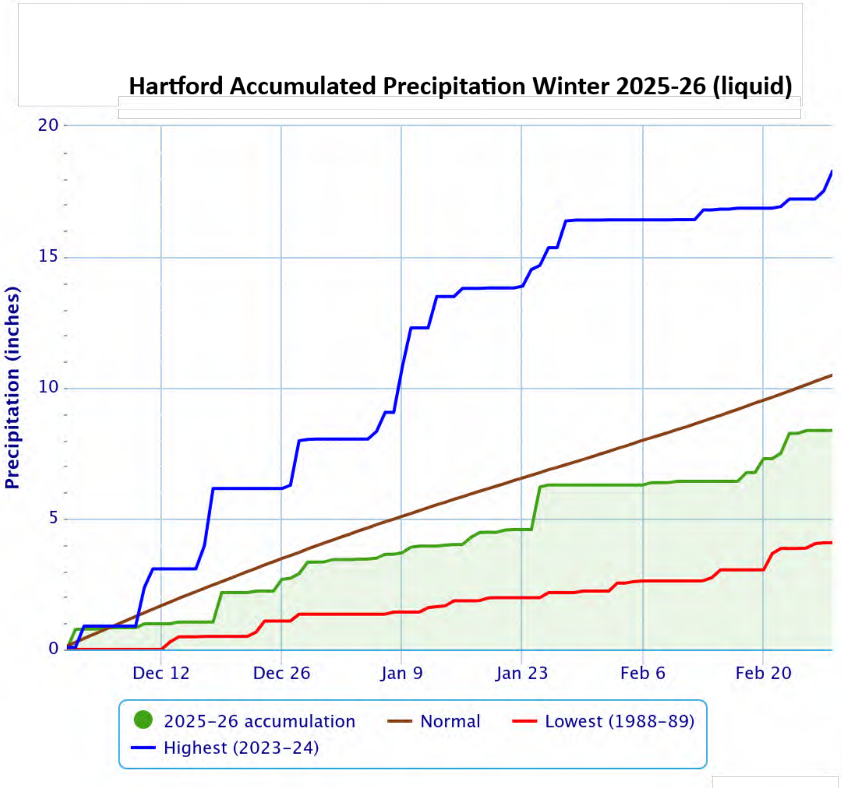
*Temperatures in the figure above are based on a New England 23-city weighted average

Total Precipitation Amounts Were Below Normal Across the Region

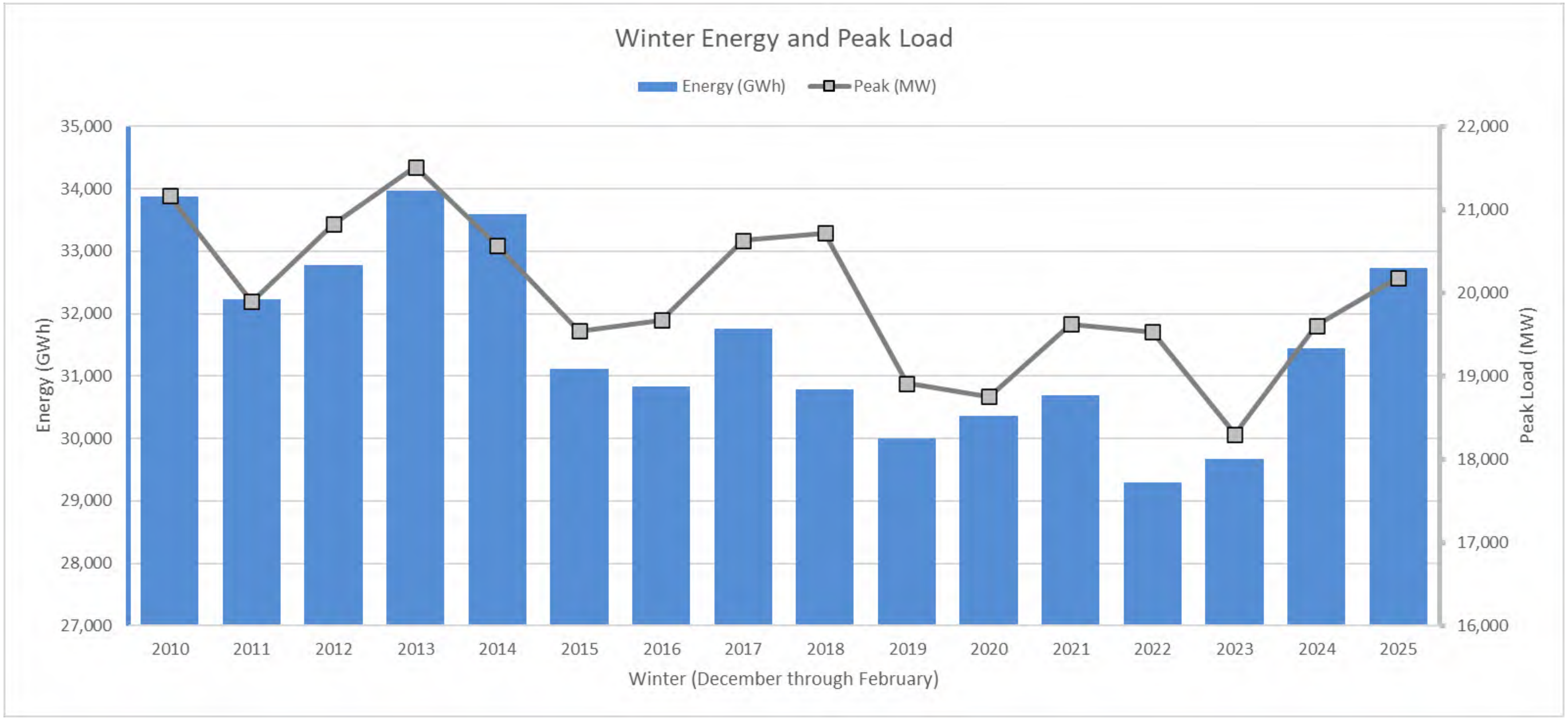
- Boston
  - 60.9” of snowfall recorded; 23.2” above normal
  - Total precipitation was 5.22” below normal

- Hartford
  - 52.3” of snowfall recorded; 13.2” above normal
  - Total precipitation was 2.12” below normal

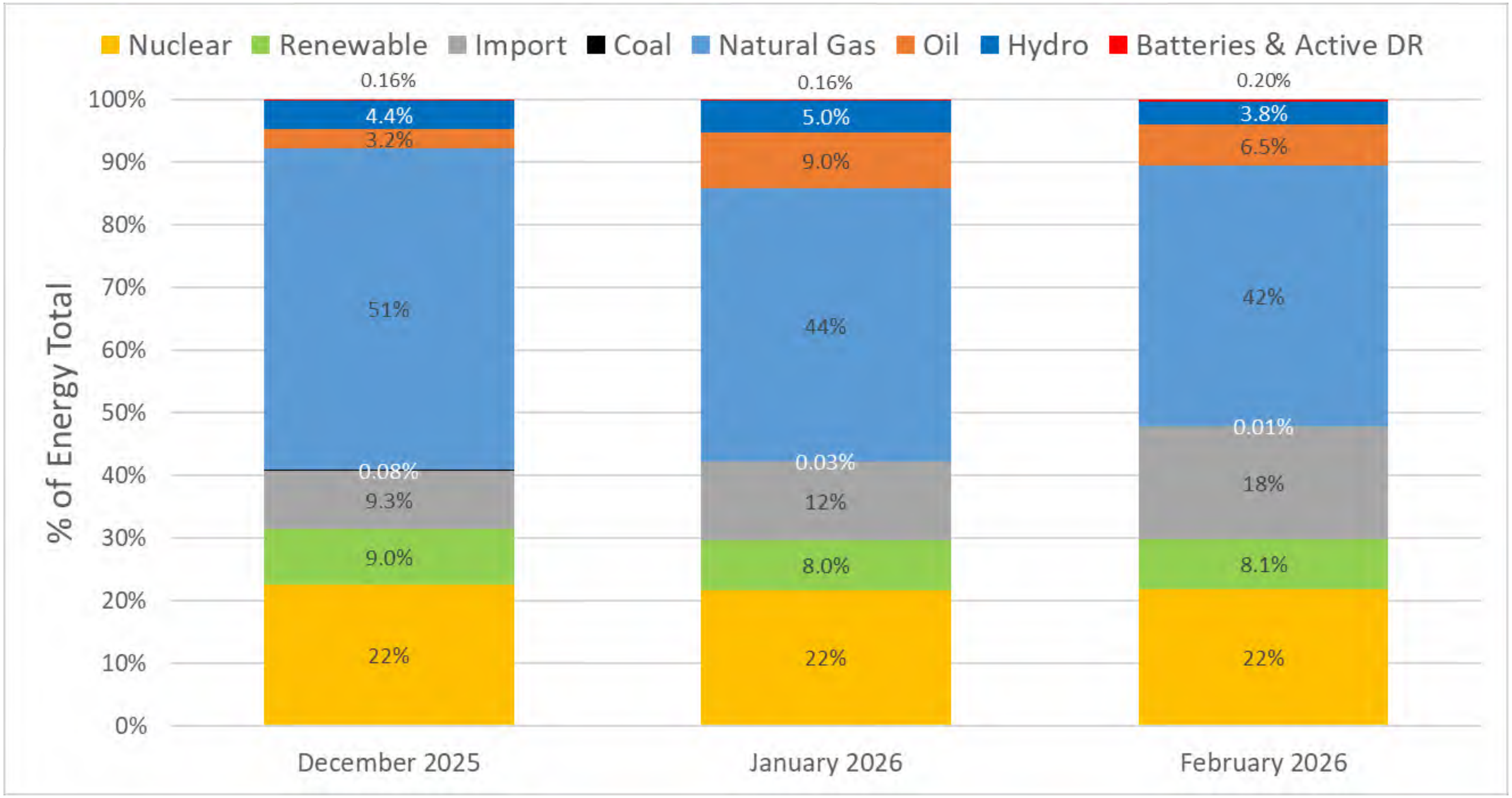




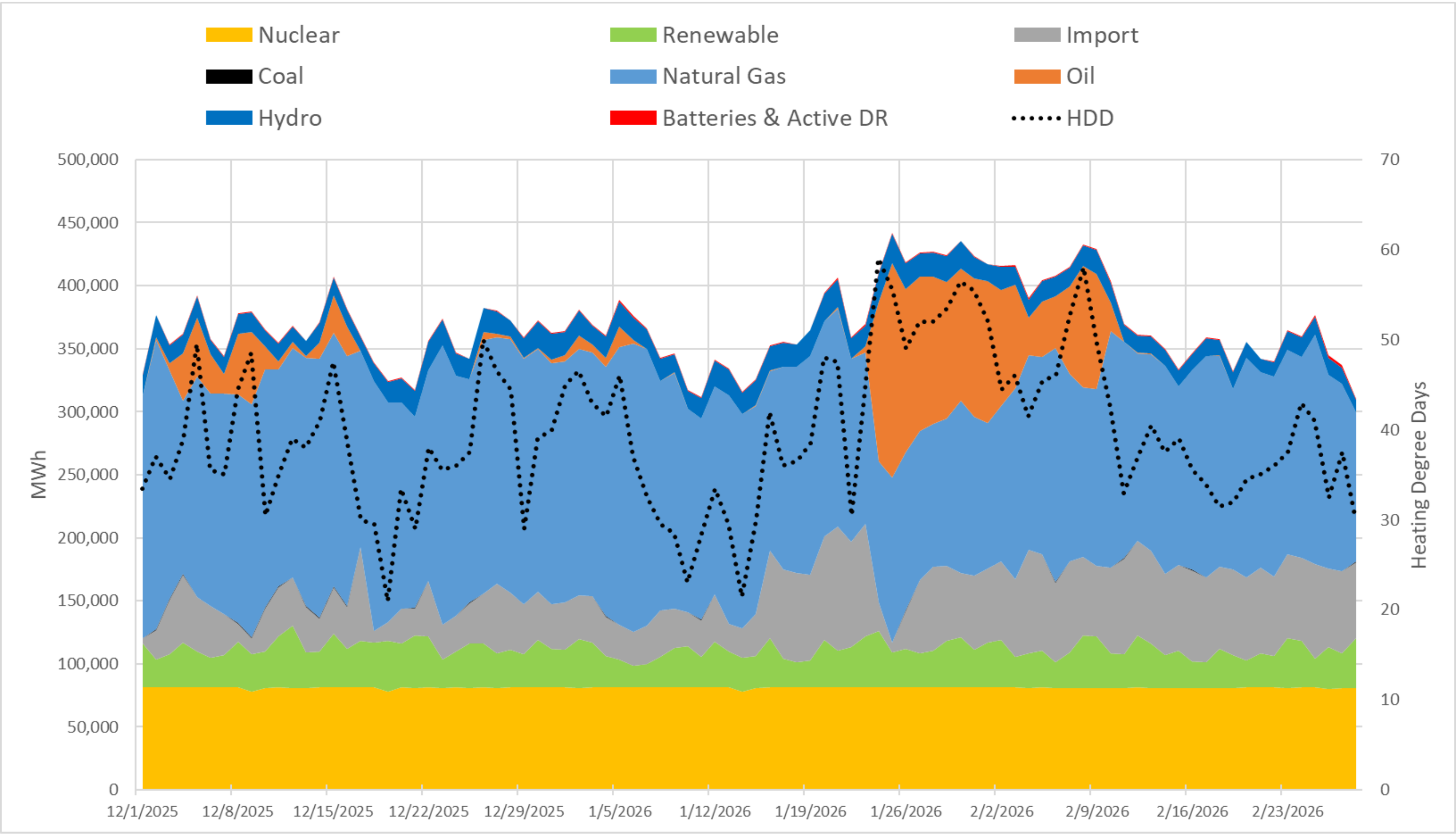
Winter Energy Demand Was the Highest Since 2014



Winter Energy Sources, by Month

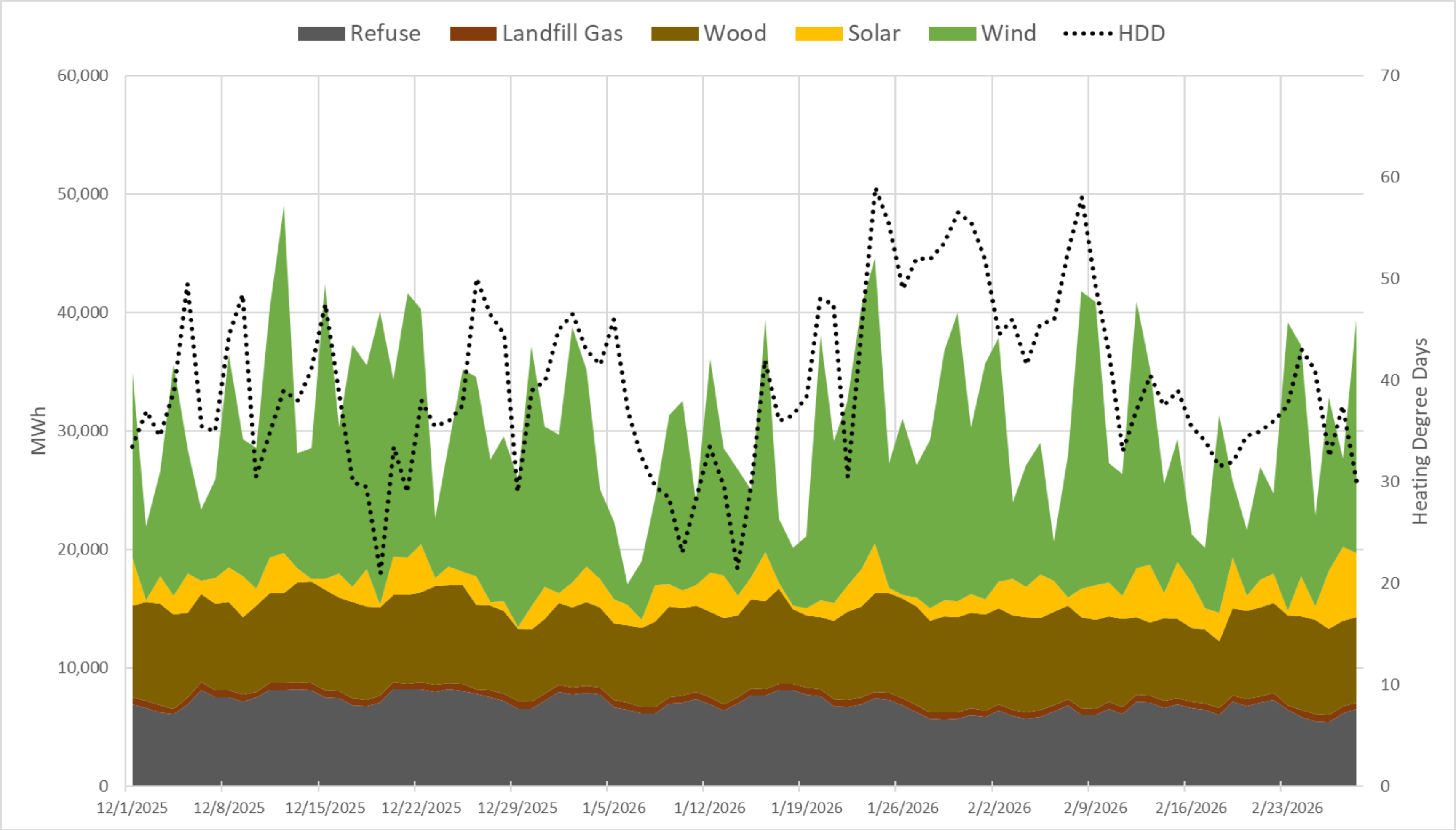


Winter Energy Sources, by Day



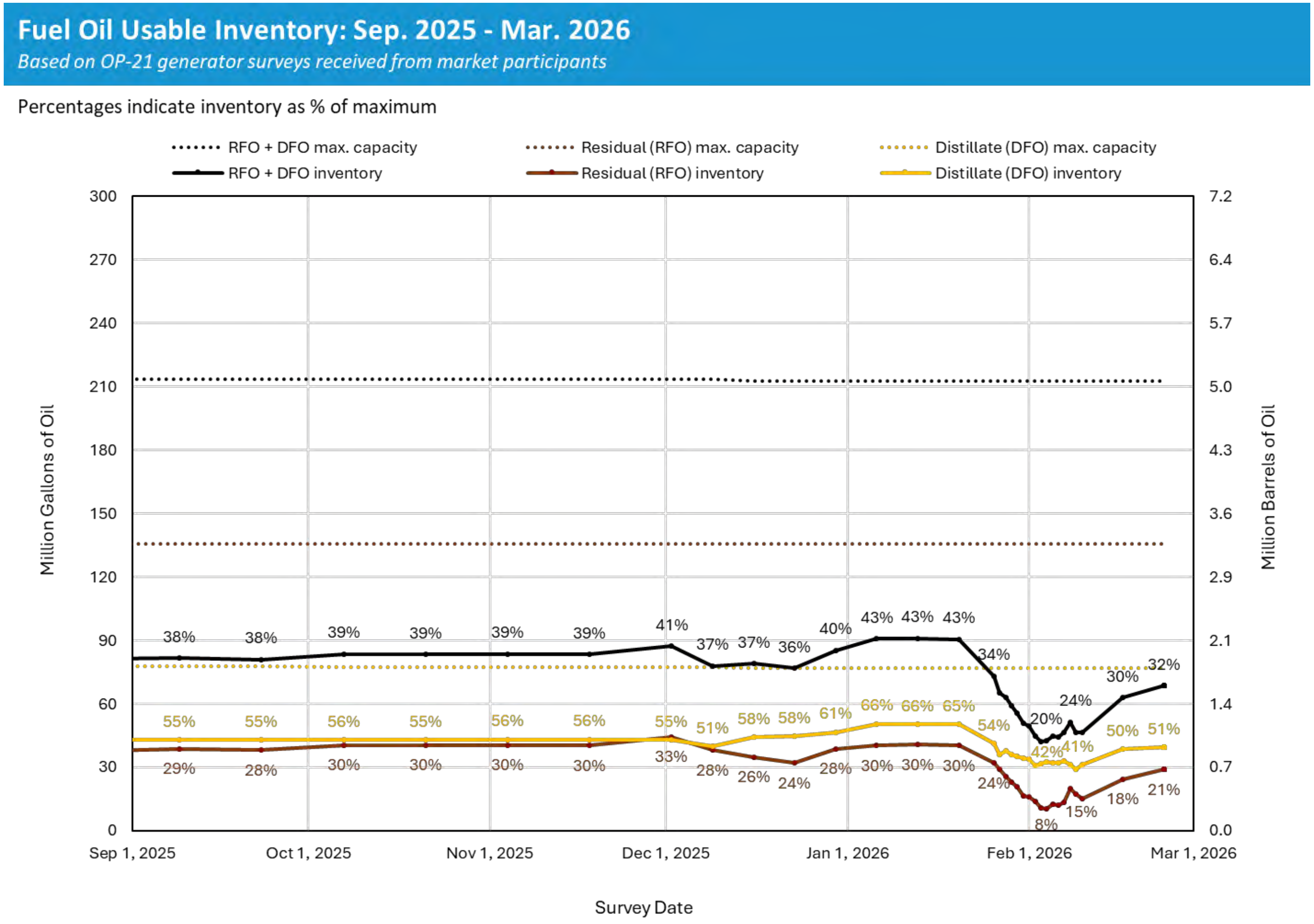
*Renewable data on this slide includes energy only from utility-scale solar PV installations

Winter Energy Sources, by Day
Renewables Only



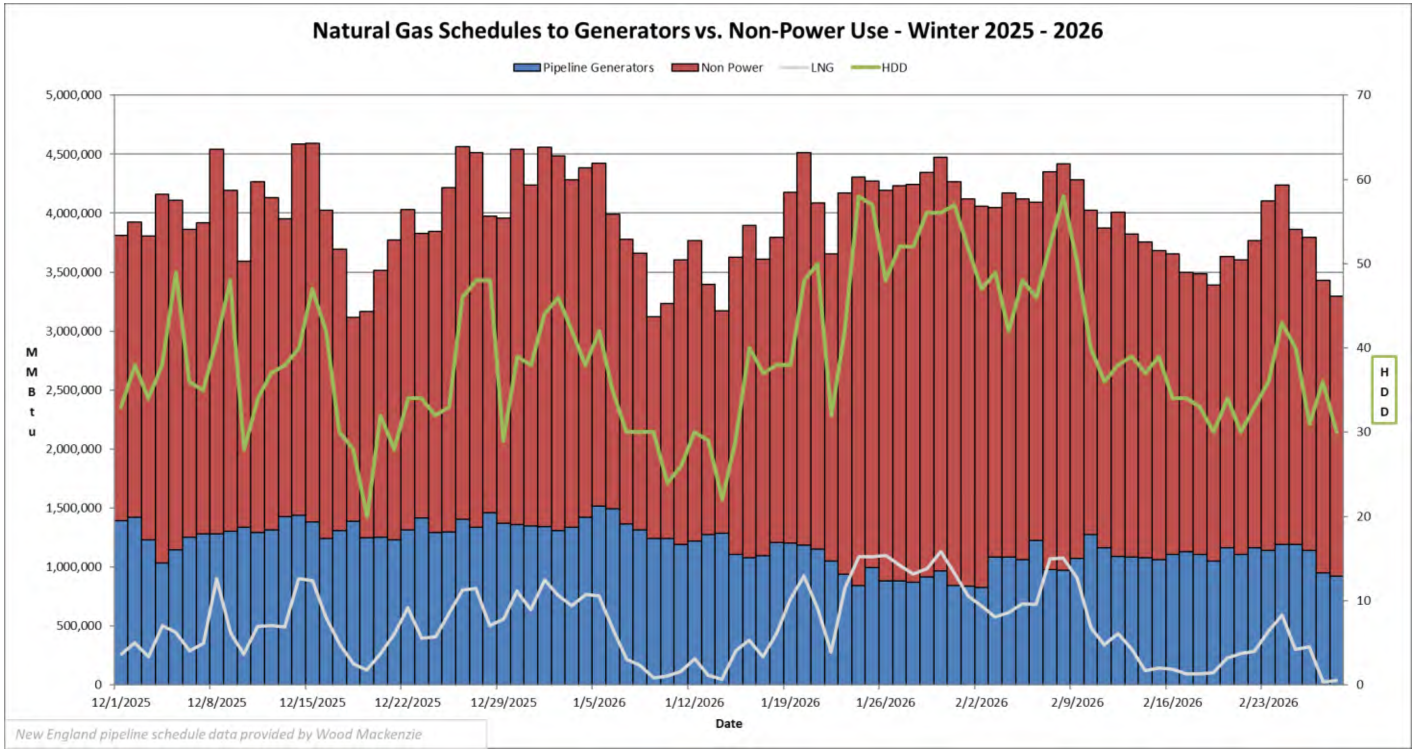
*Solar data on this slide includes energy only from utility-scale solar PV installations

Following Significant Fuel Oil Burn, Inventories Are Projected to Return to Pre-Winter Levels by Mid-March



Natural Gas Demand – Winter 2025/2026

- Scheduled LNG vaporization to the pipelines was ~45.6 Bcf, significantly higher than the previous 5-year average of ~16.6 Bcf



Winter 2025/2026 Wholesale Market Summary

- December
  - Average RT Hub LMP: **$129.89/MWh,** up ~55% from prior December
    - Highest December value since SMD
  - Average natural gas price: **$14.90/MMBtu,** up 63% from prior December
    - Highest December value since SMD
  - Temperatures* averaged **~28.0°F**, ~4.0°F colder than the prior December
    - Coldest December since 2017
  - RT Loads** averaged ~**14,870 MW**, up ~720 MW (or 5%) from the prior December
    - Highest December value since 2017

- January
  - Average RT Hub LMP: **$154.73/MWh,** up ~15% from prior January
    - 2nd highest January value since SMD
  - Average natural gas price: **$24.25/MMBtu,** up ~43% from prior January
    - 2nd highest January value since SMD
  - Temperatures averaged **~24.1°F** , ~1.4°F colder than the prior January
  - RT Loads averaged **~15,420 MW**, up ~410 MW (or 3%) from the prior January
    - Highest January value since 2015

- February***
  - Average RT Hub LMP: **$127.38/MWh,** up ~1% from prior February
    - 2nd highest February value since SMD
  - Average natural gas price: **$14.31/MMBtu**, down ~2% from prior February
  - Temperatures averaged **~25.0°F**, ~2.6°F colder than the prior February
    - Coldest February since 2015
  - RT Loads averaged **~15,160 MW**, up ~650 MW (or 5%) from the prior February
    - Highest February value since 2015

Note: Natural gas prices reflect the trade weighted average of natural gas price locations in Massachusetts
*Temperatures reflect 23-City New England weighted average
**RT Loads reflect telemetered values on this slide
***February 2026 Energy Market value includes estimations for days of February 26-28, 2026 based on pool wide DA LMP and cleared DA volumes and FER cost

Underlying natural gas data furnished by: ice

Comparison of Recent Winter Wholesale Energy Market Value

- The 2025/26 Winter Season set new records for Energy Market value, both in total and for respective similar months

Winter	December ($M)	January ($M)	February ($M)	Total ($M)	Rank[2]
2013/14	$1,161	$2,190	$1,703*	$5,054	2
2017/18	$856	$1,340	$401	$2,597	10
2018/19	$530	$671	$366	$1,568	19
2019/20	$468	$297	$233	$998	23
2020/21	$450	$489	$759	$1,698	17
2021/22	$720	$1,792	$1,216	$3,728	4
2022/23	$1,338	$552	$750	$2,640	9
2023/24	$415	$838	$375	$1,628	18
2024/25	$1,017	$1,637	$1,376	$4,030	3
2025/26	$1,839*	$2,721*	$1,500[3]	$6,060*	1

[1] Energy Market value is driven primarily by day-ahead load and pricing, since most obligations are settled day-ahead; Beginning in March 2025, FER Net Costs related to co-optimization with the DA Ancillary Services (DAAS) Market are being reflected in Energy Market value
[2] Since the beginning of Standard Market Design (SMD) in March 2003
[3] February 2026 Energy Market value includes estimations for days of February 26-28, 2026 based on pool wide DA LMP and cleared DA volumes and FER cost
* December 2025 ($1.8B), January 2026 ($2.7B), February 2014 ($1.7B) values were the highest for their respective similar months since SMD

Winter 2026/2027 Look Ahead

- ISO will continue to perform annual winter energy assessments using PEAT, in accordance with Operating Procedure 21
- Beginning in 2026, the Regional Energy Shortfall Threshold (REST) is now incorporated into seasonal and long-term energy assessments
- Winter weather forecasts will remain a critical factor in the operational outlook and will be closely monitored throughout the season
- ISO will continue to track fuel-oil replenishment and monitor potential emissions constraints following this winter's elevated oil use
- Communications with states, utilities, resource owners, and the public are expected to follow a similar approach to last year

COLD WEATHER OUTBREAK

January 23 through February 10, 2026

Key Takeaways

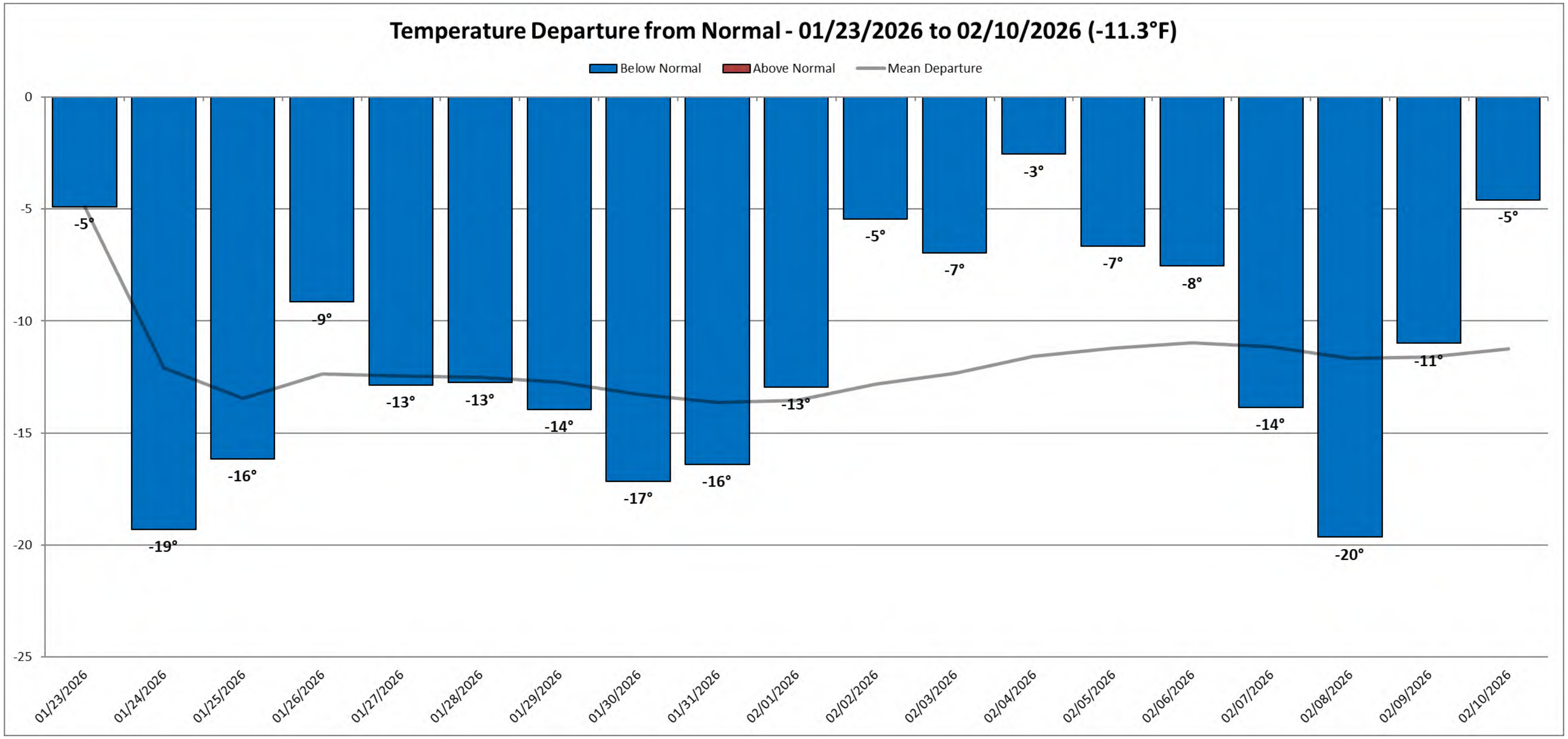
- A prolonged and widespread cold weather outbreak affected the region from January 23 through February 10, resulting in the most challenging winter conditions since 2017/18. Temperatures were consistently well below normal, leading to elevated demand and stressed system conditions.
  - Demand remained high, both in terms of peak load and overall energy use
  - Natural gas prices reached record levels, making fuel oil more economical
  - Fuel oil supplies fell to historical lows, though inventories are expected to recover to near pre-winter levels by mid-March
  - Timely replenishment of stored fuels was essential for maintaining reliable operations and opportunity-cost mechanisms helped generators optimize limited fuel supplies
- Winter Storm Fern brought widespread snowfall, impacting generation resources and fuel deliveries
  - Ahead of the storm, ISO implemented M/LCC-2, Abnormal Conditions Alert (in effect from January 25 - February 11)
  - Solar output declined due to the snowfall and remained low for several days as snow cover persisted
  - The storm's broad geographic footprint affected fuel delivery logistics across the East Coast

Key Takeaways, cont.

- Neighboring regions also faced difficult operating conditions during the cold weather outbreak, which reduced imports into New England and contributed to higher natural gas prices
- At the ISO's request, the U.S. Department of Energy issued a Section 202(c) emergency order, providing the additional operational flexibility needed during this period of extreme cold
- Throughout the event, the ISO's 21-day Energy Assessment offered transparent, actionable information on evolving energy adequacy risks with daily reports highlighting changing conditions
- Wholesale energy prices were very high due to historic gas prices and elevated consumer demand (both peak and overall)
- Close collaboration among ISO New England, industry partners, and federal and state agencies played a key role in maintaining system reliability

New England Average Temperature Was Below Normal From January 23 through February 10

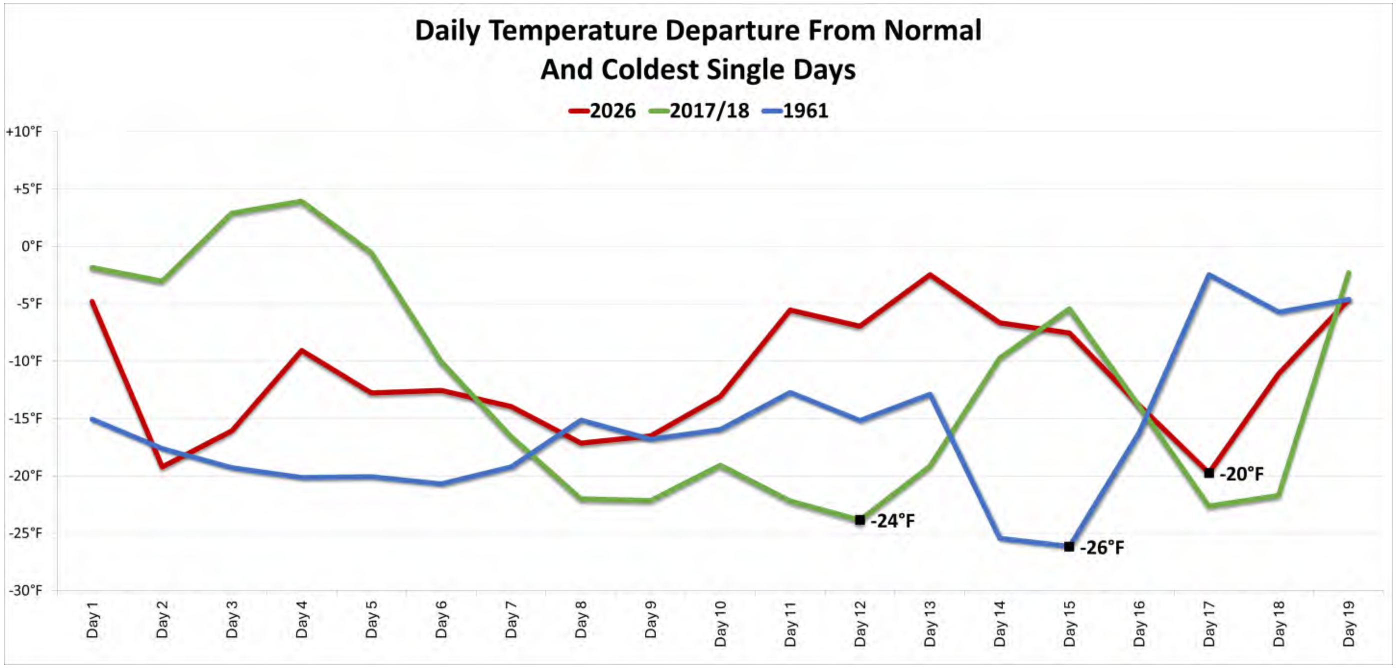
Temperature Averaged ~11.3°F Below Normal During the Cold Weather Outbreak



*Temperatures in the figure above are based on a New England 23-city weighted average

Average Temperature During the Cold Weather Outbreak Was Less Extreme Than Benchmark Historical Events

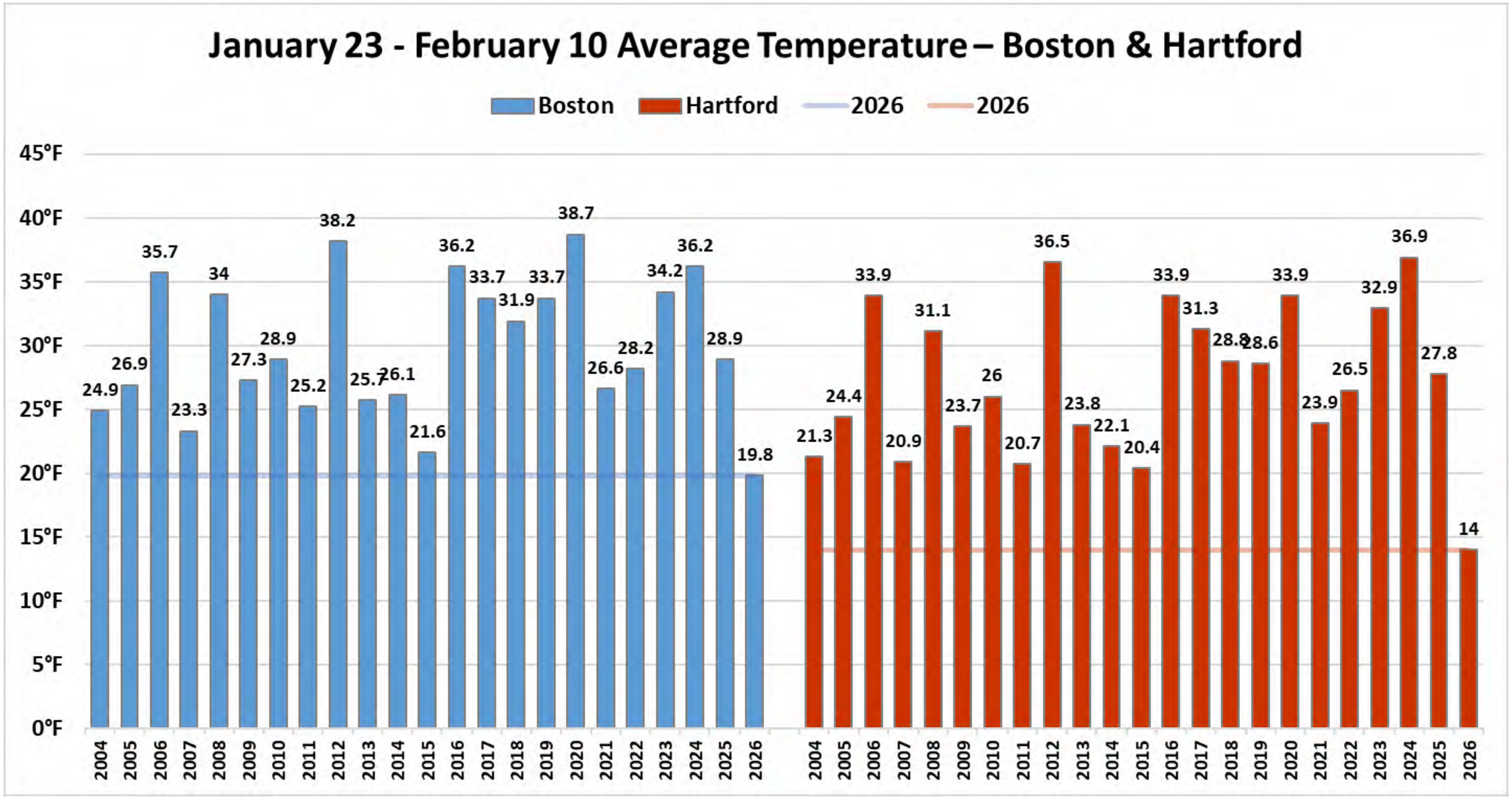
- Benchmarking the 2026 cold weather outbreak against past long-duration events shows that New England's average temperature departure from normal was significant, but not as severe as in earlier historical events*
- The average temperature departure from normal in the 2017/18 and 1961 events were -12°F and -16°F, respectively



Note: The two comparison events were selected because they represent historically significant cold periods:

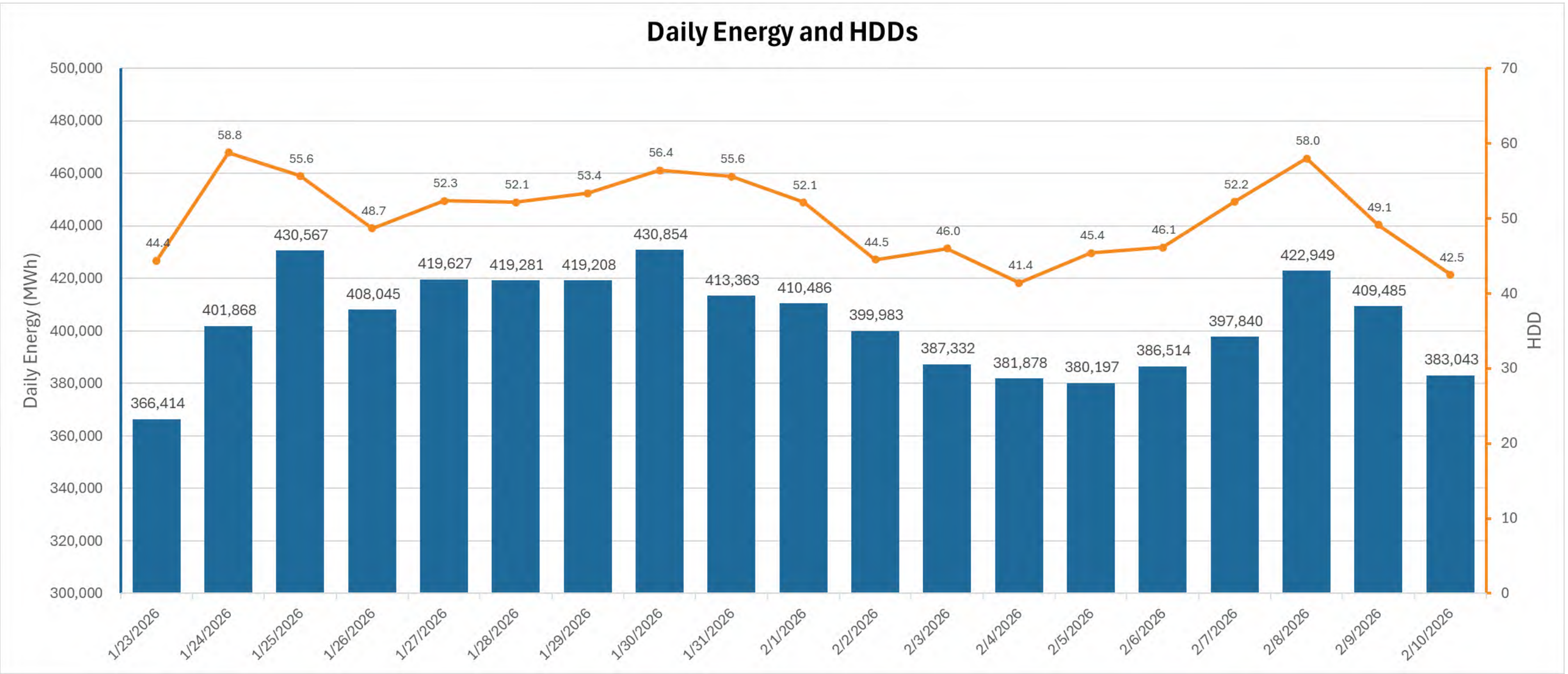
- The **2017/18 event** (Dec. 25, 2017–Jan. 8, 2018) and the **1961 event**, which was identified in the *Operational Impacts of Extreme Weather Events* study as producing the highest winter energy adequacy risk among modeled 21-day winter periods

Boston & Hartford Experienced the Coldest Jan. 23 Through Feb. 10 In More Than 20 Years



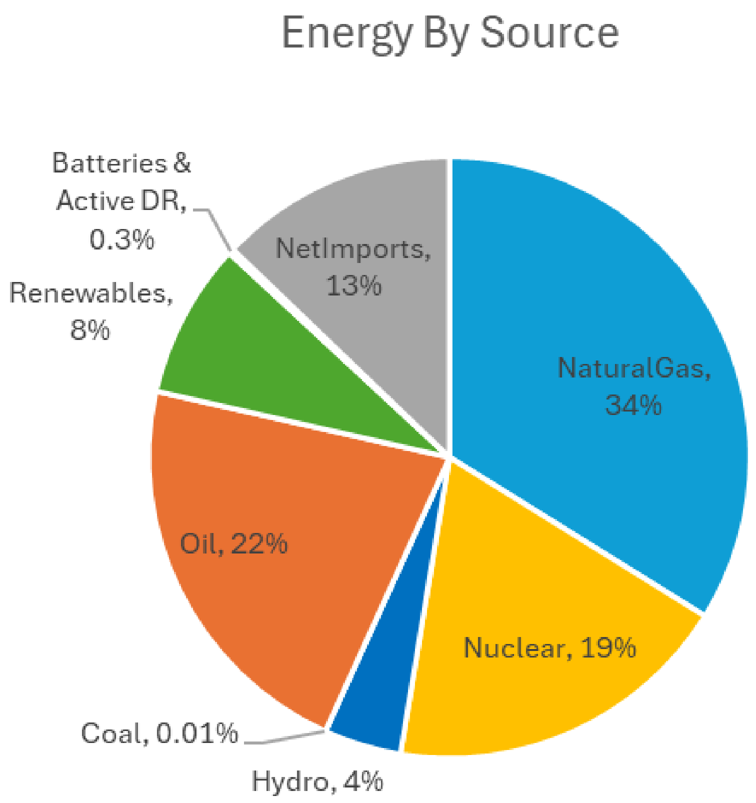
Extended Period of Bitter Cold Led to Consistently High Loads and Energy Demand

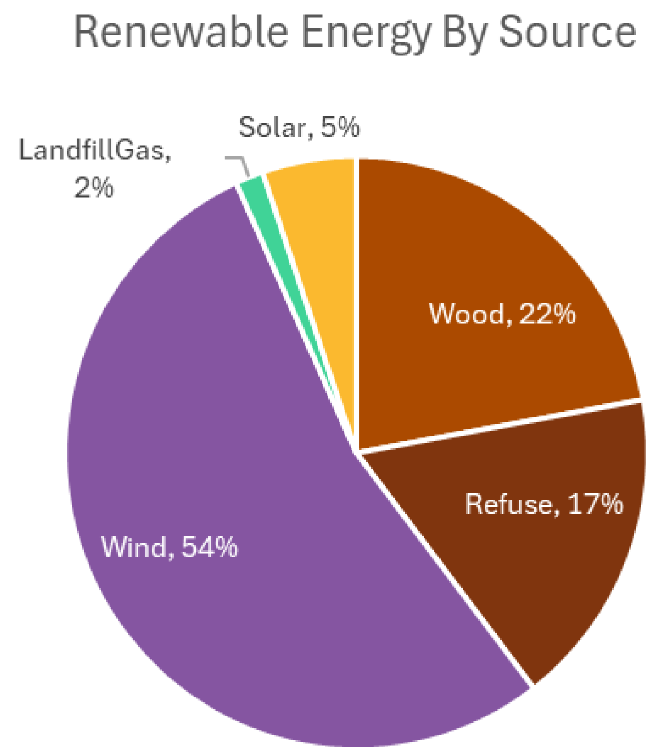
- Daily energy demand reached 430,567 MWh on Jan. 25 - the highest winter demand since 2018 (Jan. 2 at 429,960 MWh); energy demand was even higher on Jan. 30, rising to 430,854 MWh



Total Energy, By Source

January 23 – February 10, 2026

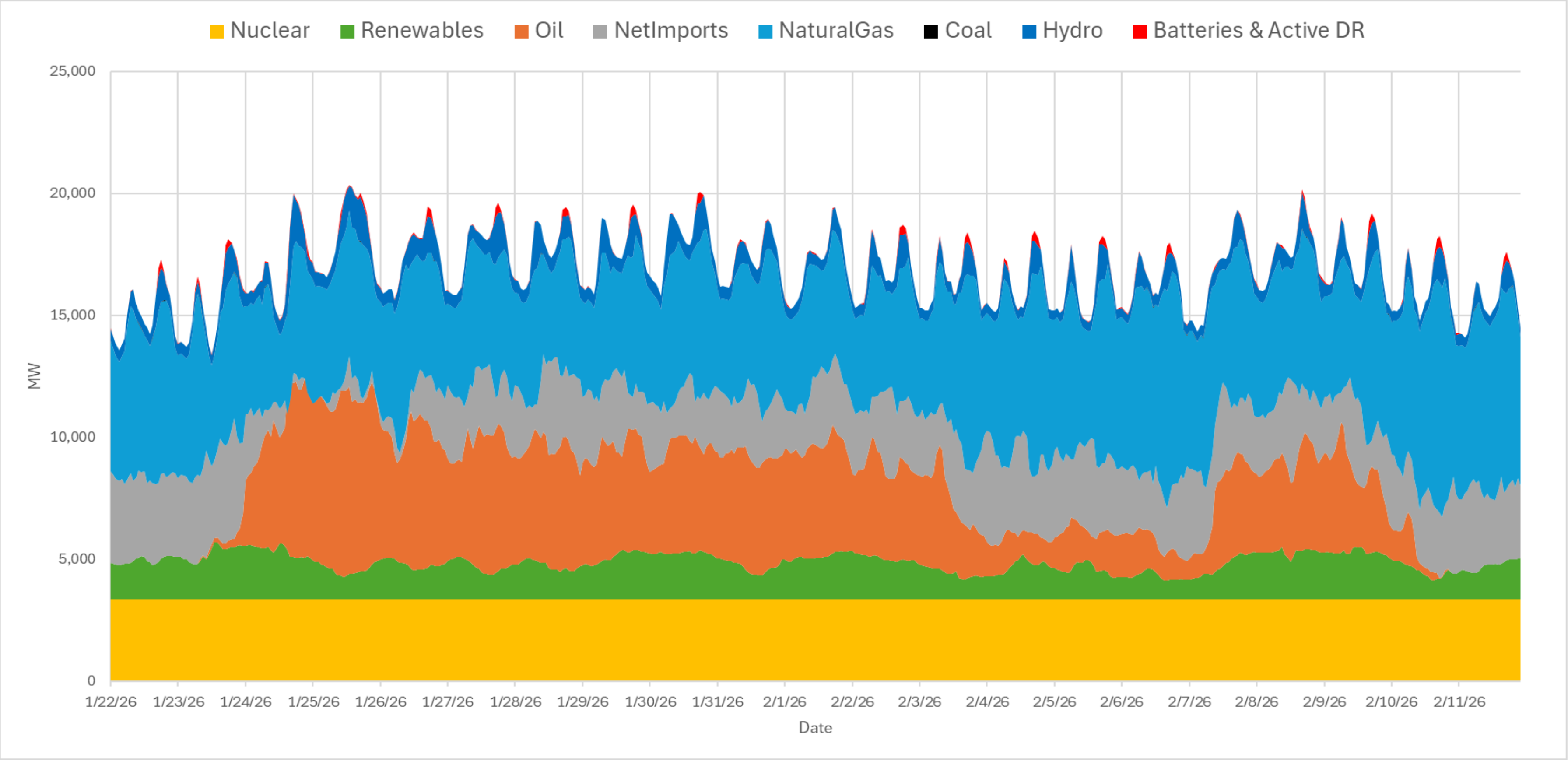




*Renewable and Solar data on this slide includes energy only from utility-scale solar PV installations

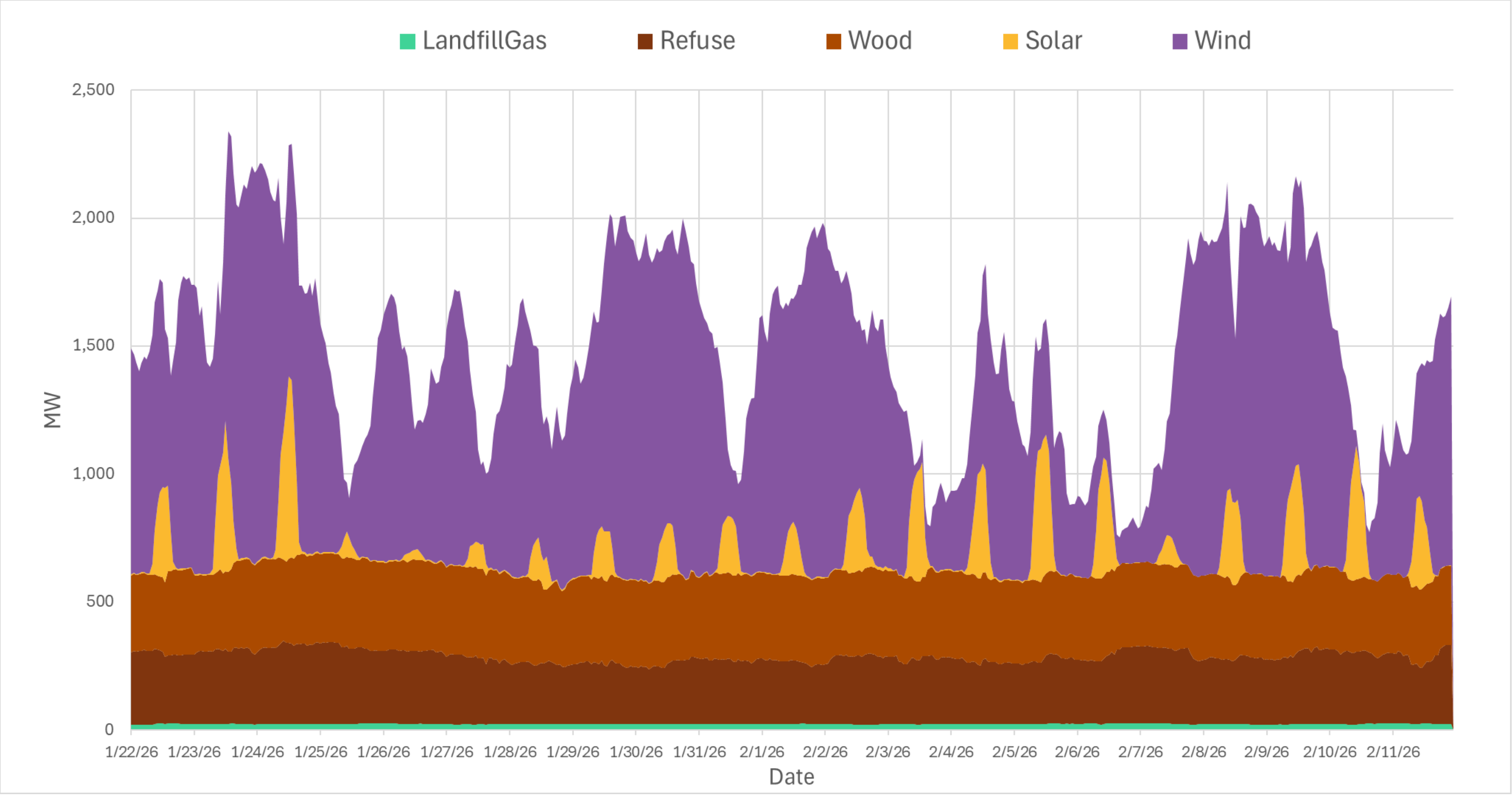
Energy Contributions From Oil-Fired Resources Increased Notably At the Onset of Severe Cold Weather

Energy from natural gas and oil-fired resources was 34% and 22%, respectively



*Renewable data on this slide includes energy only from utility-scale solar PV installations

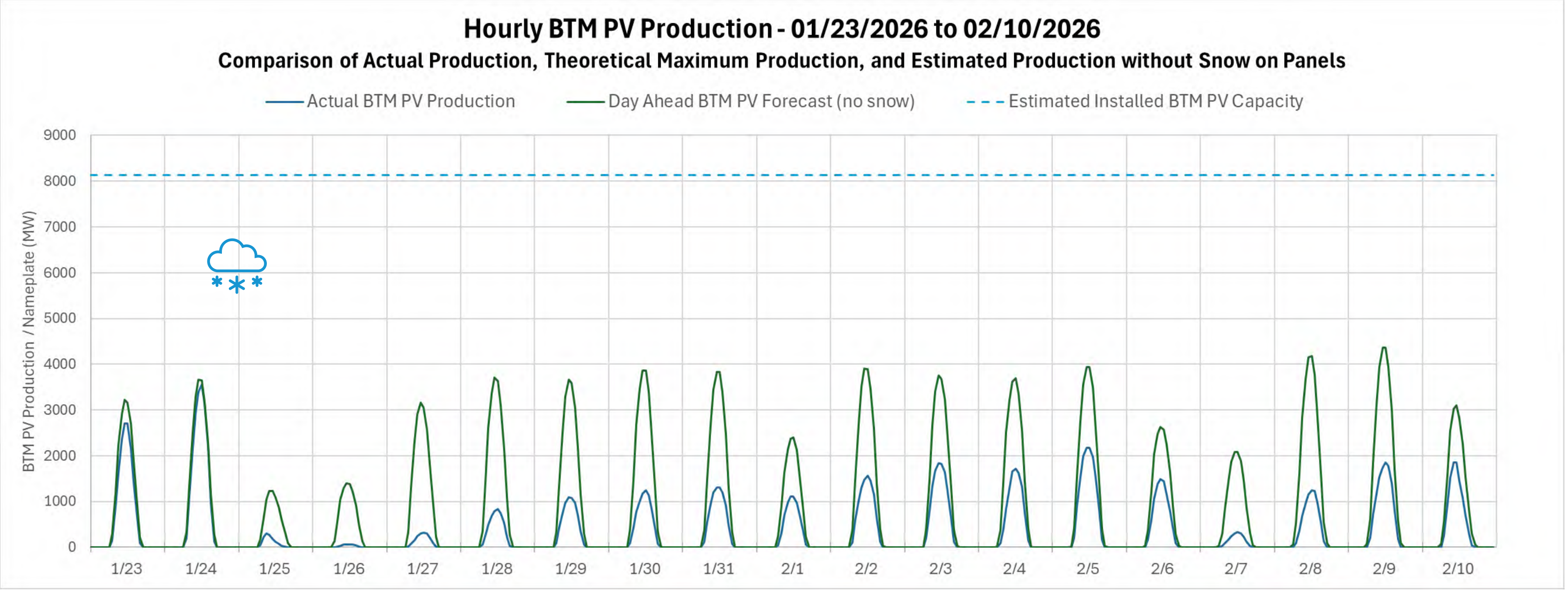
Renewable Energy, by Source



*Solar data on this slide includes energy only from utility-scale solar PV installations

Solar PV Output Was Reduced by Significant Snowfall During Winter Storm Fern

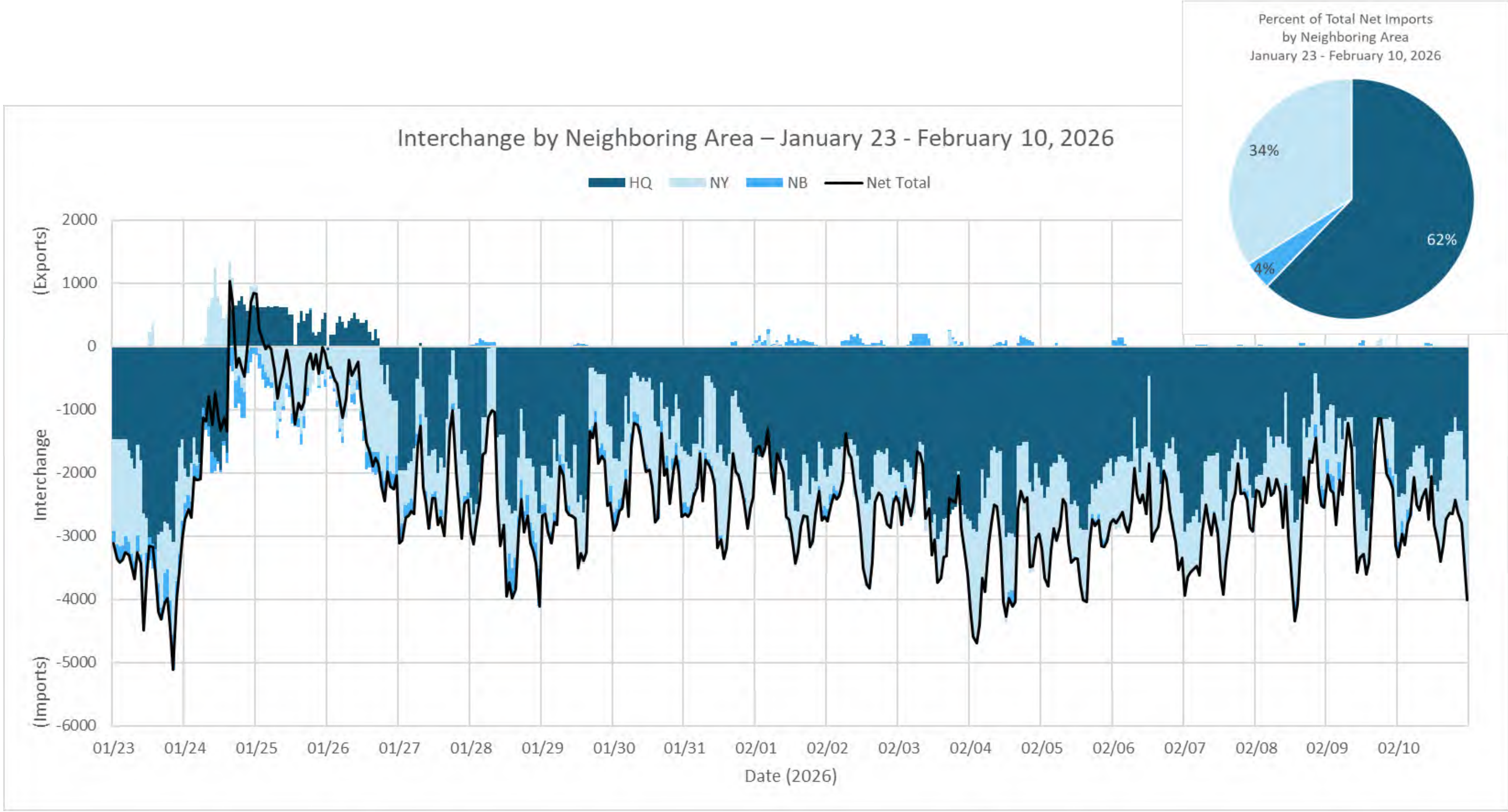
- Nearly two feet of snow fell across New England on January 25, covering many PV panels and sharply reducing solar output. Because temperatures remained below freezing for several days, snow stayed on the panels and continued to limit production.



*Day Ahead BTM PV Forecast (no snow) represents the forecast assuming no snow on the PV panels

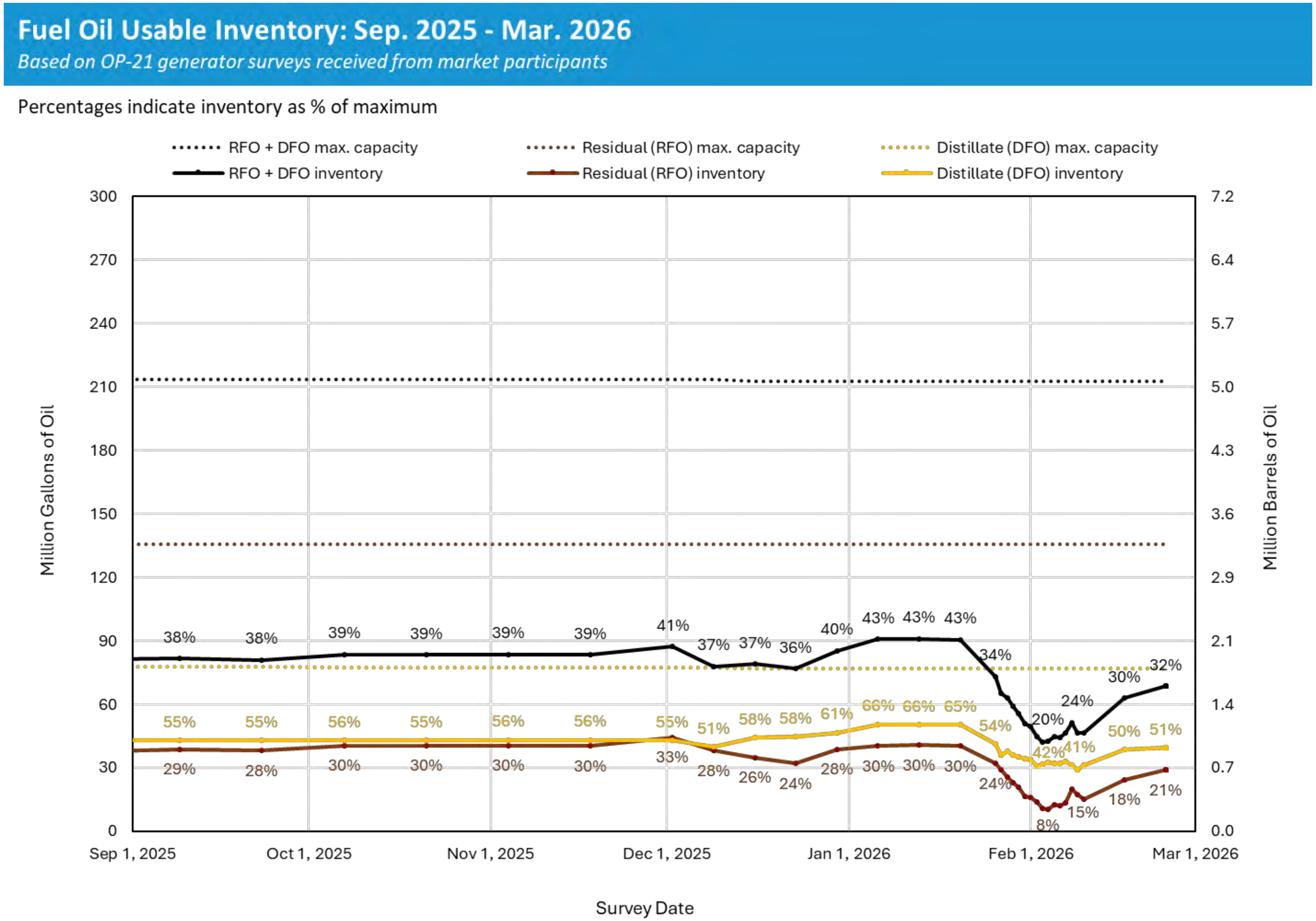
Net Interchange Decreased on January 24 As Neighboring Areas Managed Peak Loads

Imports to New England Averaged ~2,400 MW/hr During the Cold Weather Outbreak



Fuel Oil Burn During the Cold Weather Outbreak Totaled ~111M Gallons

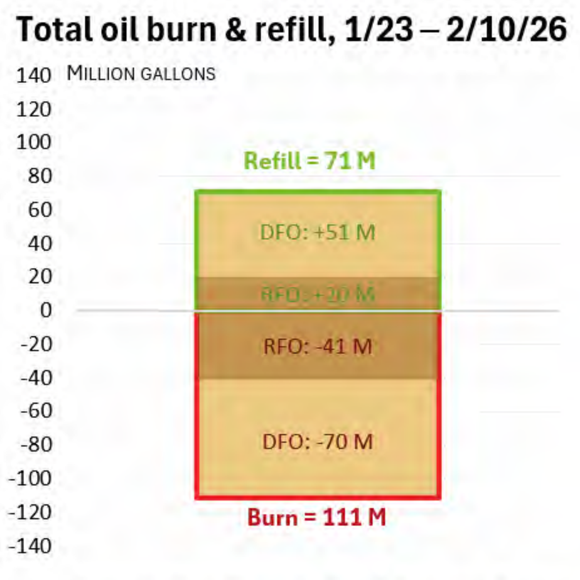
*Total Fuel Oil Burn During This Period Was Greater Than Burn in Every Winter Since 2015/16**



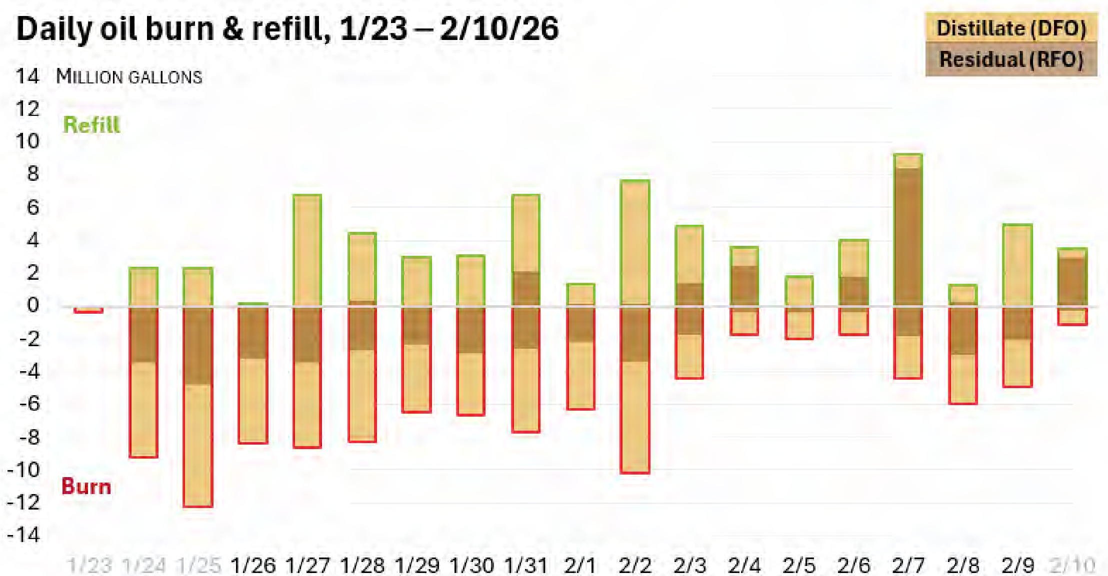
*ISO began tracking fuel oil burns starting in Winter 2015/16

Fuel Oil Burn Ramped Up At the Onset of the Cold Weather Outbreak and Persisted Throughout

- ISO began daily fuel surveys on Jan. 26; more frequent surveys allowed for enhanced situational awareness of fuel oil inventories and replenishment plans
- Impacts of the Winter Storm Fern delayed truck-based distillate fuel replenishment at the outset; in some cases, the limited availability of barges impacted the rate of residual fuel oil replenishment
- Significant fuel oil burn at dual fuel generating facilities contributed to a high demand for demineralized water trucks which were in short supply



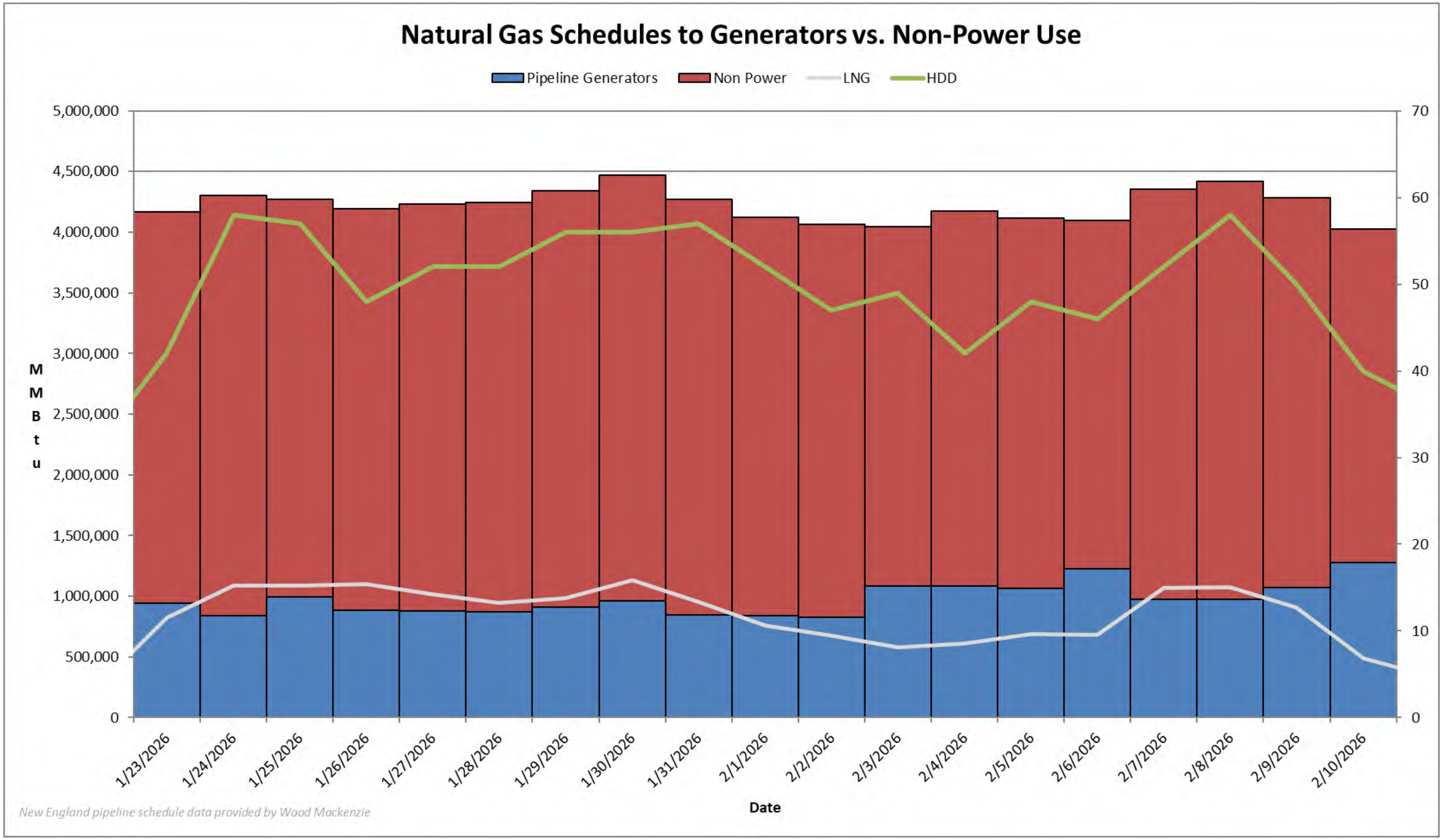
Estimated from Generator Fuel & Emissions Surveys



*Estimated from Generator Fuel & Emissions Surveys; gray dates rely on apportioning **weekly survey** amount*

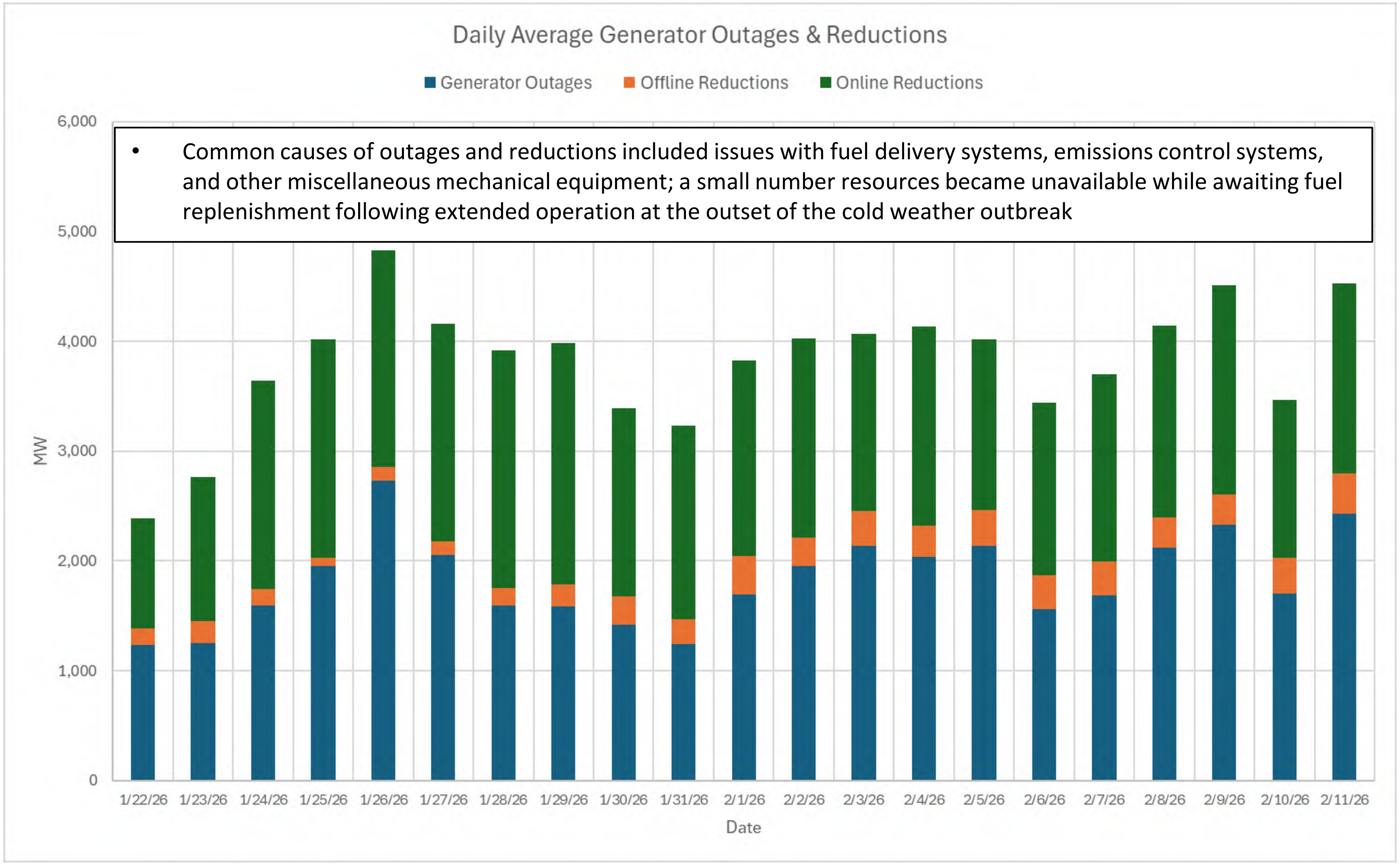
LNG Vaporization to the Pipelines Was ~16.7 Bcf During the Cold Weather Outbreak, ~0.88 Bcf/day

Natural gas demand for power generation was ~18.6 Bcf, ~0.98 Bcf/day



Generator Outages and Reductions

Averaged ~3,800 MW/hr During the Cold Weather Outbreak

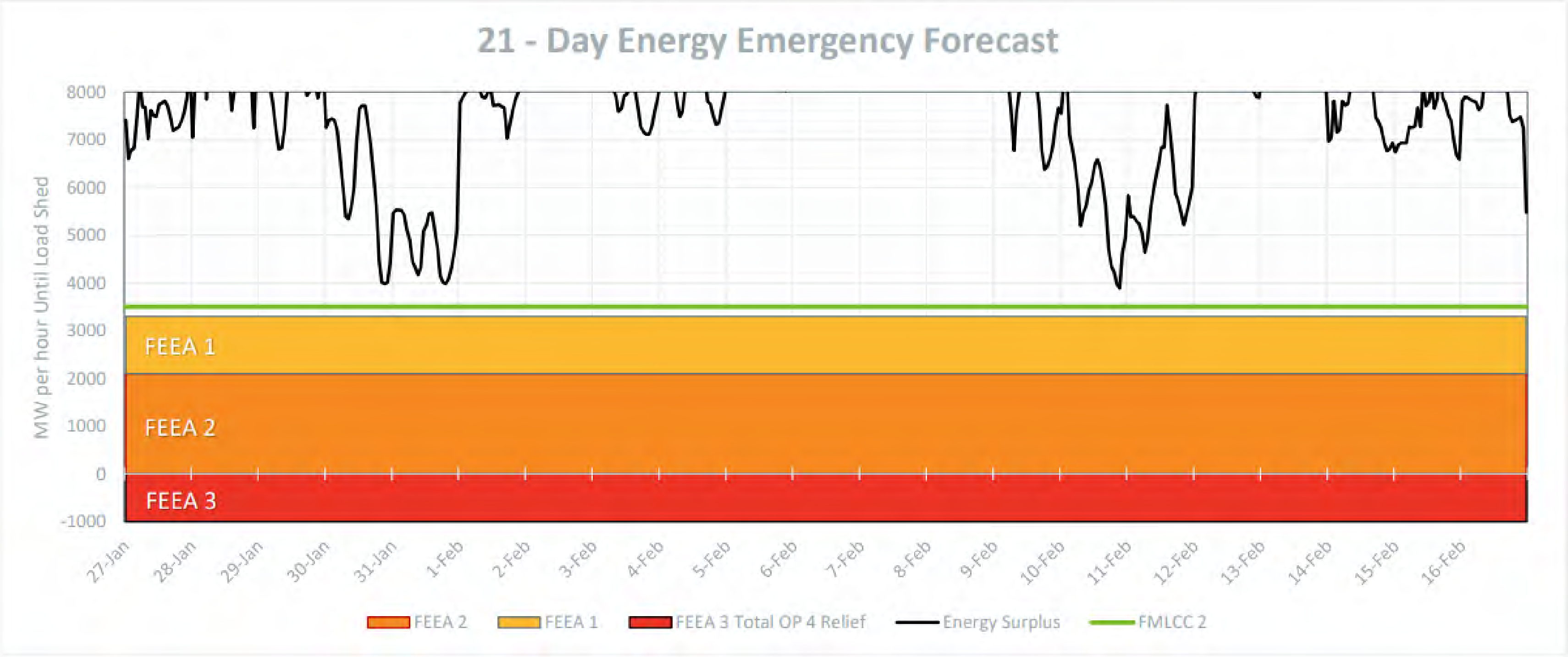


Section 202(c) Order

- As a precaution, the ISO requested a Section 202(c) order from the U.S. Department of Energy (DOE) on January 25
  - The DOE granted the request, allowing the ISO to maximize the availability of all generating resources in New England
  - On January 30, the ISO requested—and received—an extension of the order through February 14 due to the forecast of continued severe cold weather
- A total of 57 resources requested and were designated as "Specified Resources," meaning they could operate in reliance on the allowances available under the 202(c) order
  - These units represent approximately 11,215 MW of winter capacity, or about 39% of the region's total winter generating capacity
  - Of these, 26 resources reported an exceedance of a specified emissions limit during the period the 202(c) order was in effect
- Specified Resources consisted primarily of dual-fuel (gas/oil), gas-only, or generators operating on residual fuel oil

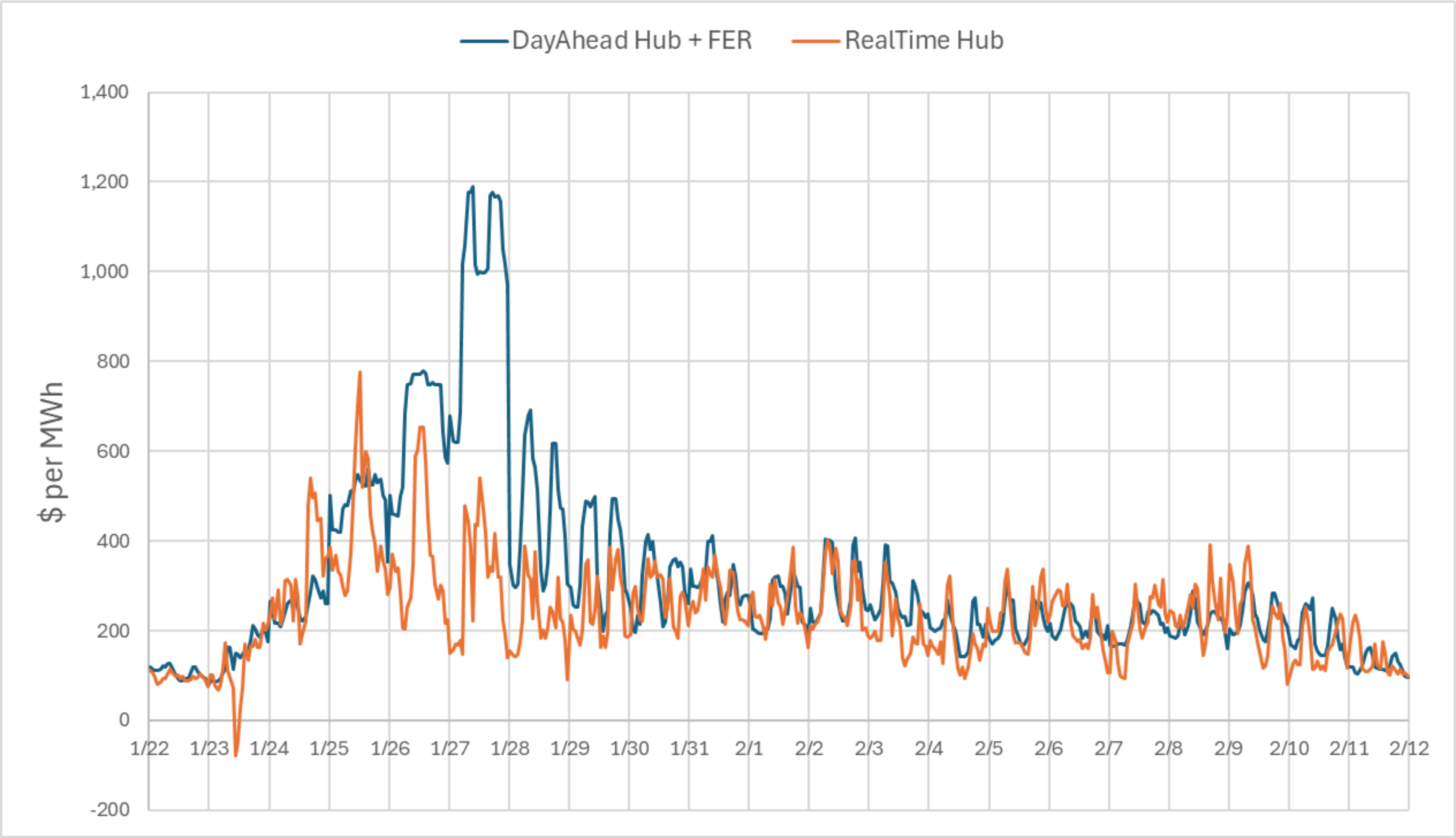
Daily Publication of the 21-day Energy Assessment Enhanced Regional Situational Awareness

- Beginning on January 27, the ISO began publishing the 21-Day Energy Assessment and Forecast Report on a daily basis to improve regional situational awareness of energy supplies
- The report highlighted periods of reduced energy surplus (see example from the Jan. 27 assessment which was posted on Jan. 28), though the forecast never indicated conditions severe enough to trigger an Energy Alert or Energy Emergency



Real-Time LMPs Averaged $250/MWh During the Cold Weather Outbreak

Day Ahead LMPs + Forecast Energy Requirement (FER) Averaged $331/MWh



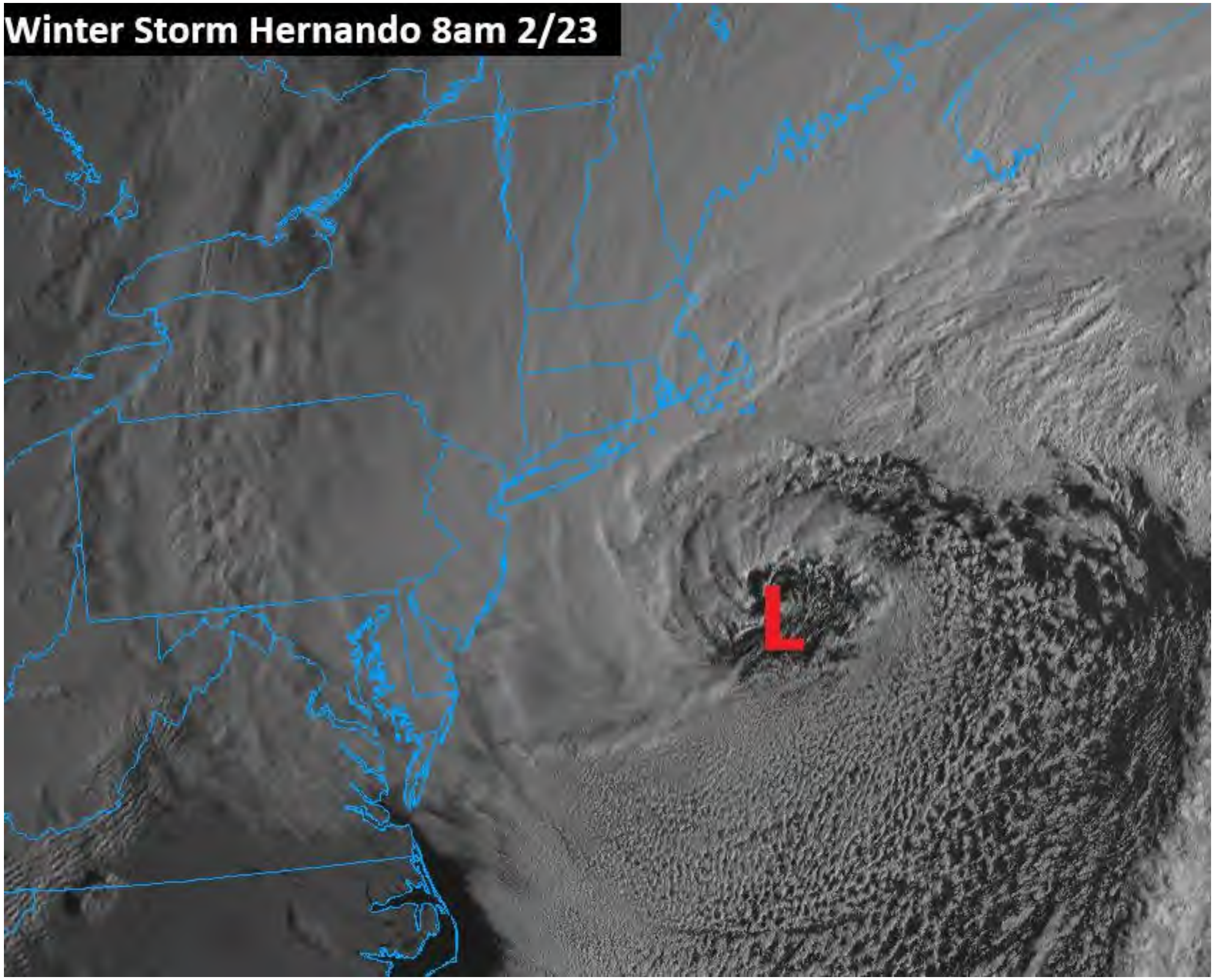
WINTER STORM HERNANDO

Winter Storm Hernando Summary

- Winter Storm Hernando impacted New England beginning on Monday, February 23 with blizzard conditions, winds of 65 mph and higher, coastal flooding, and heavy snow in excess of 3 feet in some locations
- Customer outages peaked at ~350,000 around noon on February 23
  - Most customers were restored by Friday, February 27 though some areas in Southeastern Massachusetts and Cape Cod required more time to fully restore
- The most significant impacts to the transmission system were concentrated in Southeastern Massachusetts and Cape Cod; three 345 kV circuits and nine 115 kV circuits tripped during the storm but resulted in no reliability issues
- Generation resources remained highly dependable throughout the storm with ~425 MW of generation becoming unavailable due to control and communications problems or electrical issues

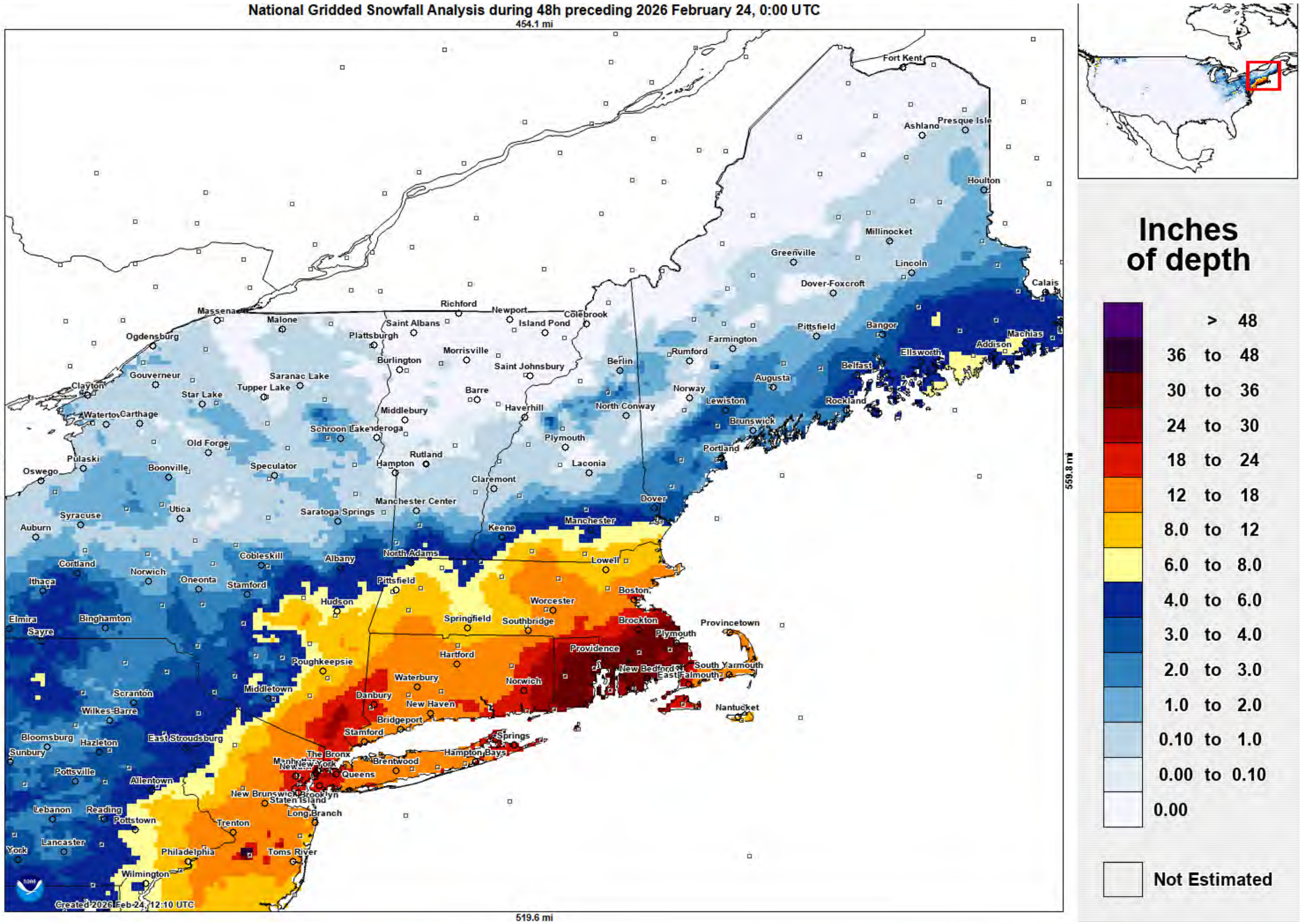
Winter Storm Hernando Became a Powerful Nor'easter Early Monday, February 23

- The storm resembled what meteorologists call a “winter hurricane” - a rapidly intensifying system that takes on the appearance of tropical cyclone with few clouds in the center, also called a “bomb cyclone”
- ISO's forecasting team closely monitored the storm in the days prior and staff was in close communication with Local Control Centers throughout



Winter Storm Hernando, Snowfall Totals

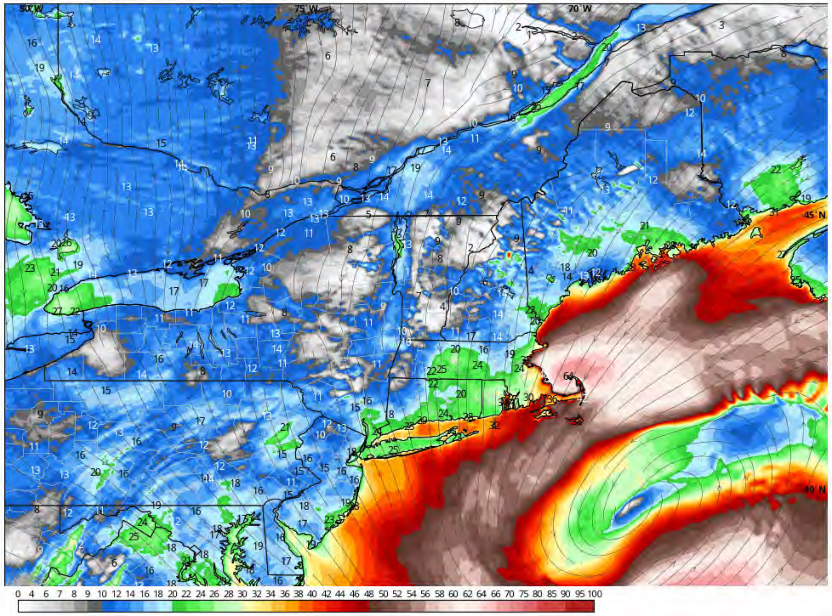
Over 3 Feet of Snow Fell in Parts of MA & RI



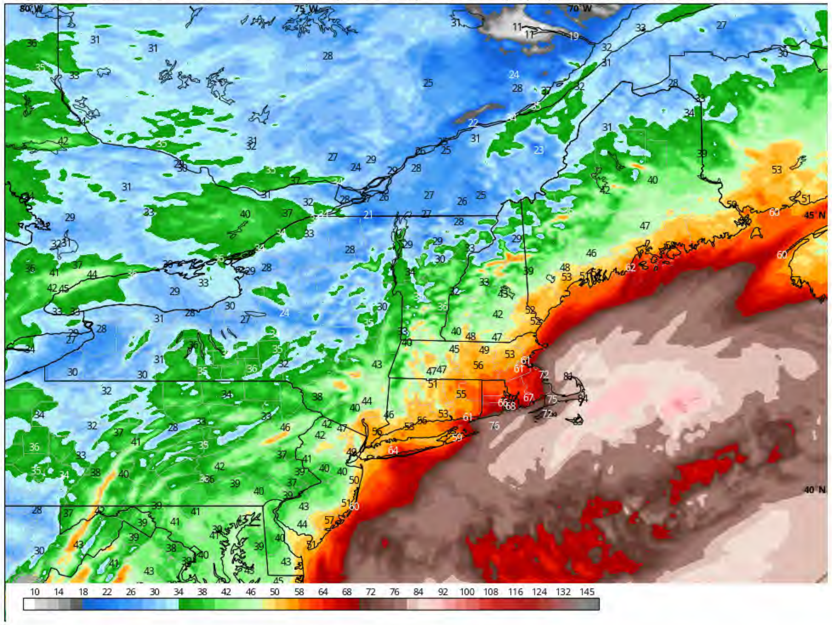
Winter Storm Hernando, Winds Summary

Winds Gusted 60-70 MPH in Parts of Eastern MA & RI, As High As 83 MPH on Nantucket

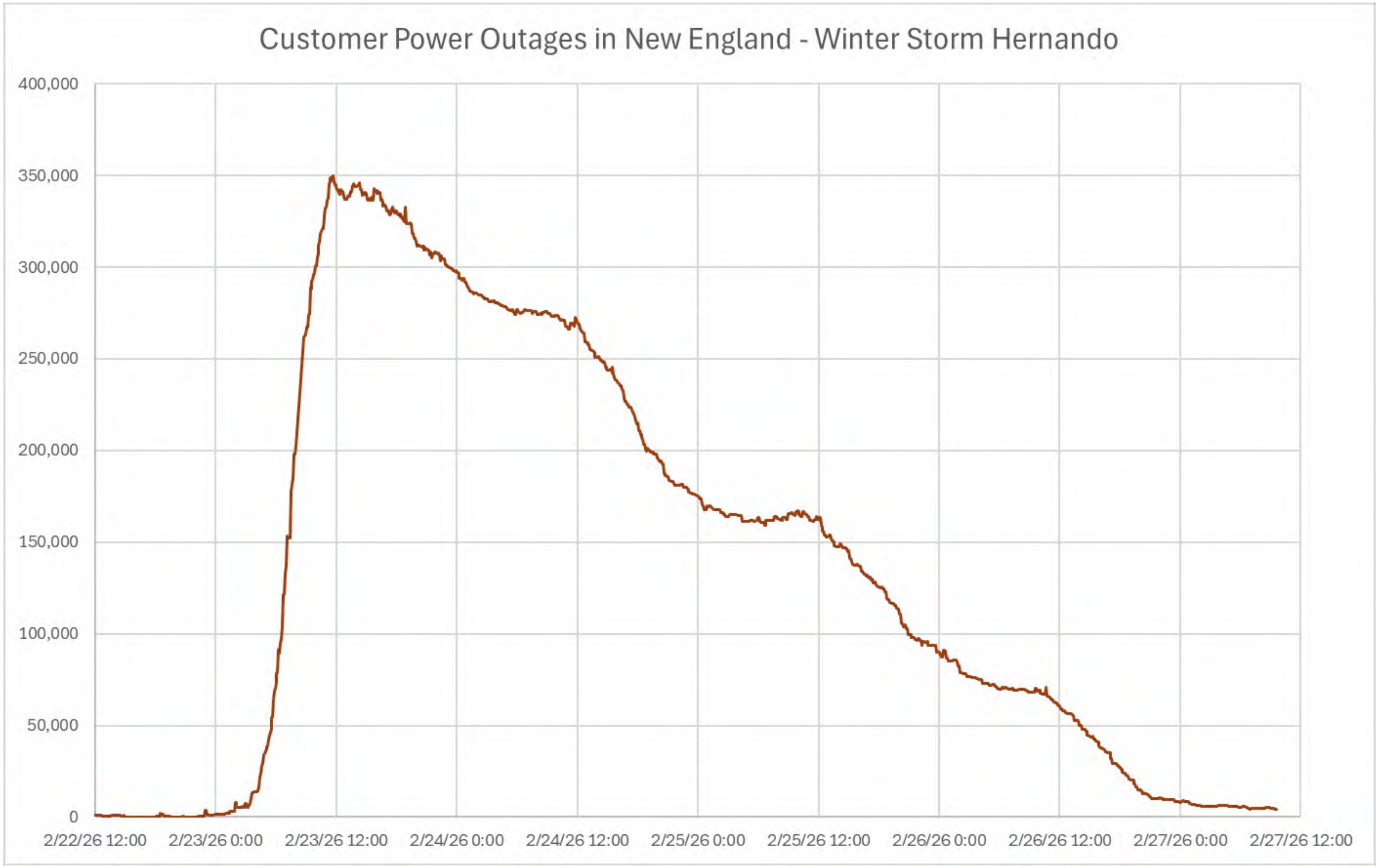
Reported Maximum Sustained Winds Monday February 23, 2026 (mph) Winter Storm Hernando



Reported Maximum Wind Gusts Monday February 23, 2026 (mph) Winter Storm Hernando



Customer Outage Totals Peaked at ~350,000 on February 23



SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Below Normal (-3.3°F) Max: 49°F, Min: 4°F Precipitation: 2.08" – Below Normal Normal: 3.21" Snow: 26.8"	Hartford	Temperature: Below Normal (-4.8°F) Max: 50°F, Min: -2°F Precipitation: 2.08" – Below Normal Normal: 3.13" Snow: 16.5"

Peak Load:	20,172 MW	February 8, 2026	18:00 (ending)
Mid-Day Minimum Load - Month:	10,514 MW	February 28, 2026	14:00 (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)

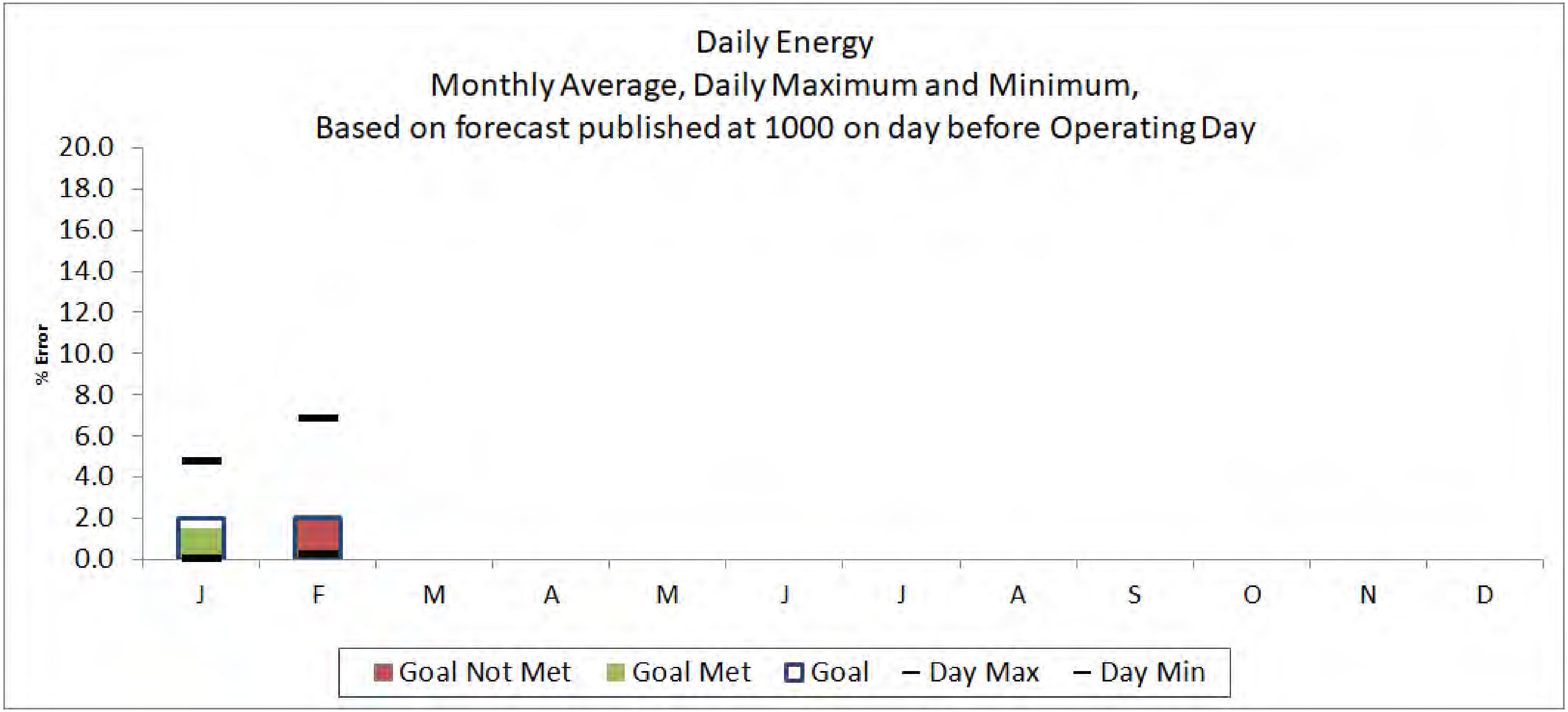
Procedure	Declared	Cancelled	Note
M/LCC 2	1/25/2026 09:00	2/11/2026 21:00	Severe Weather

System Operations

NPCC Simultaneous Activation of Ten-Minute Reserve Events

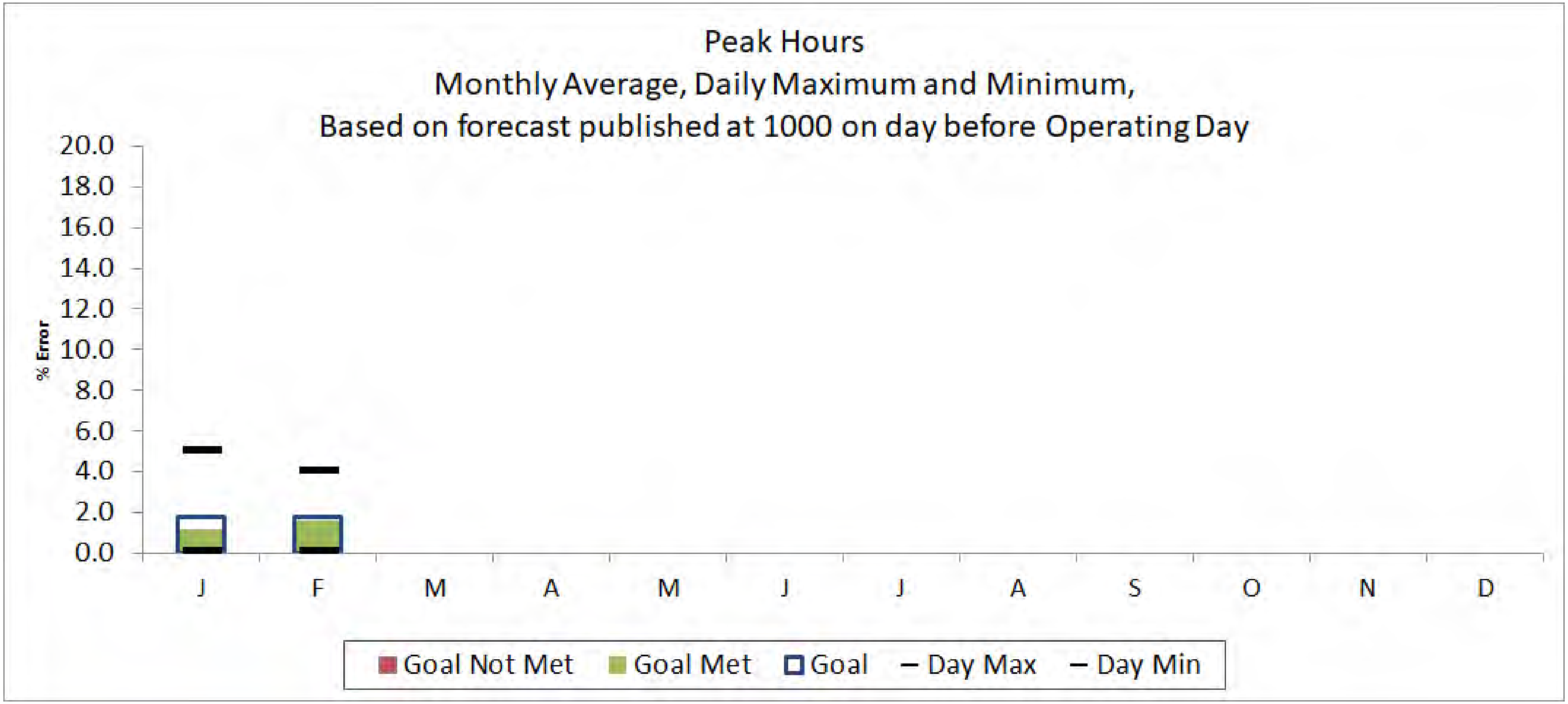
Date	Area	MW Lost
02/06/2026	NYISO	750
02/06/2026	NYISO	515
02/22/2026	NYISO	553

2026 System Operations - Load Forecast Accuracy cont.



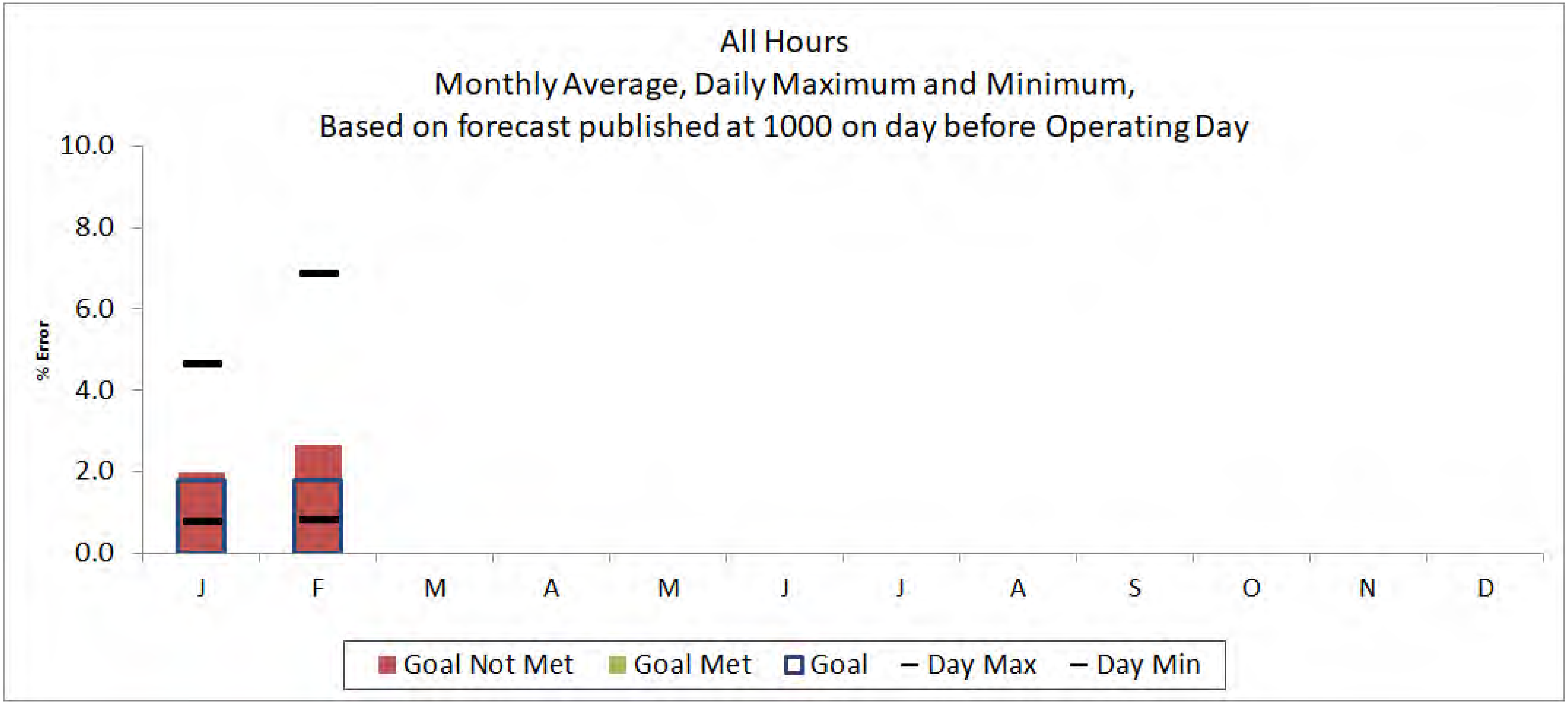
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.74	6.81											6.81
Day Min	0.01	0.22											0.01
MAPE	1.57	2.12											1.83
Goal	2.00	2.00											

2026 System Operations - Load Forecast Accuracy cont.



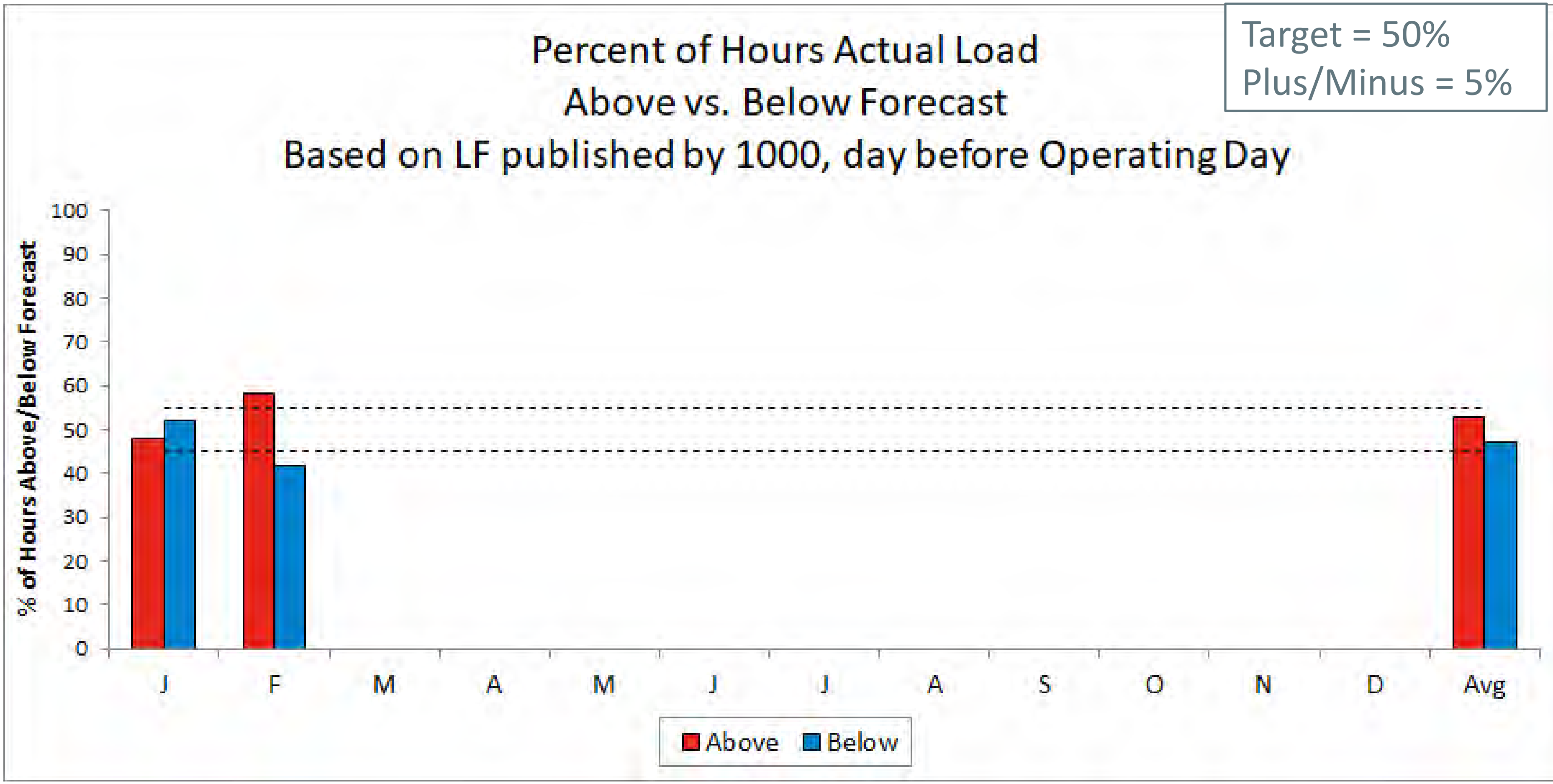
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	5.05	4.02											5.05
Day Min	0.08	0.12											0.08
MAPE	1.17	1.64											1.39
Goal	1.80	1.80											

2026 System Operations - Load Forecast Accuracy cont.



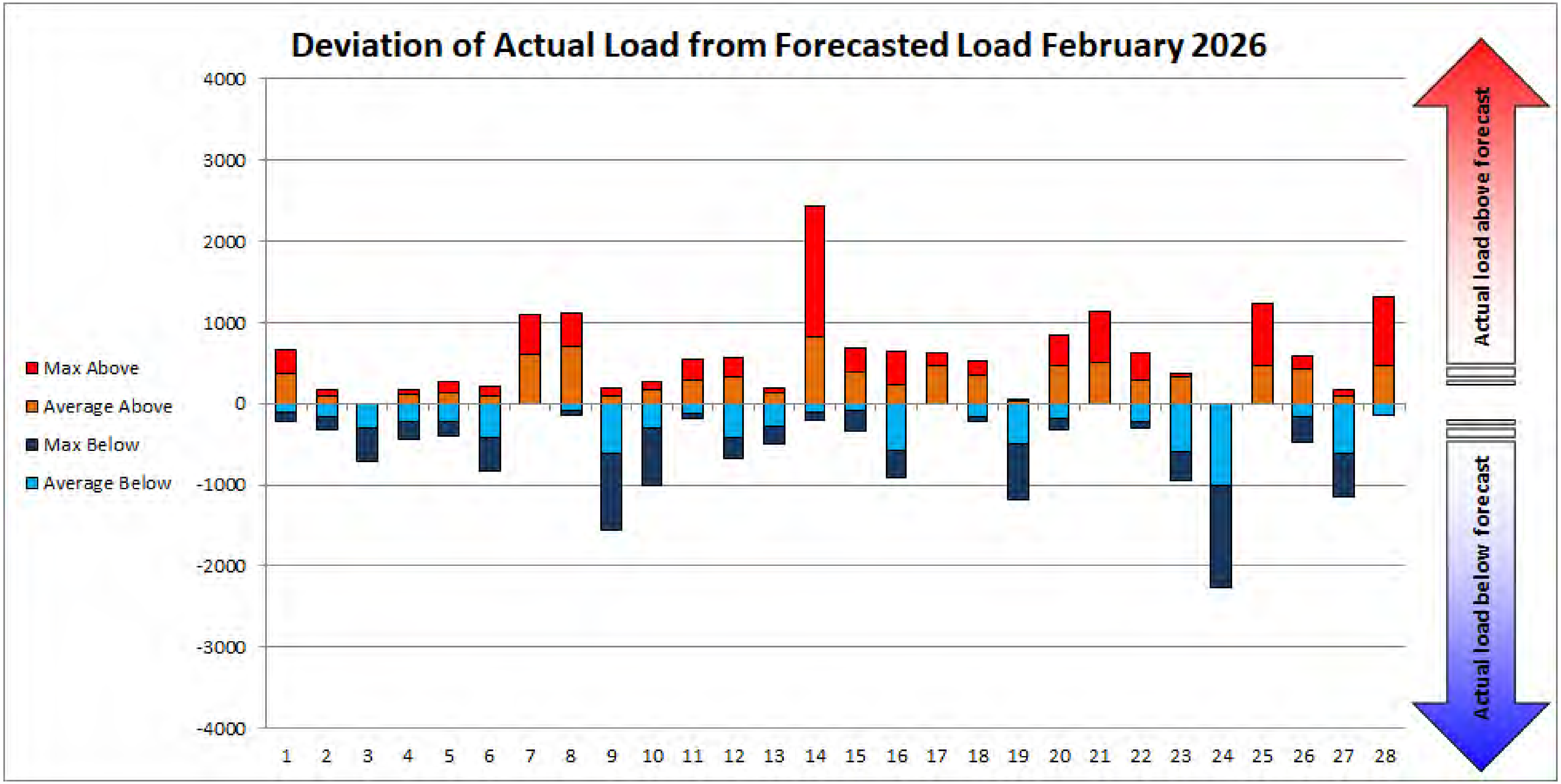
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.65	6.85											6.85
Day Min	0.76	0.82											0.76
MAPE	2.00	2.66											2.31
Goal	1.80	1.80											

2026 System Operations - Load Forecast Accuracy cont.



	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	47.8	58.2											53
Below %	52.2	41.8											47
Avg Above	204.1	299.6											300
Avg Below	-232.5	-271.5											-272
Avg All	-19	59											18

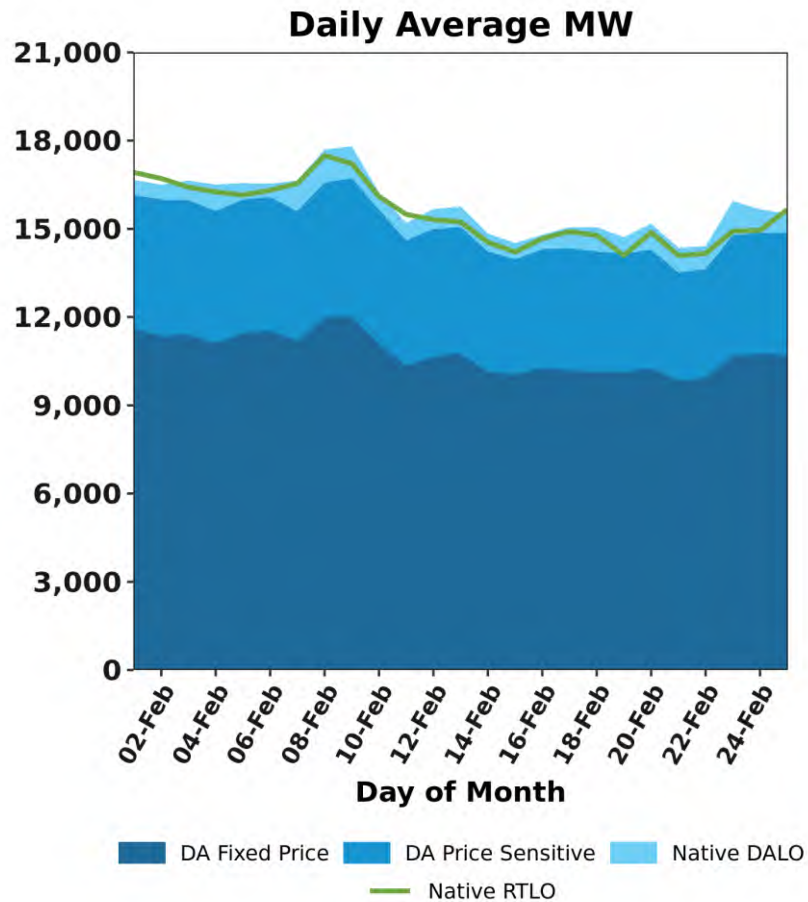
2026 System Operations - Load Forecast Accuracy

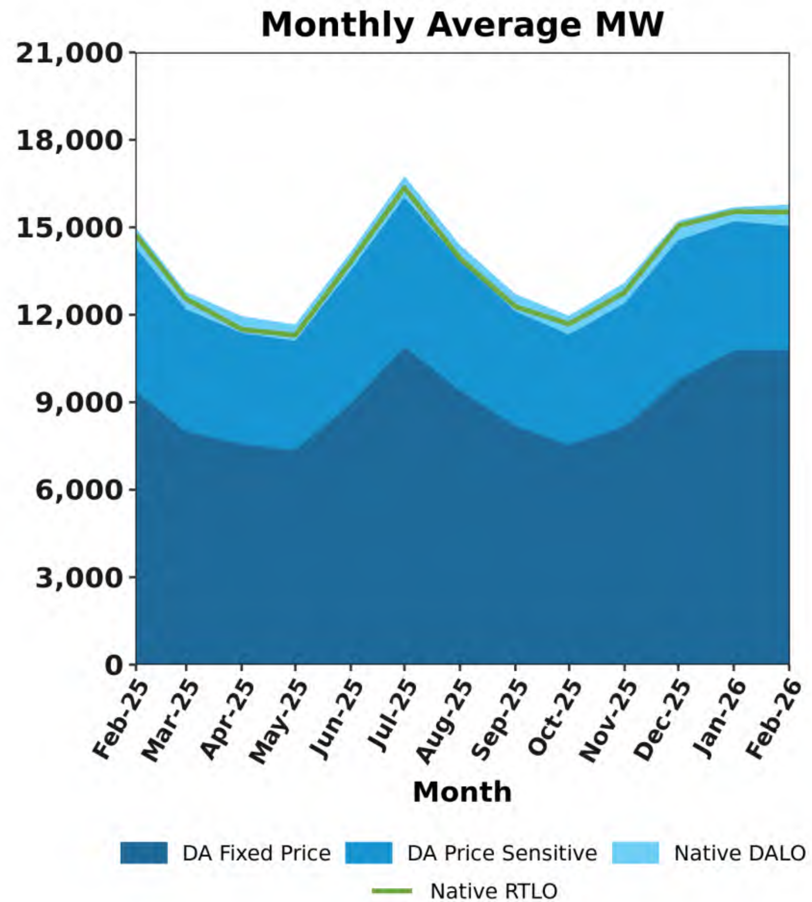


MARKET OPERATIONS

Supply and Demand Volumes

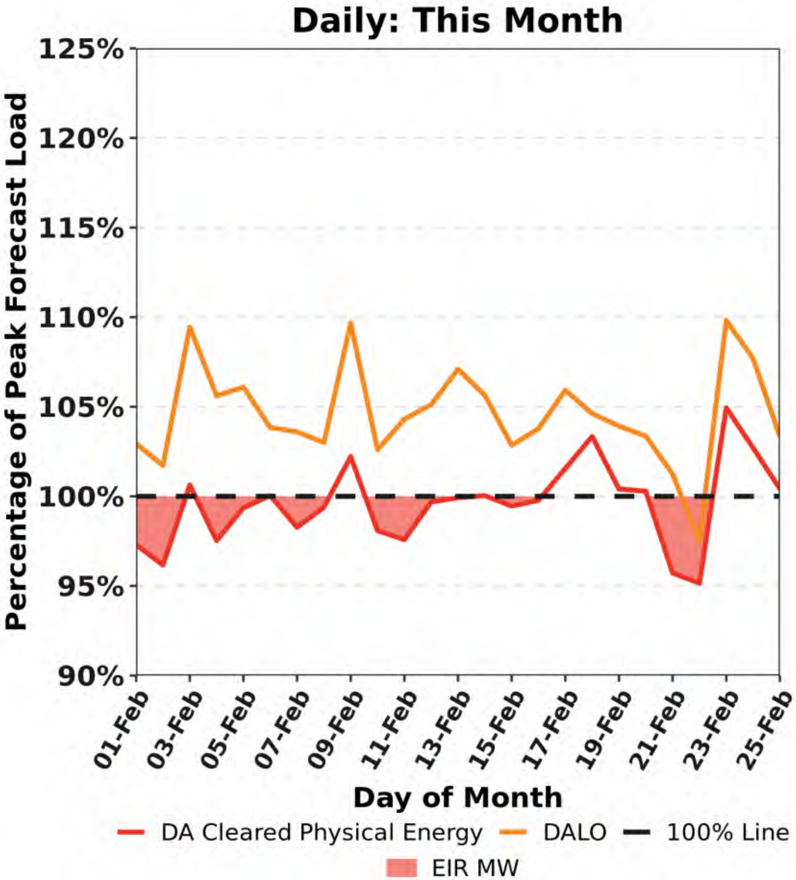
DA Cleared Native Load by Composition Compared to Native RT Load

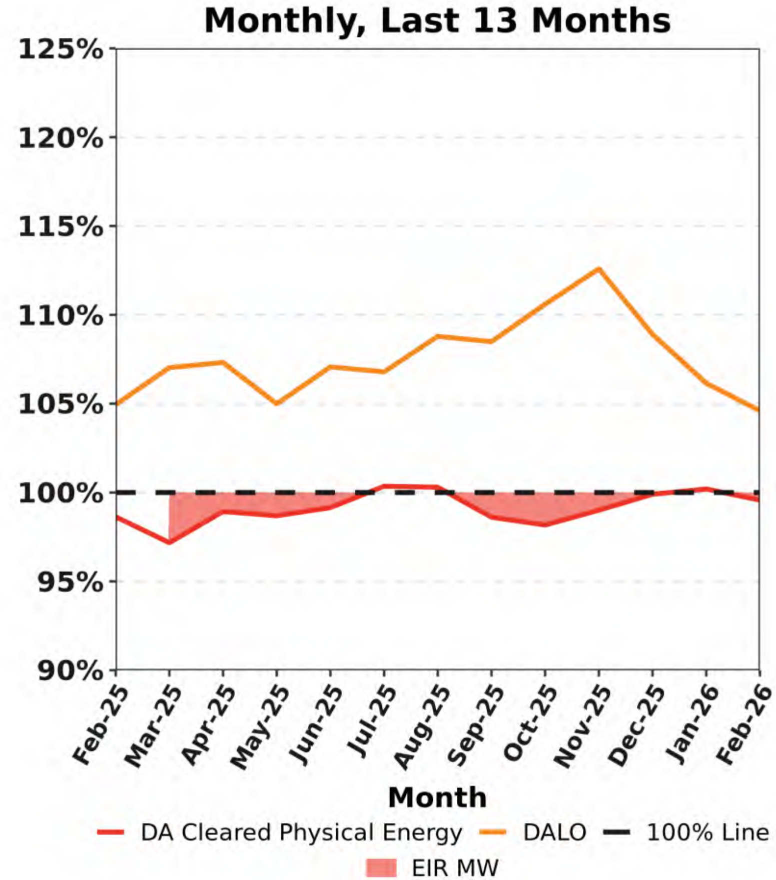




Native Day-Ahead Load Obligation (DALO) is the sum of all internal DA cleared load obligation, including internally cleared decrement bids (DECs). Native Real-Time Load Obligation (RTLO) is the sum of all internal real-time load obligation. Modeled transmission losses and exports are excluded in these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

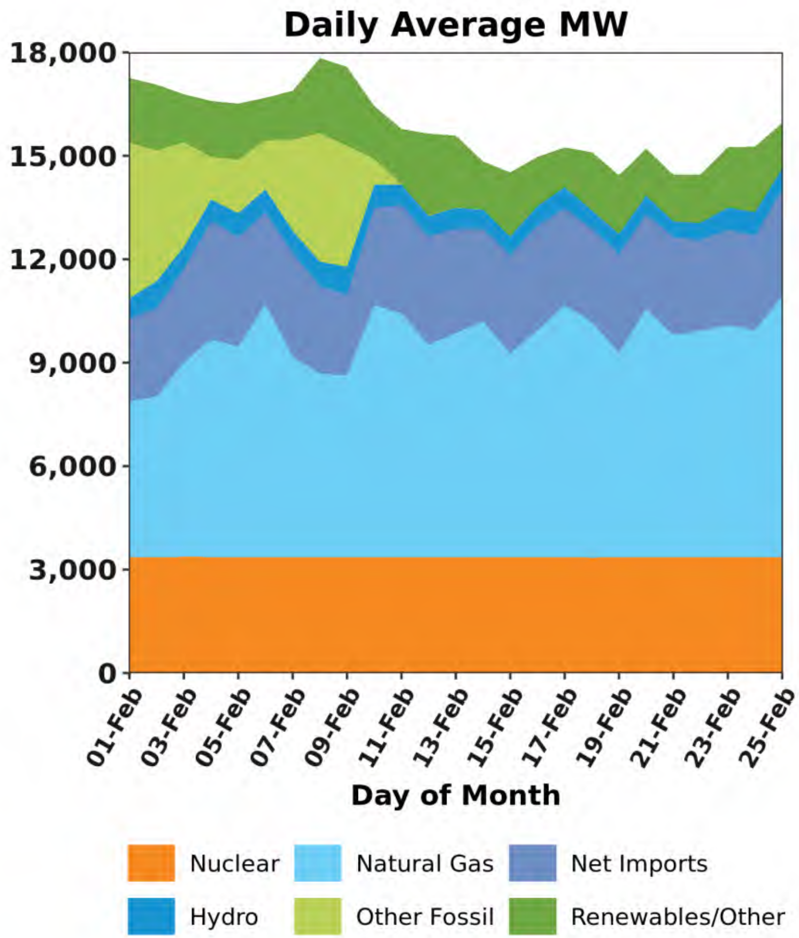
DA Volumes as % of Forecast in Peak Hour

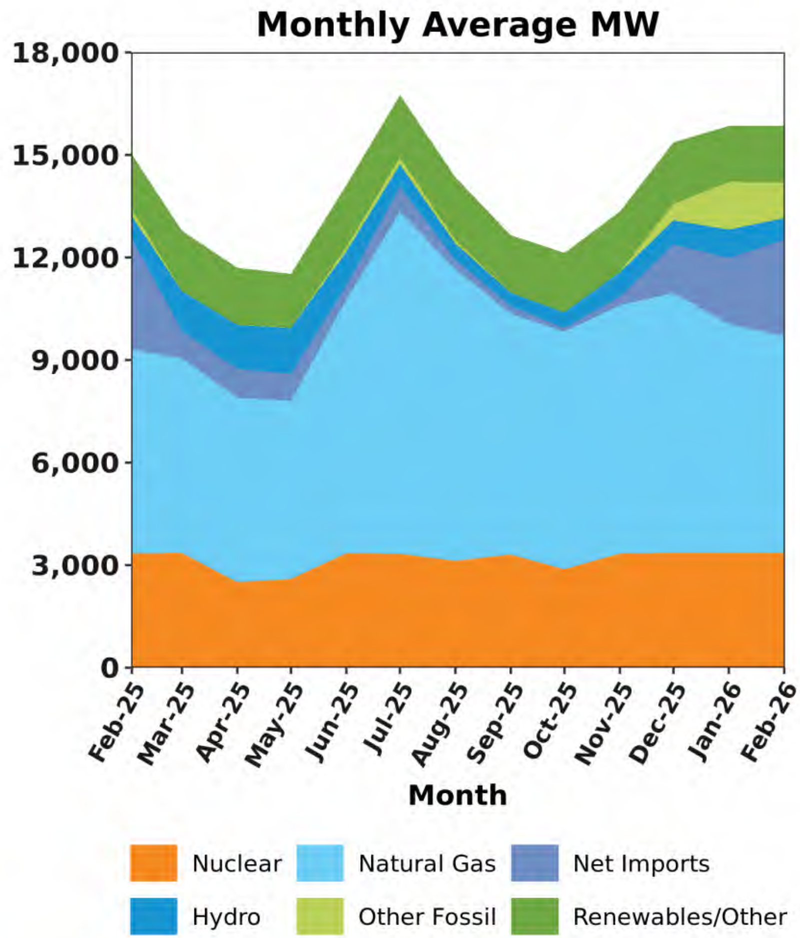




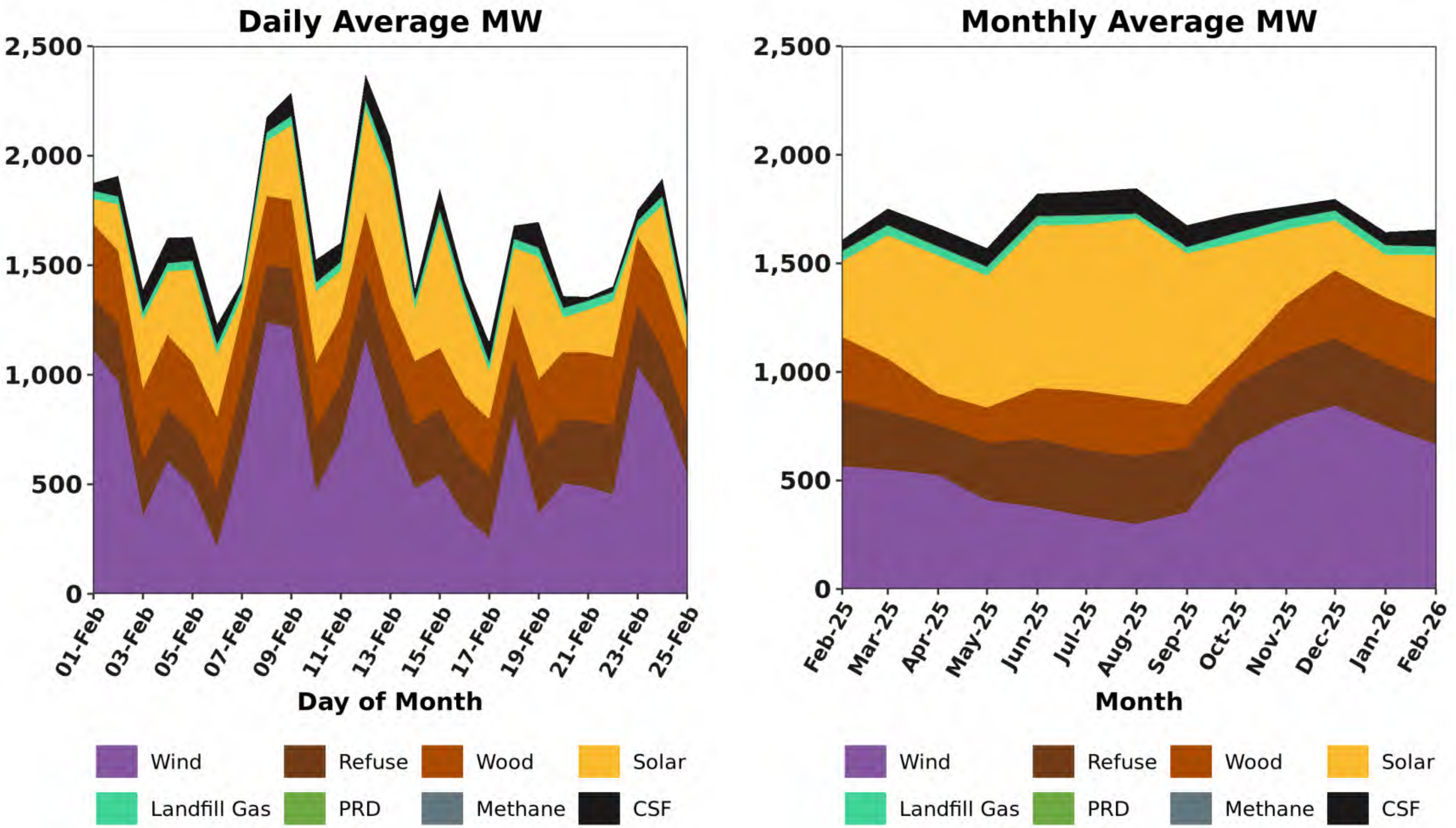
*DA cleared physical energy is the sum of generation, DRR and net imports cleared in the DA Energy Market and does not include EIR MW. Effective March 1, 2025, EIR MW obligations from physical generation and DRR are additionally procured up to (but not exceeding) 100% of the forecasted energy requirement.

Resource Mix



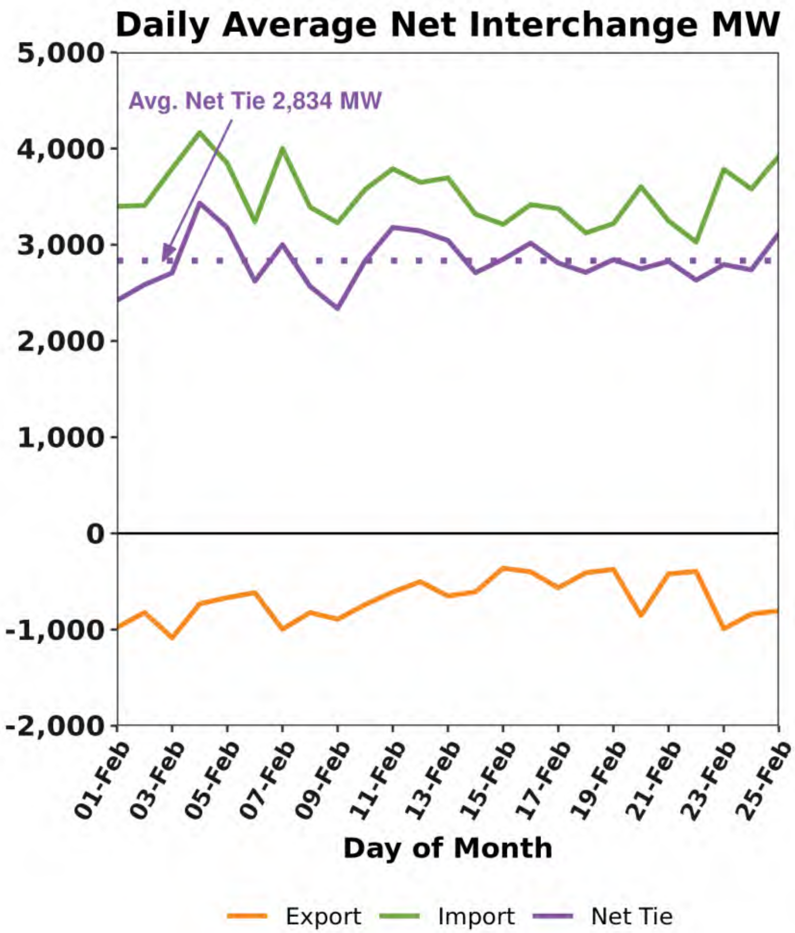


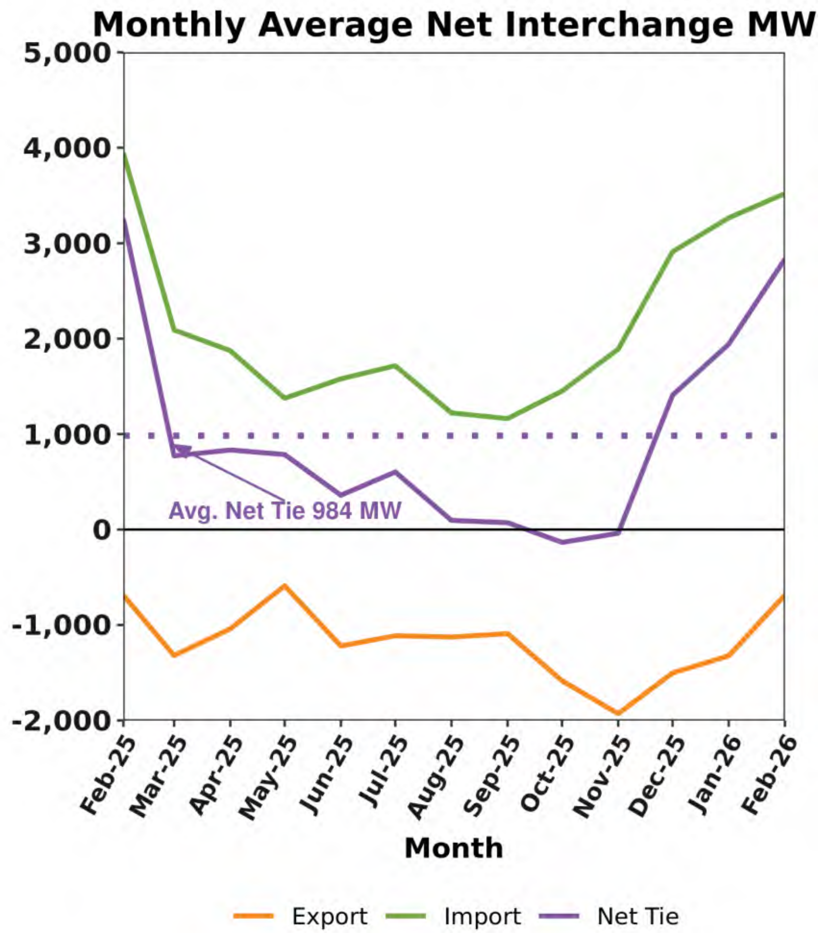
Renewable Generation by Fuel Type



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

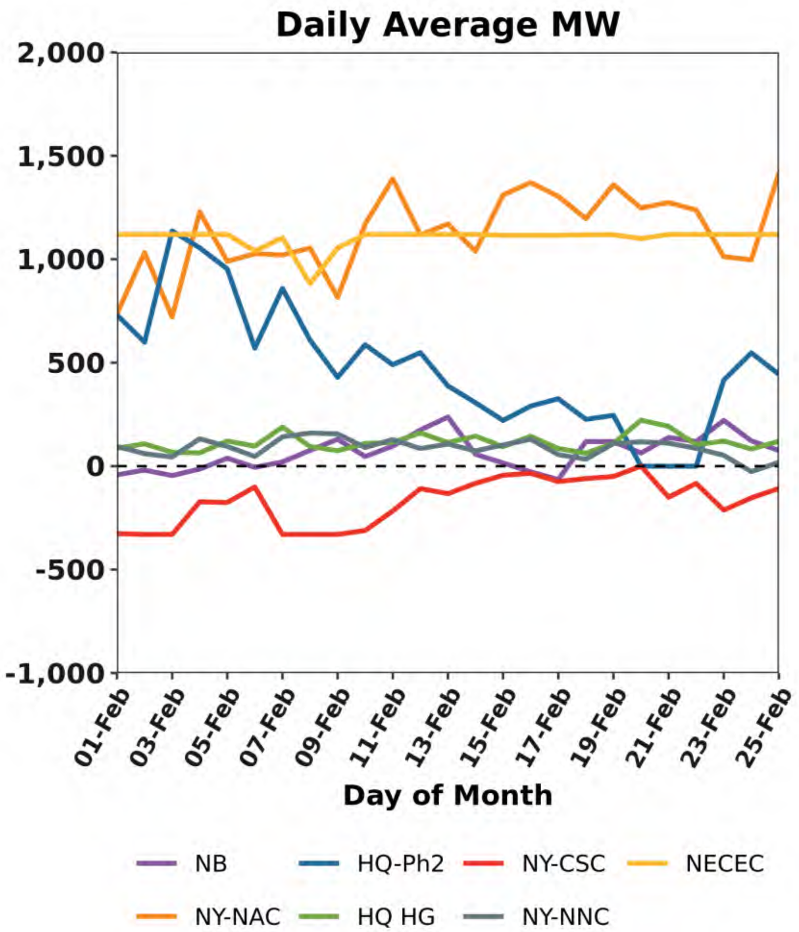
RT Net Interchange

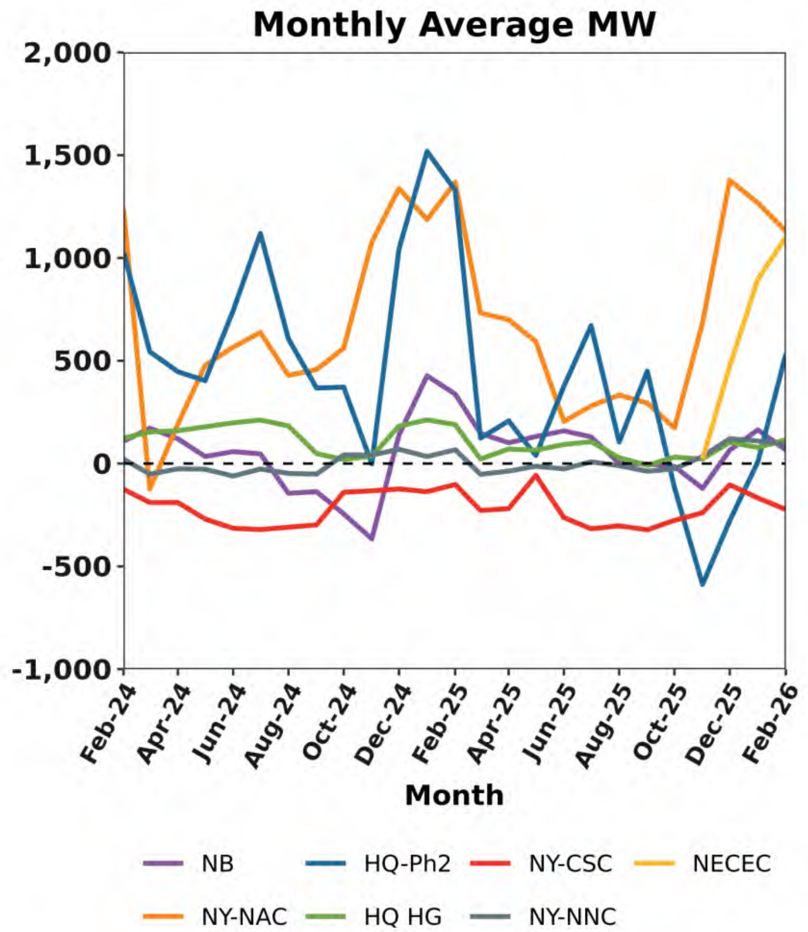




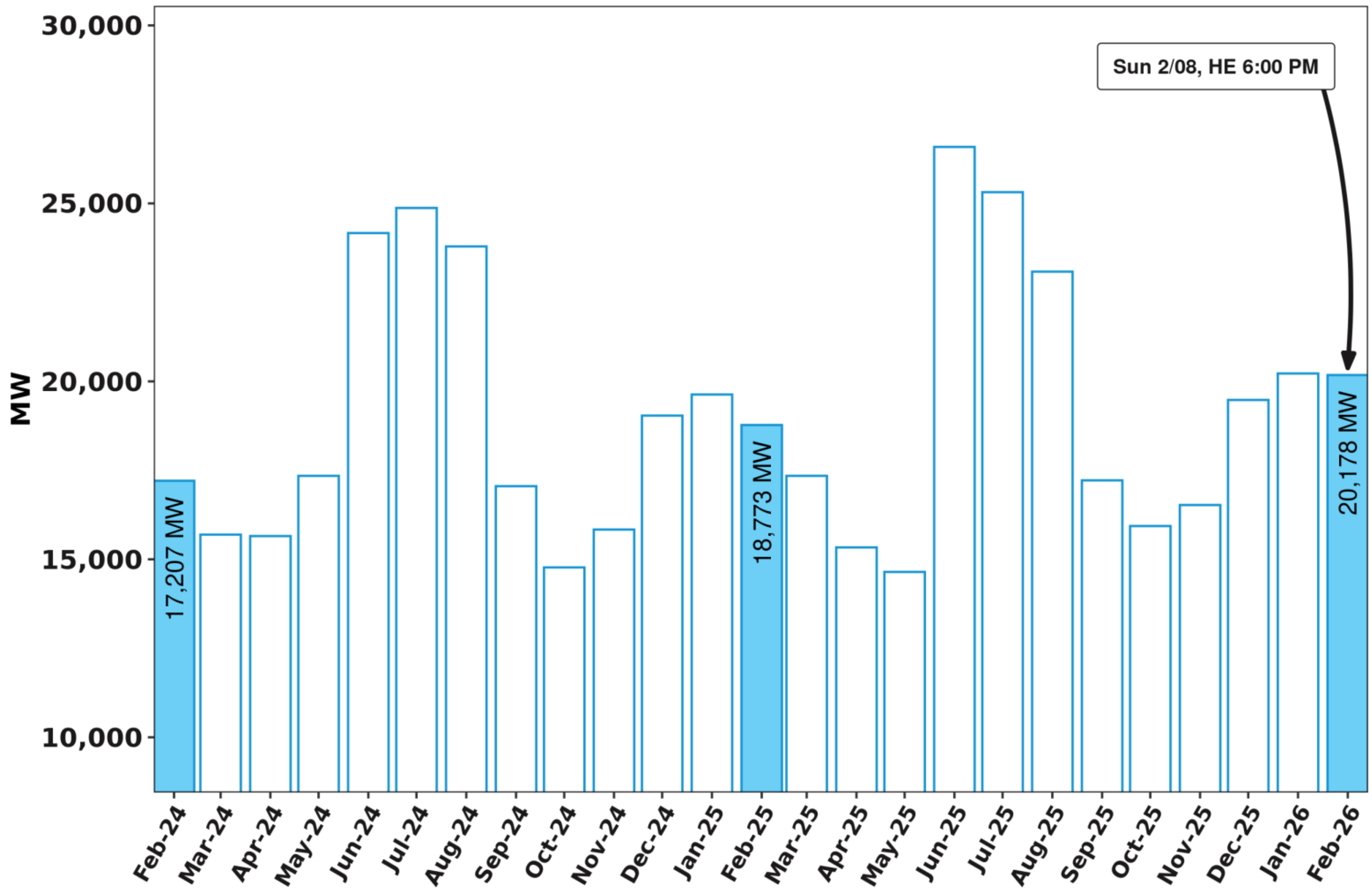
Net Interchange is the net of Participant scheduled imports (+) and exports (-). Inadvertent flows are not reflected.

RT Net Interchange by External Interface



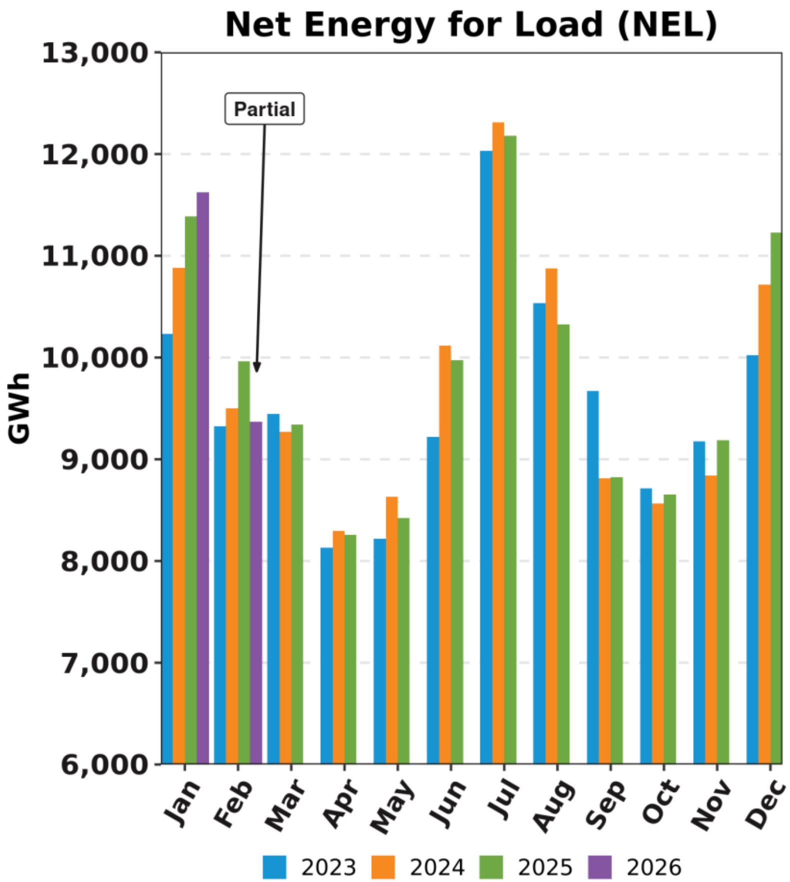


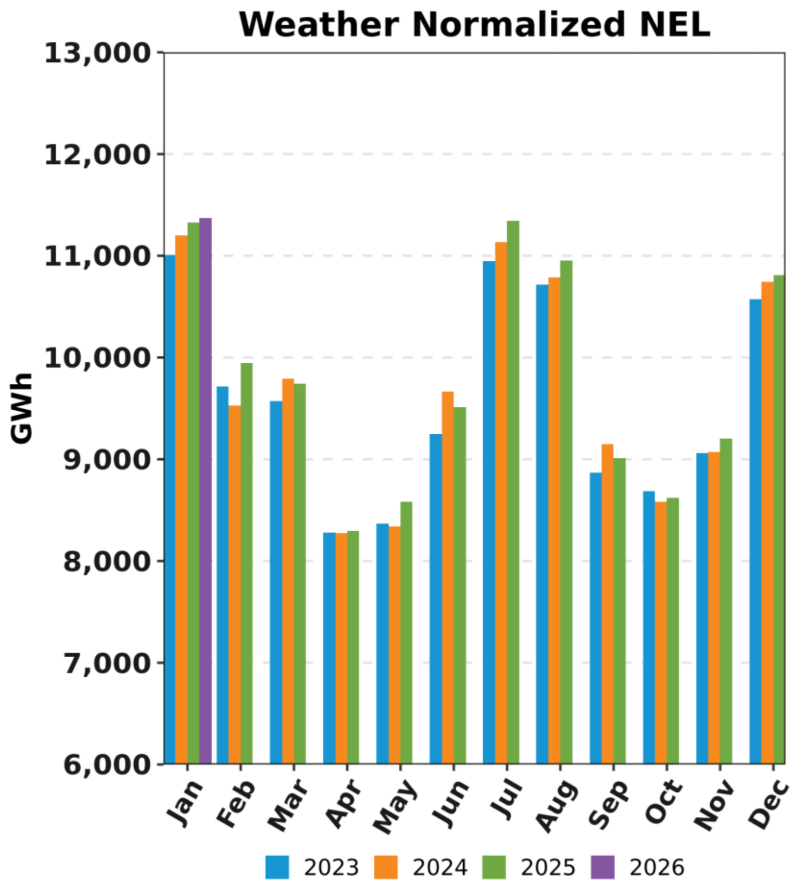
RQM System Peak Load MW by Month



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

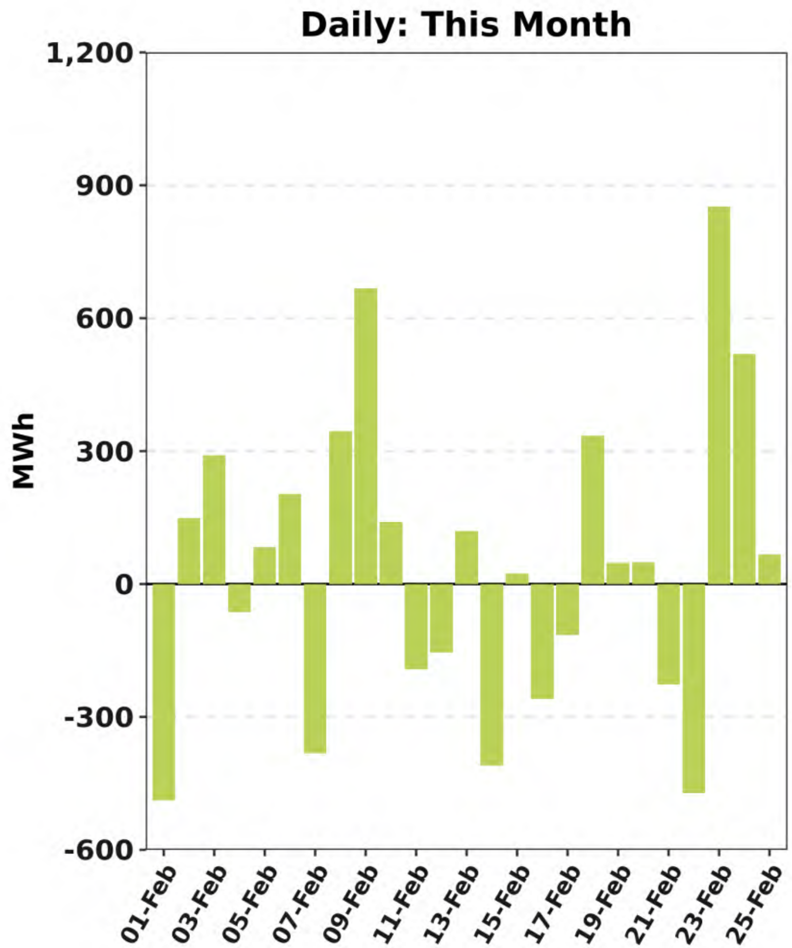
Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL

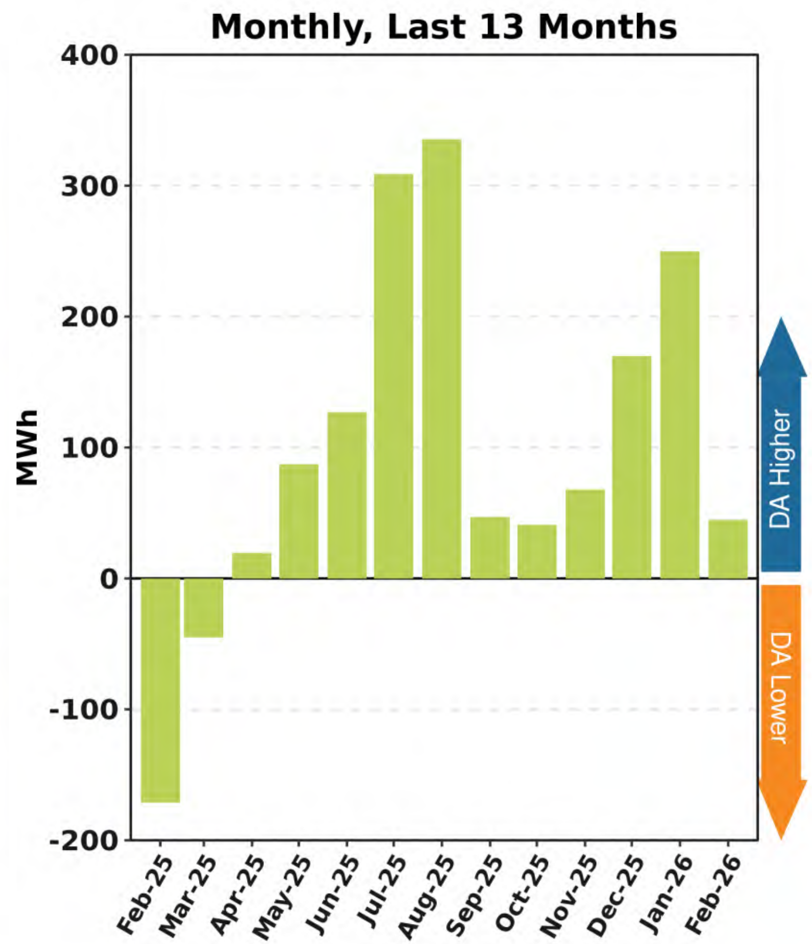




NEPOOL NEL is the total net revenue quality metered energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation + Demand Response Resource output - pumping load + net interchange where imports are positively signed. Current month's data may be preliminary. Weather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

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

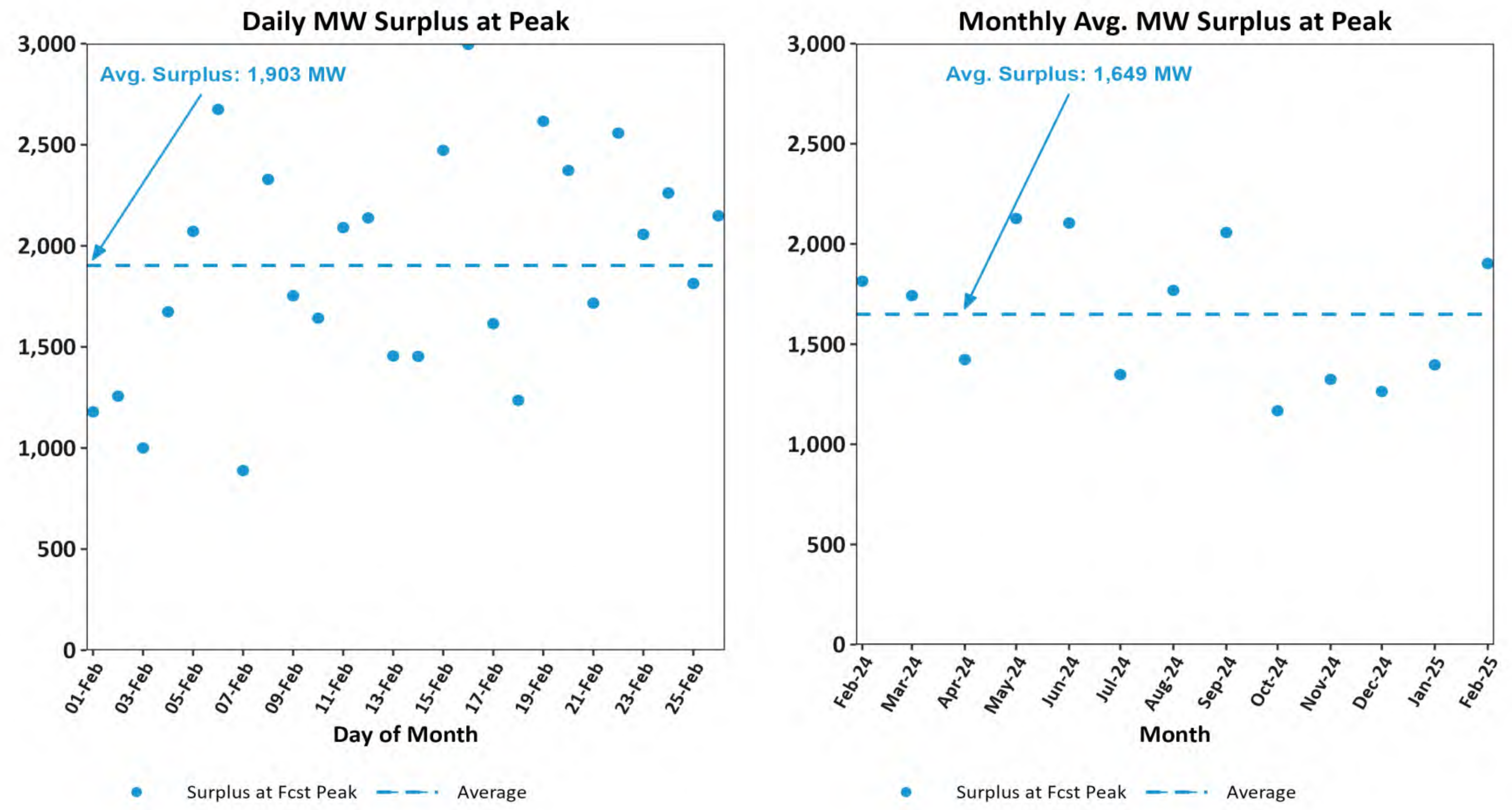




Negative values indicate DA Cleared Physical Energy value below its RT counterpart. EIR MW are not included in DA Physical Energy.

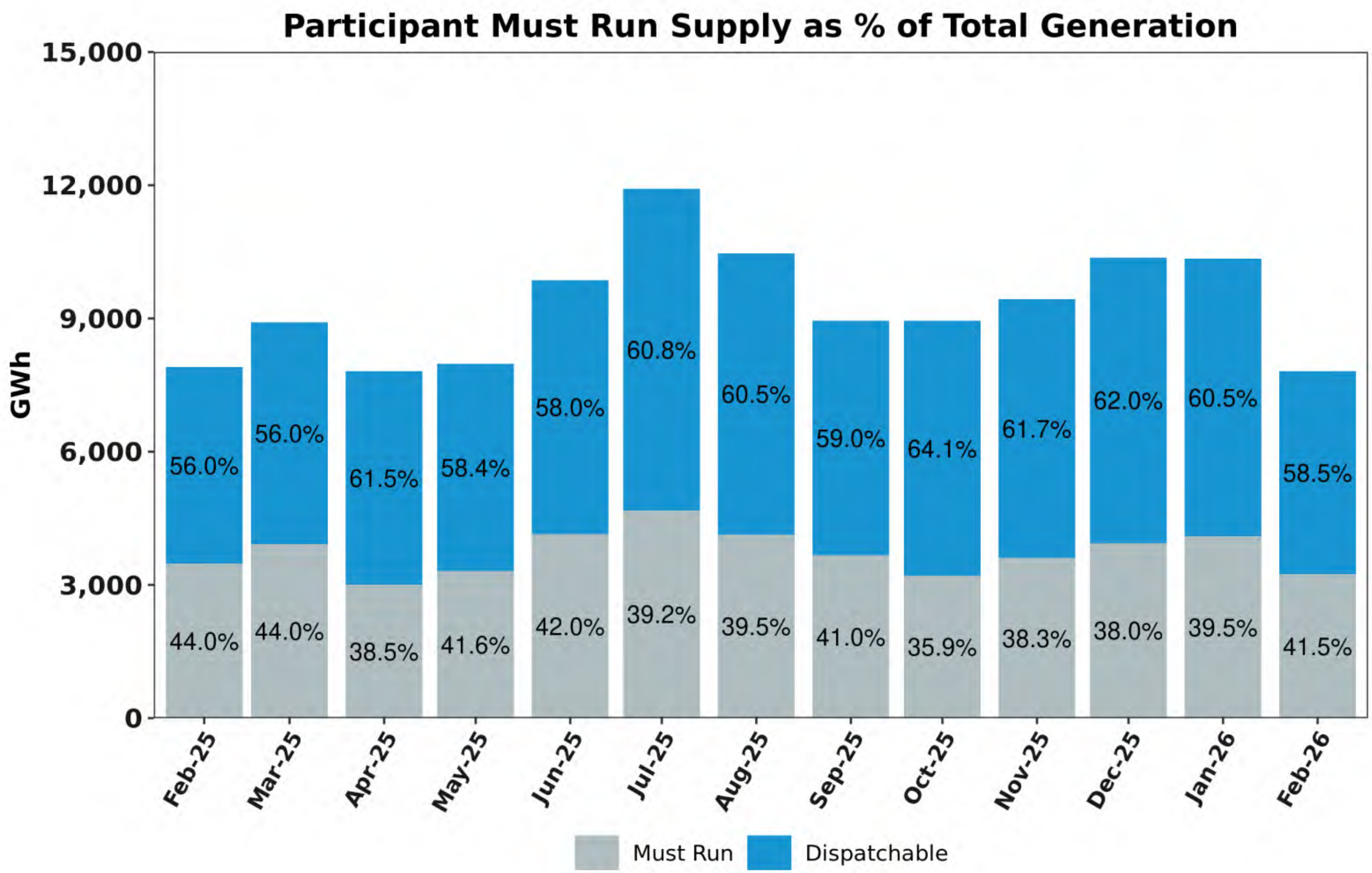
Pre-DAAS Slide

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



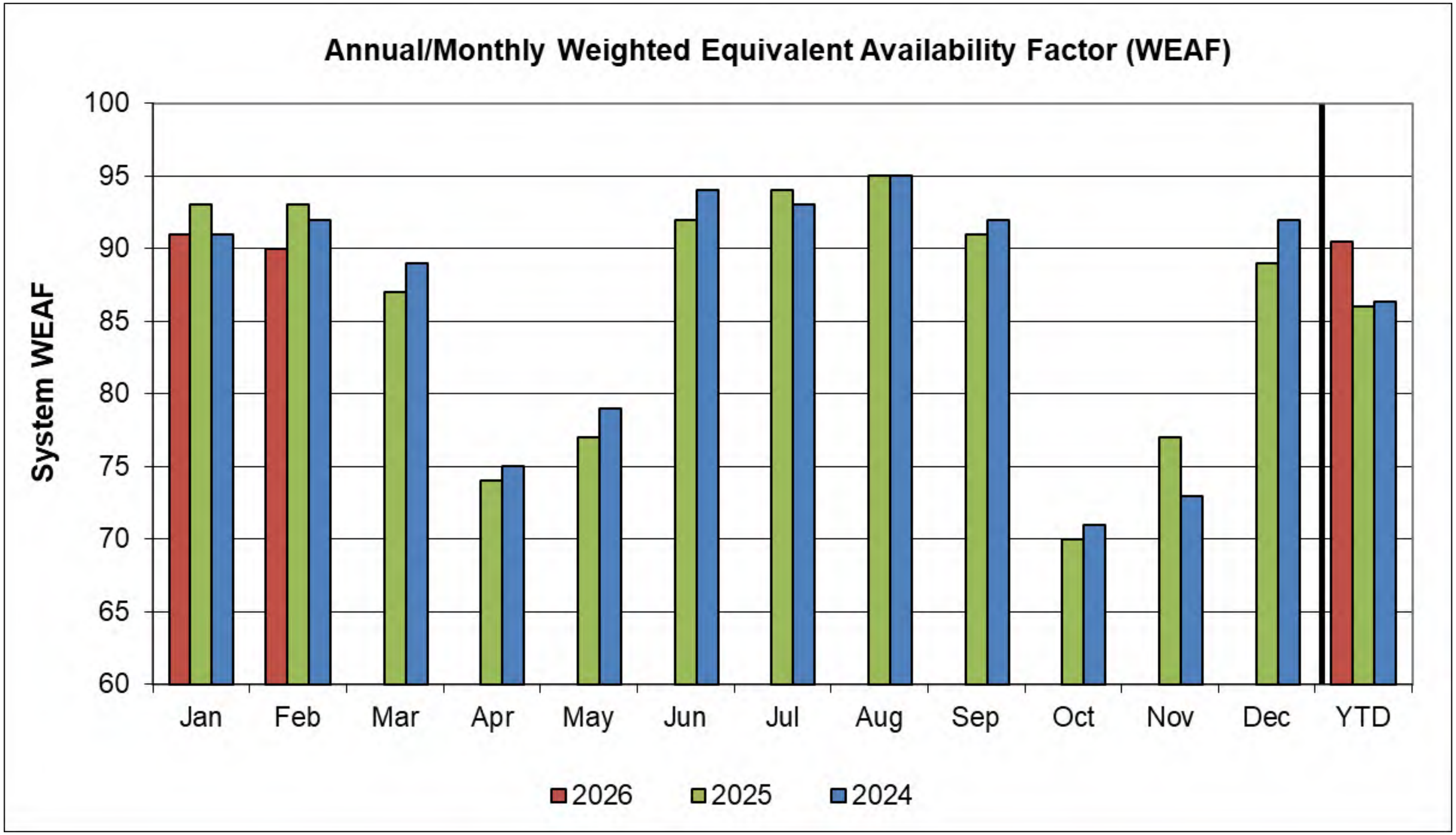
*DA capacity surplus includes DA offered ECO max above cleared amounts for cleared resources + offered reserves from available non-cleared resources + DA scheduled net interchange, reflected for the peak hour

RT Generation Output Offered as Must Run vs Dispatchable



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

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2026	91	90											91
2025	93	93	87	74	77	92	94	95	91	70	77	89	86
2024	91	92	89	75	79	94	93	95	92	71	73	92	86

Data as of 2/24/26

MARKET OPERATIONS

Market Pricing

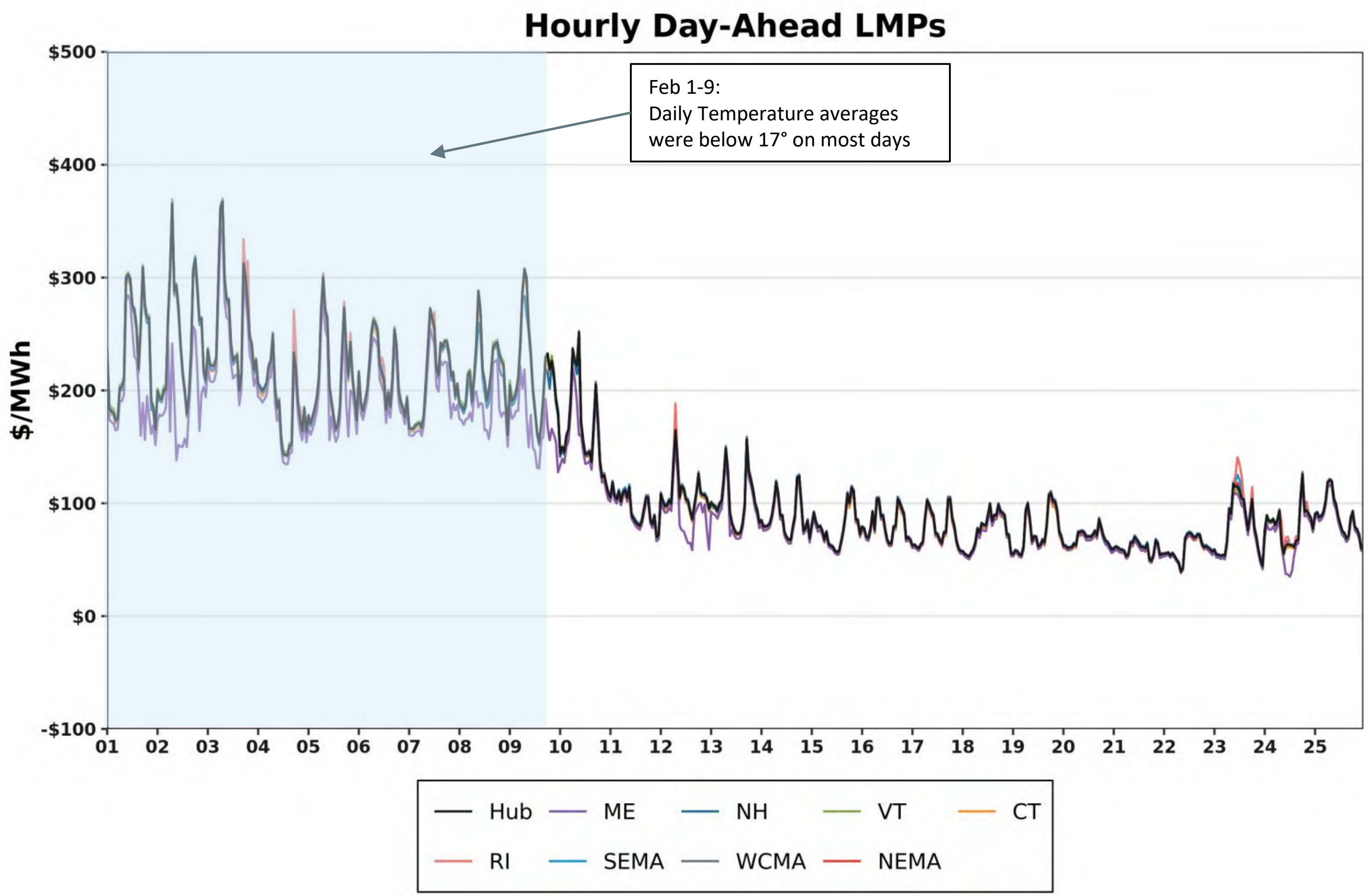
DA vs. RT LMPs ($/MWh)

Arithmetic Average

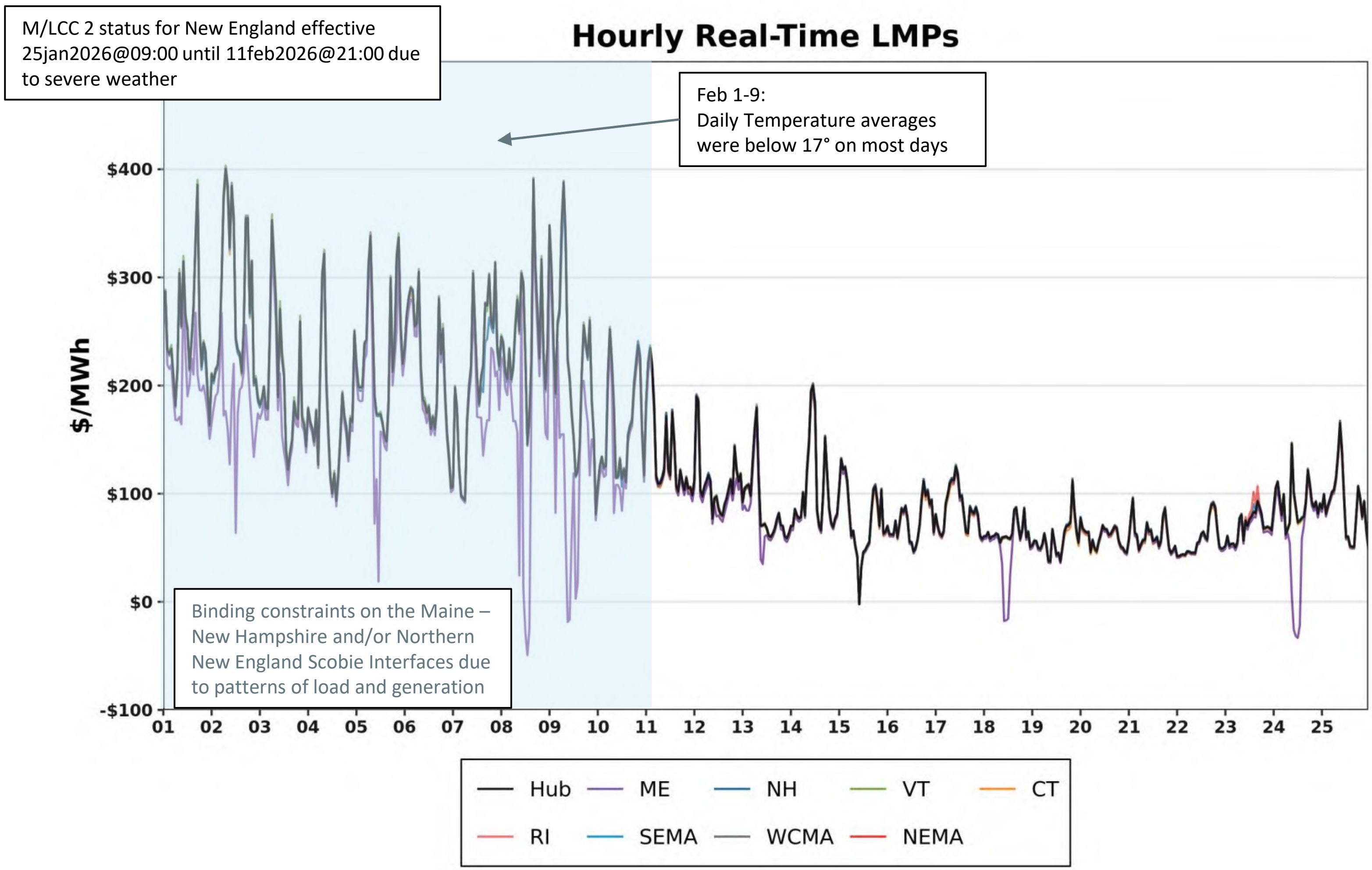
Year 2024	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$41.35	$41.07	$41.72	$41.11	$40.17	$41.28	$41.70	$41.37	$41.91
Real-Time	$39.37	$38.79	$39.65	$39.23	$38.46	$39.17	$39.62	$39.37	$39.77
RT Delta %	-4.79%	-5.55%	-4.96%	-4.57%	-4.26%	-5.11%	-4.99%	-4.83%	-5.11%
Year 2025	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$68.11	$66.29	$68.63	$68.21	$66.23	$67.78	$68.63	$68.16	$68.93
Real-Time	$66.15	$63.91	$66.63	$66.15	$64.66	$65.85	$66.56	$66.18	$66.93
RT Delta %	-4.79%	-5.55%	-4.96%	-4.57%	-4.26%	-5.11%	-4.99%	-4.83%	-5.11%

February-25	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$130.39	$128.41	$131.80	$129.23	$126.40	$130.69	$131.80	$130.38	$131.97
Real-Time	$126.40	$124.22	$127.69	$124.72	$122.89	$126.85	$127.74	$126.40	$128.00
RT Delta %	-3.06%	-3.26%	-3.12%	-3.49%	-2.78%	-2.94%	-3.08%	-3.05%	-3.01%
February-26	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$134.93	$121.90	$133.57	$134.93	$131.58	$135.45	$136.02	$134.93	$135.75
Real-Time	$136.29	$116.03	$135.34	$136.67	$133.55	$136.25	$136.88	$136.45	$137.17
RT Delta %	1.01%	-4.82%	1.33%	1.29%	1.50%	0.59%	0.63%	1.13%	1.05%
Annual Diff.	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Yr over Yr DA	3.48%	-5.07%	1.34%	4.41%	4.10%	3.64%	3.20%	3.49%	2.86%
Yr over Yr RT	7.82%	-6.59%	5.99%	9.58%	8.67%	7.41%	7.16%	7.95%	7.16%

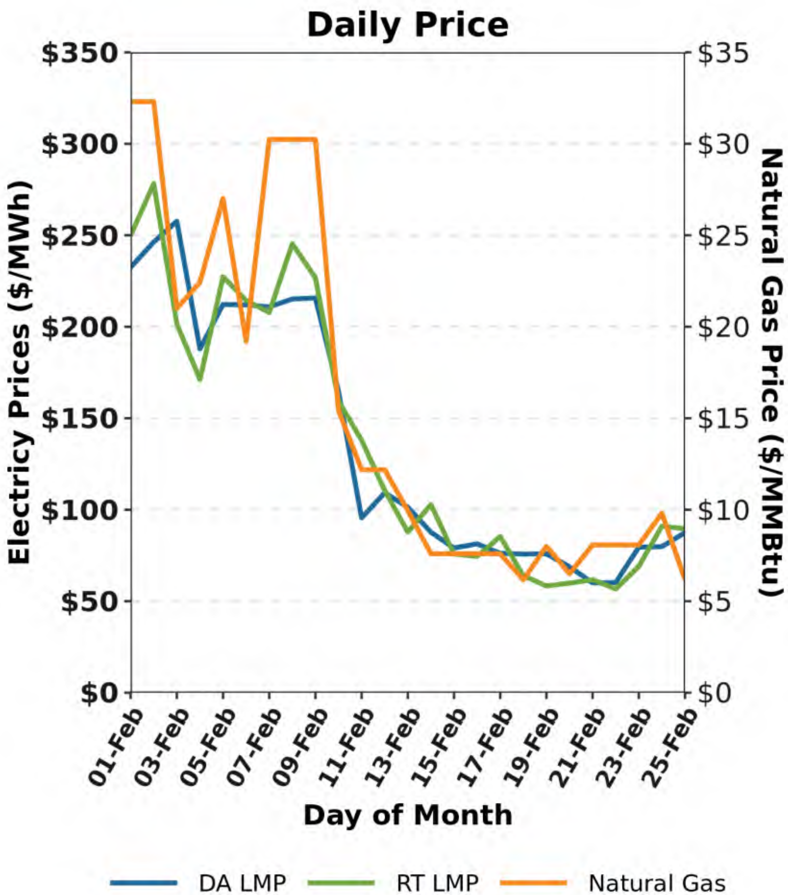
Hourly DA LMPs, February 1-25, 2026

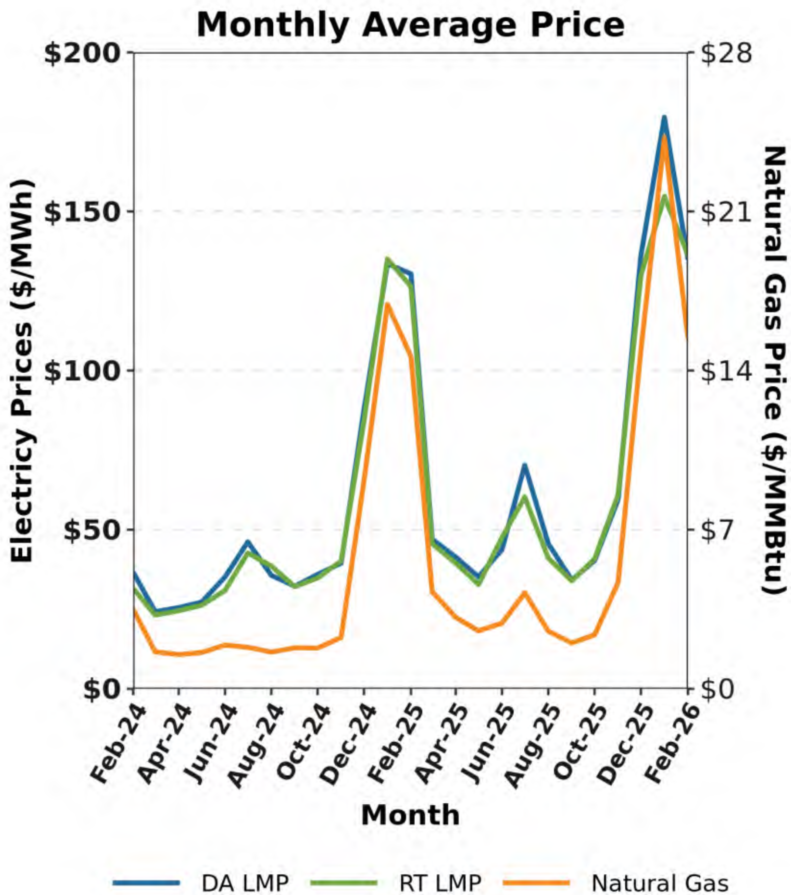


Hourly RT LMPs, February 1-25, 2026



Wholesale Electricity vs Natural Gas Price by Month

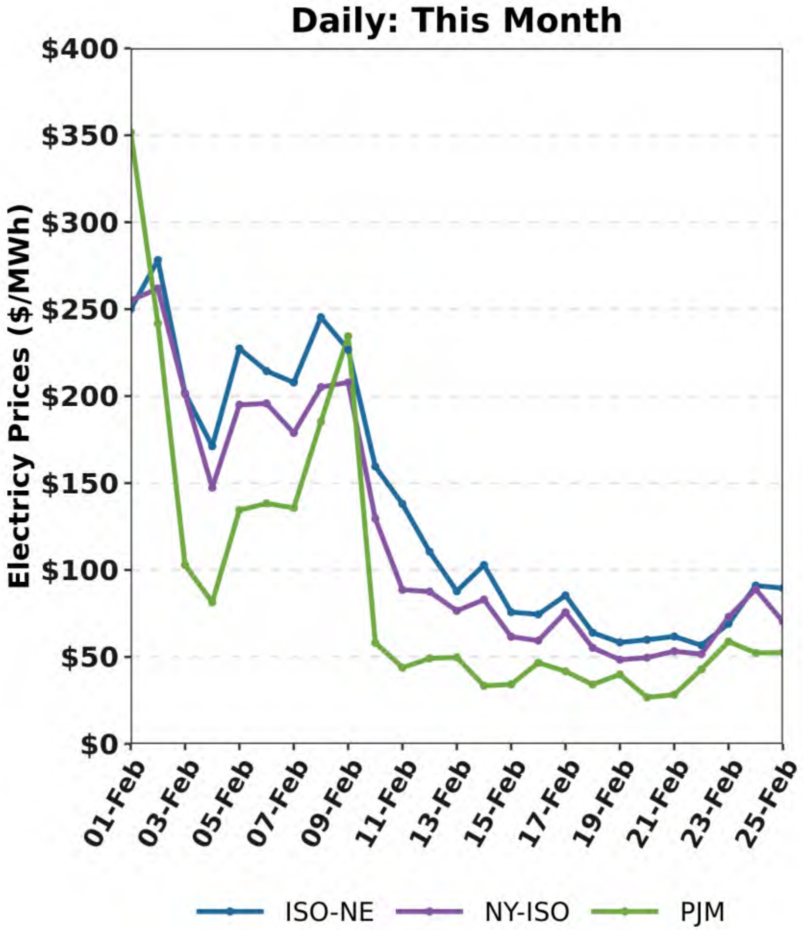


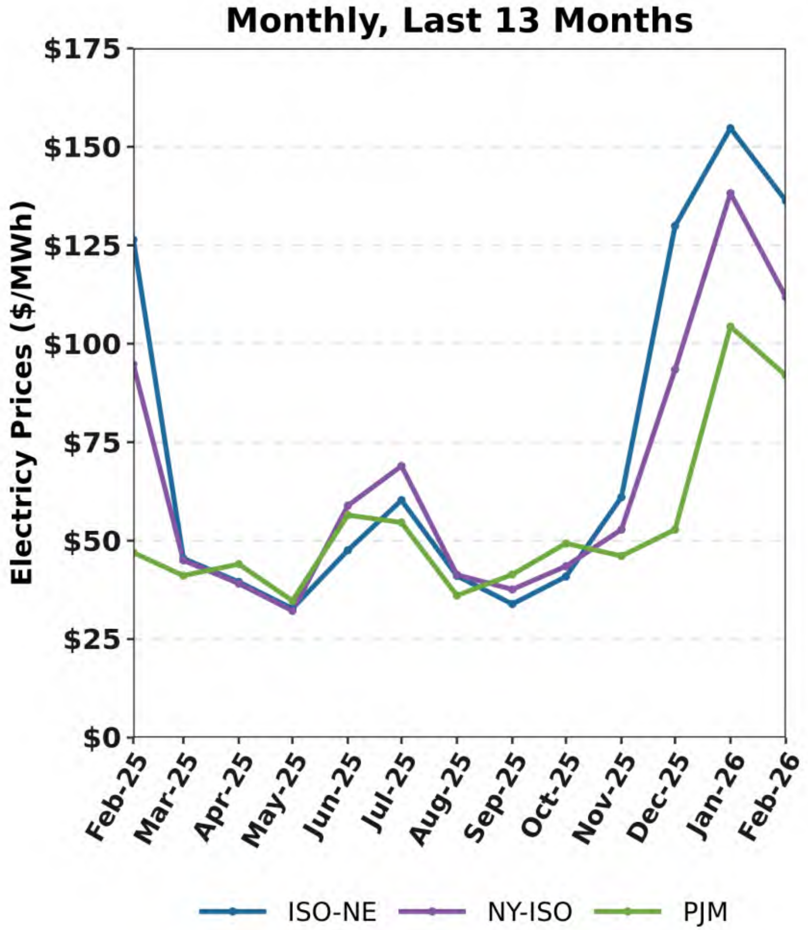


Underlying natural gas data furnished by: ice Global markets in clear view

Gas price is average of Massachusetts delivery points

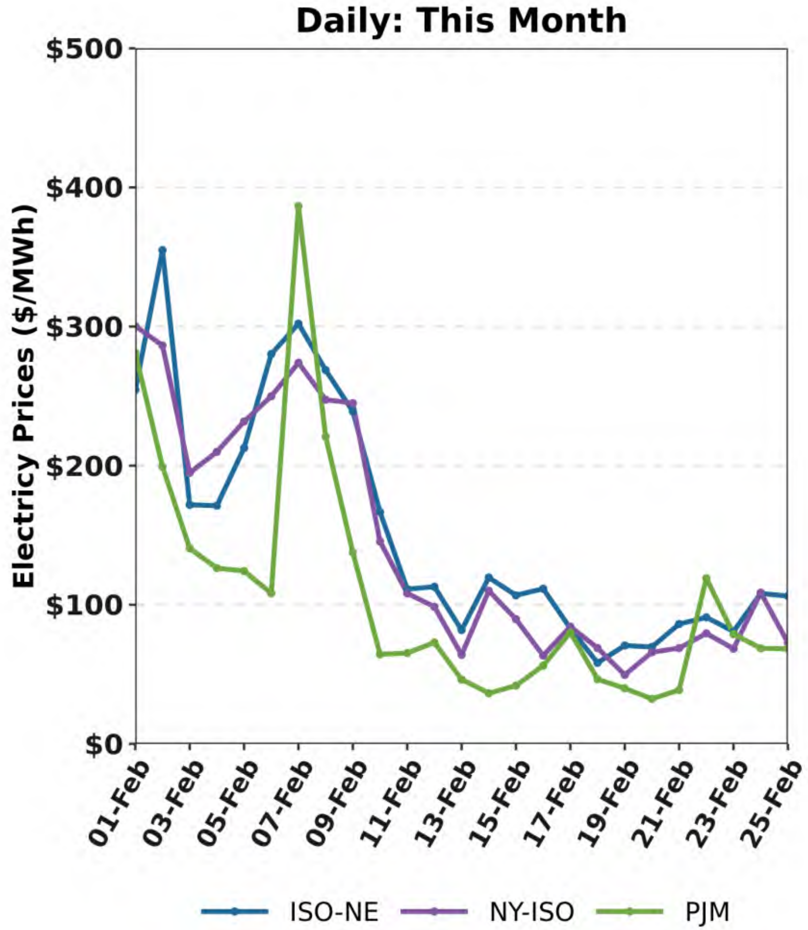
New England, NY, and PJM Hourly Average RT Prices by Month

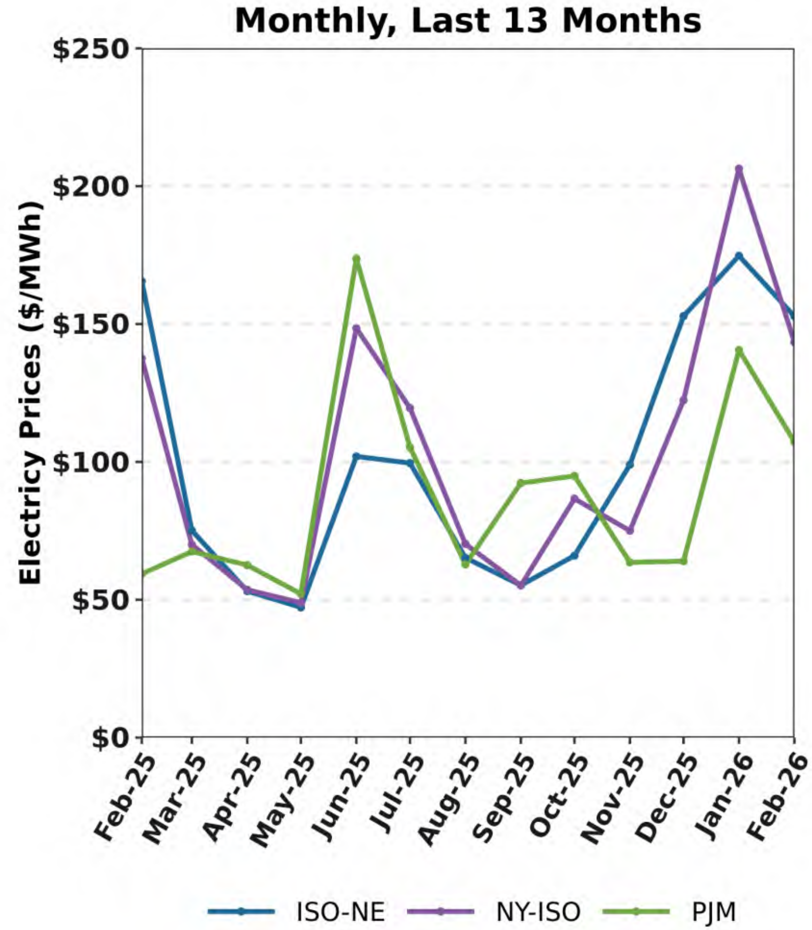




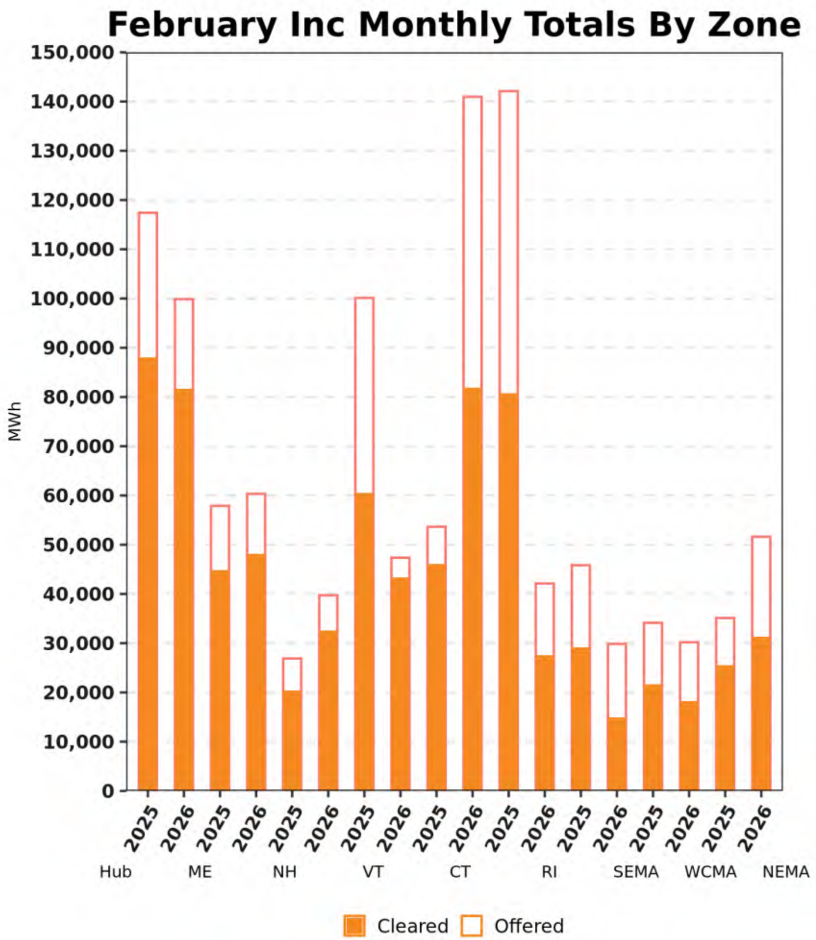
Hourly average prices are shown

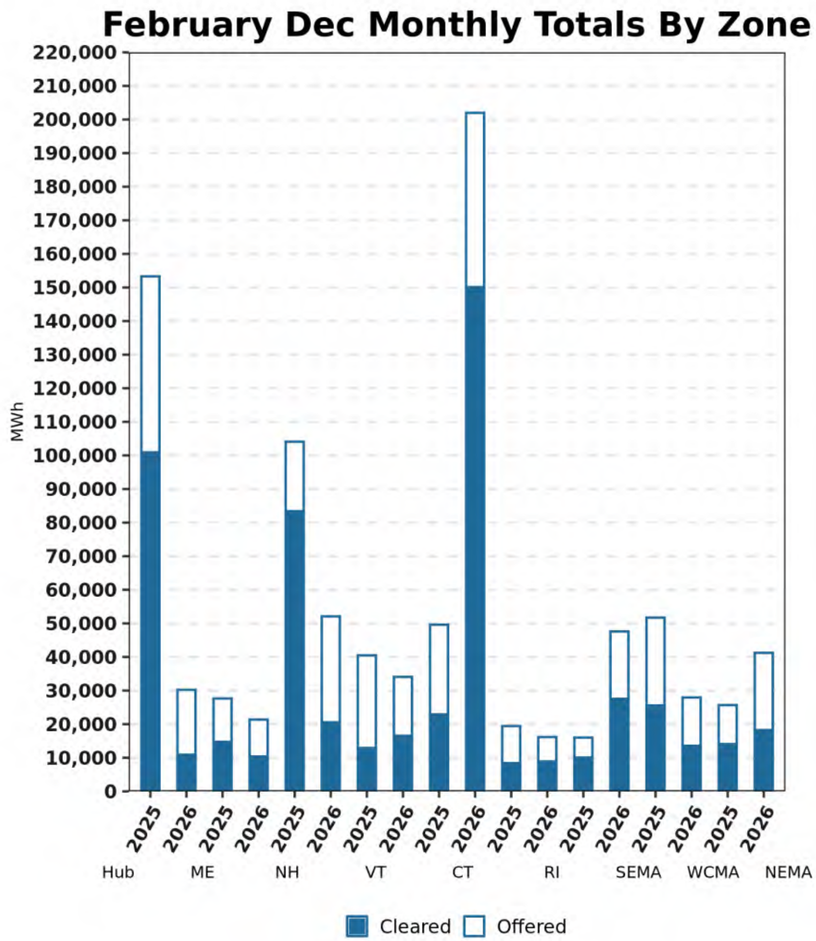
New England, NY, and PJM RT Pricing during New England's Forecasted Daily Peak Hours





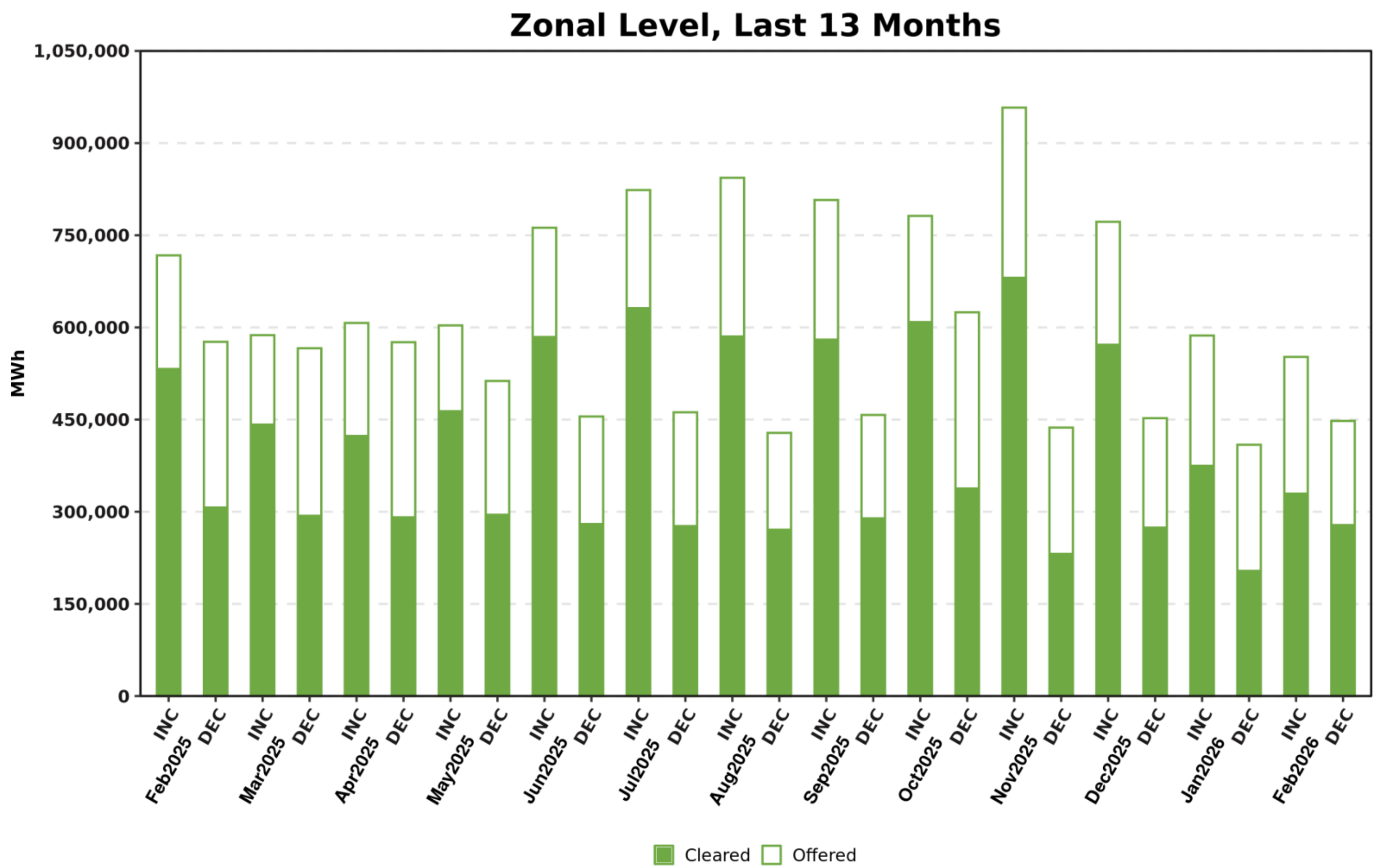
Zonal Increment Offers and Decrement Bid Amounts





Includes nodal activity within the zone; excludes external nodes

Total Increment Offers and Decrement Bids

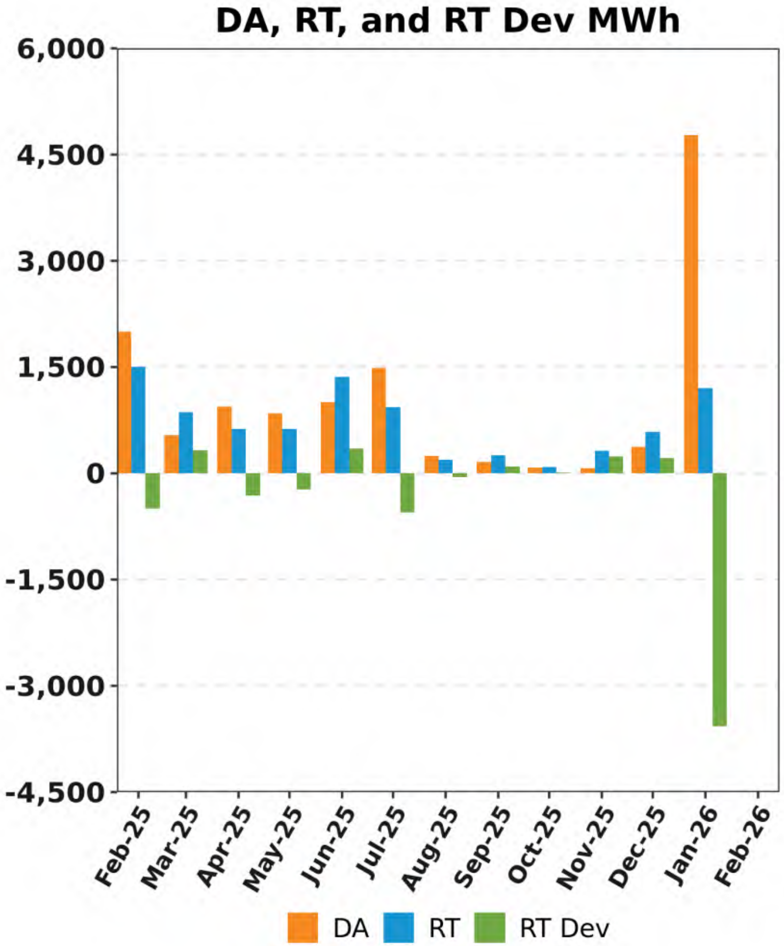


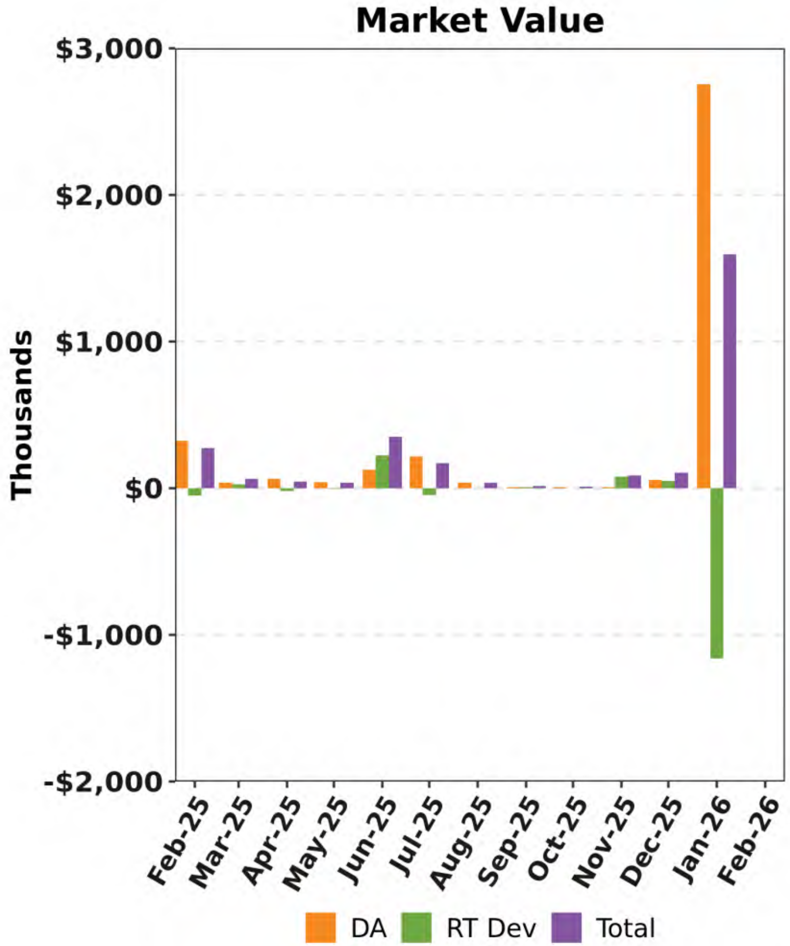
Includes nodal activity within the zone; excludes external nodes

BACK-UP DETAIL

DEMAND RESPONSE

Demand Response Resource (DRR) Energy Market Activity by Month





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

NEW GENERATION

New Generation Update

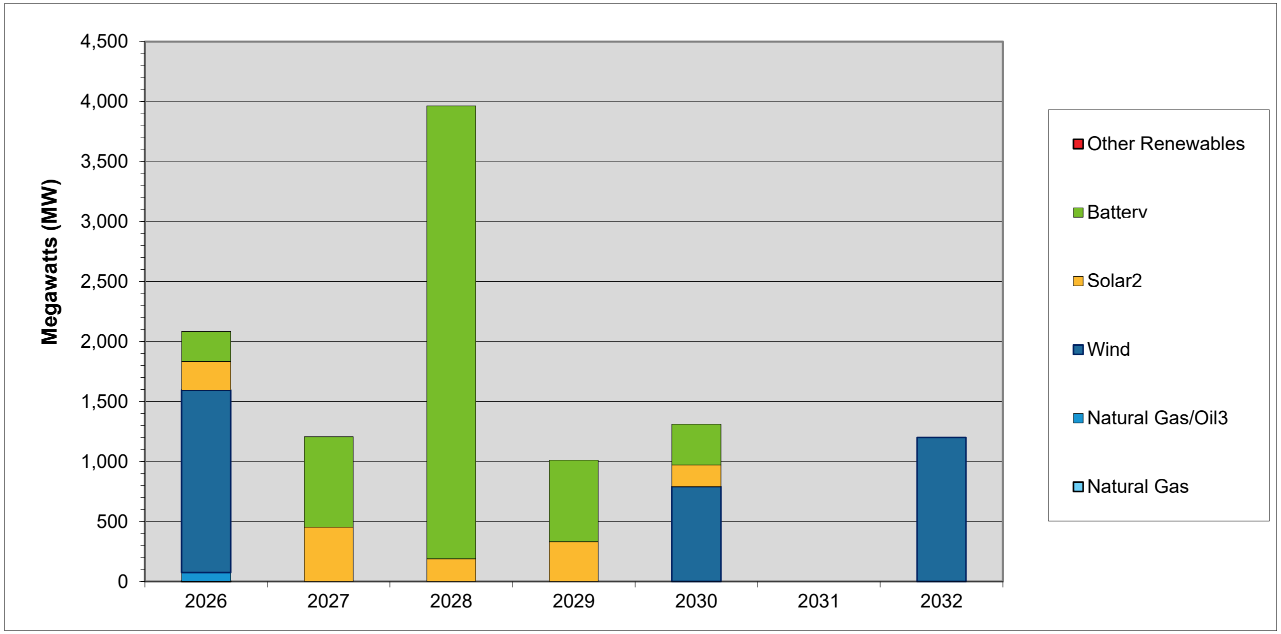
Based on Queue as of 03/02/26

- The interconnection queue has been updated to reflect the projects that have submitted the required materials to participate in the Order No. 2023 Transitional Cluster Study
- In total, 58* generation projects are currently being tracked by the ISO, totaling approximately 11,976 MW

* Total does not include CNR Only requests

Projected Annual Capacity Additions

By Supply Fuel Type



	2026	2027	2028	2029	2030	2031	2032	Total MW	% of Total[1]
Other Renewables	0	0	0	0	0	0	0	0	0.0
Battery	250	754	3,774	680	340	0	0	5,798	53.8
Solar[2]	237	453	190	332	180	0	0	1,392	12.9
Wind	1,522	0	0	0	791	0	1,200	3,513	32.6
Natural Gas/Oil[3]	73	0	0	0	0	0	0	73	0.7
Natural Gas	0	0	0	0	0	0	0	0	0.0
Totals	**2,082**	**1,207**	**3,964**	**1,012**	**1,311**	**0**	**1,200**	**10,776**	**100.0**

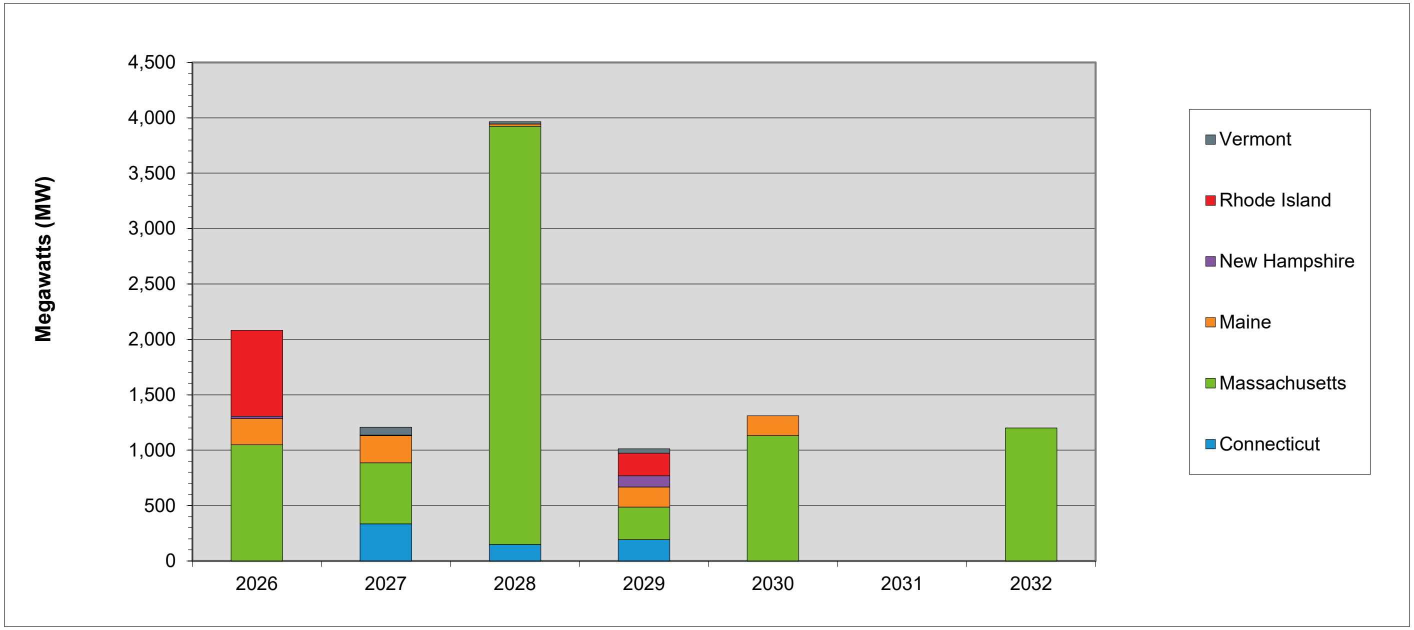
[1] Sum may not equal 100% due to rounding

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

[3] The projects in this category are dual fuel, with either gas or oil as the primary fuel

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

Projected Annual Generator Capacity Additions
By State



	2026	2027	2028	2029	2030	2031	2032	Total MW	% of Total[1]
Vermont	0	70	20	38	0	0	0	128	1.2
Rhode Island	777	0	0	205	0	0	0	982	9.1
New Hampshire	20	5	0	100	0	0	0	125	1.2
Maine	235	247	20	182	180	0	0	864	8.0
Massachusetts	1,050	549	3,774	295	1,131	0	1,200	7,999	74.2
Connecticut	0	336	150	192	0	0	0	678	6.3
Totals	**2,082**	**1,207**	**3,964**	**1,012**	**1,311**	**0**	**1,200**	**10,776**	**100.0**

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

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

New Generation Projection

By Fuel Type

Unit Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0
Battery Storage	27	5,798	1	204	26	5,594
Fuel Cell	0	0	0	0	0	0
Hydro	0	0	0	0	0	0
Natural Gas	0	0	0	0	0	0
Natural Gas/Oil	1	73	1	73	0	0
Nuclear	0	0	0	0	0	0
Solar	24	1,392	4	141	20	1,251
Wind	6	4,713	3	1,522	3	3,191
Total	58	11,976	9	1,940	49	10,036

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

New Generation Projection

By Operating Type

Operating Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	0	0	0	0	0	0
Intermediate	1	73	1	73	0	0
Peaker	51	7,190	5	345	46	6,845
Wind Turbine	6	4,713	3	1,522	3	3,191
Total	58	11,976	9	1,940	49	10,036

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

New Generation Projection

By Operating Type and Fuel Type

Unit Type	Total		Baseload		Intermediate		Peaker		Wind Turbine	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0	0	0	0	0
Battery Storage	27	5,798	0	0	0	0	27	5,798	0	0
Fuel Cell	0	0	0	0	0	0	0	0	0	0
Hydro	0	0	0	0	0	0	0	0	0	0
Natural Gas	0	0	0	0	0	0	0	0	0	0
Natural Gas/Oil	1	73	0	0	1	73	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0
Solar	24	1,392	0	0	0	0	24	1,392	0	0
Wind	6	4,713	0	0	0	0	0	0	6	4,713
Total	58	11,976	0	0	1	73	51	7,190	6	4,713

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 15

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

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

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

Capacity Supply Obligation FCA 16

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

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

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

Capacity Supply Obligation FCA 17

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	622.854	584.913	-37.941	492.363	-92.550		
	Passive Demand	2,316.815	2,314.068	-2.747	2,314.705	0.637		
Demand Total		**2,939.669**	**2,898.981**	**-40.688**	**2,807.068**	**-91.913**		
Generator	*Non-Intermittent*	26,507.420	26,715.489	208.069	26,271.866	-443.623		
	Intermittent	1,356.084	1,286.589	-69.495	1,310.622	24.033		
Generator Total		**27,863.504**	**28,002.078**	**138.574**	**27,582.488**	**-419.59**		
Import Total		**566.998**	**564.079**	**-2.919**	**636.310**	**72.231**		
Grand Total*		**31,370.171**	**31,465.138**	**94.967**	**31,025.866**	**-439.272**		
Net ICR (NICR)		**30,305**	**30,395**	**90**	**30,600**	**205**		

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

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

Capacity Supply Obligation FCA 18

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

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

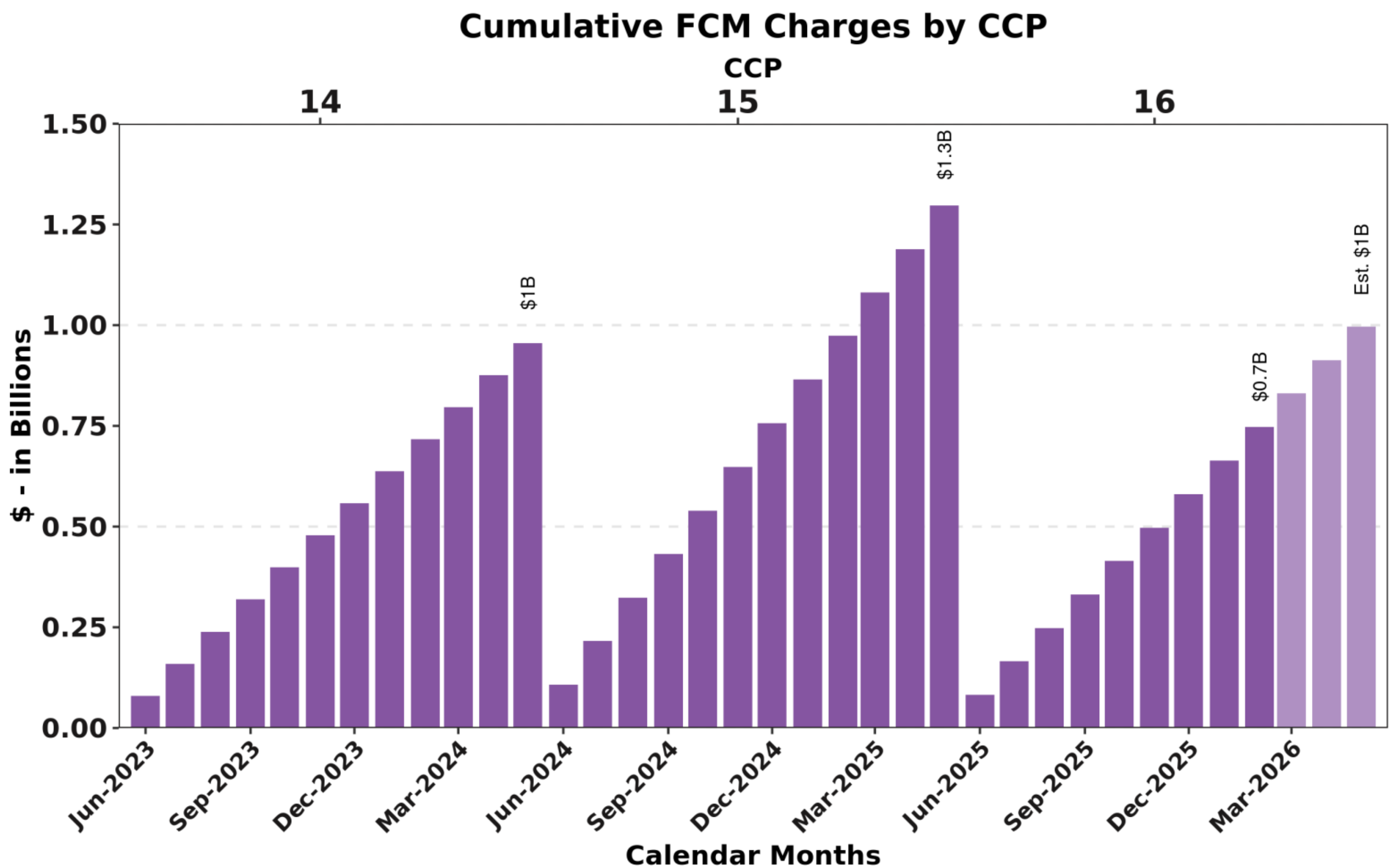
Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes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

Active/Passive Demand Response

CSO Totals by Commitment Period

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

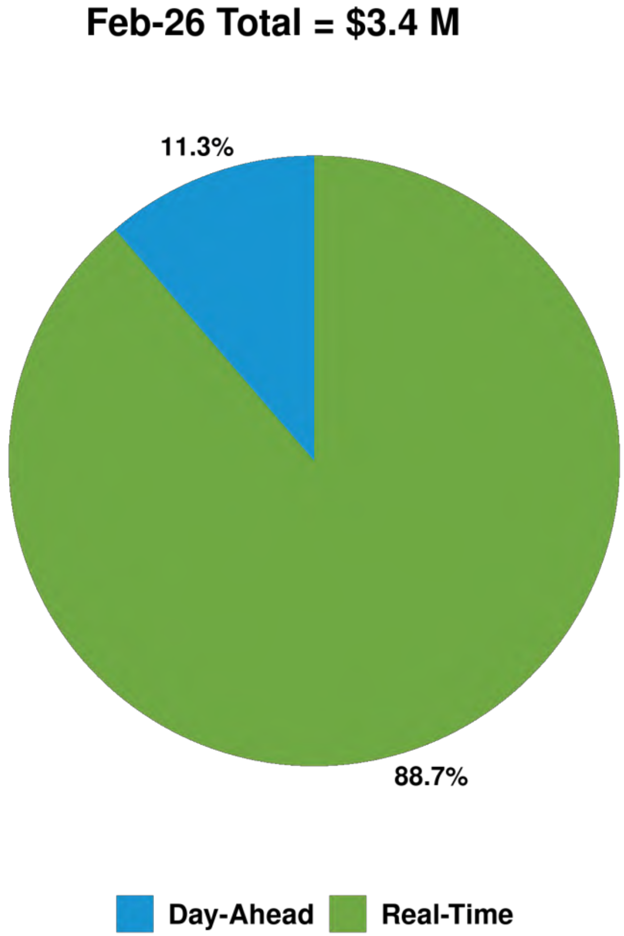
Forward Capacity Market Auctions

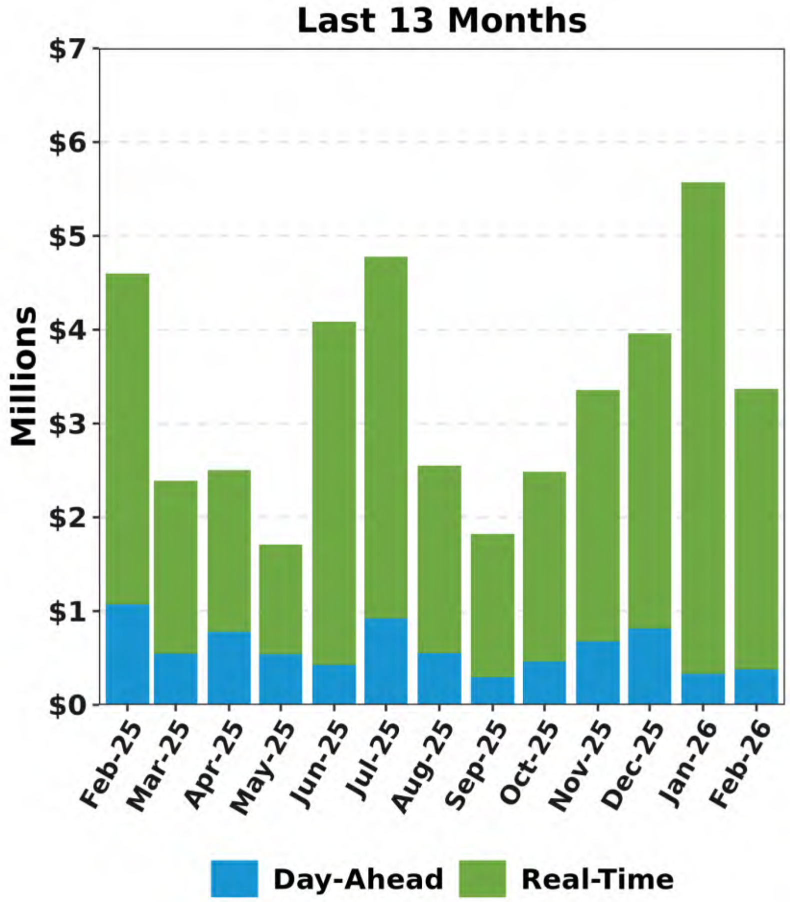


The items in the graph shaded in a lighter color represent the forecast for future months in the Capacity Commitment Period (CCP)

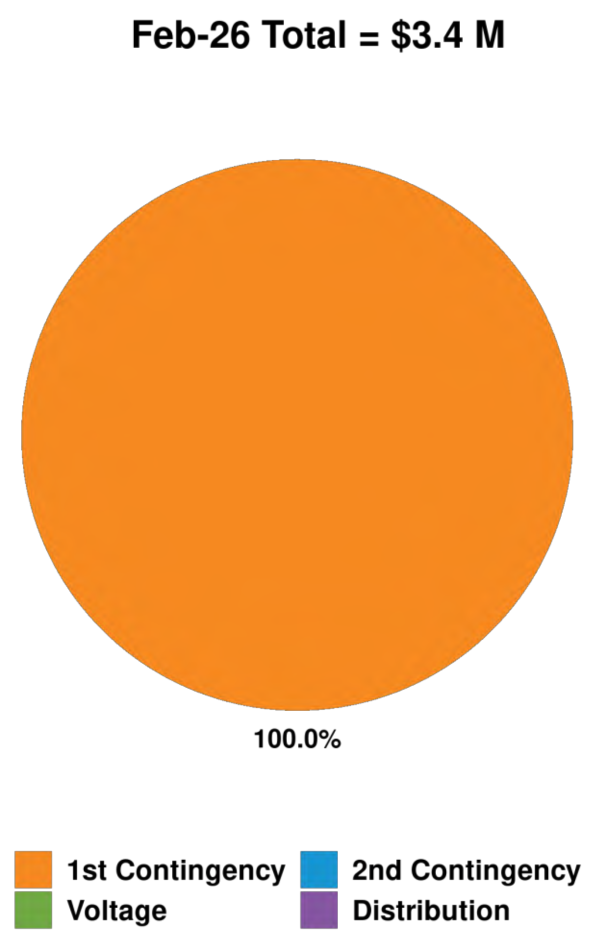
NET COMMITMENT PERIOD COMPENSATION

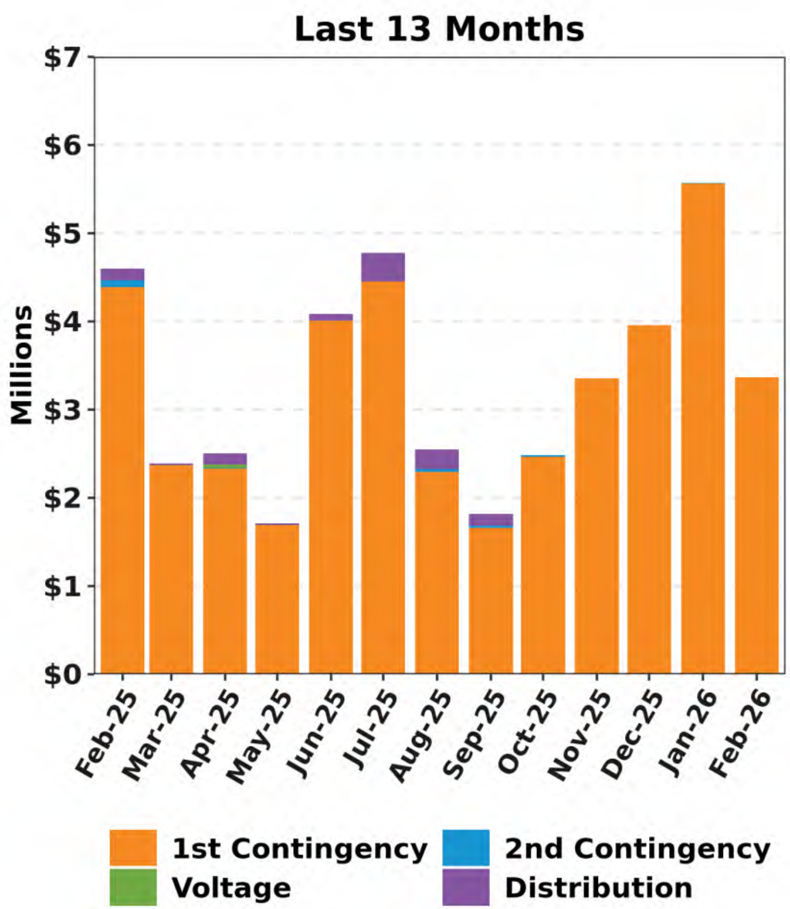
DA and RT NCPC Charges



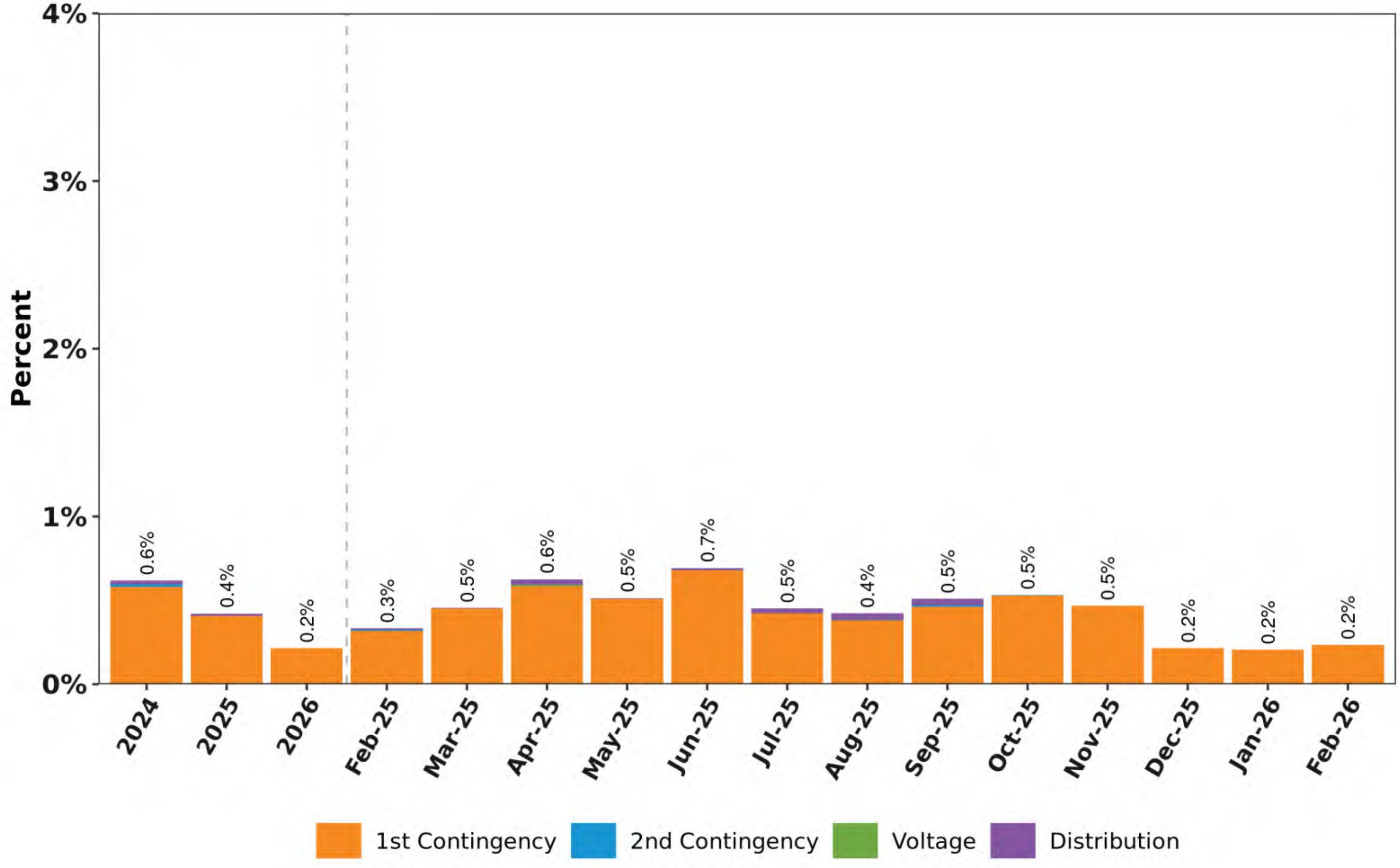


NCPC Charges by Type

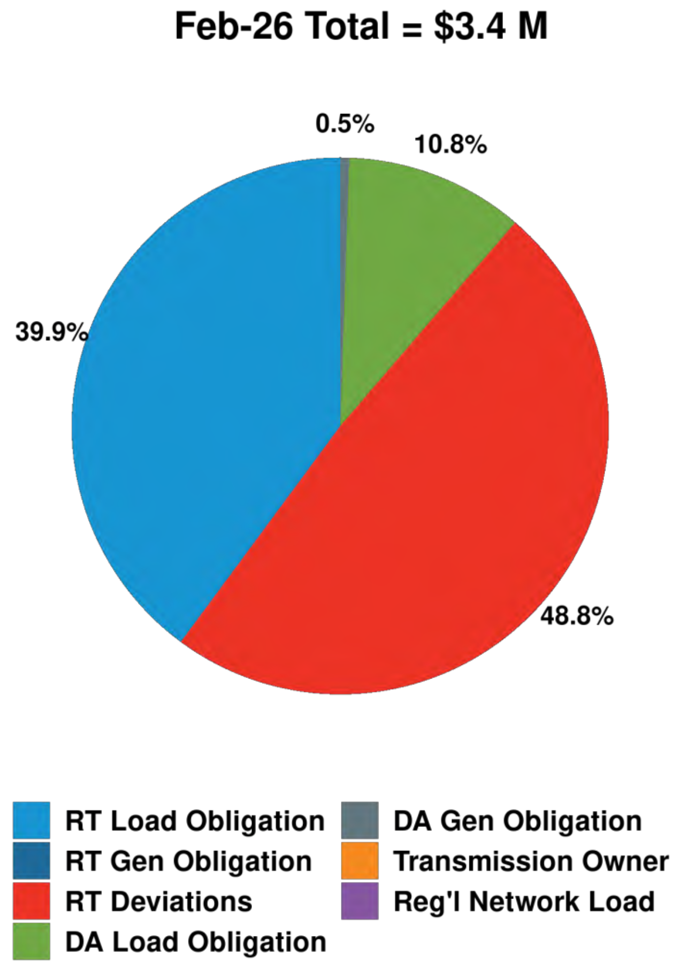


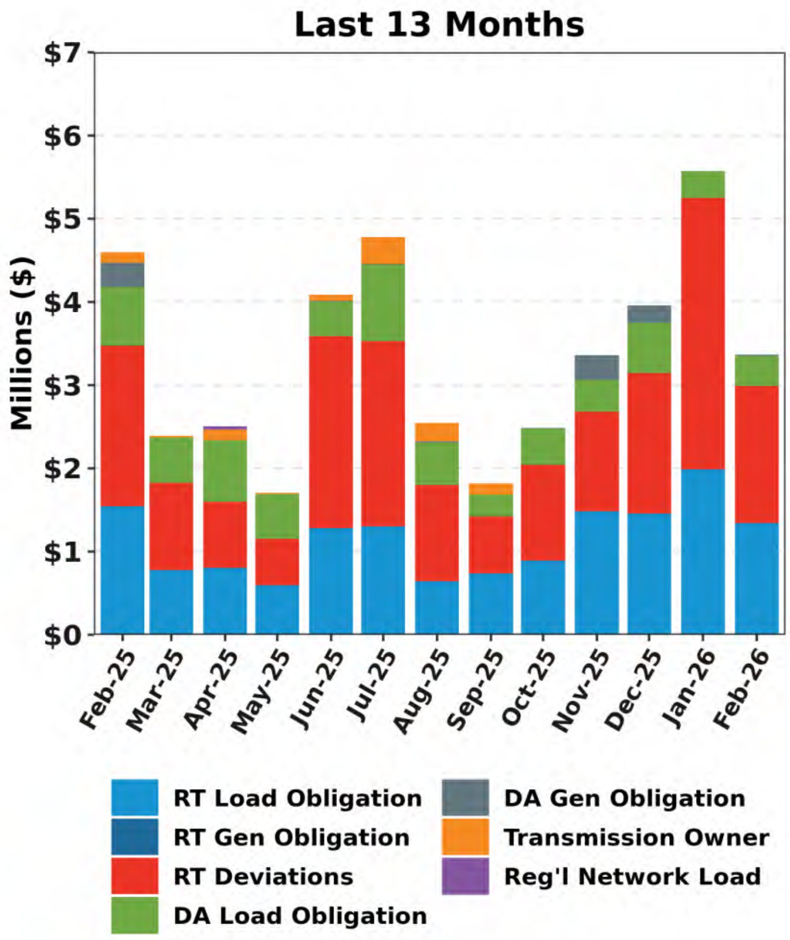


NCPC Charges by Type as Percent of Energy Market Value

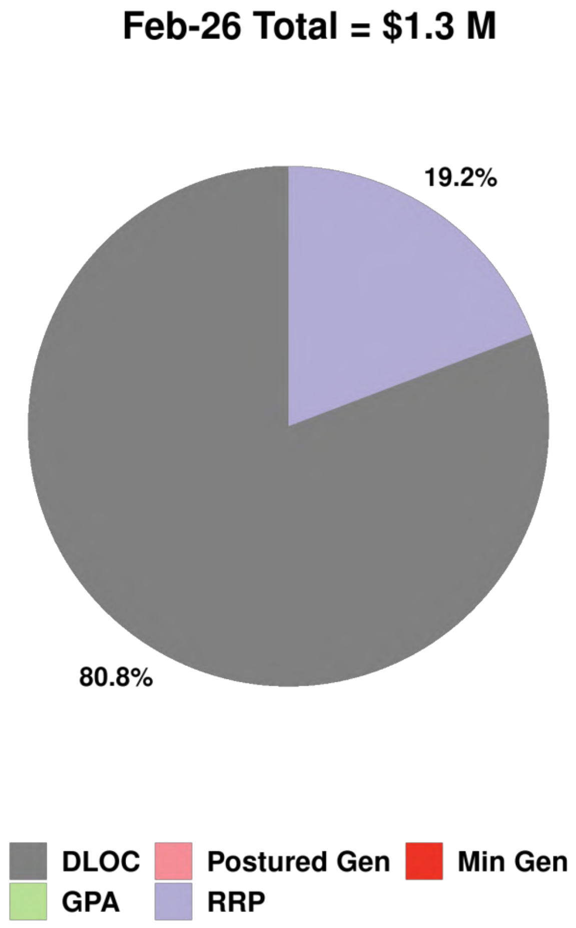


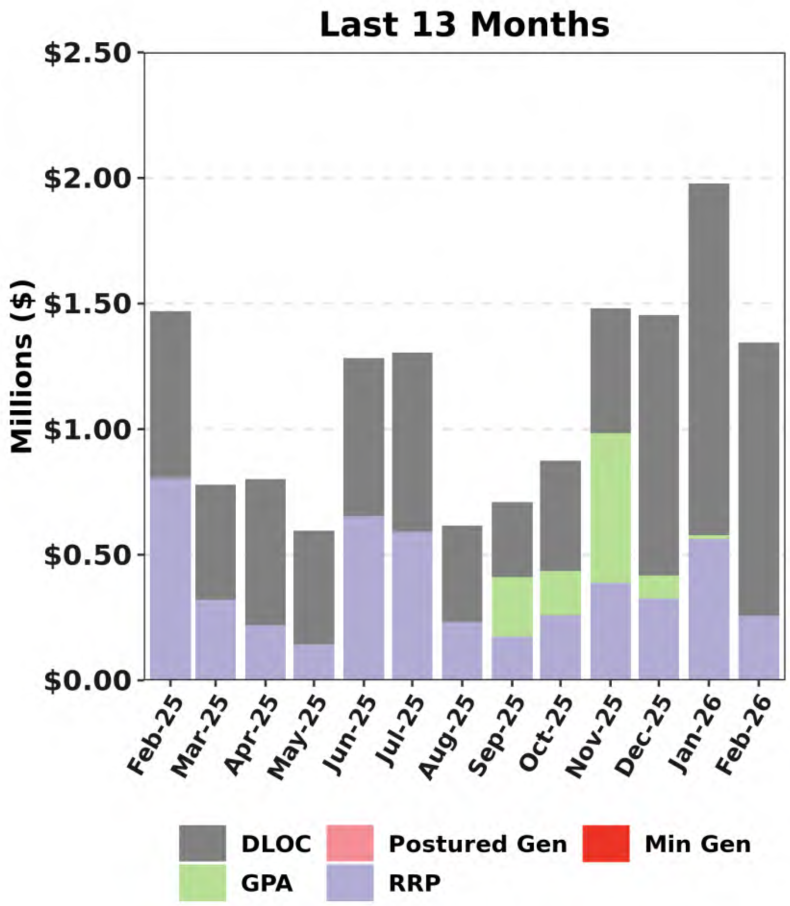
NCPC Charge Allocations





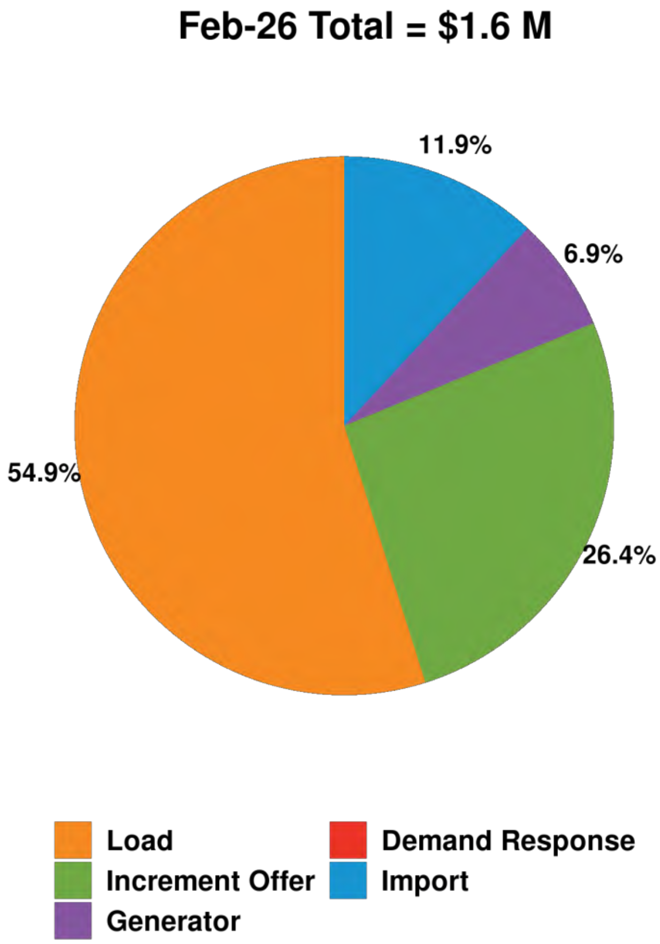
RT First Contingency NCPC Paid to Units and Allocated to RTLO and/or RTGO

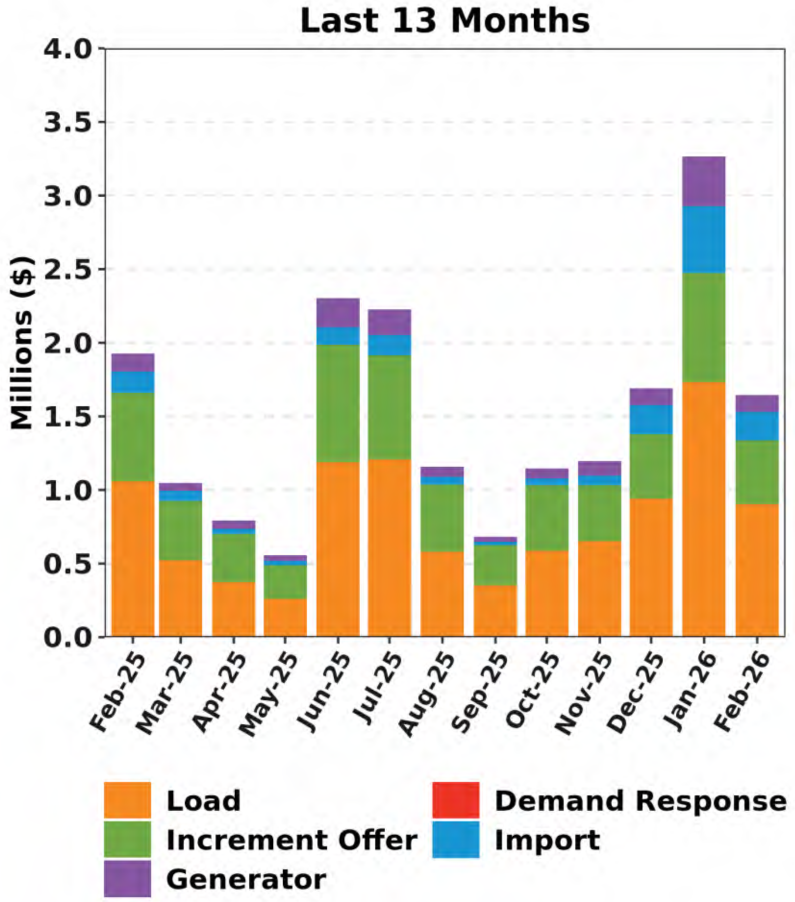




The categories shown above are a subset of those reflected in First Contingency NCPC throughout this report.
The above categories are allocated to RTLO, except for Min Gen Emergency credits, which are allocated to RTGO.

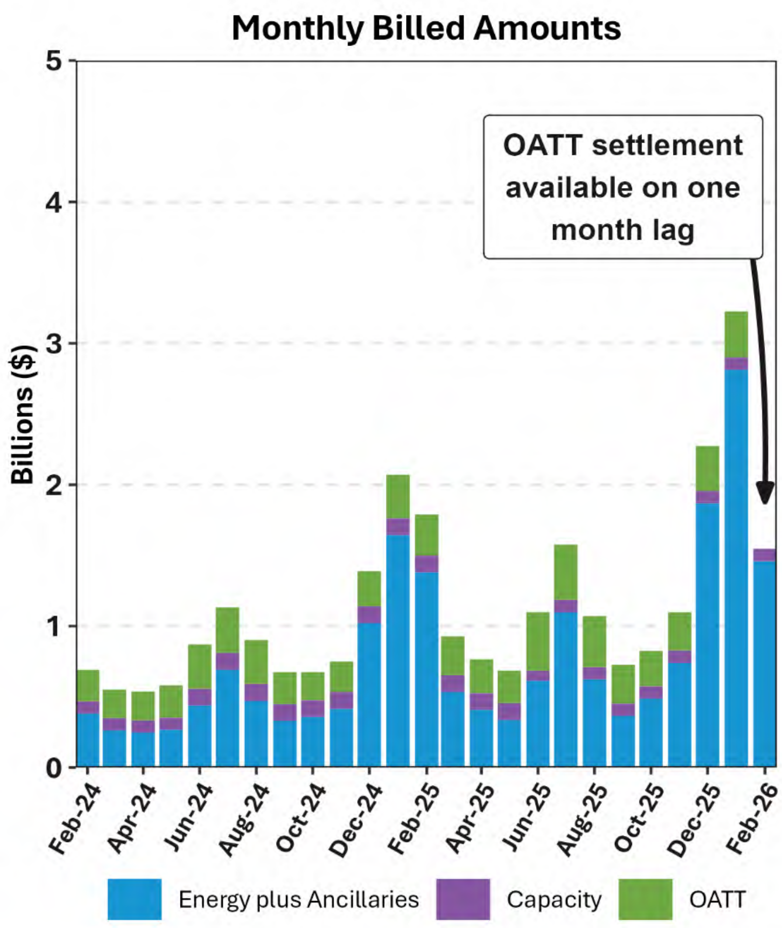
RT First Contingency Charges by Deviation Type

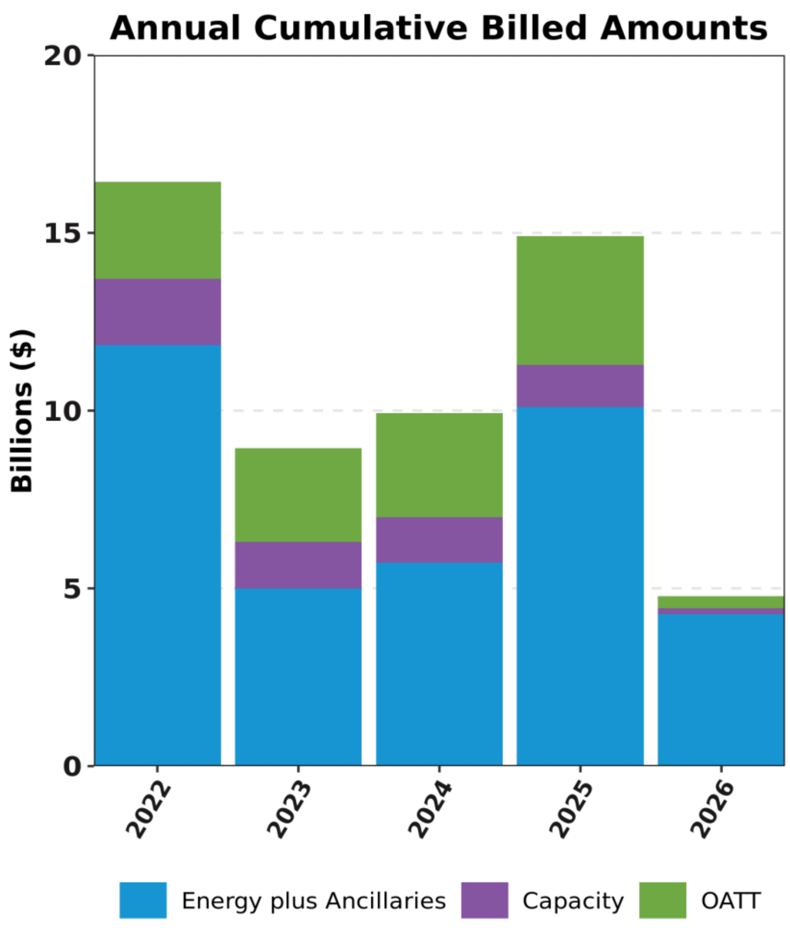




ISO BILLINGS

Total ISO Billings





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

REGIONAL SYSTEM PLAN (RSP)

Planning Advisory Committee (PAC)

- March 24 PAC Meeting Agenda Topics*
  - Asset Condition Projects
    - Chester SVC Valves and Controls Update (CEII – Avangrid)
    - Long Mountain 345 kV Breaker Replacement and Cable Separation & Shielding Project (Eversource)
    - Stony Hill 48C 115 kV Substation Relay Upgrades (Eversource)
  - 2025 LTTP RFP - Initial Review and RFP Objective Testing
  - 2026 Economic Study Workshop
  - RSP Project List and Asset Condition List March Update

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

2025 Longer-Term Transmission Planning (LTTP) RFP

- On 12/13/24, NESCOE provided its LTTP RFP request describing the needs to be addressed by 2035:*
  - Increase the Maine-New Hampshire interface capacity to at least 3,000 MW
  - Increase the Surowiec-South interface capacity to at least 3,200 MW
  - Develop new infrastructure (e.g., substation) at Pittsfield, Maine that can accommodate the interconnection of at least 1,200 MW (nameplate) of onshore wind**
- The ISO issued the RFP on 3/31/25, with proposals due by 9/30/25
- The ISO is evaluating all submissions and expects to provide an update on the initial review of proposals and results of the RFP objective analysis (transfer limits & wind accommodation) at the March PAC meeting

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

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

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

* Costs may include estimates for corollary upgrades

Permanent Asset Condition Reviewer

- The ISO began discussions of the permanent asset condition reviewer function at the January Transmission Committee (TC) and continued the discussion at the February TC meeting
  - ISO-NE would serve as the region's independent, advisory Asset Condition Reviewer (ACR) for large Asset Condition Projects (ACPs). The function would provide early, technically rigorous reviews of need, scope, alternatives, and cost drivers—without directing projects or making prudency or siting determinations
- Interim project reviews underway to inform permanent design
- Targeting January 2027 go-live, subject to FERC acceptance and operating budget; tariff changes targeted for Q3 2026 filing

Economic Studies: 2026 Study

- The 2026 Economic Study was launched in January
  - The ISO is conducting a public survey as part of a lessons learned
  - The Benchmark scenario will be presented in late Q2 after the lessons learned

RSP Project Stage Descriptions

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

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

SEMA/RI Reliability Projects

Status as of 2/18/2026

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 2/18/2026

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1718	Add 115 kV circuit breaker at Robinson Ave substation and re-terminate the Q10 line	Mar-22	4
1719	Install 45.0 MVAR capacitor bank at Berry Street substation	Cancelled*	N/A
1720	Separate the N12/M13 DCT and reconductor the N12 and M13 between Somerset and Bell Rock substations	Jun-28	2
1721	Reconfigure Bell Rock to breaker-and-a-half station, split the M13 line at Bell Rock substation, and terminate 114 line at Bell Rock; install a new breaker in series with N12/D21 tie breaker, upgrade D21 line switch, and install a 37.5 MVAR capacitor	Aug-23	4
1722	Extend the Line 114 from the Dartmouth town line (Eversource-National Grid border) to Bell Rock substation	Dec-26	2
1723	Reconductor L14 and M13 lines from Bell Rock substation to Bates Tap	Cancelled*	N/A

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

SEMA/RI Reliability Projects, cont.

Status as of 2/18/2026

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 2/18/2026

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	Nov-25	4
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 2/18/2026

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

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

Upper Maine Solution Projects

Status as of 2/18/2026

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	Dec-28	2
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	Dec-29	2
1886	Install +50/-25 MVAR synchronous condenser at Boggy Brook 115 kV substation, and install a new 115 kV breaker to separate Line 67 from the proposed solution elements	Aug-25	4

Upper Maine Solution Projects, cont.

Status as of 2/18/2026

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	Aug-26	2

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

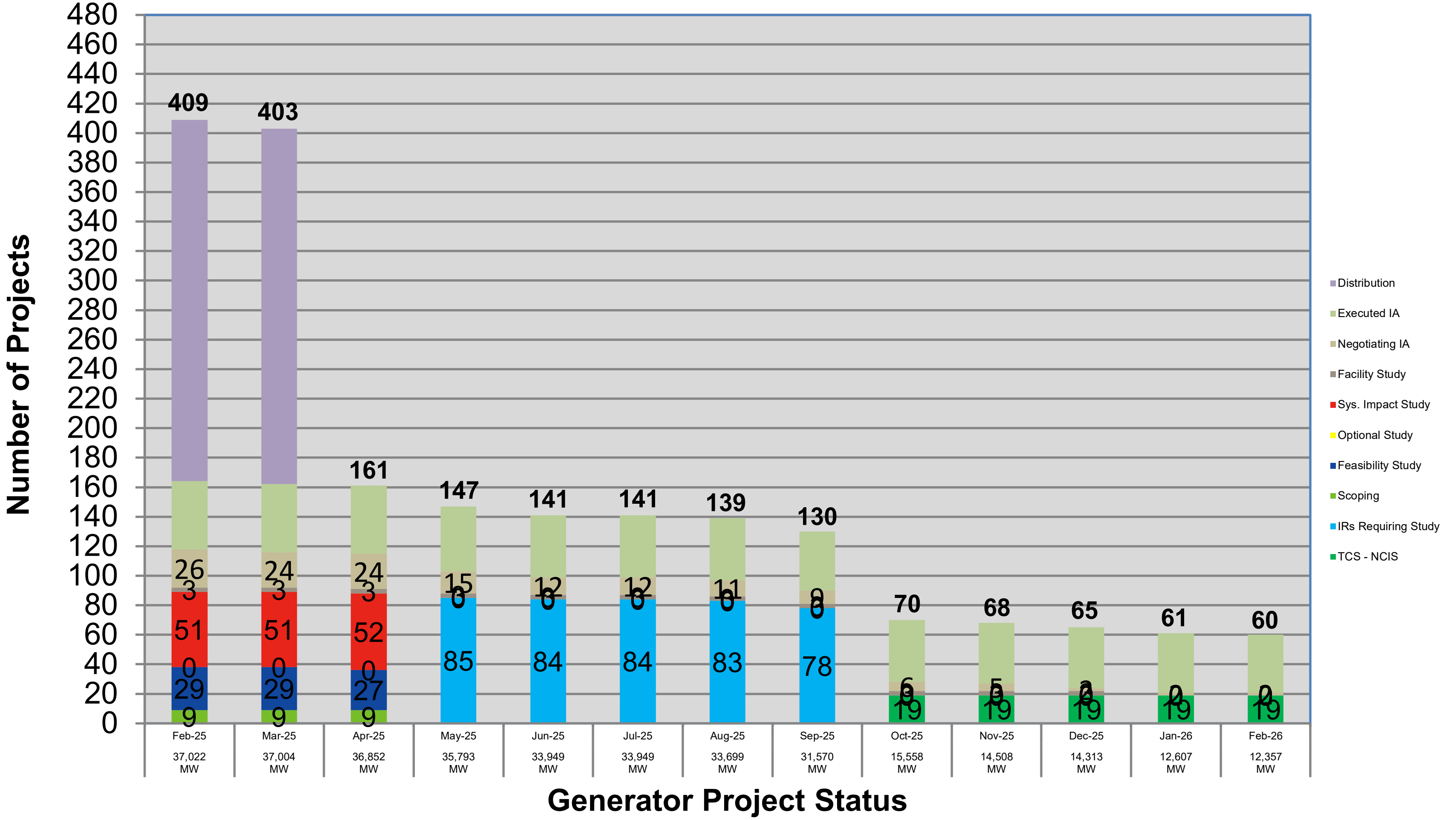
Boston 2033 Solutions Study

Status as of 2/18/2026

Project Benefit: Addresses system needs in the Boston area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1933	Install one 80 MVAR shunt reactor at the 115 kV Electric Avenue Substation	Dec-28	1
1934	Protection systems modification associated with the Stoughton RAS at three 345 kV substations (Stoughton, West Walpole and Holbrook) and two 115 kV substations (Hyde Park and K-Street)	Mar-27	1

Status of Tariff Studies as of February 25, 2026



ETUs: 0 in TCS – NCIS, 0 in OIS, 0 in FAC, 0 Negotiating IA, and 2 with Executed IA
Transmission Service Requests needing study: 0
https://irtt.iso-ne.com/external.aspx

Additional Notes provided on next slide

Status of Tariff Studies as of February 25, 2026, cont.

Additional Notes:

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

OPERABLE CAPACITY ANALYSIS

Winter 2026 Analysis

Winter 2026 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Mar - 2026[2] CSO (MW)	Mar - 2026[2] SCC (MW)
Operable Capacity MW [1]	26,667	29,810
Active Demand Capacity Resource (+) [5]	393	281
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,235	1,235
Non Commercial Capacity (+)	135	135
Non Gas-fired Planned Outage MW (-)	545	1,718
Gas Generator Outages MW (-)	1,638	1,893
Allowance for Unplanned Outages (-) [4]	2,700	2,700
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	23,547	25,150
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	17,132	17,132
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	19,257	19,257
Operable Capacity Margin	4,290	5,893

[1]Operable Capacity is based on data as of **February 24, 2026** 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 **February 24, 2026.**

[2] Load forecast that is based on the 2025 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **March 28, 2026.**

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

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

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

Winter 2026 Operable Capacity Analysis

90/10 Load Forecast	Mar - 2026[2] CSO (MW)	Mar - 2026[2] SCC (MW)
Operable Capacity MW [1]	26,667	29,810
Active Demand Capacity Resource (+) [5]	393	281
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,235	1,235
Non Commercial Capacity (+)	135	135
Non Gas-fired Planned Outage MW (-)	545	1,718
Gas Generator Outages MW (-)	1,638	1,893
Allowance for Unplanned Outages (-) [4]	2,700	2,700
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	23,547	25,150
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	18,045	18,045
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	20,170	20,170
Operable Capacity Margin	3,377	4,980

[1]Operable Capacity is based on data as of **February 24, 2026** 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 **February 24, 2026.**

[2] Load forecast that is based on the 2025 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **March 28, 2026.**

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

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

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

Winter 2026 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

February 24, 2026 - 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 March.

Report created: 2/24/2026

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
3/14/2026	26898	270	1325	10	673	690	2200	0	24940	17970	2125	20095	4845	N	Winter 2026
3/21/2026	26898	270	1325	10	557	550	2200	0	25196	17641	2125	19766	5430	N	Winter 2026
3/28/2026	26667	393	1235	135	545	1638	2700	0	23547	17132	2125	19257	4290	Y	Winter 2026

Column Definitions

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

Winter 2026 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

February 24, 2026 - 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 March.

Report created: 2/24/2026

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
3/14/2026	26898	270	1325	10	673	690	2200	0	24940	18928	2125	21053	3887	N	Winter 2026
3/21/2026	26898	270	1325	10	557	550	2200	0	25196	18582	2125	20707	4489	N	Winter 2026
3/28/2026	26667	393	1235	135	545	1638	2700	0	23547	18045	2125	20170	3377	Y	Winter 2026

Column Definitions

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

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

OPERABLE CAPACITY ANALYSIS

Spring 2026 Analysis

Spring 2026 Operable Capacity Analysis

50/50 Load Forecast (Reference)	May - 2026[2] CSO (MW)	May - 2026[2] SCC (MW)
Operable Capacity MW [1]	26,666	29,810
Active Demand Capacity Resource (+) [5]	393	281
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,235	1,235
Non Commercial Capacity (+)	135	135
Non Gas-fired Planned Outage MW (-)	1,934	3,119
Gas Generator Outages MW (-)	2,641	2,939
Allowance for Unplanned Outages (-) [4]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	20,454	22,003
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	18,794	18,794
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	20,919	20,919
Operable Capacity Margin	-465	1,084

[1] Operable Capacity is based on data as of **February 24, 2026** 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 **February 24, 2026.**

[2] Load forecast that is based on the 2025 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 9, 2026.**

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

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

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

Spring 2026 Operable Capacity Analysis

90/10 Load Forecast	May - 2026[2] CSO (MW)	May - 2026[2] SCC (MW)
Operable Capacity MW [1]	26,666	29,810
Active Demand Capacity Resource (+) [5]	393	281
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,235	1,235
Non Commercial Capacity (+)	135	135
Non Gas-fired Planned Outage MW (-)	1,934	3,119
Gas Generator Outages MW (-)	2,641	2,939
Allowance for Unplanned Outages (-) [4]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	20,454	22,003
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	19,620	19,620
Operating Reserve Requirement MW	2,125	2,125
Operable Capacity Required (NET LOAD OBLIGATION MW)	21,745	21,745
Operable Capacity Margin	-1,291	258

[1] Operable Capacity is based on data as of **February 24, 2026** 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 **February 24, 2026.**

[2] Load forecast that is based on the 2025 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 9, 2026.**

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

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

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

Spring 2026 Operable Capacity Analysis
50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

February 24, 2026 - 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 April and May.

Report created: 2/24/2026

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
4/4/2026	26667	393	1235	135	2913	2573	2700	0	20244	16687	2125	18812	1432	N	Spring 2026
4/11/2026	26667	393	1235	135	4401	3003	2700	0	18326	16460	2125	18585	-259	N	Spring 2026
4/18/2026	26667	393	1177	135	4247	3683	2700	0	17742	16001	2125	18126	-384	N	Spring 2026
4/25/2026	26667	393	1177	135	3614	3604	2700	0	18454	15762	2125	17887	567	N	Spring 2026
5/2/2026	26666	393	1177	135	2715	4309	3400	0	17947	15738	2125	17863	84	N	Spring 2026
5/9/2026	26666	393	1235	135	1934	2641	3400	0	20454	18794	2125	20919	-465	Y	Spring 2026
5/16/2026	26666	393	1235	135	1439	1836	3400	0	21754	19668	2125	21793	-39	N	Spring 2026
5/23/2026	26666	393	1235	135	1037	1836	3400	0	22156	20479	2125	22604	-448	N	Spring 2026

Column Definitions

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

Spring 2026 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

February 24, 2026 - 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 April and May.

Report created: 2/24/2026

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
4/4/2026	26667	393	1235	135	2913	2573	2700	0	20244	17576	2125	19701	543	N	Spring 2026
4/11/2026	26667	393	1235	135	4401	3003	2700	0	18326	17338	2125	19463	-1137	N	Spring 2026
4/18/2026	26667	393	1177	135	4247	3683	2700	0	17742	16854	2125	18979	-1237	N	Spring 2026
4/25/2026	26667	393	1177	135	3614	3604	2700	0	18454	16602	2125	18727	-273	N	Spring 2026
5/2/2026	26666	393	1177	135	2715	4309	3400	0	17947	16577	2125	18702	-755	N	Spring 2026
5/9/2026	26666	393	1235	135	1934	2641	3400	0	20454	19620	2125	21745	-1291	N	Spring 2026
5/16/2026	26666	393	1235	135	1439	1836	3400	0	21754	20531	2125	22656	-902	N	Spring 2026
5/23/2026	26666	393	1235	135	1037	1836	3400	0	22156	21378	2125	23503	-1347	Y	Spring 2026

Column Definitions

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

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

Possible Relief Under OP4: Appendix A

OP 4 Action Number	Page 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

6 Litigation Report

Mar 5, 2026
Meeting

NEPOOL
NEW ENGLAND POWER POOL
Participants Committee

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of March 4, 2026

The following activity, as more fully described in the attached Litigation Report, has occurred since the report dated February 4, 2026 ("last Report") was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

Executive Orders / Agency Directives

*	1	Executive Order: Strengthening US National Defense with America's Beautiful Clean Coal Power Generation Fleet (EO 14387)	Feb 12	President directs DOD and DOE to purchase power from coal plants
	3	Executive Order: Launching the Genesis Mission (EO 14363)	Feb 12	DOE announces 26 science and tech challenges and launches the Genesis Mission Consortium

I. Complaints/Section 206 Proceedings

7	BP Phantom Load Complaint (EL26-5)	Mar 3	BP advises the FERC that the MA RPS-related portion of its dispute has been resolved; BP continues to seek relief with respect to FERC-jurisdictional amounts
7	PSNH X-178 Powerline Rebuild Asset Condition Project Complaint (EL26-27)	Mar 2	FERC dismisses Complaint
8	Local Transmission Planning Complaint (EL25-44)	Feb 24	Industrial Energy Consumers of America files supplemental comments

II. Rate, ICR, FCA, Cost Recovery Filings

14	CIP IROL Cost Recovery Filing: Essential Power Newington (ER26-918)	Feb 26	FERC accepts revisions to EP Newington's CIP-IROL Rate Schedule that will allow recovery of ***$642,105*** of CIP-IROL Costs incurred between Jul 1, 2024 and Sep 30, 2025; eff. *Mar 1, 2026*
14	Transmission Rate Annual (2025-26) Update/Info Filing (NESCOE Formal Challenge) (ER20-2054)	Feb 9	NESCOE formally challenges CMP's inclusion of Incentive Compensation in RNS rates
		Feb 20	CMP requests 21-day extension of time to answer NESCOE Formal Challenge
		Feb 24	FERC grants CMP's request; response now due ***Mar 23, 2026***
14	Transmission Rate Annual (2023-24) Update/Info Filing (MPSA Formal Challenge) (ER20-2054)	Feb 9	Eversource answers MOPA Jan 8 and Jan 29 amendments to its formal challenge supplement
		Feb 17	MOPA answers Eversource, National Grid answers; Eversource answers NH OCA, CT OCC, and AEU comments
		Mar 4	National Grid files limited answer
15	ISO-NE Securities Authorization (Whiting Farms Facility) (ES26-30)	Feb 10	ISO-NE files for authorization of up to $60 million in Obligations to permanently finance its new Whiting Farms facility and related Sullivan Road (existing facility) expenses

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

	16	Adjustments to the Calculation of Load Weights used in Zonal Prices (ER26-1298)	Feb 9	ISO-NE and NEPOOL submit adjustments to the Tariff section III.2.7 calculation of load weights used in zonal prices
	17	Waiver Request: Tariff Section III.13.A.2(b) (Derby Fuel Cell) (ER26-884)	Feb 26	FERC dismisses waiver request as unnecessary, finding entities that have achieved commercial operation (like Derby) need not elect Critical Path Monitoring to qualify for participation in FCA18 reconfiguration auctions

IV. OATT Amendments / TOAs / Coordination Agreements

	17	Order 676-K Compliance Filings (ER25-2654; ER25-2657)	Mar 3	FERC accepts Order 676-K Compliance Filings, eff. *Feb 27, 2026* and *Aug 27, 2026*, with an ISO-NE compliance filing due in ER25-2654 by ***May 4, 2026***

V. Financial Assurance/Billing Policy Amendments

	18	FAP Obligation Roll-Off Timing Revisions (ER26-1091)	Feb 10	National Grid intervenes

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

No Activity to Report

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

*	19	Capital Projects Report – 2025 Q4 (ER26-1328)	Feb 6 Feb 12	ISO-NE files 2025 Q4 Report NEPOOL files comments supporting 2025 Q4 Report
*	19	IMM Quarterly Markets Reports – Fall 2025 (ZZ25-4)	Feb 5	IMM files Fall 2025 Report

IX. Membership Filings

*	20	Mar 2026 Membership Filing (ER26-1558)	Feb 27	**New Member**: Thunderhead Power LLC; comment deadline ***Mar 20, 2026***
	20	Jan 2026 Membership Filing (ER26-933)	Feb 27	FERC accepts (i) the memberships of Balyasny Asset Management (Data-Only Participant) and Geodesic 7 LLC (Supplier Sector); (ii) the termination of the Participant status of Anbaric Development Partners, EMI, Eoch Energy, Excelerate Energy, and Vineyard Reliability; and (iii) the name change of Six One Energy Corp. (f/k/a Tomorrow Energy Corp)
*	20	Suspension Notice – Clearlight Energy Services LLC (not docketed)	Feb 25	ISO-NE files notice of Feb 23, 2026 suspension of Clearlight Energy Services from the New England Markets

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

*	20	ITCS: Strengthening Reliability Through the Energy Transformation (AD25-4)	Feb 25	FERC Staff submits Report to Congress regarding NERC's Interregional Transfer Capability Study (ITCS)
*	21	NERC Errata to Reliability Standard BAL-007-1 (RD26-4)	Feb 23	NERC submits errata to Reliability Standard BAL-007-1 (Near Term Energy Reliability Assessments); comment deadline ***Mar 25, 2026***
	21	Revised Reliability Standard: MOD-026-2 (RD26-3)	Feb 19	FERC approves MOD-026-2, eff. *Apr 1, 2026*
	21	Revised Reliability Standard: MOD-033-3 (RD26-2)	Feb 19	FERC approves MOD-026-2, eff. *Jul 1, 2026*

XI. Misc. - of Regional Interest

*	23	203 Application: Vistra/Cogentrix (Nautilus Power *et al.*) (EC26-63)	Feb 6	Cogentrix Public Utilities requests authorization for a transaction pursuant to which an indirect, wholly-owned subsidiary of Vistra will acquire 100% of the voting equity interests in the Cogentrix Public Utilities; comment deadline ***Apr 7, 2026***
	23	203 Application: Gate City Power/Waterside Power (EC26-38)	Feb 11	FERC authorizes Gate City Power Holdings LLC's acquisition of Ontario Power Generation Inc.'s indirect ownership interests in Waterside Power, LLC and the Waterside Facility
			Feb 20	Waterside Power files notice that the acquisition was consummated on *Feb 12, 2026*
	23	203 Application: Constellation/Calpine (EC25-43)	Feb 19	FERC, in *Constellation Merger Allegheny Order*, modifies and sets aside in part the *Merger Order*
*	24	VSA – CL&P / MDC Milford Associates (ER26-1597)	Mar 4	CL&P files Viability Assessment Study Agreement; comment deadline ***Mar 25, 2026***
	25	*Order 676-K* Compliance Changes Versant Power MPD OATT (ER25-2566)	Mar 3	FERC conditionally accepts *Order 676-K* Compliance Changes, eff. *Feb 27, 2026* and *Aug 27, 2026;* compliance filing due ***May 4, 2026***

XII. Misc. – Administrative & Rulemaking Proceedings

	26	Joint Federal-State Current Issues Collaborative (AD24-7)	Feb 11	Collaborative meeting held in Washington, DC
	26	ANOPR: Interconnection of Large Loads to the Interstate Transmission System (RM26-4)	Feb 4	FERC Chairman Swett responds to Senators' concerns

XIII. FERC Enforcement Proceedings

No Activity to Report

XIV. Natural Gas Proceedings

30	Algonquin Cape Cod Canal Pipeline Relocation Project (CP25-552; PF25-4)	Feb 3-5	Algonquin submits responses to Dec 11 and Jan 16 data requests
		Feb 9	FERC issues data request
		Feb 17-20	Algonquin submits responses to Feb 9 data request
29	*Order 915*: Removal of Regulations Limiting Authorizations to Proceed with Construction Activities Pending Rehearing (RM25-9)	Feb 19	FERC issues *Order 915 Allegheny Order* addressing arguments on rehearing

XV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XVI. Federal Courts

32	*Order 904*: Compensation for Reactive Power (5th Circuit – 25-60055)	Feb 4	Petitioners file motion for clarification
		Feb 19	Court grants motion for clarification
		Feb 19	Petitioners' brief filed
32	*Order 1920*: Transmission Planning Reforms (4th Circuit – 24-1650)	Feb 6	Intervenors file motion to reconsider order granting filing of amicus curie
		Feb 25	Respondents' brief filed
33	*CASPR* (20-1333, 21-1031)	Mar 2	Petitioners filed motion to hold case in abeyance

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: March 4, 2026

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 March 4, 2026. In addition, in the opening Section immediately below, we continue to summarize recent Executive Orders issued by the President of the United States and Executive Agency directives related to the energy industry. If you have questions on any of these summaries, please contact us.

Executive Orders / Agency Directives

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

- **Executive Order: Strengthening US National Defense with America's Beautiful Clean Coal Power Generation Fleet (EO 14386)**

On February 11, 2026, President Trump issued an Executive Order ("EO") directing the Department of Defense (or the "Department of War") and the Department of Energy ("DOE"), to prioritize approval of long-term power purchase agreements ("PPAs") or similar contracts with coal-fired energy production facilities to serve Department of Defense installations and other critical facilities. The EO calls for priority to be given to projects that enhance grid reliability and blackout prevention, on-site fuel security, and mission assurance for defense and intelligence capabilities. The EO's stated objective is to ensure uninterrupted, on-demand baseload power for national defense facilities, and is issued in the context of two prior EOs[2] and the national emergency declared pursuant to an EO.[3]

- **DOE Emergency Orders Under FPA Section 202(c): Order No. 202-26-03 et al.**

On January 25, 2026, ISO-NE requested, pursuant to Section 202(c) of the Federal Power Act, an order from the U.S. Department of Energy ("DOE") that would allow "generating units located within the ISO-NE region to operate up to their maximum generation output levels, notwithstanding air quality or other permit limitations arising under federal, state, or local law or regulation, or other applicable source of law." ISO-NE requested the DOE order to help address high load conditions related to Winter Storm Fern. Determining that "additional

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

[2] Exec. Order No. 14261, 90 Fed. Reg. 15517 (Apr. 8, 2025) ("*Reinvigorating America's Beautiful Clean Coal Industry and Amending Executive Order 14241*"); Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) ("*Strengthening the Reliability and Security of the United States Electric Grid*").

[3] Exec. Order 14156, 90 FR 8433 (Jan. 20, 2025) ("*Declaring a National Emergency*").

dispatch of the Specified Resources[4] is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c)," the DOE Secretary Wright issued the requested order, subject to a number of conditions specified in the order (the "Emergency Order"). The Emergency Order became effective upon issuance (7:38 am EST on January 25, 2026) and was due to expire at 11:59 pm EST on January 31, 2026 (with the exception of the reporting requirements in paragraph D and applicable compliance obligations in paragraph E of the Order).

On January 30, 2026, ISO-NE requested that the relief granted in the Order be extended through February 14, 2026 at 11:59 pm. That request was granted in Order No. 202-26-03A (the "Extension Order").

On February 4, 2026, in response to an NRG Request for Rehearing, the DOE clarified the Emergency Order and Extension Order (Order No. 202-26-03B) (the "DOE Clarification Order"). Specifically, the DOE clarified that: (i) "*any* omission or action taken by a party" that is necessary to comply with the Emergency and Extension Orders is covered; (ii) the Emergency and Extension Orders protect applicable parties from "noncompliance with … *any* Federal, State, or local environmental law or regulation," including limitations on a generating unit's "emissions, hours of operation, or fuel burned" during the pendency of the Orders; and, importantly, (iii) any "emissions, hours of operation, or fuel burned" to comply with the Orders *cannot be counted towards rolling average-based limitations*.

Absent further extension, the Orders will expire at 11:59 pm EST on February 14, 2026 (again, with the exception of the reporting requirements in paragraphs D and applicable compliance obligations in paragraphs E of the Orders). Further extension of the Orders, if needed, must be requested before the Orders expire on February 14. Copies of the Orders and the Appendix A list of Specified Resources can be found at https://www.energy.gov/ceser/federal-power-act-section-202c-iso-new-england-order-no-202-26-03.

- **Revolution Wind (and Vineyard Wind) Stop-Work Order II**

On December 22, 2025, the BOEM's Acting Director issued a second order related to Revolution Wind (as well as to 4 other off-shore wind projects, including Vineyard Wind) ordering Ørsted, among others, to suspend all ongoing activities related to the Revolution Wind Project for the next 90 days for reasons of national security ("the Second Stop Work Order").[5] The national security risks, BOEM states, were identified by the Defense Department (Department of War) in recently completed classified reports.[6] In response, Ørsted moved for leave to supplement its pending complaint and moved to preliminarily enjoin the Second Stop Work Order. The State of Rhode Island, State of Connecticut, and Katie Dykes ("State Plaintiffs") filed a motion for (i) stay pending review and (ii) a preliminary injunction. Other parties also challenged the Second Stop Work Order in federal court (e.g. Dominion in the US District for the Eastern District of Virginia, in connection with the CVOW – Commercial project). On January 12, 2026, U.S. District Court (D.C.) Judge Royce Lamberth granted a stay and preliminary injunction against enforcement of the Second Work Stop Order as it applied to Revolution Wind. On January 15, 2026, Vineyard Wind filed suit to enjoin the BOEM's Second Work Stop Order.[7] On January 27, 2026, U.S. District Court (Mass.) Judge Brian Murphy blocked the Second Work Stop Order as it applied to Vineyard Wind, allowing construction to proceed while the lawsuits remain pending.

[4] "Specified Resources" are the generating units listed in Exhibit A of the Application, as updated by ISO-NE. The list of Exhibit A Specified Resources is available at: https://www.energy.gov/ceser/federal-power-act-section-202c-iso-new-england-order-no-202-26-03.

[5] *See* https://www.doi.gov/pressreleases/trump-administration-protects-us-national-security-pausing-offshore-wind-leases.

[6] Unclassified US Government reports have found that the movement of massive turbine blades and the highly reflective towers create radar interference called "clutter." The clutter caused by offshore wind projects obscures legitimate moving targets and generates false targets in the vicinity of the wind projects. A 2024 DOE report stated that a radar's threshold for false alarm detection can be increased to reduce some clutter, but an increased detection threshold could cause the radar to "miss actual targets."

[7] *Vineyard Wind 1 LLC v. U.S. Dept of the Interior*, 1:26-cv-10156, (D. Mass.).

- **Executive Memo: Withdrawing the United States From International Organizations, Conventions, and Treaties That Are Contrary to the Interests of the United States (mandated by EO 14199)**

On January 7, 2026, President Trump issued a Presidential Memorandum directing federal agencies to implement the results of the State Department review required by Executive Order 14199[8] by taking "immediate steps" to withdraw the United States from 66 identified organizations and UN entities as soon as possible, and to cease participation, funding, or other support to the extent permitted by law. The list includes the UN Framework Convention on Climate Change, the Intergovernmental Panel on Climate Change, and the International Renewable Energy Agency, among others. The Memo authorizes the Secretary of State to issue additional implementation guidance to agencies, and notes that further findings and reviews under EO 14199 remain ongoing.

- **Executive Order: Launching the Genesis Mission (EO 14363)**

On November 24, 2025, President Trump issued an EO to launch the "Genesis Mission." The EO directs DOE to create an integrated Artificial Intelligence ("AI") and high-performance computing platform to accelerate scientific discovery and advance national, economic, and energy security. The DOE Secretary must establish and operate the American Science and Security Platform, leveraging DOE supercomputers, secure cloud AI environments, and Federal scientific datasets to train scientific foundation models and deploy AI agents for automated experimentation. The EO set several milestones. On or before January 23, 2026, DOE was required to identify and submit at least 20 national science and technology challenges spanning priority domains such as advanced manufacturing, biotechnology, critical materials, nuclear fission and fusion energy, quantum information science, and semiconductors and microelectronics. Likewise, on or before February 22, 2026, the DOE Secretary was instructed to inventory Federal and industry computing, storage, and networking resources available to support the Genesis Mission. Since the last Report, DOE published 26 Genesis Mission AI challenges,[9] and announced the launch of the Genesis Mission Consortium, a public-private partnership to advance the Genesis Mission and support collaboration among DOE, National Laboratories, industry, and academia. On or before ***March 24, 2026***, the DOE must identify initial data and model assets and develop a cybersecurity-informed plan to incorporate datasets from other agencies, federally funded research, academia, and approved private partners. On or before ***July 22, 2026***, the DOE must review robotic and AI-directed experimentation capabilities across the national labs. And, on or before ***August 21, 2026***, the DOE must demonstrate an initial operating capability of the Platform for at least one of the identified national challenges. The EO also requires the DOE Secretary to report on the Platform's operational status to the President within one year and annually thereafter.[10]

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

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

[8] Withdrawing the United States From and Ending Funding to Certain United Nations Organizations and Reviewing United States Support to All International Organizations, 90 FR 9275 (Feb. 4, 2025).

[9] The Dept. of Energy Genesis Mission Science and Technology Challenges, are available here: https://www.energy.gov/documents/genesis-mission-science-and-technology-challenges.

[10] Updates are available on the DOE website: https://genesis.energy.gov/.

January 19, 2026. And, the Army must assess whether a new nationwide permit is necessary under the CWA or Rivers and Harbors Appropriation Act to facilitate the efficient permitting of Qualifying Projects. Additionally, the EO instructs the Departments of the Interior, Energy, and Defense to identify and authorize federal and military lands for qualifying development, including streamlined consultations under the Endangered Species Act for construction of Qualifying Projects over the next 10 years and competitively leasing sites for data centers. The EO also mandates FAST-41 transparency project designation and permitting dashboard integration by August 22, 2025.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

DOE Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid ("DOE RA Report"). On July 7, 2025, the DOE released a Report in response to Section 3(b) of EO 14262 (which directed the DOE to develop a uniform methodology for analyzing current and anticipated reserve margins in FERC-regulated regions of the bulk power system). The DOE RA Report provides an assessment of the U.S. grid's ability to meet projected load growth through 2030 using a deterministic approach that simulates system stress in all hours of the year and incorporates grid conditions and scenarios based on historical data.[11] Overall highlights of from the DOE RA Report include conclusions that: (i) the status quo is unsustainable; (ii) grid growth must match the pace of AI innovation; (iii) with projected load growth, retirements increase the risk of power outages by 100 times in 2030; (iv) planned supply falls short, reliability at risk; and (v) old tools won't solve new problems.

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

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

Request for Rehearing – DOE RA Report. On August 6, Clean Energy Organizations,[12] concluding that the DOE RA Report is a rule subject to rehearing, despite being styled as a report, requested rehearing of the DOA RA Report, asserting that the Report "fails to account for [] important aspects of the resource adequacy puzzle."[13] Clean Energy Organizations request that DOE "withdraw the Resource Adequacy Protocol or otherwise address the errors contained in it."

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

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

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

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

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

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

I. Complaints/Section 206 Proceedings

- **PSNH X-178 Powerline Rebuild Asset Condition Project Complaint (EL26-27)**

On March 2, 2026, the FERC dismissed the complaint[14] filed by individual complainants, Kristina Pastoriza and Ruth Ward,[15] requesting that the FERC open an investigation into the Public Service Company of New Hampshire's ("PSNH") $400 million proposed rebuild of the X-178 115 kV transmission line from Beebe River to Whitefield, NH (approximately 49 miles, including a 12.4-mile segment in the White Mountain National Forest) ("PSNH Rebuild Complaint").[16] The FERC found that the PSNH Rebuild Complaint failed to satisfy Rule 206 because it did not clearly identify or explain any action or inaction by PSNH that violates applicable statutory or regulatory requirements, or provide evidence supporting a claim that PSNH's transmission rates are unjust and unreasonable.[17] The FERC also found that any challenge to recovery of project costs is premature because PSNH has not sought to include those costs in transmission rates, and noted that interested parties will have an opportunity to challenge the prudence of such costs through the ISO-NE Formula Rate Protocols annual update process if and when PSNH seeks cost recovery.[18] Unless the *PSNH Rebuild Complaint Order* is challenged, with any challenges due on or before April 1, 2026, this proceeding will be concluded. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

On October 14, 2025, as supplemented October 17, BP Energy Retail Company ("BP") filed a complaint seeking relief from invoices issued by ISO-NE for July, August, and September of 2024 based on phantom load shifted from the NEMA to the SEMA zone, which BP asserts was incorrectly assigned to BP by Eversource (NSTAR) due to an IT system error. Answers, comments and interventions were due on or before December 12, 2025.

Answers and comments in response to the BP Complaint were filed by **ISO-NE** (opposing the Complaint and BP waiver request, asserting that the alleged error constitutes a Meter Data Error and that BP requested relief would require resettlement of final bills outside the ISO-NE Tariff and Manual M-28 settlement timelines), **Eversource** (supporting BP's request for waiver of the Market Rule 1 time limitations and requesting that the FERC direct ISO-NE to complete billing adjustments for July, August, and September 2024 based on updated data, with any resettlement extending to all affected Market Participants), and the Retail Energy Supply Association ("**RESA**") (supporting the Complaint, stating that phantom load errors harm Market Participants and requesting that any resettlement ordered by the FERC extend to all Market Participants) filed answers/comments. ISO-NE answered the December 8 comments of Eversource and BP on December 26. On December 29, BP opposed Eversource's motion to dismiss and replied to ISO-NE's December 12 answer and December 26 response (reiterating its request that the FERC direct ISO-NE to correct the July through September 2024 invoices). ISO-NE answered BP's December 29 answer on January 9, 2026. Interventions only were filed by Calpine, ENGIE, National Grid, NRG, and Public Citizen.

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[14] The Complaint requested that the FERC direct an objective expert third-party investigation into (i) the need for the project (Physical Condition, Current Demand, Projected Load, Reliability and Safety), (ii) the prudence of sunk and projected costs, and (iii) the accounting basis of the formula rate charges, and (iv) if the resulting rates are just and reasonable and not unduly discriminatory. The Complaint asserts that ISO-NE treated the project as an "asset condition" rebuild outside the ISO-NE Order 890/1000 planning process, and it notes related pending approvals before the New Hampshire Site Evaluation Committee and the U.S. Department of Agriculture Forest Service.

[15] Kristina Pastoriza is an owner of the property and lives on the property, and Ruth Ward is an owner of the property and is an Eversource retail electricity customer.

[16] *Kristina Pastoriza and Ruth Ward v. Public Service Company of New Hampshire*, 194 FERC ¶ 61,156 (Mar 2, 2026) ("*PSNH Rebuild Complaint Order*").

[17] *Id.* at PP 21-23.

[18] *Id.* at P 24.

Supplement. On March 3, 2026, BP advised the FERC that NSTAR had concluded working with the MA DOER to update data that provides the basis for renewable portfolio standard ("RPS") compliance, and that BP's MA RPS had been re-determined based on this data, reducing BP's RPS obligation to $6 million. BP stated that it has been unable to determine whether NSTAR intends to adjust BP's load allocation for settlement charges, and it continues to seek relief with respect to the remaining disputed amount under FERC jurisdiction.

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

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

As previously reported, a group of "Consumer Complainants"[19] filed a complaint more than one year ago, 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 filed by, among others, ISO-NE, New England Transmission Owners ("NETOs"),[20] 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,[21] and WIRES. Interventions only were filed by more than 100 parties, including NEPOOL. On April 4, 2025, ISO-NE answered certain comments and reiterated its request that it be dismissed as a respondent to the proceeding. Answer and reply comments were also filed by Complainants (requesting FERC grant the Complaint and deny the motions to dismiss), NESCOE (addressing the standard of review that may apply to certain reforms), MOPA (asking FERC to reject motions to dismiss and open an investigation), MPUC (requesting FERC accept its motion for to leave to answer and consider its answer), and AMP (asking FERC to deny motions to dismiss). On May 20, 2025, ISO-NE responded to Complainant's Answer and the responses of NESCOE, MPUC, and MOPA, again requesting it be dismissed as a respondent to the proceeding as a matter of law and because the Complainants failed to meet their burden under FPA Section 206. On June 30, 2025, Complainants answered the May 22 answer by "Southeast

[19] "Consumer Complainants" are Industrial Energy Consumers of America ("IECA"), 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.

[20] 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").

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

Respondents"[22] and on July 25, 2025 ATC answered Complainants April 24, 2025 answer. The Industrial Energy Consumers of America submitted comments in November rebutting utilities' opposition to competitive transmission development. Since the last Report, on the IECA submitted supplemental comments highlighting points made in the Complaint, including the rise of electricity rates tied to electric transmission, and requested that the FERC grant the Complaint. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

Still pending is the December 19, 2024 complaint by Allco Finance Limited ("Allco") asking the FERC to (i) direct ISO-NE to abolish its Planning Procedure No. 5 ("PP5") procedures by (ii) finding that PP5's procedures are unjust and unreasonable and unduly discriminatory and/or preferential in violation of section 206 of the FPA; and (iii) find that ISO-NE has violated the FPA by forcing on State jurisdictional interconnections, such as Allco's, the requirement to pay for transmission level interconnection studies, to pay for Power Systems Computer Aided Design ("PSCAD") models in connection with such studies, and by causing delays to the execution by distribution utilities of State jurisdictional generator interconnection agreements (particularly for Allco's 2 MW Winsted solar energy project). ISO-NE answered the Allco PP5 Complaint on January 15, 2025 (as corrected on January 30, 2025). On January 23, 2025, Allco answered ISO-NE's January 15 Answer. On February 7, 2025, ISO-NE answered Allco's January 23 Answer and on February 25, 2025 Allco answered ISO-NE's February 7 Answer. Doc-less interventions only were filed by NEPOOL, Calpine, National Grid, the MA DPU, and Public Citizen. There was no activity in this proceeding since Allco's February 24, 2025 answer. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **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).[23] 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.[24] 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.[25] 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.[26] The refund effective date

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

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

[24] *Id.* at P 1.

[25] *Id.*

[26] *Id.* at P 2.

for this proceeding is June 24, 2024.[27] A more detailed summary of the *TO Initial Funding Show Cause Order* was circulated to, and was reviewed with, the Transmission Committee.

Interventions were due on or before July 5, 2024 and were filed by the following New England-related parties:[28] 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*[29] 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")[30] 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[31] 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).

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

[28] 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).

[29] 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.

[30] 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").

[31] 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 Complaints I-IV: (EL11-66, EL13-33; EL14-86; EL16-64)**

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

- ***Base ROE Complaint I (EL11-66)***. In the first Base ROE Complaint proceeding, the FERC concluded that the TOs' ROE had become unjust and unreasonable,[32] 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*).[33] However, the FERC's orders were challenged, and in *Emera Maine,*[34] 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)[35] and third (EL14-86)[36] 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.[37] 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[38] also went to hearing before an Administrative Law Judge ("ALJ"), Judge Glazer, who issued his initial decision on March

[32] 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*")).

[33] *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*").

[34] *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).

[35] 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%.

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

[37] *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*").

[38] 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 ¶

27, 2017.[39] The *Base ROE IV Initial Decision* concluded that the currently-filed base ROE of 10.57%, which may reach a maximum ROE of 11.74% with incentive adders, was ***not*** unjust and unreasonable for the Complaint IV period, and hence was not unlawful under Section 206 of the FPA.[40] 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.[41] 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*[42] (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.[43]

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-

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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.

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

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

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

[42] *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*.

[43] *Id.* at P 19.

based total ROE at 13.08%.[44] The new ROE would be effective as of the date of *Opinion 531-A*, or October 16, 2014. Accordingly, the issue to be addressed in the Base ROE Complaint II proceeding is whether the ROE established on remand in the first complaint proceeding remained just and reasonable based on financial data for the six-month period September 2013 through February 2014 addressed by the evidence presented by the participants in the second proceeding. Similarly, briefing in the third and fourth complaints will have to address whether whatever ROE is in effect as a result of the immediately preceding complaint proceeding continues to be just and reasonable.

The FERC directed participants in the four proceedings to submit briefs regarding the proposed approaches to the FPA section 206 inquiry and how to apply them to the complaints (separate briefs for each proceeding). Additional financial data or evidence concerning economic conditions in any proceeding must relate to periods before the conclusion of the hearings in the relevant complaint proceeding. Following a FERC notice granting a request by the TOs and Customers[45] 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*[46] 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,[47] and CAPs[48] 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.

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[44] *Id.* at P 59.

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

[46] *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).

[47] 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.

[48] "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").

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

II. Rate, ICR, FCA, Cost Recovery Filings

- **PBOP Collections Report (CMP) (ER26-961)**

On March 4, 2026, the FERC accepted, effective March 9, 2026 as requested, Central Maine Power's ("CMP") report[49] identifying planned collection activity related to the under-recovery of ***$399,703*** in transmission-related post-retirement benefits other than pensions ("PBOP") under Appendix A to Attachment F to the ISO-NE OATT.[50] Unless the March 4 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Joan Bosma (jbosma@daypitney.com; 617-345-4651).

- **CIP-IROL Cost Recovery Filing: Essential Power Newington (ER26-918)**

On February 26, 2026, the FERC accepted, effective March 1, 2026 as requested, Essential Power Newington LLC's revised rate schedule to recover ***$642,105*** of eligible Interconnection Reliability Operating Limits ("IROL") critical infrastructure protection ("CIP") costs ("CIP-IROL Costs"), incurred between July 1, 2024 and September 30, 2025, under Schedule 17 of the ISO-NE OATT. Unless the February 26 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Transmission Rate Annual (2025-26) Update/Info Filing (NESCOE Formal Challenge) (ER20-2054)**

On February 9, 2026, NESCOE filed a formal challenge to CMP's rate schedules included in the PTO AC's 2025-26 Annual Update, filed on July 31, 2025, challenging CMP's recovery through its formula rates of incentive compensation based on financial performance targets that benefit only utility shareholders ("NESCOE Formal Challenge"). Following a CMP request, the granted CMP a 21-day extension of time, to ***March 23, 2026***, to answer the NESCOE Formal Challenge. Also since the last Report, motions to intervene were filed by EEI and American Electric Power Service Corporation ("AES").

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

As previously reported, on September 18, 2025, the FERC accepted in part and denied in part[51] the Maine Office of the Public Advocate's ("MOPA") formal challenge ("MOPA Formal Challenge")[52] to the TO's 2023-24 Annual Update.[53] Specifically, the FERC directed Eversource, National Grid, and MEPCO to respond to Maine

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

[50] *ISO New England Inc.*, Docket No. ER26-961-000 (Mar. 4, 2026) (unpublished letter order).

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

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

[53] 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.

OPA's Information Request Questions 1(b)(1) and 1(c)(2), and directed all of the Identified NETOs (Eversource; National Grid; MEPCO; Narragansett ; and VELCO/VTransco) to respond to Question 4,[54] on or before October 19, 2025. In addition, the FERC granted MOPA's request to permit it to supplement the MOPA Formal Challenge, as requested, with regard to the prudence of Identified NETOs' asset condition project costs reflected in the 2023 Annual Update, with such supplement to be filed on or before December 18, 2025. Of note, Commissioner Chang's concurrence emphasized stakeholders' fundamental right to transmission planning and investment information through existing formula rate protocols and encouraged transmission owners/planners to proactively share information on transmission projects and planning.

Of the 4 Identified TOs, only one (VELCO/VTransco on October 17, 2025) filed its response to Question 4 publicly. On December 17, 2025, MOPA supplemented its Formal Challenge, asserting that it has established serious doubt about the prudence of the NETOs planning practices governing asset management projects to trigger a formal prudence inquiry, and asking the FERC to establish evidentiary hearing and/or settlement judge procedures. On January 8, 2026, MOPA amended its December 17 supplement to incorporate additional information provided to it by VTransco subsequent to that supplement. Comments on the amendment were due on or before January 30, 2026.[55] Comments in support of MOPA's supplement were filed by Advanced Energy United, NH OCA and CT OCC. Comments opposing MOPA's supplement were filed by Eversource and National Grid. On February 9, Eversource answered MOPA's Jan 8 and Jan 29 amendments to its formal challenge supplement, asserting that the amendments underscore the impermissible vagueness of MOPA's supplement and stating support for the removal of MEPCO, RIE, and VTransco along with all New England Transmission owners from the challenge. On February 17, 2026, MOPA filed an answer to the January 30 pleadings filed by NEPCO and Eversource in response to MOPA's December 17 supplement, disputing their requests that the FERC summarily reject the supplement; and Eversource filed an answer to the comments filed by NH OCA, CT OCC, and Advanced Energy United, asserting that those comments include misstatements and unsupported new claims and reiterating that MOPA's supplement should be rejected. On March 4, 2026, National Grid filed a limited answer to respond to MOPA's February 17 answer, asserting that MOPA mischaracterized National Grid's asset condition process and has failed to present evidence sufficient to justify an evidentiary hearing, and requesting that the FERC dismiss the MOPA's formal Challenge and deny MOPA's request for a hearing. MOPA's Formal Challenge, as supplemented, is again pending before the FERC. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **ISO-NE Securities Authorization (Whiting Farms Facility) (ES26-30)**

On February 10, 2026, ISO-NE requested FERC authorization for the issuance of up to $60 million in senior obligations to permanently finance ISO-NE's Whiting Farms Road facility and related expenses for ISO-NE's existing Sullivan Road facility. ISO-NE said that the financing will be obtained either through a loan from the Massachusetts Development Authority funded by a tax-exempt bond, or, if such financing is unavailable, through a private placement transaction. ISO-NE requested that the FERC act on the application by ***March 31, 2026***. Comments on this filing were due on or before March 3, 2026; none were filed. National Grid intervened doc-lessly. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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

[55] Comments on the amendment were initially noticed for Jan. 20, 2026. "Identified TOs" (CL&P, NSATR, PSNH, and National Grid) requested a week's extension of time from that date to respond. The extension request was withdrawn after the FERC issued a subsequent errata notice setting the public comment date at Jan. 30, 2026.

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

- **Adjustments to the Calculation of Load Weights used in Zonal Prices (ER26-1298)**

On February 9, 2026, ISO-NE and NEPOOL jointly filed revisions to Tariff section III.2.7 to conform the Tariff to ISO-NE's existing implementation of the load-weight calculation used in Real-Time Zonal Prices. The filing adds Tariff language reflecting that the Real-Time load distribution used to calculate Zonal Prices is adjusted for generation modeled at load Nodes, while continuing to exclude any Asset Related Demand from the load weights. An April 10, 2026 effective date was requested. NEPOOL supported the Tariff revisions as part of the Participants Committee's February 5, 2026 Consent Agenda (Item #1). Comments on this filing were due on or before March 2, 2026; none were filed. National Grid intervened doc-lessly. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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

On October 15, 2025, Brookfield Renewable Trading and Marketing LP ("Brookfield") requested a limited waiver of the Tariff to allow it to refund to ISO-NE, with interest, improperly received CSO payments for its Lièvre Power portfolio. The payments were received for the months of October, November, and December 2024 and January 2025 (because Brookfield failed to shed a portion of its full-year CSO through the respective monthly reconfiguration auctions) and would be returned to Participants with Capacity Load Obligations during the corresponding months. While Brookfield would like to refund these payments ("BRTM Refund"), with interest, to ISO-NE, the Tariff does not have a provision that allows ISO-NE to accept the BRTM Refund or specifies how refunds should in turn be made. Brookfield asked the FERC for an order allowing ISO-NE to accept the BRTM Refund and directing ISO-NE to return the BRTM Refund to the Forward Capacity Market's ("FCM") Capacity Load Obligation for the months of October, November, and December 2024 and January 2025 ("FCM Refund"). Brookfield reported that ISO-NE authorized it to state that ISO-NE does not oppose the Waiver Request and can, if the Waiver Request is granted, implement the FCM Refund as described. Comments on this Waiver Request were due on or before November 5, 2025; none were filed. National Grid filed a doc-less intervention. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **CAR-PD (ER26-925)**

On December 30, 2025, ISO-NE and NEPOOL jointly filed Tariff revisions establish a prompt capacity market and revised deactivation framework ("CAR-PD").[56] CAR-PD, if accepted, will replace the FCM with annual capacity auctions held about one month before the Capacity Commitment Period, require resources to be commercial and demonstrate deliverability to participate, and use a sealed-bid auction rather than a descending clock, to reduce phantom entry and streamline auction administration. CAR-PD will also replace the de-list bid retirement construct with a deactivation notice one year in advance, eliminate annual reconfiguration auctions, and simplify qualification and offer administration, while largely retaining monthly settlement and PFP and maintaining existing market power mitigation with timing conforming changes. ISO-NE requested an effective date of, and an order on or before, ***March 31, 2026.***

Comments Supplementing/Supporting the CAR-PD Filing. Comments on the CAR-PD filing were due on or before January 20, 2026. ***NEPOOL*** filed supplemental comments providing for the record information regarding the stakeholder processes, modifications, and deliberations that led to NEPOOL's approval of CAR-PD. Comments supporting CAR-PD were filed by: ***the IMM*** (supporting the transition to a prompt capacity market, a sealed-bid auction format, and the revised deactivation framework, noting that it is more cost-effective and efficient than the existing forward construct); ***NESCOE*** (emphasizing the importance of transition measures to facilitate price discovery and mitigate potential near-term price volatility); ***NEPGA*** (supporting CAR-PD as a first step, while also highlighting issues to be addressed as the broader CAR initiative proceeds, including potential RMR risk

[56] This docket supersedes Docket No. ER26-912, opened on Dec. 30, 2025. All activity in the previous docket is included herein.

considerations associated with a shorter deactivation horizon); ***Public Systems***[57] (supporting CAR-PD, while urging that Phase Two reforms be completed and submitted promptly); and ***SEIA*** (supporting CAR-PD as a measured reform that better aligns capacity procurement with market conditions). No adverse comments were filed. Interventions only were filed by: Avangrid; Boston Energy and Trading and Marketing; Calpine; Constellation; CPV Towantic; Dominion; Eversource; FirstLight; HQUS; LS Power; National Grid; NH OCA; NRG; RI Energy; EPSA; MA DPU; MPUC; and RESA. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **Waiver Request: Tariff Section III.13.A.2(b) (Derby Fuel Cell) (ER26-884)**

On February 26, 2026, the FERC dismissed as unnecessary a request by Derby Fuel Cell, LLC ("Derby") for waiver of Tariff Section III.13.A.2(b) (Interim Reconfiguration Auction Qualification)[58] finding that, under the Tariff, resources like Derby that have achieved Forward Capacity Market ("FCM") Commercial Operation are not required to request critical path schedule monitoring to qualify for participation in the interim Reconfiguration Auctions ("ARAs") for the 2027-2028 Capacity Commitment Period.[59] In addition, the FERC found that Derby had not missed any applicable deadlines in the ARA qualification process and noted its expectation that ISO-NE will treat the Derby Project as a qualifying resource for the upcoming ARAs to the extent that Derby has satisfied all other applicable requirements.[60] Unless the *Derby ARA Qualification Order* is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

IV. OATT Amendments / TOAs / Coordination Agreements

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

On March 3, 2026, the FERC accepted the following two June 27, 2025 *Order 676-K*[61] compliance filings, which sought to incorporate, or receive a waiver of, the WEQ Version 004 Standards:

- ISO-NE, NEPOOL, CSC (ER25-2654). Revisions to Tariff Schedule 24 and Schedule 18 Attachment Z , including continued waiver of WEQ-001 and WEQ-008. The FERC accepted the tariff records implementing the WEQ Version 004 cybersecurity standards, effective February 27, 2026, and the tariff records implementing the remaining WEQ Version 004 revisions, effective August 27, 2026, subject to a further compliance filing (that replaces the placeholder for the *New England 676-K Order* with the actual citation) due on or before ***May 4, 2026***;[62] and
- ISO-NE, PTO AC, Schedule 20-A Service Providers (ER25-2657). Revisions to Schedules 20A-Common and 21-Common, effective *February 27, 2026* and *August 27, 2026*, as requested.[63]

[57] Public Systems are, collectively, the Massachusetts Municipal Wholesale Electric Co. ("MMWEC"), Conn. Municipal Electric Energy Coop. ("CMEEC"), New Hampshire Electric Coop., Inc. ("NHEC"), and Vermont Public Power Supply Authority ("VPPSA").

[58] Derby had sought the waiver on December 22, 2025 after ISO-NE disqualified Derby from the qualification process due to Derby not formally notifying ISO-NE by November 3, 2025 that it elected ISO-NE monitoring of its Critical Path Schedule. ISO-NE opposed the waiver request.

[59] *Derby Fuel Cell, LLC*, 194 FERC ¶ 61,147 (Feb. 26, 2026) ("*Derby ARA Qualification Order*").

[60] *Id.* at P 23.

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

[62] *ISO-NE, NEPOOL, and Cross-Sound Cable Co., LLC*, 194 FERC ¶ 61,168 (Mar. 3, 2026) ("*New England 676-K Order*").

[63] *PTO AC and ISO-NE*, Docket No. ER25-2657 (Mar. 3, 2026) (unpublished letter order) ("*PTO AC/ISO-NE 676-K Order*").

Unless the March 3 orders are challenged, ER25-2657 will be concluded and ER25-2654 will remain open subject to ISO-NE's 60-day compliance filing. If there are questions on either of these proceedings, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

- **FAP Obligation Roll-Off Timing Revisions (ER26-1091)**

On January 21, 2026, ISO-NE and NEPOOL jointly proposed Tariff revisions to the ISO-NE Financial Assurance Policy ("FAP") to align the timing of when a financial assurance obligation "rolls off" of a Market Participant's financial assurance requirements with the actual duration of the associated payment risk. The revisions address a gap under which certain obligations roll off when invoiced rather than when paid, including in the Monthly Capacity Charge component of the FCM Delivery Financial Assurance requirement and in the FTR Settlement Financial Assurance calculation. The Tariff Revisions were unanimously supported by the Participants Committee at its December 4, 2025 meeting (Agenda Item #9). ISO-NE requested an effective date of May 1, 2026. Comments on this filing were due on or before February 11, 2026; none were filed. National Grid submitted a doc-less intervention. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

VI. Schedule 20/21/22/23 Changes & Agreements[64]

- **Schedule 21-GMP: *Order 898* Revisions (ER26-1243)**

On February 2, 2026, Green Mountain Power Corporation ("GMP") filed proposed tariff revisions to Schedule 21-GMP to reflect minor modifications to the Attachment E-2 template used to calculate the annual revenue requirements for certain distribution facilities ("Annual Distribution and Meter Costs") used in connection with the provision of local transmission service to customers under Schedule 21-GMP ("*Order 898 Revisions*"). GMP explained that the *Order 898 Revisions* are necessary to "conform the FERC Accounts and FERC Form No. 1 references to the changes to the Uniform System of Accounts as a result of *Order 898*.[65] GMP requested an order approving the *Order 898 Revisions* by April 3, 2026 so that the revised template may be used for the Annual True-Up to 2025 actual costs. Comments on this filing were due on or before February 23, 2026; none were filed. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-ES: PSNH/ISO-NE/Berlin Station LSA (ER26-1072)**

On January 16, 2026, PSNH and ISO-NE filed a Local Service Agreement ("LSA") by and among PSNH, ISO-NE, and Berlin Station, LLC on behalf of its affiliate, Burgess BioPower, LLC ("Burgess") for Local Point-to-Point Service for Burgess's Large Generating Facility under Schedule 21-ES. A March 1, 2024 effective date was requested. The LSA reflects an agreed-upon discounted rate for Local Point-to-Point Service commencing the day Burgess rejected the then-existing power purchase agreement ("PPA") between PSNH and Burgess, pursuant to which Burgess sold all of the output of the Burgess Unit to PSNH, pursuant to its bankruptcy proceedings. Comments on this filing were due on or before February 6, 2026; none were filed. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

[64] 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). Reporting has also been suspended and will be continued if and when there is new activity to report on the notice of cancellation of the Green Mountain Power/Hardwick NITSA under Schedule 21-GMP (ER25-298).

[65] *Accounting and Reporting Treatment of Certain Renewable Energy Assets*, Order No. 898, 183 FERC ¶ 61,205 (June 29, 2023) ("*Order 898*").

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports[66]

- **Capital Projects Report – 2025 Q4 (ER26-1328)**

On February 6, 2026, ISO-NE filed its Capital Projects Report and Unamortized Cost Schedule covering the fourth quarter ("Q4") of calendar year 2025 (the "Report"). ISO-NE is required to file the Report under section 205 of the FPA pursuant to Section IV.B.6.2 of the Tariff. Report highlights include total 2025 capital expenditures of $37.9 million, which is $4.6 million less than the originally approved 2025 budget of $42.5 million, reflecting scope changes and budget reallocations. Report highlights also include the following new projects: (i) Unified Data Platform Cloud ($2,054,400); (ii) Storage as Transmission Only Asset ("SATOA") ($1,273,600); (iii) Upgrade Settlement Market System ("SMS") Application Technology Phase II ($839,200); (iv) 2026 Issue Resolution Project Phase I ($658,000); (v) Migration of Spring Boot BTM PV Microservices to AWS ECS ($553,000); and (vi) 2026 CAMSAMR Phase I ($355,200). Two projects were reported to have significant budget decreases: Energy Management System Communication Front End ("EMS CFE") Refresh (budget decrease of $187,900 for a total project cost of $566,400) and the Day-Ahead Market Simulator ("DAMKTSIM") project (budget decrease of $1,792,200). ISO-NE also reported a decrease in 2025 non-project capital spending (decrease of $199,800). Comments were due on or before February 27, 2026. NEPOOL filed comments on February 12, 2026 supporting the 2025 Q4 Report. National Grid submitted a doc-less intervention. 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).

- **Transmission Projects Annual Informational Filing (ER13-193)**

On January 28, 2026, ISO-NE submitted, as required under Section 4.1(j)(iii) of the OATT, its annual informational filing identifying transmission projects on the ISO Regional System Plan ("RSP") Project List that had a year of need three years or less from the completion of the applicable Needs Assessment. As required by the Tariff, the filing includes projects designated to Participating Transmission Owners following Solutions Studies, along with each project's need-by date and actual in-service date, and reflects designations made during the prior calendar year. The list of prior year designations is maintained on the ISO-NE website at: https://www.iso-ne.com/search?query=Prior%20Year%20List%20of%20Projects%20Designated%20to%20the%20PTOs. This filing was not noticed for public comment by the FERC.

- **IMM Quarterly Markets Reports (ZZ25-4)**

On February 5, 2026, the IMM filed with the FERC its Fall 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 III.A.17.2.2 of Appendix A to Market Rule 1. These filings are not noticed for public comment by the FERC. The Fall 2025 Report was discussed with the Markets Committee at its February 11, 2026 meeting.

IX. Membership Filings

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

[66] 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.

- **Mar 2026 Membership Filing (ER26-1558)**

On February 27, 2026, NEPOOL requested that the FERC accept the membership of Thunderhead Power LLC (Supplier Sector) in NEPOOL. Comments on this filing are due on or before ***March 20, 2026***.

- **Feb 2026 Membership Filing (ER26-1198)**

On January 30, 2026, NEPOOL requested that the FERC accept: (i) the following Applicants' membership in NEPOOL: Fiscal Alliance Foundation (Governance-Only End User); Green Oceans (Governance-Only End User); Invenergy Grid [Related Person to Invenergy Energy Management ("IEM") et al. (Supplier Sector)]; Marsh Hill Energy [Related Person to IEM et al. (Supplier Sector)]; and Twin Energy (AR Sector, RG Sub-Sector, Large RG Group Seat); (ii) the termination of the Participant status of Actual Energy; KCE CT 2, 9 and 11; Oxford Energy Center; Vineyard Offshore; and West Medway II; and (iii) the name change of American PowerNet Management, LLC (f/k/a American PowerNet Management, LP). Comments on this filing were due on or before February 20, 2026; none were filed. This matter is pending before the FERC.

- **Jan 2026 Membership Filing (ER26-933)**

On February 27, 2026, the FERC accepted: (i) the following Applicants' membership in NEPOOL: Balyasny Asset Management (Data-Only Participant); and Geodesic 7 LLC (Supplier Sector); and (ii) the termination of the Participant status of Anbaric Development Partners; EMI; Eoch Energy; Excelerate Energy; and Vineyard Reliability; and (iii) the name change of Six One Energy Corporation (f/k/a Tomorrow Energy Corp).[67] Unless the *January 2026 Membership Order* is challenged, this proceeding will be concluded.

- **Suspension Notice (not docketed)**

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

Date of Suspension	***Participant Name***	***Default Type***
February 23, 2026	Clearlight Energy Services LLC	Financial Assurance

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

X. Misc. - ERO Rules, Filings; Reliability Standards[68]

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).

- **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

[67] *New England Power Pool Participants Comm.*, Docket No. ER26-933 (Feb. 27, 2026) ("*January 2026 Membership Order*").

[68] 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.*).

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.

On February 25, 2026, FERC Staff submitted a report to Congress on NERC's ITCS, describing the ITCS as a reliability-focused, national assessment that uses a single transmission model and consistent assumptions across 30 defined regions. The Staff Report emphasizes that the ITCS is not a transmission planning study and it does not recommend specific projects. The Report states that the study identified 35,000 MW of technically prudent additions of interregional transfer capability under modeled year 2033 conditions. The Staff Report concludes that the ITCS does not identify or recommend any statutory changes.

- **NERC Errata to Reliability Standard BAL-007-1 (RD26-4)**

On February 23, 2026, the North American Electric Reliability Corporation ("NERC") submitted for FERC approval an errata to Reliability Standard BAL-007-1 (Near-Term Energy Reliability Assessments).[69] The proposed errata correct minor capitalization errors in the defined term "Near-Term Energy Reliability Assessment" to align with the NERC Glossary. The errata does not change the scope or intent of the Standard and does not have a material impact on the Reliability Standard's end users. Comments on the petition are due on or before ***March 25, 2026***.

- **Revised Reliability Standard: MOD-026-2 (RD26-3)**

On February 19, 2026, the FERC approved Reliability Standard MOD-026-2 (Verification and Validation of Dynamic Models and Data, and the proposed definitions of Model Validation and Model Verification).[70] As previously reported, MOD-026-2 was developed in response to *Order 901*'s Milestone 3 directives on Inverter-Based Resources ("IBRs") and will replace and combine the currently effective standards MOD-026-1 and MOD-027-1 and include new requirements addressing validation of models across modeling domains including electromagnetic transient ("EMT") models of Inverter-Based Resources ("IBR"), high-voltage direct current ("HVDC") systems, flexible alternating current transmission system ("FACTS") devices, and dynamic reactive resources. MOD-026-2 is intended to advance the reliability of the Bulk-Power System by ("BPS") improving the accuracy and dependability of models used in planning and interconnection analyses through requiring Generator Owners and Transmission Owners, particularly of IBRs, to perform Model Validation and Model Verification of positive sequence dynamic and EMT models that are provided to their Transmission Planner. Under the Implementation Plan, MOD-026-2 will become effective on *April 1, 2026* and MOD-026-1 and MOD-027-1 retired immediately prior to the effectiveness of MOD-026-2. Unless the *IBR and Generators Modeling Rel. Standards Order* is challenged, this proceeding will be concluded.

- **Revised Reliability Standard: MOD-033-3 (RD26-2)**

The *IBR and Generators Modeling Rel. Standards Order* also approved Reliability Standard MOD-033-3 (Steady-State and Dynamic System Model Validation).[71] As previously reported, MOD-033-3 was developed in

[69] BAL-007-1 was approved by the FERC and is scheduled to become eff. *Apr. 1, 2027. N. Am. Elec. Rel. Corp.*, Docket No. ER25-5-000 (Feb. 26, 2025) (unpublished letter order).

[70] *N. Am. Elec. Rel. Corp.*, 194 FERC ¶ 61,125 (Feb. 19, 2026) ("*IBR and Generators Modeling Rel. Standards Order*").

[71] *N. Am. Elec. Rel. Corp.*, 194 FERC ¶ 61,125 (Feb. 19, 2026) ("*MOD-033-3 Order*").

response to *Order 901*'s Milestone 3 directives on IBRs and will replace MOD-033-2. MOD-033-3 is intended to establish a comprehensive process for system model validation and to advance BPS reliability by enhancing existing system-level model validation requirements so that planning System models must include BPS-connected IBRs and aggregated Distributed Energy Resources ("DERs") present on the System and be validated against actual system behavior. The Reliability Standard applies to Planning Coordinators, Reliability Coordinators, and Transmission Operators. Under the Implementation Plan, MOD-033-3 will become effective on *July 1, 2026*. MOD-033-2 will be retired immediately prior to the effectiveness of MOD-033-3. Unless the *IBR and Generators Modeling Rel. Standards Order* is challenged, this proceeding will also be concluded.

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

On September 10, 2025, the FERC directed NERC to submit in an informational filing a report on best practices to reduce the risk of wildfire ignition from the BPS on or before ***May 1, 2026***.[72] The report must assess methods such as "vegetation management, the removal of forest-hazardous fuels along transmission lines, improved engineering approaches, and safer operational practices.[73] The report must also include an assessment of known and emerging technologies that can be deployed to detect and mitigate wildfire in the context of protecting the BPS and its use to provide reliable service to customers. The FERC noted its concurrently issued notice of technical conference on wildfire mitigation (*see* AD25-16 in Section XII below) and said NERC should consider the testimony from that conference as an input for its informational filing, including in its consideration of the need for new or revised Reliability Standards or alternative further action.

- **NOPR: Revised Reliability Standards: CIP-002-7 through CIP-013-3 (Virtualization[74]) (RM24-8)**

On September 18, 2025, the FERC issued a notice of proposed rulemaking ("NOPR")[75] proposing to approve 11 modified CIP Reliability Standards,[76] and 4 new and 18 modified definitions in the NERC Glossary of Terms,[77] to facilitate the full implementation of virtualization and to address the risks associated with virtualized environments.[78] As previously reported, the proposed CIP Reliability Standards would permit Responsible Entities with more "traditional" architecture to continue with their current configurations. In the NOPR, the FERC seek comments specifically on the proposed replacement of the phrase "where technically feasible" with the phrase "per system capability", including alternative approaches, which the FERC said would assist it in formulating a possible directive in a final rule.[79] Comments on the *Visualization NOPR* were due on or before November 24,

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

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

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

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

[76] 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).

[77] 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").

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

[79] *Virtualization NOPR* at P 3.

2025[80] and were filed by BPA, EEI, GE Vernova, MISO, NERC, and Portland General Electric. This matter is pending before the FERC.

XI. Misc. - of Regional Interest

- **203 Application: Vistra/Cogentrix (Nautilus Power et al.) (EC26-63)**

On February 6, 2026, Cogentrix Public Utilities (including Nautilus Power, LLC and Related Persons)[81] and Vistra requested the FERC authorize a transaction, by no later than ***June 8, 2026***, pursuant to which Vistra Operations Company LLC, an indirect wholly-owned subsidiary of Vistra, will acquire 100% of the voting equity interests in the Cogentrix Public Utilities (collectively, the "Applicants").[82] Upon consummation, Vistra Operations Company LLC will indirectly own and control the Cogentrix Public Utilities, making Nautilus Power and Dynegy Marketing and Trade Related Persons. Comments on this application are due on or before ***April 7, 2026*** (this date was extended following requests for extension of time to comment by PJM's IMM and Public Citizen. Thus far, ISO-NE's IMM and Talen Energy Corp. have intervened. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Gate City Power/Waterside Power (EC26-38)**

On February 11, 2026, the FERC authorized the disposition of jurisdictional facilities in connection with a transaction pursuant to which Gate City Power Holdings LLC will acquire all of the membership interests in Waterside Holdco, LLC and thereby indirectly acquire all of the membership interests in Waterside Power, LLC, which owns the 69.6 MW Waterside Facility in Connecticut.[83] Pursuant to the *Gate City/Waterside Power Order*, Waterside Power filed a notice on February 20, 2026 that the transaction was consummated on February 12 (making Waterside Power a Related Person to Generation Group Seat members Millennium and Berkshire Power Company). Reporting on this matter is now concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On August 13, 2025, the FERC authorized a transaction by which White Mountain Power (an affiliate of, among others, Bridgewater Power and David Energy Supply) will acquire from Burgess BioPower all of the indirect ownership interests of Berlin Station in connection with a plan of reorganization under Chapter 11 of the US Bankruptcy Code.[84] Pursuant to the August 13 order, White Mountain Power must file a notice within 10 days of consummation of the transaction, which as of the date of this Report has not yet occurred. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On July 23, 2025, the FERC conditionally authorized[85] Constellation's acquisition of Calpine, subject to Applicants' commitments to divest certain generation facilities ("Mitigation Plan"), to extend certain pre-existing commitments that apply to the Constellation Applicants and their public utility subsidiaries in PJM market to all Applicants in the PJM market, to abide by the terms of an agreement reached between Constellation and the PJM IMM, and to implement interim mitigation ("Interim Behavioral Mitigation") until the Mitigation Plan is

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

[81] Nautilus Power's Related Persons include: Acadia Renewable Energy (which is not part of the 203 application), Essential Power Massachusetts, Essential Power Newington, and Revere Power.

[82] Applicants include: Bridgeport Energy LLC, Essential Power Massachusetts, LLC, Essential Power Newington, LLC, Essential Power OPP, LLC, Essential Power Rock Springs, LLC, Hamilton Liberty LLC, Hamilton Patriot LLC, Hamilton Projects Acquiror, LLC, Lakewood Cogeneration, L.P., Nautilus Power, LLC , Revere Power, LLC, Rumford Power LLC, Tiverton Power LLC, and Vistra Corp.

[83] *Waterside Power, LLC*, 194 FERC ¶ 62,072 (Feb. 11, 2026) ("Gate City/*Waterside Power Order*").

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

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

completed. Pursuant to the July 23 order, Applicants must file a notice within 10 days of consummation of the transaction. The transaction was consummated on January 6, 2026,[86] making Constellation and Calpine Related Persons.

On August 22, 2025, two requests for rehearing of the *Merger Order* were filed, one by the Pennsylvania Office of Consumer Advocate ("PA OCA"); the other by the Public Citizen Petitioners.[87] The Constellation Applicants filed an answer on September 8, 2025, requesting the FERC deny the requests for rehearing. On September 22, 2025, the FERC issued an *Allegheny* Notice,[88] noting that the requests for rehearing may be deemed denied by operation of law, but noting that the requests will be addressed in a future order.[89] On February 19, 2026, the FERC issued that *Allegheny* Order, addressing the arguments raised on rehearing and setting aside, in part, the *Merger Order* by eliminating the one-year notification requirement related to legacy Constellation generators.[90]

As noted previously, the PA OCA petitioned the DC Circuit Court for review of the *Merger Order* and the *Constellation Merger Allegheny Notice*. Further developments will be reported, if and as appropriate, in Section XIV below. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **VSA – CL&P / MDC Milford Associates (ER26-1597)**

On March 4, 2026, CL&P filed a Viability Assessment Study Agreement ("VSA") between itself and MDC Milford Associates, LLC ("MDC Milford"), designated as Service Agreement No. VSA-CLP-002. The VSA proposes the terms and conditions under which CL&P will perform, at MDC Milford's sole expense, an interconnection viability study to assess possible adverse impacts to CL&P's transmission system and the supporting infrastructure needed to mitigate such impacts, and to establish a reasonable estimate of MDC's share, if any, of the costs for such supporting infrastructure. An effective date of March 5, 2026 was requested. Comments on this filing are due on or before ***March 25, 2026***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **VSA – CL&P / INDUS Realty (ER26-1158)**

On January 29, 2026, CL&P filed a VSA between itself and INDUS Realty, LLC ("INDUS Realty"), designated as Service Agreement No. VSA-CLP-001. The VSA proposes the terms and conditions under which CL&P will perform, at INDUS Realty's sole cost and expense, an interconnection viability study to study possible adverse impacts to CL&P's system and the supporting infrastructure needed to mitigate such possible impacts for INDUS Realty's potential interconnection to CL&P's transmission system. Comments on this filing were due on or before February 19, 2026; none were filed. This matter is pending before FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

[86] The Notice of Consummation was submitted Jan. 12, 2026 n Docket NO. EC25-43.

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

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

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

[90] *Constellation Energy Corp. et al.,* 194 FERC ¶ 61,122 (Feb. 19, 2026) *("Constellation Merger Allegheny Order"*).

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

On March 3, 2026, the FERC conditionally accepted Versant's revisions incorporating by reference certain revisions required by *Order No. 676-K* into Section 4 of the Versant Power Open Access Transmission Tariff for Maine Public District (the "MPD OATT") (the "*Order 676-K* Compliance Changes").[91] The FERC also granted, as requested, waiver of certain of the standards that Maine Public District ("MPD") is unable to meet. The *Order 676-K* Compliance Changes Versant were accepted effective as of February 27, 2026 and August 27, 2026. In accepting the changes, the FERC, noting that the MPD OATT revisions included a placeholder for the citation of the *Versant MPD OATT Order 676-K Compliance Order*, directed Versant to submit a compliance filing on or before ***May 4, 2026*** to include that citation. Subject to acceptance of that compliance filing, 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)**

On August 4, 2025, the FERC approved the settlement agreement that resolves all issues set for settlement in this proceeding,[92] effective August 4, 2025.[93] CMP was directed to make a compliance filing with revised tariff records in eTariff format on or before September 3, 2025, reflecting that effective date and the FERC's action in the Settlement Order. CMP submitted that compliance filing on September 3, 2025, with any comments due on or before September 24, 2025; none were filed. On September 15, 2025, CMP submitted a refund report confirming the $365,000 was refunded to Rumford ESS, LLC. Comments on the refund report were due on or before October 6; none were filed. The refund report remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

XII. Misc. - Administrative & Rulemaking Proceedings[94]

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

On October 21, 2025, the FERC convened a Staff-led technical conference to discuss cost-effective best practices to reduce the risk of wildfire ignition from the Bulk Power System ("BPS") in response to Executive Order 14308. There were two panel discussions – (i) interagency coordination challenges and grid-focused best practices for wildfires (Panel 1); and (ii) leveraging technology to monitor, evaluate, and mitigate wildfire risks (Panel 2). Panelists pre-filed statements are posted in the FERC's eLibrary. On October 23, 2025, the FERC invited post-technical conference comments to address issues raised during the technical conference or identified in the October 15, 2025 Second Supplemental Notice. Those comments were due on or before November 24, 2025; National Rural Electric Cooperative Association ("NRECA"), Working for Advanced Transmission Technologies Coalition ("WATT Coalition"), and several others provided comments to inform the FERC's wildfire risk mitigation efforts. On December 1, 2025, the technical conference's transcript was posted in the FERC's eLibrary.

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[91] *Versant Power*, 194 FERC ¶ 61,169 (Mar. 3, 2026) ("*Versant MPD OATT Order 676-K Compliance Order*").

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

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

[94] Reporting on the following administrative and rulemaking proceedings has been suspended and will be continued if and when there is new activity to report: Annual Reliability Technical Conference (AD25-8); Tech Conf: Meeting the Challenge of Resource Adequacy in ISO/RTOs (AD25-7); Large Loads Co-Located at Generating Facilities (AD24-11); Annual Reliability Tech. Conf. (AD24-10); Innovations and Efficiencies in Generator Interconnection (AD24-9); and the EQR Filing Process and Data Collection NOPR (RM23-9).

- **Joint Federal-State Current Issues Collaborative[95] (AD24-7)**

The most recent meeting of the Collaborative was held ***February 11, 2026,*** during NARUC's Winter Policy Summit, in Washington, DC. The Collaborative discussed the "Impact of Growth on Affordability."

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

On October 27, 2025, the FERC issued a Notice inviting comments on a Department of Energy ("DOE") proposed Advance Notice of Proposed Rulemaking ("ANOPR")[96] concerning standardized procedures for the timely and orderly interconnection of large loads to the interstate transmission system.[97] The ANOPR requests FERC take expeditious action and propose a framework under which "large loads" (defined as >20 MW) interconnecting directly to transmission (including AI data centers) would be studied and processed using LGIP/LGIA-style deposits, readiness requirements, and withdrawal penalties. Comments were due on or before November 14, 2025 and reply comments were due on or before November 28, 2025. U.S. Senator Edward J. Markey together with several other senators filed comments requesting FERC proactively investigate RTOs' treatment of AI data centers and prioritize protection of residential ratepayers. The MA AG, MOPA, NH OCA, Brookfield, LS Power Development, Enel North America, Enerwise Global, Vitol, and Voltus, among others intervened doc-lessly. The FERC granted, the November 4 request for a 2-week extension of time, to November 28, 2025, to file initial comments filed by Organization of MISO States ("OMS") and supported by the Organization of PJM States ("OPSI") on November 5, 2025. On November 21, comments were filed by over 100 parties including by ISO-NE, New England Public Systems,[98] the New England Consumer-Owned Systems ("NECOS")[99] jointly with Energy New England, LLC ("ENE"), Advanced Energy United ("AEU"), Maine Office of the Public Advocate ("MOPA"), MA AG with RI DPUC and CT DEEP, NESCOE, NEPGA, American Public Power Association ("APPA"), American Clean Power Association ("ACPA"), Union of Concerned Scientists, Eversource, Constellation, National Grid, Vistra, Energy New England, ENGIE, Shell, NRG, LS Power Development, Invenergy, Voltus, Google, Microsoft, Meta Platforms, Amazon Energy, PSEG Companies,[100] and the PPL Companies.[101] Reply comments were filed by PJM, Vistra, and ENGIE among many others. On February 4, 2026, Chairman Laura V. Swett

[95] *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.

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

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

[98] New England Public Systems consists of: Connecticut Municipal Electric Energy Cooperative ("CMEEC"), the Massachusetts Municipal Wholesale Electric Company ("MMWEC"), and the Vermont Public Power Supply Authority ("VPPSA").

[99] NECOS are: Belmont Mun. Light Dept, Block Island Utility District, Braintree Elec. Light Dept, Concord Mun. Light Plant, Danvers Elec. Division, Georgetown Mun. Light Dept, Groveland Elec. Light Dept, Hingham Mun. Lighting Plant, Hudson Light & Power Dept, Littleton Elec. Light & Water Dept, Merrimac Mun. Light Dept, Middleborough Gas & Elec. Dept, Middleton Elec. Light Dept, North Attleborough Elec. Dept, Norwood Mun. Light Dept, Clear River Elec. & Water District, Rowley Mun. Lighting Plant, Stowe Elec. Dept, Taunton Mun. Lighting Plant, Town of Wallingford, CT Dept of Public Utilities Elec. Division, Westfield Gas and Elec. Light Dept, and Mid-Coast Regional Redevelopment Authority.

[100] PSEG Companies are: Public Service and Gas Company ("PSE&G"), PSEG Power LLC, and PSEG Energy Resources & Trade LLC.

[101] PPL Companies are: PPL Electric Utilities Corp. ("PPL Electric"), Louisville Gas & Electric Co. ("LG&E") and Kentucky Utilities ("KU") (collectively, "LG&E/KU"), and The Narragansett Electric Company d/b/a Rhode Island Energy ("RIE").

responded to Senators' concerns regarding the impact of data center development on residential electric bills with a letter noting their concerns will aid the FERC's consideration of this matter. NEPOOL Counsel's memo to the Transmission Committee summarizing comments filed in this proceeding is available here.

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

On June 27, 2024, the FERC issued an advanced notice of proposed rulemaking ("ANOPR")[102] seeking comments on both the need for a dynamic line ratings ("DLRs")[103] 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[104] 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,[105] TAPS, and R Street Institute. Nine sets of reply comments were filed, including from: ISO-NE, DC Energy, and the US DOE.

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

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

As previously reported, the FERC issued on December 16, 2024 a show cause order[106] in which it directed American Efficient, LLC, its various subsidiary companies,[107] and its corporate parents[108] (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;[109] 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").[110] American Efficient was also directed to

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102 *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.

103 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.

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

105 "Public Power" for purposes of this proceeding is: The National Rural Elec. Coop. Assoc. ("NRECA"), the American Public Power Assoc. ("APPA"), and the Large Public Power Council ("LPPC").

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

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

108 Modern Energy Group LLC and MIH LLC.

109 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."

110 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

show cause why they should not (i) ***disgorge $2,116,057 and $250,937,821***, back to MISO and PJM, respectively (in each case plus interest); (ii) ***disgorge additional unjust profits*** received between April 2024 and the date of any future FERC order directing disgorgement back to PJM; and (iii) pay a ***$722 million*** civil penalty. American Efficient may seek a modification of these amounts consistent with FPA § 31(d)(4).[111]

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

On November 3, 2025, American Efficient requested that the FERC conclude its Order to Show Cause proceeding by declining the Office of Enforcement and Regulatory Accounting's ("OERA") request for an Order Assessing Penalties and closing out this investigation. FERC's OERA Litigation Staff replied to the November 3 motion on November 24, 2025. On December 12, 2025, American Efficient requested that the FERC terminate this proceeding. Since the last Report, American Efficient requested that the FERC not issue an Order assessing a penalty before the Supreme Court has rendered a decision in *AT&T, Inc v. FCC (asserting that a decision from the Supreme Court will implicate the constitutionality of FERC's civil penalty authority)*. This matter remains pending before the Commission. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

Natural Gas-Related Enforcement Actions

- **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

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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.

[111] 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."

[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*").

remains suspended until the Northern District's stay is lifted or dissolved such that hearing procedures may resume.

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

On December 16, 2021, the FERC issued a show cause order[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).

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

On October 7, 2025, the FERC issued its final rule removing from its regulations a rule that precludes the issuance of authorizations to proceed with construction activities with respect to natural gas facilities approved pursuant to section 3 or section 7 of the NGA for a limited time while certain requests for rehearing are pending before the FERC.[118] On November 6, 2025, NRDC requested rehearing of *Order 915*. On December 8, 2025, the FERC issued an *Allegheny* Notice, noting that the request for rehearing may be deemed denied by operation of law, but noting that the request will be addressed in a future order.[119] On February 19, 2026, the FERC issued an

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

[119] *Removal of Regulations Limiting Authorizations to Proceed with Construction Activities Pending Rehearing*, 193 FERC ¶ 62,148 (Dec. 8, 2025) ("*Order 915 Allegheny Notice*").

order addressing the arguments raised on rehearing.[120] The *Order 915 Allegheny Order* modified the discussion in *Order 915* but maintained the removal of 18 C.F.R. 157.23, and it confirmed *Order 915*'s February 10, 2025 effective date.

New England Pipeline Proceedings

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

- **Algonquin Cape Cod Canal Pipeline Relocation Project (CP25-552; PF25-4)**
  - Project to relocate and rebuild the Sagamore and Bourne meter and regulation ("M&R") stations to continue providing uninterrupted natural gas transportation service to National Grid to supply end users on both sides of the Cape Cod Canal. The proposed Project will not result in new or incremental capacity and is therefore not an expansion of the Algonquin system.
  - Abbreviated Application for a Certificate of Public Convenience and Necessity ("CPCN") and for Related Authorizations and Order Approving Abandonment ("Application") filed September 29, 2025. Application includes authorizations to (i) construct, install, own, operate, and maintain approximately 5.24 miles of pipeline; (ii) abandon by removal approximately 0.75 miles of existing pipeline; (iii) abandon by removal 2 existing M&R stations; and (iv) construct, install, own, operate, and maintain 4 new M&R stations.
  - Algonquin submits supplemental information to its Application on October 30, 2025.
  - Interventions filed by NSTAR Electric, NSTAR Gas, National Grid Gas Delivery Companies, and New York State Gas & Electric and Maine Natural Gas Co. Comments filed by a number of Chambers of Commerce on the Cape.
  - FERC issues November 13 data request; Algonquin submits response on November 20, 2025.
  - FERC issues December 11, 2025 data request; Algonquin submits response on January 6, 2026 and on February 3 and February 5, 2026.
  - FERC issues January 16, 2026 data request; Algonquin submits response on January 26, 2026 and on February 3, 2026.
  - FERC issues February 9, 2026 data request; Algonquin submits response on February 17 and February 20, 2026.
- **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.[121] The certificate was conditioned on: (i) Iroquois' completion of construction of the proposed facilities and making them available for service within ***three years*** of the date of the; (ii) Iroquois' compliance with all applicable FERC regulations under the NGA; (iii) Iroquois' compliance with the environmental conditions listed in the appendix to the order; and (iv) Iroquois' filing written statements affirming that it has executed firm service agreements for volumes and service terms equivalent to those in its precedent agreements, prior to commencing construction. The March 25, 2022 order also approved, as modified, Iroquois' proposed incremental recourse rate and incremental fuel retention percentages as the initial rates for transportation on the Enhancement by Compression Project.

[120] *Removal of Regulations Limiting Authorizations to Proceed with Construction Activities Pending Rehearing*, 194 FERC ¶ 61,132 (Feb. 19, 2026) ("*Order 915 Allegheny Order*").

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

- 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.[122]
- 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.[123] 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.[124]

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).

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

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

[124] *Id*. at P 15.

- ***Order 904*: Compensation for Reactive Power Within the Standard Power Factor Range (5th Circuit – 25-60055 et al.) (consolidated)**
  Case Title: Leeward *v. FERC*
  Underlying FERC Proceeding: RM22-22[125]
  Status: Briefing underway

Appeals of *Order 904* have been transferred to and consolidated in the 5th Circuit Court of Appeals, with 25-60055 as the lead docket. A briefing schedule was established on November 18, 2025 following the filing of a certified list in lieu of the administrative record, triggering the following specific dates for the approved briefing schedule: (Procedural Motions (December 2, 2025); Petitioners' Briefs (February 19, 2026); FERC's Brief (***April 17, 2026***); Response Brief Intervenors in Support of FERC (***May 1, 2026***); Petitioners' Reply Briefs (***June 1, 2026***); Deferred Joint Appendix (***June 8, 2026***); and Final Briefs (***June 15, 2026***)). Since the last Report, Petitioners' filed, and the Court granted, a motion for clarification of the Court's August 28, 2025 order granting Intervenors' motion establishing briefing notice; and Petitioners' brief was filed.

- ***Order 1920*: Transmission Planning Reforms (4th Circuit – 24-1650)**
  Case Title: *Appalachian Voices v. FERC*
  Underlying FERC Proceeding: RM21-17[126]
  Status: Briefing Underway

As previously reported, on July 18, 2024, AEU/ACPA/SEIA and Invenergy petitioned the DC Circuit Court of Appeals for review of the FERC's *Order 1920*.[127] 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. On September 10, 2025, Appalachian Voice et al submitted their opening brief. FERC's opening brief was filed on January 5, 2026. Intervenor briefs and amicus curiae briefs were filed on February 6, 2026, and a motion to reconsider the order granting filing of amicus curiae briefs was filed February 9, 2026. Petitioners' and Intervenors' reply briefs were filed February 25, 2026. The Joint Appendix is due by ***March 4, 2026***, and final briefs, by ***March 11, 2026***.

- ***Orders 2023 and 2023-A* (23-1282 et al.) (consolidated)**
  Case Title: *Advanced Energy United, et al. v. FERC*
  Underlying FERC Proceeding: RM22-14[128]
  Status: Oral Argument Held September 26, 2025; Decision Pending

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

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

[126] *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*").

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

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

- ***CASPR* (20-1333, 21-1031) (consolidated)****
  Case Title: *Sierra Club, et al. v. FERC*
  Underlying FERC Proceeding: ER18-619[129]
  Petitioners: Sierra Club, NRDC, RENEW Northeast, and CLF
  Status: Being Held in Abeyance; Fifth Abeyance Request Filed Mar 2, 2026

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

Petitioners have moved to hold this matter in abeyance now five times, with the most recent request filed March 2, 2026) (fifth abeyance request). The unopposed fifth abeyance request is pending before the Court.

- ***Opinion 531-A* Compliance Filing Undo (20-1329)**
  Case Title: *Central Maine Power Company, et al. v. FERC*
  Underlying FERC Proceeding: ER15-414[130]
  Petitioners: TOs (CMP et al.)
  Status: Being Held in Abeyance

On August 28, 2020, the TOs[131] 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*[132] decision. On September 22, 2020, the FERC submitted an unopposed motion to hold this proceeding in abeyance for four months to allow for the Commission to "a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the Commission." On October 2, 2020, the Court granted the FERC's motion, and directed the parties to file motions to govern future proceedings in this case by February 2, 2021. On January 25, 2021, the FERC requested that the Court continue to hold this petition for review in abeyance for an additional three months, with parties to file motions to govern future proceedings at the end of that period. The FERC requested continued abeyance because of its intention to issue a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the FERC. Petitioners consented to the requested abeyance. On February 11, 2021, the Court issued an order that that this case remain in abeyance pending further order of the court. On April 21, 2021, the FERC filed an unopposed motion for continued abeyance of this case *because* the Commission intends to issue a future order on Petitioners' request for rehearing of the challenged *Order Rejecting Compliance Filing*, and because the remand proceeding in which the challenged order was issued remains ongoing.

On May 4, 2021, the Court ordered that this case remain in abeyance pending further order of the Court, directing the FERC to file a status reports at 120-day intervals. The parties were directed to file motions to govern future proceedings in this case within 30 days of the completion of agency proceedings. The FERC's last status report, indicating that the proceedings before the FERC remain ongoing and that this appeal should continue to remain in abeyance, was filed on November 13, 2025.

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

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

[131] 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.

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

- ***Avangrid/NextEra NECEC Civil Suit*** **(D.MA) (Case No. 3:24CV30141)**
Case Title: ***Avangrid, Inc. et al. v. NextEra Energy, Inc. et al.***
Status: Federal Anti-Trust Claims Dismissed; State Law Claims Remain Pending

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

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

- **Allco PURPA Enforcement Petition (D.CT) (Case No. 3:25CV01321)**
Case Title: ***Allco Finance Limited Inc. v. Dykes et al.***
Status: Motions to Dismiss Pending

Following a FERC notice[133] that it had decided not to act on Allco's PURPA Complaint related to Connecticut's[134] implementation under section 210 of PURPA of its Shared Clean Energy Facility ("SCEF") Program,[135] Allco brought an enforcement action against Connecticut in federal district court in Connecticut.[136] *Allco Finance Limited Inc. v. Dykes et al.* (case no. 3:25CV01321). On November 24, 2025, Defendants[137] filed a motion to dismiss the Complaint and stay discovery. DEEP Commissioner, Katie S. Dykes, PURA Commissioners, David Arconti, Michael Caron, and Marissa Gillett,[138] and DOAG Commissioner, Bryan P. Hurlburt, (the "State Agency Defendants") also filed a joint motion to dismiss the Complaint; and on December 9, 2025, Allco filed a memo in opposition to the motion to dismiss filed by the Defendants and the State Agency Defendants. On December 23, 2025, a motion to dismiss the complaint was filed by the Defendants and a joint motion to dismiss

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

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

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

[136] 16 U.S.C. § 824a-3(h)(2)(B).

[137] Defendants are UI, Avangrid Networks, Inc., Avangrid, Iberdrola, S.A., Charlotte Ancel, and Pedro Azagra Blázquez.

[138] Marissa Gillett resigned her position as chair of PURA, effective Oct. 10, 2025.

was filed by the State Agency Defendants. On January 7, 2026, the Court granted the unopposed Motions to Stay Discovery by the State Agency Defendants and Defendants, respectively, pending the resolution of the Defendants Motions to Dismiss.

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